PUBLIC INTEREST ADVOCACY CENTRE
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Michael Janigan
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613-562-4002

September 14, 2012

VIA MAIL and E-MAIL

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

Dear Ms. Walli:

Re: EB-2012-0121Erie Thames Powerlines Corporation

Please find enclosed the interrogatories of VECC in the above-noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

Encl.
cc. Erie Thames Powerlines Corporation
Attn: Mr. Graig Petit oeb@eriethamespwerlines.com

REQUESTOR NAME	**VECC**
INFORMATION REQUEST ROUND NO:	**# 1**
TO:	**Erie Thames Powerlines**
DATE:	**August 17, 2012**
CASE NO:	**EB-2012-0121**
APPLICATION NAME	**2013Cost of Service Electricity Distribution Rate Application**

NB: In these interrogatories the following acronyms have been used:

Service Territory of former Clinton Power Corporation: CPC

Service Territory of former West Perth Power Inc. : WPPI

Current amalgamated service territories: Erie Thames or ETPC

No issues list has been issued by the OEB. VECC has generally applied the issues list proposed by the applicant at Exhibit 1, Tab 1, Schedule 7. The issues list has been slightly modified to make it more closely conform to issues lists used in past Board proceedings.

General

1.1 Has the Utility responded appropriately to all relevant Board directions from previous proceedings?

1. Reference: Exhibit 1, Tab 1, Schedule 17

a) Have the Conditions of Service been updated to be compliant with the new customer service rules for low-income electricity consumers which came into effect October 1, 2011?

- ***The Conditions of Service have been updated to be compliant with the new customer service rules for Low Income electricity consumers.***

b) If yes, please explain what changes were made to Utility practice and the conditions of service. If not, please explain when these conditions of service will be changed to be compliant with the new Board rules.

- ***Open & Closing of Accounts – includes third party acceptance***
- ***Security Deposit – request and refund criteria includes eligible low income customers as per the rules described in the DSC***

- ***Customer Collection - include Arrears Management Arrangements for residential customers. Accept third party involvement***
- ***Disconnection/Reconnection – updated to include Eligible Low-Income and Emergency Financial Assistance programs***
- ***Disconnection notification, timelines and action comply with the rules in the Distribution System Code S4.2***
- ***Use of Load Control Devices – refrain from use if notified that a Social Service Agency or Government Agency is assessing customer***

1.2 Is the proposal to have retroactive rates appropriate?

2. Reference: Exhibit 2, Tab 1, Schedule 1 pages 9-11

   a) Is ErieThames seeking to have rates set retroactive to May1, 2012? If not what date is EPTC expecting to implement new rates?

      - ***See Board Staff IR #2.***

1.3 Is service quality acceptable?

2. Reference: Exhibit 1, Tab 2, Schedule 5 / Exhibit 2, Tab 5, Schedule 2, page 126

   a) Please provide a table showing,for each of the three service areas (CPC, WPPI, EPTC), the annual SAID, SAIFI and CAIDI statistics for each year 2008 through 2011 excluding loss of supply.

      - ***See Board Staff IR #7.***

   b) Please provide a similar table including loss of supply.

      - ***See Board Staff IR #7.***

3. Reference: Exhibit 1, Tab 2, Schedule 5/ Exhibit 2, Tab 5, Schedule 2, page 126.

   a) Please provide a table similar to the one shown below which shows the number of, and reasons for, service interruptions. Please provide 1 table for each of the 3 different service territories.

- ***The following table has been completed for Erie Thames Powerlines for 2009 and 2010. The 2011 information is for the merged entity.***
- ***West Perth and Clinton did not track outages in this manner and therefore there is no data available to be filed historically.***

Outage Code	Description	2009 Totals	2010 Totals	2011 Totals
	Scheduled			20
	Supply Loss	7	12	25
	Tree Contact	3	6	18
	Lightning		6	4
	Def.Equip.(other than pole)	36	36	59
	Pole Failure			
	Weather	7	5	14
	Human Element	1	6	1
	Animals,Vehicle	11	28	25
	Environment	1	1	
	Unknown	4	3	5
	Total	70	103	171

4. Reference: Exhibit 2, Tab 3, Schedule 1, Appendix 1, Table 2 and 3

   a) Please explain what specific employee compensation incentives are related to the Service Reliability Indices.

      - ***There are no employee compensation incentives related to Service Reliability Indices.***

   b) Please show the amount of related compensation (bonus/incentives) related to these incentives that were awarded in each of the years 2008 through 2011. Please break this down by executive/management; unionized; and non-union.

      - ***Not applicable.***

Rate Base

2.1 Is the proposed rate base for 2012 appropriate?

5. Reference: Exhibit 2, Tab 3 / Exhibit 5, Tab 1, Schedule 2

   a) Please provide a detailed table showing the assets that were acquired from a related entity as part of the corporate restructuring following the 2009 strike.

Transport Equip General	269,040.01
Backhoe-2008 Case	92,995.03
Truck 7-02 FRHTLNR Bucket	243,546.25
Truck 23-5 FRHTLNR Bucket	243,546.25
Truck 5-07 FRHTLNR Bucket	205,173.08
Truck 8 -international 70s	245,856.64
Leased Truck	276,704.80

2.2 Is the proposed capital expenditure program for 2012 appropriate?

6. Reference: Exhibit 2, Tab 3, Schedule 1

   a) Please update the Table at section 6.1 - 2012 Capital Assets - by Project to show actual expenditures to date.

				2012 Capital Assets by Project			Uniform System of Accounts #								
Project Name	Poles & Fixture	OH Conductor	UG Conduit	UG Conductor	Transformers	Services	Meters	Building/Fixture	Hardware	Software	Tansportation	Tools	SCADA	Contributed Cap	TOTAL
	1830	1835	1840	1845	1850	1855	1860	1908	1920	1925	1930	1940	1980	1995	
Pole Replacement Program	$ 60,387	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,387
New Service Connections & Upgrades	$ -	$ -	$ -	$ -	$ -	$ 97,257	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,257
Aylmer, Park Street Ph2	$ 3,168	$ 1,056	$ 2,112	$ 1,056	$ 792	$ -	$ 1,320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,505
Belmont Hazelwood Crescent - Underground	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clinton MS#2 Conversion	$ 22,210	$ 32,814	$ 1,000	$ 1,000	$ 13,006	$ 1,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,031
Tavistock, William St	$ 885	$ 689	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,574
Tavistock, Maria, Adam and Area	$ 137	$ 168	$ -	$ -	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 413
Municipal Road Reconstruction	$ 4,371	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,371
Ingersoll, Ingersoll Street re-insulate	$ 31,008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,008
Ingersoll, Melita, Wohnam Street	$ -	$ 218	$ 1,632	$ 762	$ 1,306	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,917
Otterville, Dover St 27kv Ext	$ 19,788	$ 30,153	$ -	$ -	$ 14,841	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,782
Port Stanley Main St S: Jameson - Cornel	$ -	$ -	$ 164,161	$ 108,464	$ 197,873	$ 123,121	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 593,619
Mitchell Conversion, Pond St and Thames	$ 103	$ 65	$ -	$ -	$ 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 191
Mitchell Conversion, St George St	$ 728	$ 583	$ -	$ -	$ 1,603	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,914
Clinton Town Hall UG Upgrade	$ 12,150	$ 1,869	$ 17,758	$ 19,627	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,403
Substaions Upgrades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,440	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,440
Fleet	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,078	$ -	$ -	$ -	$ 37,078
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Meter Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computers, Monitors, Phones and Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,819	$ -	$ -	$ -	$ -	$ -	$ 32,819
Pole Trailer/Fork Lift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Building Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,748	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,748
SCADA and Automation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,365	$ -	$ 5,365
Total by Account GL	**$154,937**	**$ 67,615**	**$186,663**	**$130,909**	**$229,549**	**$221,379**	**$ 1,320**	**$ 24,188**	**$ 32,819**	**$ -**	**$ 37,078**	**$ -**	**$ 5,365**	**$ -**	**$1,091,822**

7. Reference: Exhibit 2, Tab 3, Schedule 1, Section 6.1

   a) Please provide the capital projects assigned by USoA accounts for:

      - CPC for years 2010 (actuals and 2010 cost of service application forecast)

      - ***CPC Application***

Project ID	Project Name	Project Description	1860 Metering	1830 Pole/Fixtures	1835 OH Conductor/Devic	1840 UG Conduit	1845 UG Conductor/Devic	1850 Transformers	1855 Services	1930 Transportation	Tools/Equip	Timing	Budgeted Costs
#1	Beech St Extension for New Fire Hall	New Overhead 3 Phase 27.6 kv supply line complete with new wholesale meter point	$40,000	$40,000	$25,000	$3,000	$15,000	$35,000				Q2	$ 158,000.00
#2	Wellington St	Overhead Rebuild 4kv to 27.6kv Conversion		$35,000	$20,000	$5,000	$5,000	$10,000				Q1	$ 75,000.00
#3	Pole Replacements	Replace identified danger poles		$15,000								Q4	$ 15,000.00
#4	New Customer Connections	Cost of Connecting New Customers						$3,500	$4,000			Q2	$ 7,500.00
#5	Tools and Equipment	Tools and equipment purchases									$5,000	Q2	$ 5,000.00
#6	Transformers	Transformer purchases for Inventory						$10,000				Q3	$ 10,000.00
#7	New Bucket Truck	Order in 2010 for delivery in 2011 to replace 1992 International Bucket Truck								$240,000		Q4	$ 240,000.00
#8	New 4X4 Pickup Truck	Replacement for 2001 1/2 Ton Pickup Truck								$45,000			$ 45,000.00
									2010 Capital Additions				**$ 555,500.00**

      - ***CPC Actual***

Clinton													
Project ID	Project Name	1820	1860	1830	1835 OH	1840	1845	1850	1855	1930	Tools & Equip	Timing	Actual
1	Beech St Extension for Fire Hall		$53,307	$40,876	$31,312	$4,443	$9,711	$18,327				Q2	$157,975
2	Wellington Street			$36,838	$28,317	$12,173	$3,573	$7,814				Q1	$88,715
3	Pole Replacements			$16,377								Q4	$16,377
4	New Customer Connections							$2,979	$9,001			Q2	$11,980
5	Tools and Equipment										$13,219	Q2	$13,219
6	Transformers							$10,467				Q3	$10,467
7	New Bucket Truck									$243,546		Q4	$243,546
8	New 4x4 Pickup Truck									$33,370		Q4	$33,370
	Substation MS1	$22,336											$22,336
	Total 2010 Capital Additions	$0	$53,307	$94,090	$59,628	$16,616	$13,284	$39,587	$9,001	$276,916	$13,219		$575,648

- WPPI for 2010 (actual and 2010 cost of service application forecast)

- ***WPPI Application***

Project ID	Project Name	Project Description	1820 dist station	1830 Pole/Fixtures	1835 OH onductor/Devic	1840 UG Conduit	1845 UG onductor/Devic	1850 Transformers	1855 Services	1930 Transportation	Tools/Equip	Timing	Budgeted Costs	Units
#1	Hwy 8, Arthur St to Town Boundary & Mitchell Ct	Overhead 4kv to 27.6kv Conversion		$45,000	$27,000		$25,000	$125,000				Q3	$ 222,000.00	1
#2	Morenz Drive	Overhead 2.4kv to 16kv Conversion		$5,000	$25,000			$10,000					$ 40,000.00	1
#3	Pole Replacement Program	Replace Danger Poles within Distribution System		$15,000	$10,000							Q4	$ 25,000.00	5
#4	New Customer Connections	Cost of Connecting New Customers						$10,000	$5,000			Q2	$ 15,000.00	10
#5	Tools and Equipment	Tools and equipment purchases									$5,000	Q2	$ 5,000.00	n/a
#6	Transformers	Transformer purchases for Inventory						$10,000				Q3	$ 10,000.00	2
#7	New Radial Boom Derrick	Order in 2010 for delivery in 2011 to replace 1992 RBD								$280,000		Q4	$ 280,000.00	1
													$ -	
										Total Capex Requirement			$ 597,000.00	

- ***WPPI Actual***

West Perth														
Project ID	Project Name		1820	1830	1835 OH	1840	1845	1850	1855	1930	Tools & Equip	Timing	Actual	Budgeted
1	Hwy 8			$15,578	$23,340	$8,236	$8,958	$53,560	$15,492			Q3	$125,164	$222,000
2	Morenz Drive			$2,270	$12,308			$8,060					$22,638	$40,000
3	Pole Replacements			$6,241	$2,254							Q4	$8,495	$25,000
4	New Customer Connections							$6,577	$3,380			Q2	$9,957	$15,000
5	Tools and Equipment										$3,384	Q2	$3,384	$5,000
6	Transformers							$15,784				Q3	$15,784	$10,000
7	New Radial Boom Derrick									$294,473		Q4	$294,473	$280,000
	Total 2010 Capital Additions		$0	$24,089	$37,902	$8,236	$8,958	$83,982	$18,872	$294,473	$3,384		$479,896	$597,000

- FET for 2008 (actual and 2008 cost of service forecast), 2009 and 2010

- ***ETPL 2008 COS Forecast***

CAPITAL BUDGET BY PROJECT				
Project Description	**USoA Account**	**Expansion or Enhancement**	**Amount**	**Spend Year**
1004 Increase Capacity/Improvements	1835	Enhancement	$28,654	Bridge
1010 Increase Capacity/Improvements	1835	Enhancement	$22,679	Bridge
1040 Station Upgrade	1808	Enhancement	$33,000	Bridge
1048 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$292,000	Bridge
1043 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$274,000	Bridge
1029 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$136,000	Bridge
5355 Line Extension Serve New C&I	1830,1835,1850,1850	Expansion	$155,000	Bridge
1044 Line Extension Serve New C&I	1830,1835,1850,1850	Expansion	$83,000	Bridge
1056 Transformer Station Upgrade	1820	Enhancement	$40,000	Bridge
1050 Broken Pole Primary Removal	1830	Enhancement	$20,000	Bridge
1046 Servicing Relocation	1850,1855,1860	Enhancement	$48,000	Bridge
1064 Burial of OH lines	1845	Enhancement	$40,000	Bridge
1058 Serve New Residential	1850,1855,1860	Enhancement	$70,000	Bridge
1059 Serve New C&I	1830,1835,1850,1855,1860	Enhancement	$80,000	Bridge
1049 Feeder Line Upgrade	1835	Enhancement	$68,000	Bridge
1036 Line Conversion	1840,1845	Enhancement	$55,000	Bridge
1003 Poles Relocation	1830,1835	Enhancement	$32,000	Bridge
1033 Increase Capacity/Improvements	1840	Enhancement	$16,155	Bridge
1003 Increase Capacity/Improvements	1845	Enhancement	$37,845	Bridge
1037 Line Enhancement/Pole Replacement	1835	Enhancement	$34,000	Bridge
1000 GIS Mapping System	1925	Enhancement	$60,000	Bridge
Project Description	**USoA Account**	**Expansion or Enhancement**	**Amount**	**Spend Year**
1113 C&I Meter Changes	1860	Enhancement	$30,000	Test
1011 Increase Capacity/Improvements	1830,1835,1840,1845,1850	Enhancement	$130,000	Test
1035 Increase Capacity/Improvements	1830,1835,1850	Enhancement	$46,000	Test
1052 Pole Replacement Program	1830,1835,1850	Enhancement	$100,000	Test
1058 Serve New Residential	1850,1855	Enhancement	$110,000	Test
1059 Serve New C&I	1830,1835,1845,1850,	Enhancement	$90,000	Test
1094 Serve New C&I	1830,1835,1850	Enhancement	$40,000	Test
1095 Increase Capacity/Improvements	1835	Expansion	$40,000	Test
1096 Increase Capacity/Improvements	1850	Enhancement	$35,000	Test
1097 Serve New Residential	1830,1835	Expansion	$60,000	Test
1098 Increase Capacity/Improvements	1840,1845,1850	Enhancement	$80,000	Test
1100 Serve New Residential	1830,1835,1850	Expansion	$17,000	Test
1101 Increase Capacity/Improvements	1830,1835,1840,1845,1850	Enhancement	$180,000	Test
1103 Increase Capacity/Improvements	1835	Enhancement	$30,000	Test
1104 Increase Capacity/Improvements	1850	Enhancement	$25,000	Test
1105 Serve New Residential	1830,1835,1850	Expansion	$75,000	Test
1107 Increase Capacity/Improvements	1830,1835,1840,1845,1850,1855	Enhancement	$175,000	Test
1108 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$95,000	Test
1109 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$100,000	Test
1110 Increase Capacity/Improvements	1835	Enhancement	$45,000	Test
1099 Increase Capacity/Improvements	1820	Enhancement	$40,000	Test
1013 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$80,000	Test

2008 Projects Actual

ETPL 2008 Capital Additions

Project ID	Project Name	Description	1808	1820	1830	1835 OH	1840	1845	1850	1855	1856	1860	1915	1920	1930	Tools & Equip	Actual
	Serve New Residential Customers	New Residential Connections Cost and Paybacks				$95,312											$95,312
	Serve New C&I Customers	Connection Cost for New C&I Customers				$210,620											$210,620
	Municipal Road Reconstruction	Relocation of Plan due to Road Reconstruction			$32,462	$19,480	$14,525	$82,017	$10,146	$19,352							$177,982
	Pole Replacement Program	End of life Pole Replacements			$45,322	$52,361											$97,683
	Insulator Replacement Ing, Emb Tav	Re-Insulate Poles Tav/Emb/Ing				$27,005											$27,005
	TX Animal Guarding Ingersoll, Norwich	Animal Guard OH Transformers							$18,579								$18,579
6174	OH PCB Removals	Replacement of OH PCB Transformers				$6,016		$36,683	$12,461								$55,160
6052	Aylmer Caverly Rd PH1	PH1 Caverly Rd 27kv Conv			$38,103	$38,887	$29,800	$95,172	$71,019	$12,362	$39,358						$324,701
6826	Otterville LTLT	Line Ext to supply ETP customer			$18,177	$4,101			$2,251								$24,529
6461	Aylmer Treelawn Line Relocation	OH Backyard Relocation to UG Front Yard			$4,165	$24,574	$24,905	$58,807	$34,471	$19,451	$63,627						$230,000
6445	Belmont Brentwood Subdivision	UG Conversion and Upgrade to Subdivision distribution			$29,924	$49,698		$96,483	$79,464		$45,678						$301,247
6376	McCarty St, Stanley-George St Thamesford	16KV Conv and removal of PCB TX			$28,374	$27,043			$39,141								$94,558
6445	Dufferin St Belmont	16KV Line Conversion for New Subdivision			$41,636	$40,701		$71,483	$18,632		$18,637						$191,089
6059	LTLT HWY 19 Thamesford Line Ext	Line Ext HWY 19 Thamesford to pick up 3 LTLT			$10,998	$12,304			$1,698								$25,000
	Belmont Hazelwood UG	16kv Conversion and UG upgrades															$0
	GIS Mapping System	Implement GIS Mapping System				$94,520											$94,520
6058	Belmont South LTLT	Line Ext to pick up LTLT Customers			$27,376	$15,543	$12,505	$ 16,131	$ 8,445								$80,000
5754	Aylmer-John Street /from2007				$18,852			$ 35,146	$83,935								$137,933
6848	Aylmer LTLT HWY 73	27kv line extension for LTLT HWY73			$23,768	$17,817		$ 18,720	$15,540								$75,845
	Substation Upgrades	painting/grounding/insulator replacement		$23,487													$23,487
6322	Meter Upgrades	Upgrade C&I Meters to Interval										$57,383					$57,383
6204	IN-17 LBS Replacement Ingersoll	Replace Cap & Pin LBS			$ 4,358	$23,091											$27,449
6224	Ingersoll-Ingwood Subdivision							$120,917	$98,309	$32,241							$251,467
	Rolling Stock														$9,980		$9,980
	Office Furniture and Equipment												$5,594				$5,594
	Building & Fixtures Other		$10,160														$10,160
	Tool & Equipment															$ 6,019	$6,019
	Computer Hardware & Software													$148,495			$148,495
	Total 2011 Capital Additions		**$10,160**	**$23,487**	**$323,515**	**$759,073**	**$81,735**	**$631,559**	**$494,091**	**$83,406**	**$167,300**	**$57,383**	**$5,594**	**$148,495**	**$9,980**	**$6,019**	**$2,801,798**

2009 Projects Actual

ETPL 2009 Capital Additions

Project ID	Project Name	1808	1830	1835 OH	1840	1845	1850	1855	1860	1915	1920	1930	1940/1945	Actual
	Serve New Residential Customers							$69,078						$69,078
	Serve New C&I Customers							$86,750						$86,750
7000	OH PCB Removals			$12,452			$28,750							$41,202
7044	Pole Replacement Program		$26,385	$19,638			$13,516							$59,539
	Municipal Road Reconstruction		$13,776	$66,495	$6,505	$45,205	$4,362	$8,266						$144,609
N/A	Tools & Equipment										$14,215		$6,746	$20,961
6848	Aylmer LTLT HWY 73		$12,310	$17,699		$37,853	$18,687	$7,285						$93,834
7021	Whiting Ext / Clarke Rd Ingersoll		$22,750	$18,965			$13,585	$12,965						$68,265
	Sales Arena Aylmer		$14,417	$32,506	$288	$45,846	$5,865	$9,867						$108,789
7079	Towerview Subdivision Ingersoll						$2,587							$2,587
	Grove Street Otterville													$0
6441	Ingersoll Street Bridge Ext		$26,841	$12,573		$32,587		$9,317						$81,318
6552	St Andrew, Rutherford, Park St Aylmer		$51,038	$167,914		$106,389	$15,909	$16,985						$358,235
7107	Delatre St, Byron, Washington Thamesford		$15,960	$37,803		$58,798	$12,718							$125,279
7108	7th line - Belmont Rd - Washburn Belmont		$9,096	$21,891		$16,897		$6,565						$54,449
7106	Padmount Transformer Maint						$14,392							$14,392
	Belmont South LTLT Line Extension		$25,875	$37,864	$1,580	$28,293	$13,754	$3,705						$111,071
N/A	Engineering Control Room	$ 12,254												$12,254
	Dufferin Brentwood & Treelawn			$ 42,689	$ 3,689	$46,879		$ 6,435						$99,692
	Smart Meter upgrades								$23,145					$23,145
	Substation Upgrades													$0
	Rolling Stock											$89,418		$89,418
	Office Furniture and Equipment									$593				$593
	Computer Hardware & Software										$35,395			$35,395
	Total 2011 Capital Additions	$12,254	$218,448	$488,489	$12,062	$418,747	$144,126	$237,218	$23,145	$593	$49,610	$89,418	$6,746	$1,700,856

ETPL 2010 Capital Additions														
Project ID	Project Name	1806	1808	1830	1835 OH	1840	1845	1850	1855	1915	1920	1925	Tools & Equip	Actual
	Land & Buildings	244.36	$6,292											$6,536
	Tools & Equipment												$7,742	$7,742
	Pole Replacement Program													$0
all	Municipal Road Reconstruction			$26,468	$72,356	$11,063	$23,861	$20,063	$5,824					$159,635
all	Serve New Residential Customers				$28,634			$48,978	$36,758					$114,370
all	Serve New C&I Customers				$85,685		$43,876	$124,650	$4,326					$258,537
9077	Clarke Rd Ingersoll			$16,850	$35,563		$1,210	$9,011	$351					$62,985
9126	Delatre St, Byron, Washington Thamesford			$23,427	$35,798		$26,341	$45,625	$52,903					$184,094
9157	Rutherford, Park St Aylmer			$13,422	$49,507	$10,867		$4,276	$3,613					$81,685
9127	7th line - Belmont Rd - Washburn Belmont			$138,641	$111,248		$5,104	$61,076						$316,069
9107	Smart Meters													$0
9045	Ingersoll Bridge			$70,062	$74,867	$23,380	$37,652	$34,589	$65,800					$306,350
9275	Aylmer-TreeLawn Line			$204	$6,989		$3,441		$4,696					$15,330
9249	Port Stanley-Main Street				25860			5916	32596					$64,372
	Office Furniture & Equipment									6,258				$6,258
	Computer Hardware/Software										2,564	61,396		$63,961
	Total 2010 Capital Additions	**$244**	**$6,292**	**$289,074**	**$526,507**	**$45,310**	**$141,485**	**$354,184**	**$206,867**	**$6,258**	**$2,564**	**$61,396**	**$7,742**	**$1,647,923**

- ETPC (amalgamated Utility) for 2011 (actuals).

ETPL 2011 Capital Additions																	
Project ID	Project Name	1805	1808	1830	1835 OH	1840	1845	1850	1855	1860	1910	1915	1920	1925	1930	Tools & Equip	Actual
9683	WPP Hwy 8 Arthur to Town Boundary				$46,531			$229,258									$275,789
	RBD Purchase														$196,925		$196,925
	Smart Grid Automation																$0
	CPC MS#2 Conversion Ph1							$46,984	$36,761								$83,745
	CPC Maple Street			$19,535	$11,799		$1,991	$1,367									$34,688
9126	Thamesford Delatre St. Byron, Washington			$37,280	$32,518	$6,641	$96	$44,703	$28,069								$149,307
9157	Aylmer Rutherford, Park St. Oak & Davis			$28,160	$52,613		$82,177	$6,058	$13,390								$182,398
9104	Pole Replacement Program			$123,580	$46,835												$170,415
	Municipal Road Reconstruction			$33,537	$19,683	$8,563											$61,783
	Serve New Residential Customers				$33,690		$13,596	$57,627	$43,249								$148,162
	Serve New C&I Customers				$36,601		$18,741	$53,245	$2,897								$111,483
	Smart Meter Upgrades									$78,815							$78,815
9118	Ingersoll Towerview Subdivision			$26,814		$12,635	$45,896	$88,964	$28,695								$203,004
	Mitchell Subdivision - Thamesview Est							$30,628	$38,692								$69,320
	Fleet														$84,761		$84,761
	Tools & Equipment															$35,412	$35,412
9857,58,59	Embro Pumping Station			$7,843	$1,248			$48,632									$57,723
9685	Norwich Albert St Upgrade			$8,547			$8,965	$4,388	$16,983								$38,883
	Norwich-Dufferin, Palmer St			$24,368		$13,458		$25,631	$58,962								$122,419
	Tavistock, William St Lagoon			5895			79852	35489									$121,236
9640	Ingersoll, Wonham St North			34722	53486	8970	4758	20309									$122,245
	Building Improvements										154461						$154,461
9761	FRS &Computer Software Automation		20327										10807	19607			$50,741
	Office Furniture & Equipment											2404					$2,404
	Leasehold Improvements	8271															$8,271
	Total 2011 Capital Additions	$8,271	$20,327	$350,281	$335,000	$50,267	$256,072	$693,252	$267,698	$78,815	$154,461	$2,404	$10,807	$19,607	$281,686	$35,412	$2,564,360

8. Reference: Exhibit 2, Tab 3, Schedule 1;

   a) Please explain why the "Table <> Capital Spending" shows identical costs for all categories for the period 2013 through 2015.

      - ***ETPL anticipates that given the asset assessment and the identification of the state of the infrastructures that the proposed level of spending will need to be maintained throughout that time period.***

9. Reference: Exhibit 2, Tab 5, Schedule 2, page 104;

Preamble: At page 104 its states "*that complete data required for condition assessment thorough this methodology is not presently available.*"

   a) In light of this statement what limitations/adjustmentswere made to the capital budget in the consideration of adopting the recommendations of the Report?

   - ***The statement refers to the methodology described in the report for establishing health indices of distribution assets to benchmark the relative health and condition of a specific asset. For those assets for which complete data for establishing asset health indices were not available, estimates of the capital investments required for replacing assets at the end of their useful service life were prepared by taking into account all the available relevant information, including results of testing, asset inspection results and age of assets.***

   b) For the following asset categories please indicate whether the assessment was based on: (1) visual inspection only; (2) physical testing – oil testing, pole core analysis etc.; or (3) other – please describe. Please indicate the percentage of each asset category that wasvisuallyor physically tested.

      - Poles – ***Age and physical testing were used to assess this asset category. As indicated in the report, a sample size of approximately 1000 poles (11% of total poles) were tested to determine their health and condition and the results used in preparation of the report.***

      - Overhead Line Circuits – ***Overhead line age profiles were used to determine the extent of lines expected to reach the end of their service life during the next 10 years and to determine mean annual expenditure required to replace***

overhead line circuits when they reach the end of their service life.

- OH Transformers – ***Distribution transformer age profiles were used to determine the extent of transformers expected to fail in service during the next 10 years and to determine mean annual expenditure required to replace failed transformers.***

- UG Cables – ***Underground cable age profiles were used to determine the length of cable circuits expected to reach the end of their service life during the next 10 years and to determine mean annual expenditure required to replace cables when they reach the end of their service life.***

- Distribution Pad Mounted transformers - ***Distribution pad mounted transformer age profiles were used to determine the extent of transformers expected to fail in service during the next 10 years and to determine mean annual expenditure required to replace pad mounted transformers when they reach the end of their service life.***

- Distribution stations – ***Equipment Age, Results of physical testing and physical inspections were employed to establish heath index for each of the stations. Data related to age, physical testing and physical inspections for 100% of the distribution stations was available and was used in establishing annual expenditure required to replace assets when they reach the end of their service life.***

10. Reference Exhibit 2, Tab 5, Schedule 2, page 127

a) The Asset Management Plan states that "[*O*]*wing to inadequate level of investment during the past years, investment levels over the next 10 year will need to be higher than the above indicated annual average investment level*." What is the basis of this statement?

- ***Based on the quantities of assets employed on ETPL's distribution system and mean design life of assets, Exhibit 5-1 details the level of investment required annually to allow replacement of the assets (not including station assets) when the reach the end of their anticipated service life. It is evident that the***

annual investment level during the recent past years into these assets have remained below these levels and as a result the percentage of assets well past their reliable service life has been steadily increasing. The statement is based on these facts.

b) Please provide details as to the level and nature of the underinvestment in each of the three service territories CPC, WPPI, FET over the past 10 years.

- ***The asset condition assessment that was completed for ETPL is available in the application and details the age and issues with respect to the existing distribution system and produced a sustainable reinvestment level that ETPL has used as a guide to build its asset management plan on a go forward basis.***

c) Please explain why EPTC and its predecessor companies have underinvested in capital over the past 10 years. In particular please explain the reasons for the inadequate in these service territories since 2006.

- ***ETPL historically reinvested at a similar level to its annual depreciation expense, this simple spending philosophy did not take into consideration that a large percentage of ETPL's infrastructure was fully amortized and not attracting reinvestment. With the completion of ETPL's asset condition assessment it has become apparent that a significant portion of ETPL's distribution is in need of repair and has been in use in excess of 50 years. Within the asset condition assessment an optimal spend level was recommended to sustain the distribution system and ETPL has actually proposed to spend approximately $300,000 less than the recommended level.***
- ***In the case of CPC and WPPI, ETPL management cannot comment as to the reasons that the reinvestment in its distribution system was lacking other than to point out that historically both municipalities were responsible for Hydro and Water and that with the split of resources between the two functions investment in new assets was completed on an absolute as needed basis.***

11. Reference: Exhibit 2, Tab 3, Schedule 1, Section 6.2.21

a) Please provide a table showing the SCADA and Smart Grid Capital expenditures, OM&A expenditures and associated consulting costs for the period 2011 through 2015.

- ***ETPL is only currently planning to invest in the SCADA system as outlined in this application and then integreated switches in 2013 that will allow for some automation within ETPL's outage management system planning.***

b) Have any SCADA investments been made prior to 2011?

- ***No SCADA investments have been made prior to 2011.***

12. Reference: Exhibit 2, Tab 5, Schedule 2, page 134

a) Please describe the 2013 SCADA pilot project, including the cost of the pilot (both capital and OM&A), and the objectives of the program.

- ***The SCADA project for 2013 is simply to install automated switches to allow for better control of the distribution system and dealing with outages.***

13. Reference: Exhibit 2, Tab 3, Schedule 1

Pre-amble: In the evidence Erie Thames classifies its capital projects as

- Sustainment/Enhancements
- Municipal Reconstruction
- Regulatory Requirements
- Substations
- Ongoing Asset Replacements
- Development/Subdivisions
- Customer Connections
- Fleet
- General Plan

Section 4 of the Asset Management Plan uses a slightly different set of classifications, including Smart Grid Initiatives, Preventative Maintenance and some similar classifications, including Motor Vehicle Fleet.

a) Please provide a table using the classification above (modified as necessary to conform with the Asset Management Plan) which shows the capital expenditures for Erie Thames for the period 2011 through 2016. Include in the capital contributions for each category.

	2011	2012	2013	2014	2015	2016
Sustainment Enhancements	$ -	$ 200,000	$ 200,000	$ 200,000	$ 200,000	
Municipal Reconstruction	$ 64,289	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Regulatory Requirements						
Substations	$ 20,327	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Ongoing Asset Replacements	$1,753,538	$2,245,000	$2,245,000	$2,245,000	$2,245,000	$2,245,000
Development/Subdivisions	$ 259,645	$ 285,000	$ 28,500	$ 285,000	$ 285,000	$ 285,000
Fleet	$ 281,686	$ 340,000	$ 340,000	$ 340,000	$ 340,000	$ 340,000
Accounting System	$ 30,414					
General Plant	$ 154,461	$ 185,000	$ 100,000	$ 105,000	$ 105,000	$ 105,000
	$2,564,360	$3,325,000	$2,983,500	$3,245,000	$3,245,000	$3,045,000

14. Reference: Exhibit 2, Tab 5, Schedule 2, page 134

a) Please explain how the $285,000 annual expenditure for system extensions and regulatory obligations was calculated.

- ***See response to Board Staff IR #15A.***

15. Reference: Exhibit 2, Tab 5, Schedule 2, page 137

a) Were there any reductions in vehicles subsequent to the amalgamation of utilities in 2011? Please explain

- ***The amalgamation of ETPL with West Perth and Clinton and the subsequent fleet assessment lead to the reduction in one large bucket truck required to be in service, as well as the elimination of one pickup truck from the fleet.***

16. Reference: Exhibit 2, Tab 5, Schedule 2, page 138

a) Please explain how the estimates shown on page 138 of the Asset Management Plan were calculated.

- ***The estimate of expenditure for each of the line items in Exhibit 5-9 is described in detail in Sections 5-1 through 5-13. In other words, Exhibit 5-9 on page 138 merely summarizes the expenditures which are described in detail, complete with all the underlying assumptions in Sections 5-1 through 5-13 of the report.***

17. Reference Exhibit 4, Tab 2, Schedule 1

a) Please provide a description of the plan to convert ETPC to a 27kV system. Please show the expected capital expenditures for this program for each of 2011 through 2016.

- ***ETPL is planning to convert all 4kV to 27 kV in due course as the distribution system is rebuilt at the end of its useful life. ETPL has no plans to convert 4kV systems that are not required to be replaced as part of the Asset Management Plan.***
- ***The total value of conversion that is required over 10 years is $3.96 million which roughly amounts to $400,000 spent annually to replace end of life 4kV assets with 27.6 kV.***

2.2 Is the proposed Working Capital Allowance for 2012 appropriate?

18. Reference: Exhibit 2, Tab 3, Schedule 1

a) On April 12, 2012, the OEB updated the default working capital allowance to 13% of controllable costs and the cost of power. In light of the late filing of this Application please explain why EPTC has not elected to use the most up-to-date working capital calculation?

   - ***ETPC inadvertently did not employ the most up to date default working capital allowance calculation in its application and agrees it should have been changed.***

b) Please calculate the adjustment to revenue requirement if a working capital allowance of 13% were used instead of the 15% proposed.

Working Capital Allowance Calculation

Account	Description	Test Year	13%
Operations			
5005	Operation Supervision and Engineering	$ 193,036	$ 25,095
5010	Load Dispatching		$ -
5012	Station Buildings and Fixtures Expense		$ -
5014	Transformer Station Equipment - Operation Labour		$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses		$ -
5016	Distribution Station Equipment - Operation Labour		$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 3,519	$ 457
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 3,683	$ 479
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 1,441	$ 187
5030	Overhead Sub-transmission Feeders - Operation		$ -
5035	Overhead Distribution Transformers - Operation		$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 384	$ 50
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exper	$ 28	$ 4
5050	Underground Sub-transmission Feeders - Operation		$ -
5055	Underground Distribution Transformers - Operation		$ -
5060	Street Lighting and Signal System Expense		$ -
5065	Meter Expense	$ 6,150	$ 799
5070	Customer Premises - Operation Labour	$ 196	$ 25
5075	Customer Premises - Operation Materials and Expenses	$ 9	$ 1
5085	Miscellaneous Distribution Expenses	$ 73,770	$ 9,590
5090	Underground Distribution Lines and Feeders - Rental Paid		$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid		$ -
5096	Other Rent		$ -
Total - Operations		$ 282,215	$ 36,688

Account	Description	Test Year	
Maintenance			$ -
5105	Maintenance Supervision and Engineering		$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 95,941	$ 12,472
5112	Maintenance of Transformer Station Equipment		$ -
5114	Maintenance of Distribution Station Equipment	$ 3,386	$ 440
5120	Maintenance of Poles, Towers and Fixtures	$ 39,790	$ 5,173
5125	Maintenance of Overhead Conductors and Devices	$ 5,846	$ 760
5130	Maintenance of Overhead Services	$ 76,064	$ 9,888
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 114,915	$ 14,939
5145	Maintenance of Underground Conduit	$ 145,053	$ 18,857
5150	Maintenance of Underground Conductors and Devices	$ 54,472	$ 7,081
5155	Maintenance of Underground Services	$ 55,162	$ 7,171
5160	Maintenance of Line Transformers	$ 103,105	$ 13,404
5165	Maintenance of Street Lighting and Signal Systems		$ -
5170	Sentinel Lights - Labour		$ -
5172	Sentinel Lights - Materials and Expenses		$ -
5175	Maintenance of Meters	$ 30,616	$ 3,980
5178	Customer Installations Expenses - Leased Property		$ -
5195	Maintenance of Other Installations on Customer Premises		$ -
Total - Maintenance		$ 724,349	$ 94,165

Account	Description	Test Year	
Billing and Collecting			$ -
5305	Supervision	$ 18,631	$ 2,422
5310	Meter Reading Expense	$ 118,209	$ 15,367
5315	Customer Billing	$ 906,125	$ 117,796
5320	Collecting	$ 21,823	$ 2,837
5325	Collecting - Cash Over and Short		$ -
5330	Collection Charges	$ 118,316	$ 15,381
5335	Bad Debt Expense	$ -	$ -
5340	Miscellaneous Customer Accounts Expenses	$ 27	$ 3
Total - Billing and Collecting		$ 1,183,131	$ 153,807
Account	**Description**	**Test Year**	
Community Relations			$ -
5405	Supervision	$ 2,160	$ 281
5410	Community Relations - Sundry	$ 19,179	$ 2,493
5415	Energy Conservation		$ -
5420	Community Safety Program		$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ 120,029	$ 15,604
5505	Supervision		$ -
5510	Demonstrating and Selling Expense		$ -
5515	Advertising Expenses	$ 7,415	$ 964
5520	Miscellaneous Sales Expense		$ -
Total - Community Relations		$ 148,783	$ 19,342

Account	Description	Test Year	
Administrative and General Expenses			$ -
5605	Executive Salaries and Expenses	$ 218,390	$ 28,391
5610	Management Salaries and Expenses	$ 1,194,776	$ 155,321
5615	General Administrative Salaries and Expenses	$ 361,626	$ 47,011
5620	Office Supplies and Expenses	$ 143,722	$ 18,684
5625	Administrative Expense Transferred - Credit	$ -	$ -
5630	Outside Services Employed	$ 225,378	$ 29,299
5635	Property Insurance	$ -	$ -
5640	Injuries and Damages	$ 13,438	$ 1,747
5645	Employee Pensions and Benefits	$ 413,502	$ 53,755
5650	Franchise Requirements	$ -	$ -
5655	Regulatory Expenses	$ 115,000	$ 14,950
5660	General Advertising Expenses	$ -	$ -
5665	Miscellaneous General Expenses	$ 295,456	$ 38,409
5670	Rent	$ 322,401	$ 41,912
5675	Maintenance of General Plant	$ 80,204	$ 10,427
5680	Electrical Safety Authority Fees	$ 7,865	$ 1,022
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -
5695	OM&A Contra Account	$ -	$ -
6205	Donations (Charitable Contributions)	$ -	$ -
Total - Administrative and General Expenses		$ 3,391,759	$ 440,929
Total OM&A		$ 5,730,237	$ 744,931

Amortization Expenses			
5705			
5710	Amortization of Limited Term Electric Plant	$ 1,759,025	$ 228,673.25
Cost of Power			
4705		$ 28,937,365	$ 3,761,857.39
4708		$ 2,326,408	$ 302,433.05
4710		$ -	$ -
4712		$ -	$ -
4714		$ 2,705,003	$ 351,650.38
4715		$ -	$ -
4716		$ 2,401,439	$ 312,187.09
4720		$ -	$ -
4725		$ -	$ -
4730			$ -
		$ 38,129,240	$ 4,956,801
Total Contributed Capital @13%		$ 43,859,477	$ 5,701,732

19. Reference: Exhibit 4, Tab 2, Schedule 1

a) Please confirm that all ETPL customers are currently billed monthly.

- ***All ETPL customers are currently billed monthly.***

2.3 Is the proposed Green Energy Act Plan appropriate?

20. Reference: Exhibit 2, Tab 5, Schedule 3, page 153

a) EPTL is seeking a deferral account for “qualifying expenditures” related to its Green Energy Plan. Please explain the type of investments that would constitute a “qualifying expenditure”

- ***Currently ETPL does not have any expenditures that would be deemed a qualifying expenditure.***

b) Does EPTL have estimates as to quantum of costs that would be booked into this account?

- ***ETPL currently has no estimates for these amounts.***

c) In what way would these investments differ from the normal Utility investments?

- ***ETPL is uncertain as to what type of GEA costs it may incur in the future that would qualify and therefore cannot comment on how these investments may differ from the normal investments.***

d) Would EPTL be seeking provincial recovery of all or some of these costs?

- ***There are no costs that ETPL would seek provincial recovery for that ETPL is currently aware of.***

e) Are there any Green Energy Plan costs being sought for recovery in 2012 rates?

- ***There are not Green Energy Plan costs being sought for recovery in 2012 rates.***

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalizationcustomer/connections and load forecast for the test year appropriate?

21. Reference: Exhibit 3, Tab 2, Schedule 1, Section 2

a) Please provide a revised version of Table 2 that also includes 2010 weather adjusted values as well as 2011 actual and weather adjusted actual values.

- ***The revised Table 2 including 2010 weather adjusted values is shown below. The 2011 actual and weathered adjusted values were not included. The load forecast model was prepared in 2011 and no weather data and analysis was performed for 2011. Due to the amalgamation of Erie Thames, West Perth and Clinton and some customers were re-classified in 2012, we do not have sufficient time to update the 2011 data within the required timeline of the interrogatories.***
- ***Errors were found in in the Street Lighting and Sentinel Lighting KW and KWH values and have now been corrected.***
  - ***Revised Table 2 - Exhibit 3, Tab 2, Schedule 1, Section 2 below***

			Actual		Weather adjusted	
Consumption	**2012**	**2012**	**2010**	**2010**	**2010**	**2010**
	KW	**KWH**	**KW**	**KWH**	**kW**	**KWH**
Residential actual		147,767,075		148,114,381		147,118,213
General Service <50		50,460,667		50,456,016		50,122,927
GS > 50	143,211	44,453,178	139,928	43,335,594	139,928	43,335,594
GI > 50	84,710	33,395,845	82,948	32,698,642	82,948	32,698,642
General Service 1000-2999	96,900	59,000,000	93,487	57,741,953	93,487	57,741,953
General Service 3000-4999	26,704	10,200,000	29,135	11,691,664	29,135	11,691,664
Large user	160,146	97,146,783	152,704	92,434,594	152,704	92,434,594
Unmetered scattered load		618,341		605,495	-	605,495
Sentinel	757	274,492	741	272,919	741	272,919
Streetlights	10,818	3,920,893	10,707	3,940,846	10,707	3,940,846
Embedded Distributors	39,284	17,350,000	39,665	17,518,323	39,665	17,518,323
Total	**562,529**	**464,587,273**	**549,315**	**458,810,428**	549,315	457,481,171
Changes from 2010	2.4%	1.3%				

22. Reference: Exhibit 3, Tab 2, Schedule 1, Section 3

a) Please provide revised versions of Tables 3-5 that include the actual 2011 and weather adjusted actual values.

- ***Please see answer in 1A.***

b) How was the average kW, Non-coincident kW and Coincident kW values determined for Table 6?

- ***The 2010 Net System Load Shape (NSLS) hourly data set (8760 data per LDC) of Erie Thames, Clinton and West Perth was each scaled to the 2010 actual Residential kWh consumption of each utility. The three sets of 2010 scaled NSLS data were combined to form the 2010 Consolidated Residential hourly consumption data set. For each month the average kW was calculated as the average of all the hourly consumption in that month. The non-coincident kW for each month was the maximum hourly kWh of each***

month. The Coincident Peak of each month was the kWh consumption of the hour coincided with the peak hour of the aggregated system load of all custom classes.

Table 6 – 2010 Consolidated Residential Class

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	14,511,182	19,504	26,354	74%	04/01/2010	18	26,336	99.9%
Feb	12,694,205	18,890	24,491	77%	09/02/2010	19	23,983	97.9%
Mar	12,117,674	16,287	23,950	68%	26/03/2010	8	23,673	98.8%
Apr	10,183,201	14,143	21,541	66%	09/04/2010	9	18,574	86.2%
May	10,922,333	14,681	25,011	59%	31/05/2010	13	22,980	91.9%
Jun	11,349,635	15,763	30,832	51%	23/06/2010	17	30,712	99.6%
Jul	13,614,622	18,299	30,226	61%	28/07/2010	14	24,861	82.2%
Aug	13,243,194	17,800	29,281	61%	12/08/2010	14	27,126	92.6%
Sep	10,405,622	14,452	28,935	50%	01/09/2010	16	28,552	98.7%
Oct	10,997,346	14,781	23,461	63%	13/10/2010	19	23,135	98.6%
Nov	12,039,576	16,722	28,655	58%	29/11/2010	18	28,317	98.8%
Dec	16,035,793	21,553	34,153	63%	13/12/2010	18	34,066	99.7%
Annual	148,114,381		326,890		13/12/2010	18	34,066	99.7%

c) Are the kW values in Table 6 used at all in the Application (e.g. in the Cost Allocation)?

- ***The values in Table 6 are used in Cost Allocation.***

d) Please provide a Table that sets out for 2006-2012 the total (consolidated) Residential class kWh use, the number of customers and the average use per customer (both actual and weather normalized).

Consolidated Residential Class	2007	2008	2009	2010	2011	2012
Actual kWh	148,716,307	145,775,894	145,021,202	148,114,381		
Weather adjusted kWh	148,167,694	144,805,579	146,275,664	147,118,213	147,353,371	147,767,075
# of customers	15,494	15,613	15,313	16,058	16,379	16,461
Average use per customer/month (actual)	800	778	789	769		
Average use per customer/month (weather adjusted)	797	773	796	763	750	748

23. Reference: Exhibit 3, Tab 2, Schedule 1, Section 4

a) Please revise Table 8 so as to also include the number of customers and kWh/customer weather adjusted.

Clinton General Services < 50 kW	2007	2008	2009	2010	2011	2012
Actual kWh	6,002,124	5,219,160	5,196,841	5,392,837		
Weather adjusted kWh	5,984,939	5,189,387	5,228,685	5,365,596	5,420,000	5,500,000
Number of Customers	235	239	241	243	247	250
kWh/customer/month (weather adjusted)	2,122	1,809	1,808	1,840	1,829	1,833

b) Please provide revised versions of Tables 8-10 that include the 2011 actual and weather adjusted actual values.

- ***Please see answer above in question 1A.***

c) Please provide a Table that sets out for 2006-2012 the total (consolidated) GS<50 class kWh use, the number of customers and the average use per customer (both actual and weather normalized).

Consolidated GS < 50 class	2007	2008	2009	2010	2011	2012
Actual kWh	51,985,850	50,595,686	49,273,971	50,456,016		
Weather adjusted kWh	51,793,445	50,259,678	49,687,134	50,122,927	50,330,861	50,537,700
# of Customers	1,837	1,847	1,696	1,842	1,858	1,860
kWh/customer/month (Actual)	2,358	2,283	2,421	2,283		
kWh/customer/month (Weather Adjusted)	2,350	2,268	2,441	2,268	2,257	2,264

24. Reference: Exhibit 3, Tab 2, Schedule 1, Section 5
Exhibit 3, Tab 2, Schedule 1, Section 12

a) Please provide revised versions of Tables 13-15 that include the 2011 actual values.

- ***Please see answer above in question 1A.***

b) Please provide revised versions of Tables 18-19 that include the 2011 actual values.

- ***Please see answer above in question 1A.***

c) Please provide a Table that sets out for 2006-2012 the total (consolidated) GS>50 class kWh use, the number of customer and the average use per customer (both actual and weather normalized).

- ***Please see below. No weather adjustment was applied to this class as explained in more details in section 4d) below.***

GS> 50 Class	2007	2008	2009	2010	2011	2012
Number of Customers	169	173	176	173	173	173
kWh (actual)	51,046,009	47,491,795	42,228,877	43,335,595		
kWh (weather adjusted)	51,046,009	47,491,795	42,228,877	43,335,595	43,552,273	44,453,178
kWh/customer/month	25,171	22,877	19,995	20,875	20,979	21,413

d) Section 5 suggests that the IESO Energy Growth is used to escalate the 2010 values for all GS>50 sub-groups. Section 12 (part b) states that "historic trending and extrapolation" were used to forecast load for the GS>50 class. Please explain more fully how the 2011 and 2012 load forecasts for this class were prepared.

- ***The forecast involved the following steps:***

1. ***Collect historical data (annual kW demand, annual KWh and number of customers) from 2006 to 2010 for Erie Thames, Clinton and West Perth.***

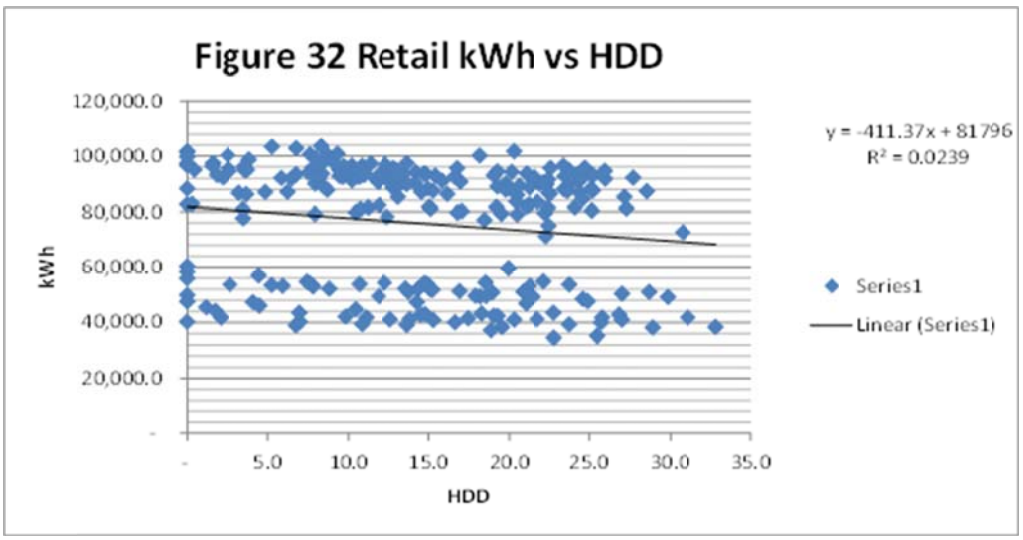
2. ***Collect 2010 hourly kWh data of the Total Grid Delivery and subtract the Net System Load Shape hourly kWh data and the hourly kWh data of the interval meter accounts larger than 1000 kW to create the hourly load profile for this class. Use this process for Erie Thames, Clinton and West Perth to create three sets of 2010 hourly kWh data sets.***

3. ***Collect hourly temperature data from Environment Canada for 2010. Calculate the average temperature for each day.***

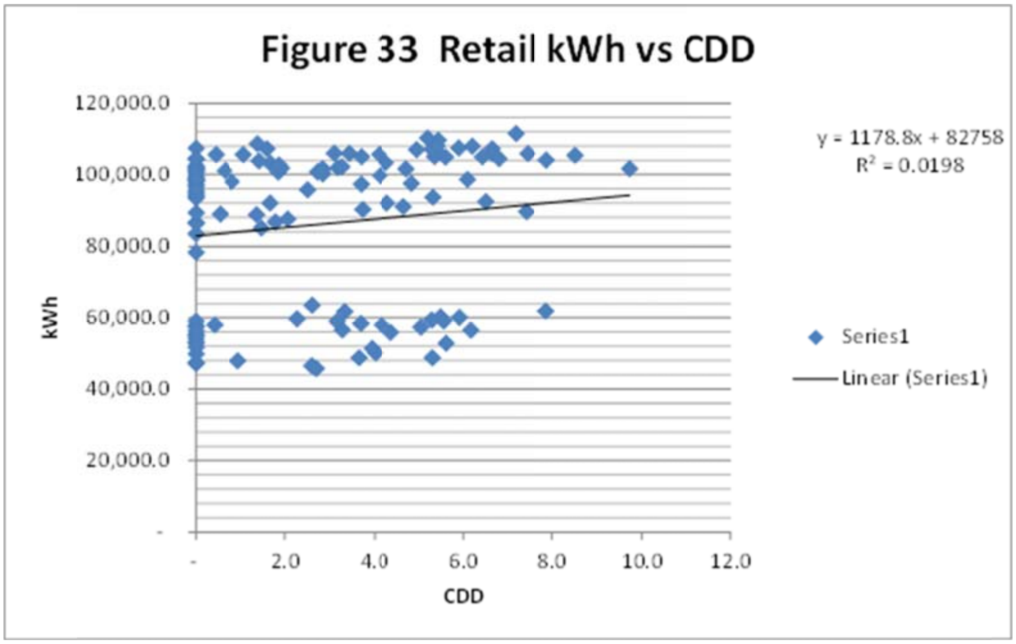
Calculate the Heating Degree Days "HDD" and Cooling Degree Days "CDD" using the following formula:

HDD =18 ˚C minus average temperature of the day. If the value calculated is less than or equal to zero, that day has zero HDD. But if the value is positive, that number represents the number of HDD on that day.
CDD= Average temperature of the day minus 18 ˚C. If the value calculated is less than or equal to zero, that day has zero CDD. But if the value is positive, that number represents the number of CDD on that day.

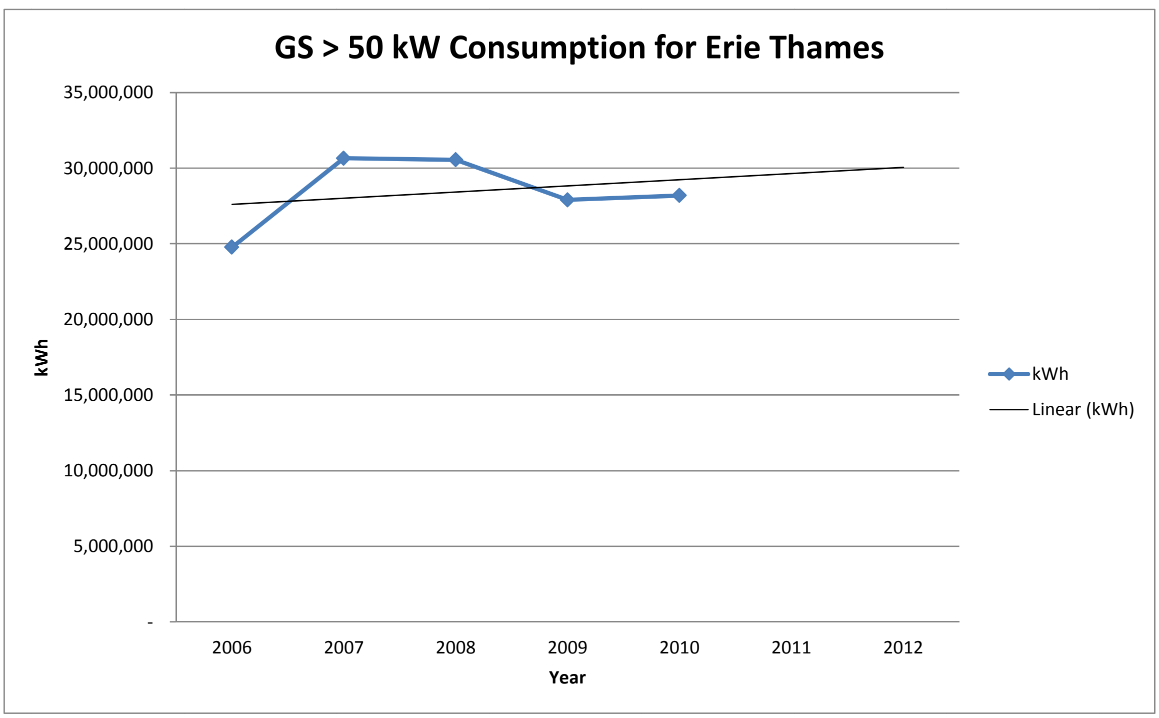
4. Plot the daily kWh of this class against the HDD from January to May and from October to December. Insert a linear trend line for this plot to test the relationship between daily kWh and HDD. As shown in Figure 32 of Load Forecast report (Exhibit 3, Tab 2, Schedule 1), there was no meaningful correlation between HDD and kWh for this class of customer for Erie Thames. The same process was repeated for Clinton and West Perth separately. The same conclusion was found.



5. Plot the daily kWh of this class against the CDD from June to September. Insert a linear trend line for this plot to test the relationship between daily kWh and CDD. As shown in Figure 33 of the Load Forecast report there was no meaningful correlation between CDD and kWh.



6. ***After determining that there was no weather correction for this class, the kWh from 2006 to 2010 were plotted and a trend line was inserted to estimate the demand in 2011 and 2012. The trend line showed the 2011 and 2012 extrapolated values were around 29,000,000 kWh and 30,000,000 kWh respectively.***



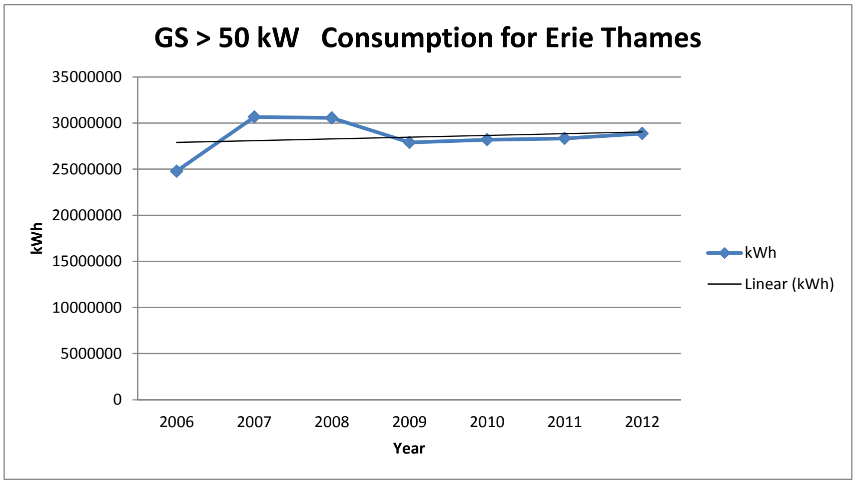
7. At the time the analysis was made, the most recent IESO's 18 month outlook (May 2011) was used as a reference. According to the IESO report, the Ontario energy consumption was expected to grow by 0.5% in 2011 and 1.9% in 2012. The report mentioned that economic and population growth would promote higher electricity demand but conservation programs would act to reduce the demand. The economic assumptions used in the IESO's forecast included the Ontario Employment, Ontario Housing Starts and Ontario Growth Index. A copy of the table from the IESO's 18 month outlook was shown below.

Year	Ontario Employment		Ontario Housing Starts		Ontario Growth Index	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)	Index	Annual Growth (%)
1995	5,098	2.0	31.9	-23.3	1.025	1.42
1996	5,161	1.2	39.5	23.9	1.036	1.05
1997	5,277	2.3	50.0	26.5	1.054	1.69
1998	5,440	3.1	50.1	0.2	1.077	2.18
1999	5,621	3.3	62.9	25.6	1.102	2.34
2000	5,801	3.2	67.4	7.1	1.128	2.39
2001	5,924	2.1	70.3	4.2	1.150	1.88
2002	6,014	1.5	79.6	13.3	1.169	1.65
2003	6,203	3.1	80.9	1.7	1.198	2.49
2004	6,310	1.7	79.9	-1.3	1.219	1.78
2005	6,390	1.3	73.2	-8.4	1.237	1.49
2006	6,485	1.5	67.8	-7.4	1.256	1.53
2007	6,585	1.6	62.8	-7.4	1.275	1.47
2008	6,686	1.5	71.9	14.6	1.294	1.50
2009	6,535	-2.3	47.9	-33.3	1.286	-0.63
2010	6,632	1.5	57.8	20.5	1.303	1.34
2011 (f)	6,731	1.5	52.1	-9.7	1.320	1.29
2012 (f)	6,826	1.4	51.6	-1.0	1.336	1.23

8. IESO's energy growth estimates for 2011 (0.5%) and 2012 (1.9%) were used to test the validity of the growth rate for this class. The difference of the 2011 and 2012 forecast using the extrapolated historical trending values and the IESO's growth rate is shown in the table below. In 2012, using IESO's growth rate, the forecast value was 1,129,903 kWh lower than the historical trending value. The 2012 CDM target for this class (consolidated) is 219,280 kWh (see response to the Board Staff IR question 1C). The IESO's growth rate was considered reasonable for this class and the impact of the CDM was already included in the forecast.

Erie Thames kWh forecast	2011	2012
Extrapolated values using historiacal data	29,000,000	30,000,000
Using IESO's estimated growth rate	28,331,793	28,870,097
Difference	668,207	1,129,903

	2006	2007	2008	2009	2010	2011	2012
kWh	24,776,038	30,653,353	30,553,013	27,896,587	28,190,839	28,331,793	28,870,097
% change		23.7%	-0.3%	-8.7%	1.1%	0.5%	1.9%



e) If IESO forecast of energy growth was used, what alternative escalation factors did EPTC consider and why was IESO forecast energy growth chosen?

- ***EPTC considered the Ontario Growth Index of 1.29% (2011) and 1.23% (2012) but decided to use the IESO's forecast because IESO factored in both the impacts of economic growth and conservation efforts.***

25. Reference: Exhibit 3, Tab 2, Schedule 1, Section 6
Exhibit 3, Tab 2, Schedule 1, Section 12

a) Please confirm that Section 6.1 (Tables 22-24) deals with GS>1000 but less than 3000.

- ***Confirmed.***

b) Please provide a Table that sets out the (consolidated) GS 1,000-4,999 kWh class kWh use, number of customers and average use per customer for each year from 2008 to 2012. Please include 2011 actual values if available.

- ***In the table shown below, the 2009 to 2011 values are actual values. All 5 customers were from the Erie Thames supply area.***

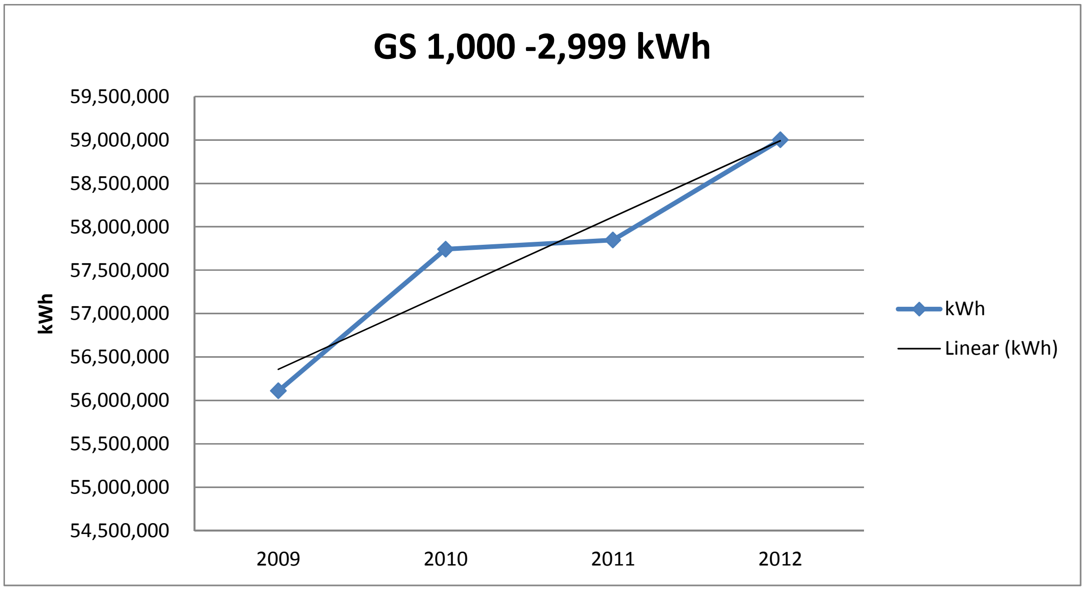
	2009	2010	2011	2012
kWh (no loss)	68,512,814	69,433,617	68,743,695	69,200,000
Number of Customers	5	5	5	5
Average per customer per month	1,141,880	1,157,227	1,145,728	1,153,333

c) Section 12 parts c) and d) state that "historic trending and extrapolation were used to forecast load" for the GS 1,000-2,999 class and also for the GS 3,000-4,999 class. Please explain more fully how the load forecast for the GS 1,000-4,999 class was developed for each sub-group.

- ***The GS 1,000 – 4,999 consists of two sub-groups: the GS 1,000-2,999 and GS 3,000 – 4,999. Historic trending and extrapolation were used for each sub-group. No weather adjustments were applied to these sub-groups because no significant correlations between HDD and kWh or CDD and kWh were observed (See sections 12.3 and 12.4 of Exhibit 3, Tab 2, Schedule 1).***
- ***The forecasts for each sub-group are shown below. All values are actual values with the exception of 2012. The % change from the previous year for 2011 and 2012 were 0.2 % and 2.0 % respectively. These growth rates were consistent with the IESO's growth rate of 0.5% in 2011 and 1.9% in 2012.***

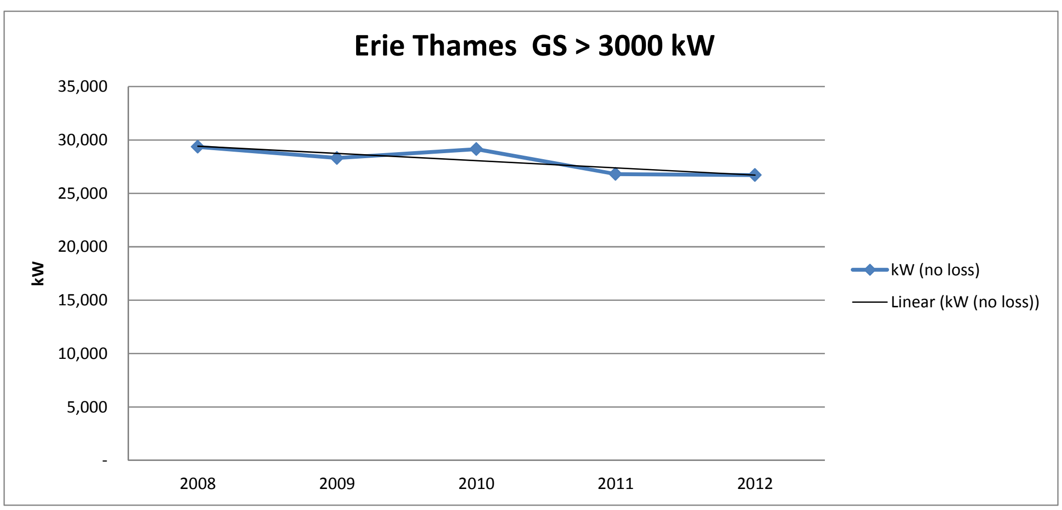
Revised Table 22

GS 1,000-2,999	2009	2010	2011	2012
kWh	56,110,476	57,741,953	57,847,516	59,000,000
% change from previous year		2.9%	0.2%	2.0%
Number of Customers	4	4	4	4



Revised Table 25

GS 3,000-4,999	2008	2009	2010	2011	2012
kWh	12,935,014	12,402,337	11,691,664	10,896,179	10,200,000
% change from previous year		-4.1%	-5.7%	-6.8%	-6.4%
Number of Customers	1	1	1	1	1



d) Please provide revised versions of Tables 22 and 25 that include the 2011 actual use and number of customers.

- ***See section C above.***

26. Reference: Exhibit 3, Tab 2, Schedule 1, Section 7

a) Please provide a revised version of Table 30 that includes the actual 2011 values.

- ***All values shown in the table below from 2006 to 2011 were actual values.***

Revised Table 30

	2006	2007	2008	2009	2010	2011	2012
kWh	91,130,718	83,755,976	74,125,314	69,719,263	92,434,591	94,046,108	97,146,783
% change		-8.1%	-11.5%	-5.9%	32.6%	1.7%	3.3%

b) How were the forecast values for 2011 and 2012 established?

- ***This class consisted of only one large industrial customer in the automotive manufacturing sector. The electricity demand was mainly affected by the economy of the auto industry. No weather adjustment was applied for this class since no correlation between weather and electricity demand was observed (Exhibit 3, Tab 2, Schedule 1, section 12.5).***
- ***As shown in the table below, there were wide swings of electricity demand. All values shown in the table with the exception of those cells highlighted in yellow were actual values. From 2007 to 2009, the demand dropped every year and in 2010, the demand rebounded strongly.***

	2006	2007	2008	2009	2010	2011	2012
kWh	91,130,718	83,755,976	74,125,314	69,719,263	92,434,591	95,335,410	97,146,783
kWh(Jan to May)	36,632,192	33,694,998	34,406,450	22,754,607	37,494,179	39,833,551	40,590,388
% change kWh		-8.1%	-11.5%	-5.9%	32.6%	3.1%	1.9%
% change kWh(Jan to May)		-8.0%	2.1%	-33.9%	64.8%	6.2%	1.9%

- ***At the time when the 2011 forecast was made, the first five month's actual kWh values were used to estimate the 3.1% growth rate for 2011 (6.2% x 32.6%/64.8%). For 2012, the IESO's 1.9% growth rate was used.***

27. Reference: Exhibit 3, Tab 2, Schedule 1, Section 8

a) Pease provide a table that sets out the total actual use in 2010 and 2011 (kWh and billing kW) and the forecast use for 2012 for Clinton, West Perth, (former) Erie Thames and the consolidated utility.

- ***The 2010 and 2011 actual Street Light kWh and kW values are shown below. The 2012 forecast have been revised.***

	Actual		Forecast
Street Light kWh	2010	2011	2012
Clinton	348,986	350,935	350,935
ETPL	3,151,063	3,129,160	3,129,160
West Perth	440,798	440,797	440,797
Total	3,940,846	3,920,893	3,920,893

	Actual		Forecast
Street Light kW	2010	2011	2012
Clinton	1,002	1,002	1,002
ETPL	8,509	8,620	8,620
West Perth	1,196	1,196	1,196
Total	10,707	10,818	10,818

b) How were the forecast values for 2011 and 2012 established? In particular, what was the basis for the forecast increase in Street Light load for the (former) Erie Thames service area?

- ***The 2012 forecast have been revised. Please see above.***

28. Reference: Exhibit 3, Tab 2, Schedule 1, Section 9

a) Pease provide a table that sets out the total actual use in 2010 and 2011 (kWh and billing kW) and the forecast use for 2012 for Clinton, West Perth, (former) Erie Thames and the consolidated utility.

- ***The 2010 and 2011 actual Sentinel Light kWh and kW values are shown below. The 2012 forecast have been revised.***

	Actual		Forecast
Sentinel Light kWh	2010	2011	2012
Clinton	35,561	36,137	36,137
ETPL	222,912	223,433	223,433
West Perth	14,446	14,922	14,922
Total	272,919	274,492	274,492

	Actual		Forecast
Sentinel Light kW	2010	2011	2012
Clinton	102	103	103
ETPL	602	615	615
West Perth	39	40	40
Total	741	757	757

29. Reference: Exhibit 3, Tab 2, Schedule 1, Section 10

a) Pease provide a table similar to Table 49 based on 2011 actual values.

Table 49 Unmetered Load Forecast

	2008		**2009**		**2010**		**2011**		**2012**	
	kWh	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**
Clinton	56,070	13	59,245	14	56,040	13	45,555	13	56,040	13
Erie Thames	500,236	114	538,055	123	533,136	122	496,647	124	545,982	125
West Perth	16,368	4	16,368	4	16,319	4	16,368	4	16,319	4
Consolidated	**572,674**	**131**	**613,668**	**141**	**605,495**	**139**	**558,570**	**141**	**618,341**	**142**

30. Reference: Exhibit 3, Tab 2, Schedule 1, Section 11

a) Pease provide tables similar to Tables 50-51 based on 2011 actual values.

Table 50 & 51 Embedded Distributor Load Forecast

	2006		**2007**		**2008**		**2009**		**2010**		**2011**		**2012**	
	kWh	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**
Non Weather Adjusted	17,916,584	4,277	18,577,150	4,434	18,516,267	3,923	18,513,267	4,419	17,518,323	4,182	17,465,324	3,044	17,350,000	4141
Weather Adjusted	17,896,299	4,272	18,558,538	4,430	18,594,719	3,925	18,594,719	4,438	17,451,503	4,166	17,398,706	3,044	17,350,000	4,141

31. Reference: Exhibit 3, Tab 2, Schedule 1, Section 12
Exhibit 3, Tab 2, Schedule 2

a) With respect to Schedule 2 (pages 1-3), are the customer count values shown year-end or average annual values?

- ***Year end values.***

b) Please provide the actual customer count for 2011 for each of the Tables shown on pages 1-3 of Schedule 2.

	2011		
	ETPL	CPC	WPPI
	Customer Count	Customer Count	Customer Count
Residential	12,965	1,428	1,836
GS<50	1,426	210	241
GS>50 to 999	138	17	20
GS> 1000 to 2999	8		
GS> 3000 to 4999	1		
Large Use	1		
Unmetered	105	11	5
Sentinel Light	256	38	7
Street Light	2,956	709	618
Embedded	3	-	-

c) Please provide the consolidated customer count by class as of June 30, 2012 and as of June 30, 2011

	Jun-11			Jun-12
	ETPL	CPC	WPPI	ETPL
	Customer Count	Customer Count	Customer Count	Customer Count
Residential	12,691	1,401	1,797	16,007
GS<50	1,292	218	235	1,762
GS>50 to 999	146	19	20	182
GS> 1000 to 2999	5			5
GS> 3000 to 4999	1			1
Large Use	1			1
Unmetered	99	11	4	113
Sentinel Light	256	38	7	301
Street Light	2,956	709	618	4,283
Embedded	4			4

d) How was the Net System Load Shape (Section 12, 1st page) determined and what customer classes is it meant to include?

- ***The Net System Load Shape (NSLS) was calculated by subtracting from the LDC Delivery Point Load data all the interval meter accounts load profile. NSLS represents the load shape for residential and GS < 50 customer classes.***

e) Tab 2, Schedule 1, Section 12 (2nd page) states that a liner trend line was used to project customer growth in 2012 for Residential and GS<50. However, in Tab 2, Schedule 2 (page 3) it appears that a more qualitative approach was used. Please provide the forecast customer counts for each of these two classes based a linear trend line staring with 2006.

- ***The residential and GS <50 forecasts were based on projecting the weather adjusted historical kWh consumption as shown in Figures 1, 3, 5,7 and 9. The customer counts were also projected using historical values. Please see Figure 31.***

f) With respect to Tab 2, Schedule 1, Section 12 (2nd page), please provide a schedule that sets out the determination of the "weather adjusted kWh per customer per month" for each of the Residential and GS<50 classes that was used in conjunction with the forecast customer count to forecast load for 2012 for each of these two classes.

- ***For the residential and GS<50 classes, the weather adjusted historical kWh from 2006 to 2010 were calculated. A trend line was used to project the 2011 and 2012 kWh consumption. The customer counts were also projected using historical values. The "weather adjusted kWh per customer per month" was calculated by dividing the weather adjusted kWh by the customer count of the same year.***

g) Please prepare a forecast for 2012 Large Use class load, using actual data to date for 2012 along with the historical 2011 use for the Large Use class and applying the same methodology as set out in Section 12, part e).

- ***Please see section 6 a) using the actual 2011 data.***

32. Reference: Exhibit 3, Tab 2, Schedule 1, Section 12
Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), pages 12 and 14

a) Has ETPC included the impact of CDM programs (up to and including 2011 programs) in its Load Forecast?

   - ***ETPL has included the impact of CDM programs in its load forecast.***

b) If yes, please explain how program impacts (i.e., what years' programs) have been reflected in the Load Forecast.

- ***Please see answers to the Board Staff questions 1a) to 1c).***

c) If the impacts of the 2011 CDM programs are not reflected in the forecast, please address the issues required as per the first full paragraph on page 13 of the Board's Guidelines.

   - ***Not applicable.***

d) Please provide a copy of the OPA's report on ETPC's 2011 CDM program results for each of the three service areas.

   - ***The OPA's report on ETPC's 2011 CDM program is not available at this time.***

e) Please provide a copy of the OPA's 2010 report on ETPC's CDM activity results for each of the three service areas.

- ***The OPA's report is provided with this response as 2006-2010 Final OPA CDM Results by Service area.***

3.2 Is the test year forecast of other revenues appropriate?

33. Reference: Exhibit 3, Tab 3, Schedule 1, page 1

a) Please explain why the Retail Services Revenues are forecast to decline to zero in 2011 and 2012 while the STR revenues increase.

   - ***Retail services revenue has been recorded in the STR Revenue account beginning in 2011.***

b) Please explain the significant increase in Late Payment Charge revenues forecast for 2011 over 2010.

- ***Late payment charge revenue for 2010 is ETPL revenues alone and 2011 is for the combined entity.***

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

a) What was the impact on 2012 OM&A of moving the billing staff over to ETPC? Where in Exhibit 4 is can this change be seen?

- ***There was no impact of moving the staff over.***

b) Please explain more fully the portion of the $160,000 decrease due changes in how revenues are posted to the GL by Clinton and West Perth. In particular, why is there no offset in revenues somewhere else?

- ***The $160,000 was for water and sewer other revenues that CPC and WPPI posted in with the electricity other revenues and did not belong there and should not be offset elsewhere.***

Operating Costs

4.1 Is the proposed 2012 OM&A forecast appropriate?

35. Reference: Exhibit 4, Tab 2, Schedule 1

a) Please file the 2010 Board approvedOM&A Detailed Cost Table for CPC and WPPI.

   - ***Given the nature of the settlement for both CPC and WPPI there is no Board approved OM&A Detailed Cost Table. Both CPC and WPPI settled with a percentage increase to their existing rates and as such not specific determination was mad on costs.***

b) Please file the 2008 Board approved OM&A Detailed Cost Table for EPTL

2008 Board Approved Detailed OM&A Costs		2008 Test Decision
Operation (Working Capital)		
5005-Operation Supervision and Engineering		$20,259.00
5010-Load Dispatching		$0.00
5012-Station Buildings and Fixtures Expense		$12,949.00
5014-Transformer Station Equipment - Operation Labour		$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses		$0.00
5016-Distribution Station Equipment - Operation Labour		$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses		$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour		$0.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		$329.00
5030-Overhead Sub transmission Feeders - Operation		$0.00
5035-Overhead Distribution Transformers- Operation		$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour		$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses		$0.00
5050-Underground Sub transmission Feeders - Operation		$0.00
5055-Underground Distribution Transformers - Operation		$0.00
5060-Street Lighting and Signal System Expense		$0.00
5065-Meter Expense		$0.00
5070-Customer Premises - Operation Labour		$0.00
5075-Customer Premises - Materials and Expenses		$0.00
5085-Miscellaneous Distribution Expense		$0.00
5090-Underground Distribution Lines and Feeders - Rental Paid		$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid		$0.00
5096-Other Rent		$1,219.00
Sub-Total		$34,756.00
Maintenance (Working Capital)		
5105-Maintenance Supervision and Engineering		$0.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations		$390,088.00
5112-Maintenance of Transformer Station Equipment		$51,667.00
5114-Maintenance of Distribution Station Equipment		$0.00
5120-Maintenance of Poles, Tow ers and Fixtures		$199,567.00
5125-Maintenance of Overhead Conductors and Devices		$69,602.00
5130-Maintenance of Overhead Services		$180,674.00
5135-Overhead Distribution Lines and Feeders - Right of Way		$118,292.00
5145-Maintenance of Underground Conduit		$0.00
5150-Maintenance of Underground Conductors and Devices		$77,680.00
5155-Maintenance of Underground Services		$74,175.00
5160-Maintenance of Line Transformers		$122,337.00
5165-Maintenance of Street Lighting and Signal Systems		$0.00
5170-Sentinel Lights - Labour		$0.00
5172-Sentinel Lights - Materials and Expenses		$0.00
5175-Maintenance of Meters		$177,815.00
5178-Customer Installations Expenses- Leased Property		$0.00
5185-Water Heater Rentals - Labour		$0.00
Sub-Total		$1,461,897.00

Billing and Collections		
5305-Supervision		$0.00
5310-Meter Reading Expense		$0.00
5315-Customer Billing		$943,739.00
5320-Collecting		$0.00
5325-Collecting- Cash Over and Short		$0.00
5330-Collection Charges		$10,669.00
5335-Bad Debt Expense		$119,078.00
5340-Miscellaneous Customer Accounts Expenses		$0.00
Sub-Total		$1,073,486.00
Community Relations		
5405-Supervision		$27,879.00
5410-Community Relations - Sundry		$0.00
5415-Energy Conservation		
5420-Community Safety Program		
5425-Miscellaneous Customer Service and Informational Expenses		
5505-Supervision		
5510-Demonstrating and Selling Expense		
5515-Advertising Expense		$1,000.00
5520-Miscellaneous Sales Expense		
Sub-Total		$28,879.00

Administrative and General Expenses		
5605-Executive Salaries and Expenses		$83,836.00
5610-Management Salaries and Expenses		$492,202.00
5615-General Administrative Salaries and Expenses		$464,550.00
5620-Office Supplies and Expenses		$110,848.00
5625-Administrative Expense Transferred Credit		$0.00
5630-Outside Services Employed		$178,000.00
5635-Property Insurance		$51,685.00
5640-Injuries and Damages		$0.00
5645-Employee Pensions and Benefits		-$208.00
5650-Franchise Requirements		$0.00
5655-Regulatory Expenses		$40,000.00
5660-General Advertising Expenses		$0.00
5665-Miscellaneous General Expenses		$65,687.00
5670-Rent		$108,190.00
5675-Maintenance of General Plant		$0.00
5680-Electrical Safety Authority Fees		$0.00
5685-Independent Market Operator Fees and Penalties		$0.00
Sub-Total		$1,594,790.00

36. Reference: Exhibit 4, Tab 2

a) Please provide the costs for 2008 through 2012 (combined) of all voluntary memberships, such as the EDA. Please identify each separately.

- ***ETPL and its predecessors are members of the EDA. No other voluntary memberships are applicable.***

37. Reference: Exhibit 4, Tab 2, Schedule 2

a) Please provide the OM&A Cost per customer and per FTEE for CPC, WPPI and ETPC for 2008 through 2010

- ***See response to Board Staff IR#40.***

b) Please provide the OM&A cost per customer and per FTEE for the cohort of utilities defined by the Board to be most like EPTC.

- ***Cost per customer for ETPL's cohort of utilities 2010 data.***

Mid-Size Southern Medium-High Undergrounding	2010 Cost Per Customer	2010 PP&E Per Customer	2010 Combined
Wasaga Distribution Inc.	$182.89	$732	$915
COLLUS Power Corp.	$275.69	$857	$1,133
Welland Hydro-Electric System Corp.	$224.13	$1,018	$1,242
Kingston Electricity Distribution Limited	$228.55	$1,066	$1,295
Chatham-Kent Hydro Inc.	$208.20	$1,104	$1,321
St. Thomas Energy Inc.	$210.22	$1,142	$1,352
Bluewater Power Distribution Corporation	$293.94	$1,192	$1,486
Essex Powerlines Corporation	$196.87	$1,314	$1,511
Erie Thames Powerlines Corporation	$310.93	$1,245	$1,556
Westario Power Inc.	$200.37	$1,373	$1,573
Peterborough Distribution Incorporated	$209.09	$1,371	$1,580
Woodstock Hydro Services Inc.	$243.45	$1,397	$1,640
Festival Hydro Inc.	$206.34	$1,712	$1,918
Niagara Falls Hydro Inc.	$263.72	$2,315	$2,579

- ***FTEE counts for utilities within ETPL's cohort group are not readily available.***

38. Reference: Exhibit 4, Tab 2, Schedule 1, 3

a) Please provide the detailed variance analysis (accounts 5005 through 6205) for OM&A as between 2011 actuals and 2012 forecast.

Account	Description	Bridge Year	Test Year	Difference
Operations				
5005	Operation Supervision and Engineering	$ 205,803	$ 193,036	$ 12,767
5010	Load Dispatching			$ -
5012	Station Buildings and Fixtures Expense			$ -
5014	Transformer Station Equipment - Operation Labour			$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses			$ -
5016	Distribution Station Equipment - Operation Labour			$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ 3,519	-$ 3,519
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -	$ 3,683	-$ 3,683
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 1,794	$ 1,441	$ 354
5030	Overhead Sub-transmission Feeders - Operation			$ -
5035	Overhead Distribution Transformers - Operation			$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ 384	-$ 384
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exper	$ -	$ 28	-$ 28
5050	Underground Sub-transmission Feeders - Operation			$ -
5055	Underground Distribution Transformers - Operation			$ -
5060	Street Lighting and Signal System Expense			$ -
5065	Meter Expense	$ 4,556	$ 6,150	-$ 1,594
5070	Customer Premises - Operation Labour	$ -	$ 196	-$ 196
5075	Customer Premises - Operation Materials and Expenses	$ -	$ 9	-$ 9
5085	Miscellaneous Distribution Expenses	$ 94,139	$ 73,770	$ 20,369
5090	Underground Distribution Lines and Feeders - Rental Paid			$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid			$ -
5096	Other Rent	$ 1,013		$ 1,013
Total - Operations		$ 274,004	$ 282,215	-$ 8,210

Account	Description	Bridge Year	Test Year	Difference
Maintenance				$ -
5105	Maintenance Supervision and Engineering			$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 115,589	$ 95,941	$ 19,648
5112	Maintenance of Transformer Station Equipment			$ -
5114	Maintenance of Distribution Station Equipment	$ 11,126	$ 3,386	$ 7,741
5120	Maintenance of Poles, Towers and Fixtures	$ 36,036	$ 39,790	-$ 3,754
5125	Maintenance of Overhead Conductors and Devices	$ 4,981	$ 5,846	-$ 865
5130	Maintenance of Overhead Services	$ 267,318	$ 76,064	$ 191,254
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 79,400	$ 114,915	-$ 35,515
5145	Maintenance of Underground Conduit	$ -	$ 145,053	-$ 145,053
5150	Maintenance of Underground Conductors and Devices	$ 61,039	$ 54,472	$ 6,567
5155	Maintenance of Underground Services	$ 76,808	$ 55,162	$ 21,646
5160	Maintenance of Line Transformers	$ 104,500	$ 103,105	$ 1,395
5165	Maintenance of Street Lighting and Signal Systems			$ -
5170	Sentinel Lights - Labour			$ -
5172	Sentinel Lights - Materials and Expenses			$ -
5175	Maintenance of Meters	$ 111,536	$ 30,616	$ 80,920
5178	Customer Installations Expenses - Leased Property			$ -
5195	Maintenance of Other Installations on Customer Premises			$ -
Total - Maintenance		$ 693,543	$ 724,349	-$ 30,806
Account	**Description**	**Bridge Year**	**Test Year**	**Difference**

Account	Description	Bridge Year	Test Year	Difference
Billing and Collecting				$ -
5305	Supervision	$ -	$ 18,631	-$ 18,631
5310	Meter Reading Expense	$ -	$ 118,209	-$ 118,209
5315	Customer Billing	$ 900,539	$ 906,125	-$ 5,586
5320	Collecting	$ -	$ 21,823	-$ 21,823
5325	Collecting - Cash Over and Short			$ -
5330	Collection Charges	$ 99,746	$ 118,316	-$ 18,570
5335	Bad Debt Expense	$ 39,032	$ -	$ 39,032
5340	Miscellaneous Customer Accounts Expenses	$ 26	$ 27	-$ 1
Total - Billing and Collecting		$ 983,630	$ 1,183,131	-$ 199,501
Account	**Description**	**Bridge Year**	**Test Year**	**Difference**
Community Relations				$ -
5405	Supervision	$ 25,738	$ 2,160	$ 23,578
5410	Community Relations - Sundry	$ -	$ 19,179	-$ 19,179
5415	Energy Conservation			$ -
5420	Community Safety Program			$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ 181,845	$ 120,029	$ 61,816
5505	Supervision			$ -
5510	Demonstrating and Selling Expense			$ -
5515	Advertising Expenses	$ 15,248	$ 7,415	$ 7,833
5520	Miscellaneous Sales Expense			$ -
Total - Community Relations		$ 144,449	$ 148,783	-$ 4,333

Account	Description	Bridge Year	Test Year	Difference
Administrative and General Expenses				$ -
5605	Executive Salaries and Expenses	$ 242,079	$ 218,390	$ 23,689
5610	Management Salaries and Expenses	$ 826,982	$ 1,194,776	-$ 367,794
5615	General Administrative Salaries and Expenses	$ 356,218	$ 361,626	-$ 5,408
5620	Office Supplies and Expenses	$ 144,048	$ 143,722	$ 326
5625	Administrative Expense Transferred - Credit		$ -	$ -
5630	Outside Services Employed	$ 402,986	$ 225,378	$ 177,608
5635	Property Insurance		$ -	$ -
5640	Injuries and Damages	$ 32,767	$ 13,438	$ 19,329
5645	Employee Pensions and Benefits	$ 365,096	$ 413,502	-$ 48,406
5650	Franchise Requirements		$ -	$ -
5655	Regulatory Expenses	$ 60,567	$ 115,000	-$ 54,433
5660	General Advertising Expenses		$ -	$ -
5665	Miscellaneous General Expenses	$ 524,282	$ 295,456	$ 228,826
5670	Rent	$ 313,614	$ 322,401	-$ 8,787
5675	Maintenance of General Plant	$ -	$ 80,204	-$ 80,204
5680	Electrical Safety Authority Fees	$ -	$ 7,865	-$ 7,865
5685	Independent Electricity System Operator Fees and Penalties		$ -	$ -
5695	OM&A Contra Account		$ -	$ -
6205	Donations (Charitable Contributions)		$ -	$ -
Total - Administrative and General Expenses		$ 3,686,891	$ 3,391,759	$ 295,132
Total OM&A		$ 5,782,518	$ 5,730,237	$ 52,281

b) Specifically provide details on accounts: 5315 (Customer Billing); 5310 (Meter Reading); 5645 (Employee Pension and Benefits); and 5665 (Miscellaneous General Expenses).

c) Please explain why there are no bad debt forecast costs for 2012 (account 5335).

- ***ETPL based its forecast on 2011 figures and there was a prior period adjustment for bad debts that resulted in no bad debt expense in 2011.***

39. Reference: Exhibit 4, Tab 2, Schedule 3

a) Please provide the 2012 detailed OM&A actuals to date by USoA account.

Account	Description	Aug YTD
Operations		
5005	Operation Supervision and Engineering	$ 103,464
5010	Load Dispatching	$ -
5012	Station Buildings and Fixtures Expense	$ -
5014	Transformer Station Equipment - Operation Labour	$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -
5016	Distribution Station Equipment - Operation Labour	$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -
5030	Overhead Sub-transmission Feeders - Operation	$ -
5035	Overhead Distribution Transformers - Operation	$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exper	$ -
5050	Underground Sub-transmission Feeders - Operation	$ -
5055	Underground Distribution Transformers - Operation	$ -
5060	Street Lighting and Signal System Expense	$ -
5065	Meter Expense	$ -
5070	Customer Premises - Operation Labour	$ -
5075	Customer Premises - Operation Materials and Expenses	$ -
5085	Miscellaneous Distribution Expenses	$ 81,741
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -
5096	Other Rent	$ 1,928
Total - Operations		$ 187,134

Account	Description	Aug YTD
Maintenance		$ -
5105	Maintenance Supervision and Engineering	$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 87,303
5112	Maintenance of Transformer Station Equipment	$ -
5114	Maintenance of Distribution Station Equipment	$ -
5120	Maintenance of Poles, Towers and Fixtures	$ 21,590
5125	Maintenance of Overhead Conductors and Devices	$ -
5130	Maintenance of Overhead Services	$ 91,971
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 107,171
5145	Maintenance of Underground Conduit	$ -
5150	Maintenance of Underground Conductors and Devices	$ 19,720
5155	Maintenance of Underground Services	$ 108,677
5160	Maintenance of Line Transformers	$ 65,185
5165	Maintenance of Street Lighting and Signal Systems	$ -
5170	Sentinel Lights - Labour	$ -
5172	Sentinel Lights - Materials and Expenses	$ -
5175	Maintenance of Meters	$ 103,901
5178	Customer Installations Expenses - Leased Property	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -
Total - Maintenance		$ 605,519

Account	Description	Aug YTD
Billing and Collecting		$ -
5305	Supervision	$ -
5310	Meter Reading Expense	$ 78,806
5315	Customer Billing	$ 567,797
5320	Collecting	$ -
5325	Collecting - Cash Over and Short	$ -
5330	Collection Charges	$ 73,304
5335	Bad Debt Expense	-$ 6,150
5340	Miscellaneous Customer Accounts Expenses	$ -
Total - Billing and Collecting		$ 713,758

Account	Description	Aug YTD
Community Relations		$ -
5405	Supervision	$ 16,091
5410	Community Relations - Sundry	$ -
5415	Energy Conservation	$ -
5420	Community Safety Program	$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ 88,812
5505	Supervision	$ -
5510	Demonstrating and Selling Expense	$ -
5515	Advertising Expenses	$ 44,598
5520	Miscellaneous Sales Expense	$ -
Total - Community Relations		$ 149,502

Account	Description	Aug YTD
Administrative and General Expenses		$ -
5605	Executive Salaries and Expenses	$ 54,102
5610	Management Salaries and Expenses	$ 1,111,282
5615	General Administrative Salaries and Expenses	$ 484,792
5620	Office Supplies and Expenses	$ 78,344
5625	Administrative Expense Transferred - Credit	$ -
5630	Outside Services Employed	$ 87,373
5635	Property Insurance	$ 6,255
5640	Injuries and Damages	$ -
5645	Employee Pensions and Benefits	$ 113,225
5650	Franchise Requirements	$ -
5655	Regulatory Expenses	$ 50,622
5660	General Advertising Expenses	$ -
5665	Miscellaneous General Expenses	$ 137,497
5670	Rent	$ 144,147
5675	Maintenance of General Plant	$ -
5680	Electrical Safety Authority Fees	$ -
5685	Independent Electricity System Operator Fees and Penalties	$ -
5695	OM&A Contra Account	$ -
6205	Donations (Charitable Contributions)	$ -
Total - Administrative and General Expenses		$ 2,267,637
Total OM&A		$ 3,923,549

40. Reference: Appendix 2H

a) Please provide an explanation of the $85,000 for on-going regulatory consulting.

- ***ETPL inadvertently listed these costs as on going they are in fact one time costs for the rate application.***

4.2 Are the compensation costs and employee levels appropriate?

41. Reference: Exhibit 4, Tab 2, Schedule 4

a) Please provide details as to the contract with ETPL staff, including the when the contract was negotiated and the annual increases including that for 2012.

- ***Please see response to Board Staff IR#30 A***

b) When does ETPC expect to complete negotiations on a new contract?

- ***ETPL hopes to complete negotiations on a new contract in December of 2012.***

42. Reference: Exhibit 4, Tab 2, Schedule 4

a) Please modify Appendix 2-K (Employee Costs) to show the Actual and Board approved 2010 employee costs for WPPI and CPC.

- ***CPC and WPPI were settled during a Settlement Conference in which the parties agreed, and the Board approved a 33.3% increase in rates for CPC and a 10% increase to rates for WPPI, therefore there was not decision on 2010 employee costs for WPPI and CPC.***
- ***This increase in rates was not based upon any approval of OM&A costs and should not be represented in that manner in this table. The settlement acknowledged that both WPPI and CPC were in need of financial relief and reinvestment in its infrastructure and provided increases to help in this end and should not be taken as definitive decision on costs. Further, there was an explicit recognition that even with the additional revenue CPC may not be able to earn its rate of return. The Settlement Agreement filed for CPC acknowledged the particular circumstances for CPC in the following:***
- ***"The Parties came to this agreement through a process of recognizing a need for additional revenue for CPC to provide safe, reliable service yet balancing the impact of such costs on the ratepayers. The Parties acknowledge that CPC may not actually earn its deemed return on equity, and that its PILs provision has been reduced to zero by the application of loss carry forwards. However, the Parties view this as a reasonable approach given the particular circumstances."***

b) Provide modify Appendix 2-K to show the 2008 actual and Board Approved employee costs for EPTC adding a row to show the affiliate FTEs for 2008 through 2010 ETPC.

	LRY - Board Approved	LRY - Actual	2009	2010	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	2	2	6	10	12	12
Affiliate Management Staff	25	25	21	13		
Affiliatet Union	60	60	51	27		
Non-Union						
Union			9	24	33	33
Total	87	87	87	74	45	45

43. Reference: Exhibit 4, Tab 2, Schedule 4, page 2, Appendix 2-K.

a) Please explain why the proportion of OM&A capitalized increases significantly in 2012.

- ***Please see all responses with respect to the increase in capital spend.***
- ***Due to the large increase in capital spend the amount of labour that is capitalized has increased as a result.***

4.3 Are the allocation and shared service costs appropriate?

44. Reference: Exhibit 4, Tab 2, Schedule 5

a) For each of the services offered by the affiliate companies please describe the nature of the service; the method of allocation and the total cost being allocated. Please show the allocation percentage for each of 2010 through 2012

- ***Please see responses to Board Staff IR #35.***

b) For the period 2010 through 2012 for Human Resource, Legal and IT services please provide the number of staff in each category supporting the utility.

- ***2 Human Resource staff, 1 Legal staff and 6 IT staff support the utility.***

c) For the affiliate service of rent, please describe what space is being rented and for what purpose.

- ***Office space in the town of Ingersoll is being rented.***
- ***Operations space (truck bays, yard, inventory storage) is being rented in the towns of Ingersoll, Aylmer and Mitchell.***

45. Reference: Exhibit 4, Tab 2, Schedule 5

a) In respect to the Ecaliber billing services please provide the cost per bill.

- ***Please see responses to Board Staff IR #35.***

b) When was this contract last tendered? Was it competitively tendered at that time?

- ***The contract was just awarded in 2011. The contract was not competitively tendered.***

c) Please provide details as to the due diligence ETPC has undertaken to ensure its billing costs are competitive.

- ***ETPL received costing to receive the service directly from Harris as opposed to Ecaliber as the reseller in order to ensure that the application service provider contract was competitive.***

4.4 Is the proposed level of Depreciation/Amortization expense for the 2012 Test Year appropriate?

46. Reference: Exhibit 4, Tab 2, Schedule 6

a) Please explain why there is no depreciation for smart meters (account 1860)

- ***Smart meters are not part of account 1860 at this point.***

47. Please provide the Depreciation, Amortization and Depletion schedules for 2010 and 2011.

Depreciation and Amortization Expense

Year: 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1805	Land	$ 150,428.71	$ -	$ 150,428.71	$ -	$ 150,428.71	-		
1808	Buildings	$ 148,263.12	$ -	$ 148,263.12	$ 10,160.00	$ 153,343.12	25.00	4.0%	$ 6,133.72
1810	Leasehold Improvements	$ 7,040.00	$ -	$ 7,040.00	$ -	$ 7,040.00	10.00	10.0%	$ 704.00
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-		
1820	Distribution Station Equipment <50 kV	$ 499,228.76	$ -	$ 499,228.76	$ 24,559.98	$ 511,508.75	25.00	4.0%	$ 20,460.35
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	25.00	4.0%	$ -
1830	Poles, Towers & Fixtures	$ 4,660,838.59	$ -	$ 4,660,838.59	$ 367,222.68	$ 4,844,449.93	25.00	4.0%	$ 193,778.00
1835	Overhead Conductors & Devices	$ 9,531,431.70	$ -	$ 9,531,431.70	$ 811,112.38	$ 9,936,987.89	25.00	4.0%	$ 397,479.52
1840	Underground Conduit	$ 2,212,620.07	$ -	$ 2,212,620.07	$ 104,872.61	$ 2,265,056.37	25.00	4.0%	$ 90,602.25
1845	Underground Conductors & Devices	$ 4,748,171.94	$ -	$ 4,748,171.94	$ 648,401.29	$ 5,072,372.59	25.00	4.0%	$ 202,894.90
1850	Line Transformers	$ 5,975,585.15	$ -	$ 5,975,585.15	$ 544,806.18	$ 6,247,988.24	25.00	4.0%	$ 249,919.53
1855	Services (Overhead and Underground)	$ 2,797,273.88	$ -	$ 2,797,273.88	$ 309,883.66	$ 2,952,215.71	25.00	4.0%	$ 118,088.63
1860	Meters	$ 2,721,532.09	$ -	$ 2,721,532.09	$ 128,946.36	$ 2,786,005.27	25.00	4.0%	$ 111,440.21
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-		
1905	Land	$ -	$ -	$ -	$ -	$ -	-		
1906	Land Rights	$ -	$ -	$ -	$ -	$ -	-		
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-		
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-		
1915	Office Furniture & Equipment (10 Years)	$ 58,466.26	$ -	$ 58,466.26	$ 1,323.00	$ 59,127.76	10.00	10.0%	$ 5,912.78
1915	Office Furniture & Equipment (5 Years)	$ 5,594.49	$ -	$ 5,594.49	$ 5,594.49	$ 8,391.74	5.00	20.0%	$ 1,678.35
1920	Computer Equipment - Hardware	$ 80,632.78	$ -	$ 80,632.78	$ 4,868.89	$ 83,067.23	5.00	20.0%	$ 16,613.45
1920	Computer Equip. - Hardware (Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-		
1920	Computer Equip. - Hardware (Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-		
1925	Computer Software	$ 610,688.04	$ -	$ 610,688.04	$ 143,626.10	$ 682,501.09	5.00	20.0%	$ 136,500.22
1930	Transportation Equipment	$ 224,426.45	$ -	$ 224,426.45	$ 66,156.00	$ 257,504.45	8.00	12.5%	$ 32,188.06
1935	Stores Equipment	$ 531.32	$ -	$ 531.32	$ -	$ 531.32	10.00	10.0%	$ 53.13
1940	Tools, Shop & Garage Equipment	$ 94,886.68	$ -	$ 94,886.68	$ 7,497.00	$ 98,635.18	10.00	10.0%	$ 9,863.52
1945	Measurement & Testing Equipment	$ 14,406.30	$ -	$ 14,406.30	$ -	$ 14,406.30	10.00	10.0%	$ 1,440.63
1950	Power Operated Equipment	$ 64,091.00	$ -	$ 64,091.00	$ -	$ 64,091.00	10.00	10.0%	$ 6,409.10
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	-		
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-		
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-		
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-		
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-		
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-		
1995	Contributions & Grants	$ (2,852,310.69)	$ -	$ (2,852,310.69)	$ (688,197.25)	$ (3,196,409.31)	25.00	4.0%	$ (127,856.37)
etc.				$ -		$ -			
				$ -		$ -			
	Total	$ 31,753,826.64	$ -	$ 31,753,826.64	$ 2,490,833.37	$ 32,999,243.32			$ 1,474,303.96

Depreciation and Amortization Expense

Year: 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1805	Land	$ 150,428.71	$ -	$ 150,428.71	$ 8,270.89	$ 154,564.16	-		
1808	Buildings	$ 158,423.12	$ -	$ 158,423.12	$ 20,326.58	$ 168,586.41	25.00	4.0%	$ 6,743.46
1810	Leasehold Improvements	$ 7,040.00	$ -	$ 7,040.00	$ -	$ 7,040.00	10.00	10.0%	$ 704.00
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-		
1820	Distribution Station Equipment <50 kV	$ 523,788.74	$ -	$ 523,788.74	$ -	$ 523,788.74	25.00	4.0%	$ 20,951.55
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	25.00	4.0%	$ -
1830	Poles, Towers & Fixtures	$ 5,028,061.27	$ -	$ 5,028,061.27	$ 350,281.34	$ 5,203,201.94	25.00	4.0%	$ 208,128.08
1835	Overhead Conductors & Devices	$ 10,342,544.08	$ -	$ 10,342,544.08	$ 335,000.42	$ 10,510,044.29	25.00	4.0%	$ 420,401.77
1840	Underground Conduit	$ 2,317,492.68	$ -	$ 2,317,492.68	$ 50,266.89	$ 2,342,626.12	25.00	4.0%	$ 93,705.04
1845	Underground Conductors & Devices	$ 5,396,573.23	$ -	$ 5,396,573.23	$ 256,072.04	$ 5,524,609.25	25.00	4.0%	$ 220,984.37
1850	Line Transformers	$ 6,520,391.33	$ -	$ 6,520,391.33	$ 693,252.12	$ 6,867,017.39	25.00	4.0%	$ 274,680.70
1855	Services (Overhead and Underground)	$ 3,107,157.54	$ -	$ 3,107,157.54	$ 267,697.83	$ 3,241,006.46	25.00	4.0%	$ 129,640.26
1860	Meters	$ 2,850,478.45	$ -	$ 2,850,478.45	$ 78,815.14	$ 2,889,886.02	25.00	4.0%	$ 115,595.44
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-		
1905	Land	$ -	$ -	$ -	$ -	$ -	-		
1906	Land Rights	$ -	$ -	$ -	$ -	$ -	-		
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-		
1910	Leasehold Improvements	$ -	$ -	$ -	$ 154,460.94	$ 77,230.47	-		
1915	Office Furniture & Equipment (10 Years)	$ 59,789.26	$ -	$ 59,789.26	$ 2,404.46	$ 60,991.49	10.00	10.0%	$ 6,099.15
1915	Office Furniture & Equipment (5 Years)	$ 11,188.98	$ -	$ 11,188.98	$ -	$ 11,188.98	5.00	20.0%	$ 2,237.80
1920	Computer Equipment - Hardware	$ 85,501.67	$ -	$ 85,501.67	$ 10,807.44	$ 90,905.39	5.00	20.0%	$ 18,181.08
1920	Computer Equip. - Hardware (Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-		
1920	Computer Equip. - Hardware (Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-		
1925	Computer Software	$ 754,314.14	$ -	$ 754,314.14	$ 19,606.90	$ 764,117.59	5.00	20.0%	$ 152,823.52
1930	Transportation Equipment	$ 290,582.45	$ -	$ 290,582.45	$ 596,684.96	$ 588,924.93	8.00	12.5%	$ 73,615.62
1935	Stores Equipment	$ 531.32	$ -	$ 531.32	$ -	$ 531.32	10.00	10.0%	$ 53.13
1940	Tools, Shop & Garage Equipment	$ 102,383.68	$ -	$ 102,383.68	$ 35,356.44	$ 120,061.90	10.00	10.0%	$ 12,006.19
1945	Measurement & Testing Equipment	$ 14,406.30	$ -	$ 14,406.30	$ 56.00	$ 14,434.30	10.00	10.0%	$ 1,443.43
1950	Power Operated Equipment	$ 64,091.00	$ -	$ 64,091.00	$ -	$ 64,091.00	10.00	10.0%	$ 6,409.10
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	-		
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-		
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-		
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-		
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-		
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-		
1995	Contributions & Grants	$ (3,540,507.94)	$ -	$ (3,540,507.94)	$ (445,442.65)	$ (3,763,229.26)	25.00	4.0%	$ (150,529.17)
etc.				$ -		$ -			
				$ -		$ -			
	Total	$ 34,244,660.01	$ -	$ 34,244,660.01	$ 2,433,917.74	$ 35,461,618.88			$ 1,613,874.50

Capital Structure and Cost of Capital

5.1 Is the proposed long term debt cost for 2012 appropriate?

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

a) Please file a table listing all the current and forecast long-term debt for 2012. Use this table to show the derivation of the weighted average cost of long-term debt and the interest costs for 2012.

	Debt	Rate	Cost
Town of Aylmer	$ 1,394,863.00	7.25%	$ 101,127.57
Central Elgin	$ 806,436.00	7.25%	$ 58,466.61
East Zorra Tavistock	$ 569,073.00	7.25%	$ 41,257.79
Ingersoll	$ 3,402,080.00	7.25%	$ 246,650.80
Norwich	$ 763,755.00	7.25%	$ 55,372.24
Southwest Oxford	$ 192,062.00	7.25%	$ 13,924.50
Zorra	$ 610,255.00	7.25%	$ 44,243.49
Town of Clinton	$ 900,000.00	7.00%	$ 63,000.00
Town of Mitchell	$ 1,183,391.00	7.25%	$ 85,795.85
Total Promissory Notes	$ 9,821,915.00	7.23%	$ 709,838.84
Future Bank Debt	$ 3,846,062.40	2.08%	$ 79,998.10
	$ 13,667,977.40	5.78%	$ 789,836.94

Cost Allocation

6.1 Is the proposed cost allocation methodology for 2012 appropriate?

49. Reference: Exhibit 7, Tab 1, Schedule 1

a) With respect to the Cost Allocation models dated June 4, 2012, please confirm that these are the cost allocation results (existing and updated classes) that ETPC is relying on. . If not, what cost allocation model results is it relying on for its Application.

- ***These are the cost allocation results ETPL is relying on.***

b) Please explain why the revenue at current rates (Sheet I6.1, Rows 39-41) is different as between the two models.

- ***The revenues at current rates are different between the two models due to a minor error is summing the merged classes between exhibits.***

c) Please provide a schedule that sets out the derivation of 2012 revenues at 2011 rates that takes into account the fact that each service area has different rates for 2011. In doing, please ensure that the rates used do not include any rate riders or adders (e.g. smart meter or low voltage) and also account for the transformer discount's impact on revenues.

	2012 Test Using Existing Rates ETPL		
	Customers	**Consumption**	**Distribution Revenues**
	(Year-End)	**(kWh / KW)**	**($)**
Residential	13,250	119,707,075	$3,980,001
GS<50	1,396	37,037,700	$713,586
GS>50 to 999 kW	138	91,030	$502,432
Greater than 1,000 to 2,999 kW	7	81,947	$456,134
Greater than 3,000 to 4,999 kW	1	26,704	$59,512
Large Use	1	160,146	$445,561
Unmetered Scattered Load	105	545,982	$10,823
Sentinel Lighting	256	52	$16,431
Street Lighting	2,956	758	$140,388
Embedded Distributor	3	23,768	$119,649
TOTAL	18,113	157,675,163	$6,444,516.81
	2012 Test Using Existing Rates WPPI		
	Customers	**Consumption**	**Distribution Revenues**
	(Year-End)	**(kWh / KW)**	**($)**
Residential	1,797	16,400,000	$485,275
GS<50	243	8,000,000	$160,446
GS>50 to 999 kW	20	27,500	$120,769
Unmetered Scattered Load	5	16,319	$479
Sentinel Lighting	7	46	$362
Street Lighting	618	1,196	$25,828
TOTAL	2,690	24,445,061	$793,159.96

	2012 Test Using Existing Rates CPC		
	Customers	Consumption	Distribution Revenues
	(Year-End)	(kWh / KW)	($)
Residential	1,414	11,660,000	$403,402
GS<50	221	5,422,967	$148,697
GS>50 to 999 kW	17	21,458	$133,190
Unmetered Scattered Load	11	56,040	$2,593
Sentinel Lighting	38	108	$346
Street Lighting	709	1,008	$24,461
TOTAL	2,410	17,161,581	$712,689.39

	2012 Test Using Existing Rates Total		
	Customers	Consumption	Distribution Revenues
	(Year-End)	(kWh / KW)	($)
Residential	16,461	147,767,075	$4,868,678
GS<50	1,860	50,460,667	$1,022,730
GS>50 to 999 kW	175	139,988	$756,391
Greater than 1,000 to 2,999 kW	7	81,947	$456,134
Greater than 3,000 to 4,999 kW	1	26,704	$59,512
Large Use	1	160,146	$445,561
Unmetered Scattered Load	121	618,341	$13,896
Sentinel Lighting	301	206	$17,140
Street Lighting	4,283	2,962	$190,677
Embedded Distributor	3	23,768	$119,649
TOTAL	23,213	199,281,804	$7,950,366.16

d) In the response to part c) please show separately the total fixed and variable revenues (the later net of the transformer ownership allowance) for each customer class and calculate the overall fixed-variable split for each class based on current rates.

	2012 Test Using Existing Rates ETPL			
	Customers	Consumption	Distribution Revenues	Distribution Revenues
	(Year-End)	(kWh / KW)	($)	($)
			Fixed	Variable
Residential	13,250	119,707,075	$2,256,219	$1,723,782
GS<50	1,396	37,037,700	$317,283	$389,717
GS>50 to 999 kW	138	91,030	$341,136	$136,612
Greater than 1,000 to 2,999 kW	7	81,947	$200,344	$197,650
Greater than 3,000 to 4,999 kW	1	26,704	$16,855	$42,657
Large Use	1	160,146	$116,894	$232,580
Unmetered Scattered Load	105	545,982	$3,452	$7,371
Sentinel Lighting	256	52	$15,667	$764
Street Lighting	2,956	758	$131,956	$8,432
Embedded Distributor	3	23,768	$79,915	$35,067
TOTAL	18,113	157,675,163	$3,479,721.10	$2,774,631.36

	2012 Test Using Existing Rates WPPI			
	Customers	Consumption	Distribution Revenues	Distribution Revenues
	(Year-End)	(kWh / KW)	($)	($)
			Fixed	Variable
Residential	1,797	16,400,000	$299,955	$185,320
GS<50	243	8,000,000	$34,846	$125,600
GS>50 to 999 kW	20	27,500	$49,162	$60,649
Unmetered Scattered Load	5	16,319	$40	$439
Sentinel Lighting	7	46	$0	$362
Street Lighting	618	1,196	$2,299	$23,529
TOTAL	2,690	24,445,061	$386,302.20	$395,899.17

	2012 Test Using Existing Rates CPC			
	Customers	Consumption	Distribution Revenues	Distribution Revenues
	(Year-End)	(kWh / KW)	($)	($)
			Fixed	Variable
Residential	1,414	11,660,000	$208,680	$194,722
GS<50	221	5,422,967	$64,099	$84,598
GS>50 to 999 kW	17	21,458	$8,658	$105,474
Unmetered Scattered Load	11	56,040	$1,596	$998
Sentinel Lighting	38	108	$128	$218
Street Lighting	709	1,008	$1,787	$22,674
TOTAL	2,410	17,161,581	$284,946.92	$408,684.40

	2012 Test Using Existing Rates Total			
	Customers	Consumption	Distribution Revenues	Distribution Revenues
	(Year-End)	(kWh / KW)	($)	($)
			Fixed	Variable
Residential	16,461	147,767,075	$2,764,854	$2,103,824
GS<50	1,860	50,460,667	$416,228	$599,916
GS>50 to 999 kW	175	139,988	$398,955	$302,735
Greater than 1,000 to 2,999 kW	7	81,947	$200,344	$197,650
Greater than 3,000 to 4,999 kW	1	26,704	$16,855	$42,657
Large Use	1	160,146	$116,894	$232,580
Unmetered Scattered Load	121	618,341	$5,088	$8,807
Sentinel Lighting	301	206	$15,795	$1,345
Street Lighting	4,283	2,962	$136,041	$54,636
Embedded Distributor	3	23,768	$79,915	$35,067
TOTAL	23,213	199,281,804	$4,150,970.22	$3,579,214.93

e) With respect to Sheet I5.2 has ETPC undertaken any review of the appropriateness of using the default weighting factors for services and billing for its circumstances as directed by the Board's EB-2010-0219 Report on Electricity Distribution Cost Allocation Policy (page 26)? If yes, please provide the associated analyses/reports.

- ***ETPL has not undertaken a review.***

f) With respect to Sheet I7.1, do all GS<50 customers and Residential customers have the same type of smart meter? If not, please update the unit costs used in this Sheet.

- ***All GS<50 and Residential customers have the same type of smart meter.***

g) Please explain why the revenue at current rates used in the Cost Allocation Model (Sheet O1) does not match the revenue at current rates used in the deficiency calculation in Exhibit 6, Tab 2, Schedule 2.

- ***In the calculation of distribution revenue at existing rates in tab I6.1 Revenue only one set of rates could be used and by applying those rates to one set of billing determinants the distribution revenue at existing rates cannot be made to match within the cost allocation model.***
- ***Secondly the transformer allowance input in tab I6.1 that calculates distribution revenue at existing rates was input as $0.60 per class and was applied to all consumptions.***

50. Reference: Exhibit 7, Tab 1, Schedule 2

a) The text on the 2nd page states that the Table on the first page reflects the Cost Allocation based on the existing customer classes. However, the 2012 DDR at current rates and the Miscellaneous Revenues by class do not match those in the June 4th Cost Allocation model. Please reconcile.

- ***In the calculation of distribution revenue at existing rates in tab I6.1 Revenue only one set of rates could be used and by applying those rates to one set of billing determinants the distribution revenue at existing rates cannot be made to match within the cost allocation model.***

b) The text on the 2nd page states that the Table on the 3rd page reflects the updated customer classes. However, the actual table is based on the existing customer classes. Please reconcile and revise.

- ***See responses to Board Staff IR 51 and 52.***

c) For both Tables, the policy ranges used for the customer class R/C ratios do not match those set out in the Board's EB-2010-0219 Report on Electricity Distribution Cost Allocation Policy. Please revise as appropriate.

- ***See responses to Board Staff IR 51 and 52.***

d) Also, in the Tables provided on the first and third pages please explain the various references to/use of 2006 and 2009 revenues

- ***The references to those dates were not updated from a previous use of the table in past COS applications. The***

data in the table is up to date and the 2006 date should be 2012.

e) Based on the foregoing, please provide updated versions of both tables.

- ***Updates provided in the responses to Board staff IR's 51 and 52.***

f) Also, please provide a completed copy of Appendix 2-O per Chapter 2 of the Board's Filing Guidelines. The material filed does not match the required tables.

- ***ETPL has included a copy of Appendix 2-O as excel model VECC IR#50 F***

51. Reference: Exhibit 7, Tab 1, Schedule 2

a) Please confirm that, based the Cost Allocation using the updated classes, the only customer classes outside the Board Policy ranges based on Status Quo rates are:
   - Large Use – at 122.23% vs. 120%
   - USL – at 28.55% vs. 80%
   - Sentinel Lights – at 76.51% vs. 80%
   - Embedded Distributor – at 71.42% vs. 80% (lower boundary for all GS and LU classes)

   - ***Confirmed.***

b) Please calculate the resulting revenue shortfall/excess assuming that each of the R/C ratios for each of the four classes noted in part (a) are moved to the upper/lower end of the policy range as appropriate.

- ***The revenue excess under these circumstances is $16,179.***

c) If there is a revenue shortfall, by how much would the R/C ratio for USL, Sentinel Lights and Embedded Distributors all have to change so that the resulting common value recovered the shortfall?

d) If there is a revenue excess, by how much would the Large Use R/C ratio have to decrease in order to eliminate the revenue excess?

- ***The large use RC ratio would have to decrease by a further 2.2% to eliminate the revenue excess.***

Rate Design

7.1 Is the derivation of the proposed base distribution rates appropriate?

52. Reference: Exhibit 8, Tab 1, Schedule 1
Exhibit 8, Tab 1, Schedule 6

a) Please confirm that the Board's EB-2007-0667 Report (Application of Cost Allocation to Electricity Distributors – page 12) rejected the use of 120% mark-up and set the ceiling at the MSC value base on minimum system with PLCC adjustment.

- ***Confirmed.***

b) Please provide a schedule that compares ETPC's proposed 2012 MSC (excluding any rate riders or adders) for each customer class with this value as found in Sheet O2 of the Cost Allocation based on updated classes.

Customer Class	Proposed Service Charge	MSC Value
Residential	$ 15.21	$ 19.68
GS < 50 kW	$ 20.95	$ 34.84
GS>50 to 999 kW	$ 226.60	$ 117.93
GS>1000 kW to 4999 kW	$ 2,862.06	$ 190.02
Large Use	$10,715.28	$ 457.31
Sentinel Lighting	$ 5.25	$ 9.16
Street Lights	$ 3.80	$ 8.13
Unmetered	$ 3.00	$ 58.81
Embedded Distributor	$ 2,219.86	$ 100.75

c) Please provide the derivation of the MSC (excluding any rate riders or adders) for each customer class, showing that it is based on the existing fixed variable split (calculated exclusive of any rate riders or adders) and the proposed Base Distribution Revenue Requirement allocated to each customer class. In the same schedule please show that the resulting variable charge is equivalent the proposed Distribution Volumetric Rate for each class as set out in Exhibit 8, Tab 1, Schedule 6.

d) In its Rate Design, how has ETPC provided for the recovery of the "cost" of the transformer ownership allowance discount?

- ***ETPL has allocated the cost for transformer ownership to the by class***

53. Reference: Exhibit 8, Tab 1, Schedule 7

a) Please provide a Schedule setting out the calculation of the class revenues as shown in Column A of the Table.

		Revenue Requirement	$ 8,920,713.67
		Class Allocation	
Residential		57.24%	$ 5,105,794.26
GS < 50 kW		13.84%	$ 1,234,832.75
GS>50 to 999 kW		13.25%	$ 1,182,361.12
GS>1000 to 4999 kW		4.96%	$ 442,385.01
Large Use		3.23%	$ 288,569.41
Sentinel Lighting		0.35%	$ 31,076.62
Street Lights		4.25%	$ 379,194.46
Embedded Distributor		1.90%	$ 169,394.08
Unmetered		0.98%	$ 87,105.96
Total		100.00%	$ 8,920,713.67

b) Please explain why the total revenue shown here is not equal to the total base distribution revenue requirement as shown in Sheet O1 of the Cost Allocation model.

- ***The table was not updated following changes to the calculation of revenue requirement.***

		A	B	A+B		
	Revenue Requirement	$ 8,920,713.67	**Transformer Allowance Recovery**		**Low Voltage Revenue**	
Residential	57.24%	$ 5,105,794.26	$ -	$ 5,105,794.26	$ 305,133.64	$ 5,410,927.90
GS<50	13.84%	$ 1,234,832.75	$ 6,586.00	$ 1,241,418.75	$ 98,410.58	$ 1,339,829.33
GS>50 to 499 kW	13.25%	$ 1,182,361.12	$ 54,701.00	$ 1,237,062.12	$ 161,798.52	$ 1,398,860.64
GS>1000 to 4999 kW	4.96%	$ 442,385.01	$ 58,140.00	$ 500,525.01	$ 73,979.56	$ 574,504.57
Large Use	3.23%	$ 288,569.41	$ 96,087.00	$ 384,656.41	$ 11,739.70	$ 396,396.10
Unmetered Scattered Load	0.98%	$ 87,105.96		$ 87,105.96	$ 1,205.92	$ 88,311.88
Sentinel Lighting	0.35%	$ 31,076.62		$ 31,076.62	$ 423.25	$ 31,499.87
Embedded Distributor	1.90%	$ 169,394.08	$ 4,667.00	$ 174,061.08	$ -	$ 174,061.08
Street Lighting	4.25%	$ 379,194.46		$ 379,194.46	$ 7,405.18	$ 386,599.65
Total	100.00%	$ 8,920,713.67	$220,181.00	$ 9,140,894.67	$ 660,096.34	$ 9,800,991.01

c) Please explain why the total Transformer Allowance value shown in the Table (Column B) does not equal the transformer ownership allowance value as shown in Sheet I6.1 of the Cost Allocation.

- ***The cost allocation model utilized the incorrect forecast for kW. When the correct value is input into the Cost Allocation model the numbers agree.***

7.2 Are the specific Service Charges appropriate?

54. Reference: Exhibit 1, Tab 2, Schedule 1 – Specific Service Charges

a) The reference to Exhibit 8, Schedule 6, Tab 1 does not appear to be correct. Please revise as necessary.

- ***The proposed service charges are included in the Proposed tariff sheet that is bookmarked in the PDF of ETPL's application, beginning at page 927of the application and specifically on page 930 and 931.***

b) Please confirm that the current (2012) Specific Service Charges are the same for all three service areas: (former Erie Thames; WWPI and CPC.

- ***The current specific service charges for all three service areas are the same.***

c) If not, where are they currently different?

- ***Not applicable.***

7.3 Are the proposed changes to Low Voltage rates appropriate?

55. Reference: Exhibit 8, Tab 1, Schedule 11

a) Please explain what "service area" the first table on the second page is meant to reflect.

- ***The first table reflect Erie Thames Service area prior to the merger.***

b) Please explain why the 2011 actual LV costs shown at the bottom of the second page for EPTC overall ($658,603.6) do not reconcile with sum of the 2011 Expenses shown in the preceding tables for the individual service areas.

- ***The table referred to with ETPL costs for LV totaling $658,603 does sum to the total in the above tables since the amounts after the merger are included in the total for Erie Thames in the table at the top of the page.***

c) Please confirm what the actual cost of LV service from HON was for 2011.

- ***Low Voltage costs from Hydro One for 2011 were $605,833.81.***

7.4 Are the proposed Loss Factors appropriate?

56. Reference: Exhibit 8

a) Please indicate where in Exhibit 8 ETPC explains its proposal with respect to loss factors for 2012.

- ***ETPL's proposal with respect to loss factors can be found in Exhibit 4, Tab 2, Schedule 7.***

Deferral and Variance Accounts

8.1 Are the account balances, cost allocation methodology and disposition period appropriate?

57. Reference: Exhibit 9, Tab 1, Schedule 1

a) Please provide details as to why it is unable to give an accounting of account 1562 PILs for both WPPI and CPC.

- ***Historical information is not available for the previous management.***

b) When does ETPC expect to be able to provide the necessary information to the Board.

- ***ETPC will undertake to provide the necessary information to the Board after the culmination of this rate proceeding.***

8.2 Are the proposed new deferral and variance accounts appropriate? (See Green Energy Plan)

Smart Meters

9.1 Is the proposed elimination of the Smart Meter Rate Adder and the inclusion of the Smart Meter Incremental Rate Rider appropriate?

58. Reference: Exhibit 9, Tab 1, Schedule 5

a) Is ETPC proposing to include ongoing smart meter OM&A and capital costs as part of its 2012 revenue requirement?

- ***Please see ETPL's responses to Board staff IR # 66.***

b) If not please explain why not?

- ***Please see ETPL's responses to Board staff IR #66.***

c) If yes, please provide the 2012 smart meter costs (OM&A, capital and depreciation costs)

- ***Please see ETPL's responses to Board staff IR # 66.***

59. Reference: Exhibit 9, Tab 1, Schedule 1

a) Please provide a summary table to the derivation of the smart meter disposition rate rider in the following form:

	Total	Residential	GS <50
Allocators			
LDC Average SmartMeterUnitCost		**$**	**$**
SmartMeterCost	$ 3,125,191	**$ 2,809,806**	**$ 315,385**
Allocation ofSmartMeterCosts	**100.00%**	**90%**	**10%**
Numberofmeters installed	17,886	16,081	1,805
Allocation ofNumberofmeters installed	**100.00%**	**90%**	**10%**
TotalReturn (deemed interestplus return on equity)	**$ 429,078.00**	**$ 385,776.77**	**$ 43,301.23**
Amortization	**$ 504,452.00**	**$ 453,544.26**	**$ 50,907.74**
OM&A	**$ 556,266.00**	**$ 500,129.35**	**$ 56,136.65**
Total BeforePILs	**$ 1,490,805.00**	**$ 1,340,357.55**	**$ 150,447.45**
PILs	**$ (171,415.04)**	**$ (154,116.36)**	**$ (17,298.68)**
TotalRevenue Requirement2006 to 2011	**$ 2,809,185.96**	**$ 2,525,691.57**	**$ 283,494.39**
	100.00%	90%	**10%**
SmartMeterRate Adder Revenues	**-890007.41**	-800190.605	-89816.805
Carrying Charge	**-37865.26**	-34044.01465	-3821.24535
SmartMeterTrue-up	**$ 1,881,313.29**	**$ 1,691,456.95**	**$ 189,856.34**
Metered Customers	17886	16081	1805
Recovery Period in Months	24	24	24
Rate Rider to RecoverSmartMeterCosts Yr	**$ 4.38**	**$ 4.38**	**$ 4.38**

9.2 Is the Smart Meter Disposition Rate Rider appropriate?

60. Reference: Exhibit 9, Tab 1, Schedule 5

a) Why is ETPC not proposing to calculate the smart meter disposition rate rider on a class specific basis.

- ***ETPL is not proposing to calculate the smart meter disposition rate rider on a class specific basis since the costs incurred for the installation of smart meters is the same for bothe the residential and gs<50 classes.***

b) Is it the contention of EPTC that there are no cost differences between the classes for the cost and installation of smart meters?

- ***ETPL does feel there are no cost differences between the two classes for smart meter cost and installation.***

9.1 Is the proposed Stranded Meter rate rider appropriate?

61. Reference: Exhibit 9, Tab 1, Schedule 1

a) Why is ETPC proposing not to dispose of its stranded meter costs in 2012?

- ***Please see responses to Board Staff IR #70.***

b) When does ETPC expect to dispose of these balances?

- ***ETPL would expect to dispose of these balances in its next rate proceeding.***

c) Please provide separately for the three service territories the amounts to be recovered for stranded meters.

- ***$174,606 for Clinton Power Corp.***
- ***$169,843 for West Perth Power Corp.***
- ***$469,201 for Erie Thames Powerlines Corp.***

LRAM/SSM

10.1 Is the proposal related to LRAM/SSM appropriate?

62. Reference: Exhibit10, Tab 1, Schedule 4

a) Please provide the source of the Measure Life in Appendix A.

- ***The source of all measure lives in Appendix A are found on the rightmost column in both Table 8 and Table 9. These sources refer to the documents listed in the Reference section on page 16 of IndEco's third party report.***

63. Reference: Exhibit 10, Tab 1, Schedule 4

a) In the 2012 cost of service application of Halton Hills Hydro Inc. Indeco also filed a review of CDM programs (see EB-2011-0271, Exhibit 10, Appendix A). The reports were completed by the consultant within one month of each other (Halton Hills August 2011 and Erie Thames September of 2011). A comparison of Tables 9 and 10 (SSM and LRAM Inputs respectively) with similar tables in the Halton Hills report's Table 8 and 9 (SSM and LRAM respectively) show sometimes significantly different "measure life" for identical programs. In many cases the measure life of the Erie Thames program is significantly greater. Please explain why there would be differences in measured lives for identical program offered by different utilities.

- ***Board LRAM/SSM Guidelines state that LRAM claims should be completed with the best available information at the time of the third party review. They also state that for the calculation of SSM claims, the best available information at the beginning of the year the program was launched should be used. Erie Thames confirms that it followed these guidelines when preparing its LRAM/SSM claims. This includes using measure lives that were the best available at the time of the third party review for LRAM claims and the best available at the beginning on the year the program was launched for the calculation of SSM claims.***

- ***IndEco has advised that the measure lives reported in the Appendices of the Halton Hills LRAM and SSM report are truncated measure lives that extend no longer than the period over which Halton Hills was claiming lost revenue. The Halton Hills LRAM and SSM claims were calculated using full measure lives consistent with both Board LRAM/SSM Guidelines and the measure lives used in the ERTH LRAM/SSM claim. The truncated***

measures lives were inadvertently posted into the Halton Hills Appendices tables.

64. Reference: Exhibit10, Tab 1, Schedule 4, page 3

a) Please provide the calculation supporting the use of the weighted average cost of capital used for the SSM claim.

- ***SSM claims are based on 5% of net TRC benefits. In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. The OEB has dictated that the discount rate to be used is the weighted average cost of capital (WACC). The WACC provided by Erie Thames is as follows:***
    - ***2005: 10%***
    - ***2006: 8.13%***
    - ***2007: 8.13%***

- ***Because the WACC is only used to calculate present values for TRC calculations for the SSM, it is only required for 2005-2007 since these are the years for which an SSM amount is being claimed.***

- ***The figure below demonstrates the use of Erie Thames' weighted average cost of capital for its SSM claim associated with 15W CFLs from the 2007 EKC program. The weighted average cost of capital was used in the same manner for all measures that make up Erie Thames' SSM claim.***

2007 Every Kilowatt Counts 15 W CFLs		
Energy savings	43	kWh
Peak demand savings	0.0013	kW
Measure life	8	years

		Winter Peak	Winter Mid	Winter Off Peak	Summer Peak	Summer Mid	Summer Off Peak	Shoulder Mid	Shoulder Off	Demand savings on peak kW
	Load profile:	15%	7%	19%	0%	11%	13%	17%	17%	
		× 43 kWh of energy savings =								
		6.45	3.01	8.17	0	4.73	5.59	7.31	7.31	0.0013
		× Avoided energy and capacity costs over the lifetime of the measure =								

Avoided costs in each year												Yearly total		**WACC discount factor**		Discounted TRC benefits
	2007	$0.80	$0.25	$0.37	$0.00	$0.38	$0.26	$0.60	$0.30	$0.00		$2.95		**1.000**		$2.95
	2008	$0.74	$0.26	$0.40	$0.00	$0.40	$0.28	$0.66	$0.33	$0.10		$3.17		**1.081**		$2.94
	2009	$0.72	$0.23	$0.40	$0.00	$0.38	$0.27	$0.63	$0.32	$0.13		$3.07		**1.169**		$2.62
	2010	$0.73	$0.23	$0.43	$0.00	$0.38	$0.27	$0.61	$0.32	$0.11	=	$3.08	÷	**1.264**	=	$2.44
	2011	$0.71	$0.23	$0.43	$0.00	$0.38	$0.27	$0.62	$0.31	$0.13		$3.09		**1.367**		$2.26
	2012	$0.72	$0.24	$0.44	$0.00	$0.40	$0.29	$0.65	$0.35	$0.12		$3.20		**1.478**		$2.17
	2013	$0.81	$0.26	$0.49	$0.00	$0.43	$0.30	$0.68	$0.38	$0.10		$3.44		**1.598**		$2.16
	2014	$0.81	$0.28	$0.51	$0.00	$0.46	$0.32	$0.72	$0.40	$0.08		$3.58		**1.728**		$2.07

Note the bolded column where the WACC discount factor appears. This factor is calculated as:

$$WACC\ discount\ factor = (1 + WACC)^{(Future\ year - Base\ year)}$$

$$2007\ WACC\ discount\ factor = (1 + 0.0813)^{(Future\ year - 2007)}$$

b) When does ETPC expect to dispose of these balances?

- ***Erie Thames expects to dispose of the related SSM balances as part of a one-year rate rider applied to the appropriate rate class(es).***

65. Reference: Exhibit 10, Tab 1, Schedule 4

a) List and confirm OPAs input assumptions for EKC 2006 including the measure life and unit kwh savings for Compact Fluorescent Lights and Seasonal Light Emitting Diodes. Confirm some of these assumptions were changed in 2007 and again in 2009 and compare the values.

- ***Table 1 confirms final OPA-verified 2006 EKC results for 2006 EKC CFLs and seasonal light emitting diodes (SLEDs), final OPA-verified 2007 EKC results, and assumptions from the 2009 OPA Measures and Assumptions list. Input assumptions for CFLs and SLEDs have changed periodically, as reflected in updates to the generic OPA Measures and Assumptions list.***

Table 1. Comparison of inputs from three different sources for CFLs and SLEDs

	OPA-verified Final 2006 EKC results			OPA-verified Final 2007 EKC results			From 2009 OPA M&A list		
Measure	**Measure life**	**Gross savings (kWh/a)**	**Free rider rate**	**Measure life**	**Gross savings (kWh/a)**	**Free rider rate**	**Measure life**	**Gross savings (kWh/a)**	**Free rider rate**
Energy Star® CFL	4	104	10%	8	43	22%	8	43	30%
SLEDs	30	31	10%	5	14	51%	5	14	30%

b) Demonstrate that savings for EKC 2006 Mass market measures 13-15W Energy Star CFLs etc. have been removed from the LRAM claim in the Indeco Report.

- ***In IndEco's third party report, Exhibit 10, Appendix A, Table 9, page 20, CFLs delivered as part of the 2006 EKC Spring and Autumn campaigns are listed as contributing $21,533 and $31,927 to the total LRAM claim. These claims are broken down as shown in Table 2.***

Table 2. LRAM claims associated with 2006 EKC CFLs

2006 EKC CFLs	2006	2007	2008	2009	2010	2011	2012	Total
Energy Star® CFL - Spring	$5,187	$5,461	$5,499	$5,386	$0	$0	$0	$21,533
Energy Star® CFL - Autumn	$7,691	$8,097	$8,154	$7,985	$0	$0	$0	$31,927

- ***As seen in Table 2, savings from 2006 EKC CFLs have been removed from the LRAM claim beginning in 2010.***

66. Reference: Exhibit 10, Tab 1, Schedule 4

a) Is the current LRAM claim the only claim filed by EPTC or its predecessors? If not, provide a copy of the prior claim(s).

- ***The current LRAM claim is the only LRAM claim that has ever been filed by Erie Thames or its predecessors.***

b) Identify all Mass market measures (CFLs etc.) installed in 2006 with measure lives of 4 years or less for which savings have been claimed in any prior claim.

- ***Erie Thames has not filed any other previous claims.***

c) Adjust the current Third Tranche LRAM claim as necessary to reflect the measure lives (and Unit savings) for any/all measures that have expired starting in 2010.

- ***No adjustments to the current LRAM claim are needed in order to reflect measure lives (and unit savings) for OPA measures that have expired.***

- ***The requested LRAM claim already accounts for any measures that have expired before the full span of the LRAM claim. The LRAM claim is based on lost revenue over the span of the LRAM claim, or until the end of each measure's respective measure life, whichever is shorter. For example, if a measure installed in 2009 had a measure life of 1 year, LRAM was only claimed for that measure between January 1 2009 and December 31 2009.***

Mitigation Plan

67. Reference: Exhibit 11

a) Please provide a schedule that sets out for the most recent 12 month period the actual number of CPC Residential customers whose monthly use falls into the following ranges:
- 0-250 kWh
- >250-500 kWh
- >500-800 kWh
- >800-1500 kWh
- >1500 kWh

Count of Usage per month from July 2011 to July 2012

Sum of 0-250			Sum of 250-500			Sum of 500-800			Sum of 800-1500			Sum of >1500			
year	month	Total	year	month	Total	year	month	Total	year	month	Total	year	month	Total	Total
2011	7	170	2011	7	284	2011	7	337	2011	7	440	2011	7	114	1345
	8	198		8	350		8	410		8	373		8	68	1399
	9	218		9	418		9	427		9	285		9	42	1390
	10	175		10	408		10	444		10	344		10	27	1398
	11	162		11	399		11	451		11	320		11	57	1389
	12	134		12	291		12	409		12	430		12	138	1402
2012	1	138	2012	1	299	2012	1	420	2012	1	392	2012	1	146	1395
	2	174		2	380		2	429		2	338		2	92	1413
	3	184		3	405		3	459		3	307		3	55	1410
	4	198		4	449		4	436		4	273		4	37	1393
	5	236		5	453		5	422		5	264		5	29	1404
	6	203		6	361		6	428		6	338		6	54	1384
	7	159		7	268		7	336		7	478		7	118	1359

68. Reference: Exhibit 8, Tab 1, Schedule 8
Exhibit 11, Tab 1, Schedule 1

a) The detailed bill impacts for Clinton's GS<50 customers as shown in Exhibit 8 do not appear to exceed the 10% threshold as suggested in Exhibit 11. Please substantiate the claim that the bill impacts for Clinton's GS<50 customers are greater than 10% prior to mitigation.

- ***The bill impacts were updated to remove the DVAD Global Adjustment Disposition which was a credit and the removal resulted in the impacts being greater than 10% as follows.***

Customer Class:	General Service < 50								
	Consumption	1000	kWh						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 24.1700	1	$ 24.17	$ 20.9451	1	$ 20.95	-$ 3.22	-13.34%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00		1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly		1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 0.3500	1	$ 0.35		1	$ -	-$ 0.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0131	1000	$ 13.10	$ 0.0153	1000	$ 15.34	$ 2.24	17.08%
Low Voltage Rate Adder	per kWh	$ 0.0025	1000	$ 2.50	$ 0.0020	1000	$ 1.95	-$ 0.55	-21.99%
Volumetric Rate Adder(s)			1000	$ -		1000	$ -	$ -	
Volumetric Rate Rider(s)			1000	$ -		1000	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly		1000	$ -	$ 0.0004	1000	$ 0.40	$ 0.40	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0033	1000	$ 3.30	$ 0.0146	1000	$ 14.56	$ 11.26	341.23%
Global Adjustment Disposition	Monthly			$ -		1000	$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 44.42**			**$ 55.01**	**$ 10.59**	**23.85%**
RTSR - Network		$ 0.0049	1055.4	$ 5.17	$ 0.0054	1042.1	$ 5.63	$ 0.46	8.86%
RTSR - Line and Transformation Connection		$ 0.0012	1055.4	$ 1.27	$ 0.0036	1042.1	$ 3.76	$ 2.50	197.15%
Sub-Total B - Delivery (including Sub-Total A)				**$ 50.86**			**$ 64.41**	**$ 13.55**	**26.64%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	1055.4	$ 5.49	$ 0.0052	1042.1	$ 5.42	-$ 0.07	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	1055.4	$ 1.37	$ 0.0011	1042.1	$ 1.15	-$ 0.23	-16.45%
Special Purpose Charge		$ -	1055.4	$ -	$ -	1042.1	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	1055.4	$ 7.39	$ 0.0070	1042.1	$ 7.29	-$ 0.09	-1.26%
Energy		$ 0.0560	1055.4	$ 59.10	$ 0.0560	1042.1	$ 58.36	-$ 0.74	-1.26%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 124.46**			**$ 136.87**	**$ 12.42**	**9.98%**
HST		13%		$ 16.18	13%		$ 17.79	$ 1.61	9.98%
Total Bill (including Sub-total B)				**$ 140.64**			**$ 154.67**	**$ 14.03**	**9.98%**
Ontario Clean Energy Benefit [1]				**-$ 14.06**			**-$ 15.47**	**-$ 1.41**	**10.03%**
Total Bill (including OCEB)				**$ 126.58**			**$ 139.20**	**$ 12.62**	**9.97%**
Loss Factor (%)		5.54%			4.21%				

	Consumption	2000	kWh						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 24.1700	1	$ 24.17	$ 20.9451	1	$ 20.95	-$ 3.22	-13.34%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 0.3500	1	$ 0.35	$ -	1	$ -	-$ 0.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0131	2000	$ 26.20	$ 0.0153	2000	$ 30.67	$ 4.47	17.08%
Low Voltage Rate Adder	per kWh	$ 0.0025	2000	$ 5.00	$ 0.0020	2000	$ 3.90	-$ 1.10	-21.99%
Volumetric Rate Adder(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	2000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	2000	$ -	$ 0.0004	2000	$ 0.80	$ 0.80	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0033	2000	$ 6.60	$ 0.0146	2000	$ 29.12	$ 22.52	341.23%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	2000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 63.32**			**$ 87.26**	**$ 23.94**	**37.81%**
RTSR - Network		$ 0.0049	2110.8	$ 10.34	$ 0.0054	2084.2	$ 11.26	$ 0.92	8.86%
RTSR - Line and Transformation Connection		$ 0.0012	2110.8	$ 2.53	$ 0.0036	2084.2	$ 7.53	$ 4.99	197.15%
Sub-Total B - Delivery (including Sub-Total A)				**$ 76.20**			**$ 106.05**	**$ 29.85**	**39.18%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	2110.8	$ 10.98	$ 0.0052	2084.2	$ 10.84	-$ 0.14	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	2110.8	$ 2.74	$ 0.0011	2084.2	$ 2.29	-$ 0.45	-16.45%
Special Purpose Charge		$ -	2110.8	$ -	$ -	2084.2	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	2110.8	$ 14.78	$ 0.0070	2084.2	$ 14.59	-$ 0.19	-1.26%
Energy		$ 0.0560	2110.8	$ 118.20	$ 0.0560	2084.2	$ 116.72	-$ 1.49	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 223.15**			**$ 250.73**	**$ 27.59**	**12.36%**
HST		13%		$ 29.01	13%		$ 32.60	$ 3.59	12.36%
Total Bill (including Sub-total B)				**$ 252.16**			**$ 283.33**	**$ 31.17**	**12.36%**
***Ontario Clean Energy Benefit* [1]**				**-$ 25.22**			**-$ 28.33**	**-$ 3.11**	**12.33%**
Total Bill (including OCEB)				**$ 226.94**			**$ 255.00**	**$ 28.06**	**12.36%**

	Consumption	5000 kWh								
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 24.1700	1	$ 24.17	$ 20.9451	1	$ 20.95	-$ 3.22	-13.34%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 0.3500	1	$ 0.35	$ -	1	$ -	-$ 0.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0131	5000	$ 65.50	$ 0.0153	5000	$ 76.69	$ 11.19	17.08%
Low Voltage Rate Adder	per kWh	$ 0.0025	5000	$ 12.50	$ 0.0020	5000	$ 9.75	-$ 2.75	-21.99%
Volumetric Rate Adder(s)		$ -	5000	$ -	$ -	5000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	5000	$ -	$ -	5000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	5000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	5000	$ -	$ 0.0004	5000	$ 2.00	$ 2.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0033	5000	$ 16.50	$ 0.0146	5000	$ 72.80	$ 56.30	341.23%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	5000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 120.02**			**$ 184.00**	**$ 63.98**	**53.31%**
RTSR - Network		$ 0.0049	5277	$ 25.86	$ 0.0054	5210.5	$ 28.15	$ 2.29	8.86%
RTSR - Line and Transformation Connection		$ 0.0012	5277	$ 6.33	$ 0.0036	5210.5	$ 18.82	$ 12.48	197.15%
Sub-Total B - Delivery (including Sub-Total A)				**$ 152.21**			**$ 230.97**	**$ 78.76**	**51.74%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	5277	$ 27.44	$ 0.0052	5210.5	$ 27.09	-$ 0.35	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	5277	$ 6.86	$ 0.0011	5210.5	$ 5.73	-$ 1.13	-16.45%
Special Purpose Charge		$ -	5277	$ -	$ -	5210.5	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	5277	$ 36.94	$ 0.0070	5210.5	$ 36.47	-$ 0.47	-1.26%
Energy		$ 0.0560	5277	$ 295.51	$ 0.0560	5210.5	$ 291.79	-$ 3.72	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 519.21**			**$ 592.31**	**$ 73.10**	**14.08%**
HST		13%		$ 67.50	13%		$ 77.00	$ 9.50	14.08%
Total Bill (including Sub-total B)				**$ 586.71**			**$ 669.31**	**$ 82.60**	**14.08%**
Ontario Clean Energy Benefit [1]				**-$ 58.67**			**-$ 66.93**	**-$ 8.26**	**14.08%**
Total Bill (including OCEB)				**$ 528.04**			**$ 602.38**	**$ 74.34**	**14.08%**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
	Consumption	10000	kWh						
Monthly Service Charge	Monthly	$ 24.1700	1	$ 24.17	$ 20.9451	1	$ 20.95	-$ 3.22	-13.34%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 0.3500	1	$ 0.35	$ -	1	$ -	-$ 0.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0131	10000	$ 131.00	$ 0.0153	10000	$ 153.37	$ 22.37	17.08%
Low Voltage Rate Adder	per kWh	$ 0.0025	10000	$ 25.00	$ 0.0020	10000	$ 19.50	-$ 5.50	-21.99%
Volumetric Rate Adder(s)		$ -	10000	$ -	$ -	10000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	10000	$ -	$ -	10000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	10000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	10000	$ -	$ 0.0004	10000	$ 4.00	$ 4.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0033	10000	$ 33.00	$ 0.0146	10000	$ 145.60	$112.60	341.23%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	10000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 214.52**			**$ 345.24**	**$ 130.72**	**60.94%**
RTSR - Network		$ 0.0049	10554	$ 51.71	$ 0.0054	10421	$ 56.30	$ 4.58	8.86%
RTSR - Line and Transformation Connection		$ 0.0012	10554	$ 12.66	$ 0.0036	10421	$ 37.63	$ 24.97	197.15%
Sub-Total B - Delivery (including Sub-Total A)				**$ 278.90**			**$ 439.17**	**$ 160.27**	**57.47%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	10554	$ 54.88	$ 0.0052	10421	$ 54.19	-$ 0.69	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	10554	$ 13.72	$ 0.0011	10421	$ 11.46	-$ 2.26	-16.45%
Special Purpose Charge		$ -	10554	$ -	$ -	10421	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	10554	$ 73.88	$ 0.0070	10421	$ 72.95	-$ 0.93	-1.26%
Energy		$ 0.0560	10554	$ 591.02	$ 0.0560	10421	$ 583.58	-$ 7.45	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$1,012.65**			**$ 1,161.60**	**$ 148.95**	**14.71%**
HST		13%		$ 131.64	13%		$ 151.01	$ 19.36	14.71%
Total Bill (including Sub-total B)				**$1,144.30**			**$ 1,312.61**	**$ 168.31**	**14.71%**
***Ontario Clean Energy Benefit* [1]**				**-$ 114.43**			**-$ 131.26**	**-$ 16.83**	**14.71%**
Total Bill (including OCEB)				**$1,029.87**			**$ 1,181.35**	**$ 151.48**	**14.71%**

	Consumption	15000	kWh						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 24.1700	1	$ 24.17	$ 20.9451	1	$ 20.95	-$ 3.22	-13.34%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 0.3500	1	$ 0.35	$ -	1	$ -	-$ 0.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0131	15000	$ 196.50	$ 0.0153	15000	$ 230.06	$ 33.56	17.08%
Low Voltage Rate Adder	per kWh	$ 0.0025	15000	$ 37.50	$ 0.0020	15000	$ 29.25	-$ 8.25	-21.99%
Volumetric Rate Adder(s)		$ -	15000	$ -	$ -	15000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	15000	$ -	$ -	15000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	15000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	15000	$ -	$ 0.0004	15000	$ 6.00	$ 6.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0033	15000	$ 49.50	$ 0.0146	15000	$ 218.41	$168.91	341.23%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	15000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 309.02**			**$ 506.48**	**$ 197.46**	**63.90%**
RTSR - Network		$ 0.0049	15831	$ 77.57	$ 0.0054	15631.5	$ 84.45	$ 6.87	8.86%
RTSR - Line and Transformation Connection		$ 0.0012	15831	$ 19.00	$ 0.0036	15631.5	$ 56.45	$ 37.45	197.15%
Sub-Total B - Delivery (including Sub-Total A)				**$ 405.59**			**$ 647.38**	**$ 241.79**	**59.61%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	15831	$ 82.32	$ 0.0052	15631.5	$ 81.28	-$ 1.04	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	15831	$ 20.58	$ 0.0011	15631.5	$ 17.19	-$ 3.39	-16.45%
Special Purpose Charge		$ -	15831	$ -	$ -	15631.5	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	15831	$ 110.82	$ 0.0070	15631.5	$ 109.42	-$ 1.40	-1.26%
Energy		$ 0.0560	15831	$ 886.54	$ 0.0560	15631.5	$ 875.36	-$ 11.17	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$1,506.09**			**$ 1,730.89**	**$ 224.80**	**14.93%**
HST		13%		$ 195.79	13%		$ 225.02	$ 29.22	14.93%
Total Bill (including Sub-total B)				**$1,701.89**			**$ 1,955.91**	**$ 254.02**	**14.93%**
Ontario Clean Energy Benefit [1]				**-$ 170.19**			**-$ 195.59**	**-$ 25.40**	**14.92%**
Total Bill (including OCEB)				**$1,531.70**			**$ 1,760.32**	**$ 228.62**	**14.93%**

b) Please indicate the range of monthly usage over which the bill impact for GS<50 customers will be greater than 10% and the number of GS<50 customers whose usage falls in this range based on the most recent 12 months data.

- ***The following table details how many customers are billed within the ranges utilized in the impact tables above.***

GS<50 Count of Usage per month from July 2011 to July 2012

Sum of 0-1000			Sum of 1000-2000			Sum of 2000-5000			Sum of 5000-10000			Sum of >10000		
year	month	Total	year	month	Total	year	month	Total	year	month	Total	year	month	Total
2011	7	90	2011	7	38	2011	7	37	2011	7	12	2011	7	4
	8	103		8	40		8	43		8	18		8	5
	9	110		9	41		9	39		9	20		9	2
	10	107		10	47		10	42		10	15		10	2
	11	101		11	39		11	49		11	16		11	3
	12	93		12	40		12	54		12	16		12	5
2011 Total		**604**	**2011 Total**		**245**	**2011 Total**		**264**	**2011 Total**		**97**	**2011 Total**		**21**
2012	1	96	2012	1	40	2012	1	55	2012	1	16	2012	1	8
	2	96		2	47		2	44		2	18		2	5
	3	104		3	44		3	42		3	19		3	5
	4	105		4	45		4	40		4	16		4	3
	5	107		5	36		5	38		5	21		5	4
	6	98		6	42		6	40		6	22		6	2
	7	88		7	41		7	43		7	19		7	7
2012 Total		**694**	**2012 Total**		**295**	**2012 Total**		**302**	**2012 Total**		**131**	**2012 Total**		**34**
Grand Total		**1298**	**Grand Total**		**540**	**Grand Total**		**566**	**Grand Total**		**228**	**Grand Total**		**55**

c) The detailed bill impacts for Clinton's GS>50-999 customers as shown in Exhibit 8 do not appear to exceed the 10% threshold as suggested in Exhibit 11. Please substantiate the claim that the bill impacts for Clinton's GS>50 customers are greater than 10% prior to mitigation.

- ***The bill impacts were updated to remove the DVAD Global Adjustment Disposition which was a credit and the removal resulted in the impacts being greater than 10% as follows.***

Customer Class:	General Service > 50 to 999 kW								
	Consumption	60	kW						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 42.4400	1	$ 42.44	$ 226.6000	1	$ 226.60	$ 184.16	433.93%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00		1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly		1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 5.3520	1	$ 5.35		1	$ -	-$ 5.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 4.6338	60	$ 278.03	$ 3.3398	60	$ 200.39	-$ 77.64	-27.93%
Low Voltage Rate Adder	per kWh	$ 1.1697	60	$ 70.18	$ 0.7099	60	$ 42.59	-$ 27.59	-39.31%
Volumetric Rate Adder(s)			60	$ -		60	$ -	$ -	
Volumetric Rate Rider(s)			60	$ -		60	$ -	$ -	
Smart Meter Disposition Rider	Monthly		60	$ -	$ 0.3500	60	$ 21.00	$ 21.00	
LRAM & SSM Rate Rider	Monthly		60	$ -	$ 0.3481	1	$ 0.35	$ 0.35	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 1.0997	60	$ 65.98	$ 4.9202	60	$ 295.21	$ 229.23	347.41%
Global Adjustment Disposition	Monthly			$ -		60	$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 462.98**			**$ 787.61**	**$ 324.62**	**70.12%**
RTSR - Network		$ 2.0227	63.324	$ 128.09	$ 2.4575	62.526	$ 153.66	$ 25.58	19.97%
RTSR - Line and Transformation Connection		$ 0.4787	63.324	$ 30.31	$ 1.2953	62.526	$ 80.99	$ 50.67	167.17%
Sub-Total B - Delivery (including Sub-Total A)				**$ 621.38**			**$ 1,022.26**	**$ 400.87**	**64.51%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	63.324	$ 0.33	$ 0.0052	62.526	$ 0.33	-$ 0.00	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	63.324	$ 0.08	$ 0.0011	62.526	$ 0.07	-$ 0.01	-16.45%
Special Purpose Charge		$ -	63.324	$ -	$ -	62.526	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	52770	$ 369.39	$ 0.0070	52105	$ 364.74	-$ 4.65	-1.26%
Energy		$ 0.0560	52770	$ 2,955.12	$ 0.0560	52105	$ 2,917.88	-$ 37.24	-1.26%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 3,946.55**			**$ 4,305.52**	**$ 358.96**	**9.10%**
HST		13%		$ 513.05	13%		$ 559.72	$ 46.67	9.10%
Total Bill (including Sub-total B)				**$ 4,459.61**			**$ 4,865.23**	**$ 405.62**	**9.10%**
Ontario Clean Energy Benefit [1]				**-$ 445.96**			**-$ 486.52**	**-$ 40.56**	**9.09%**
Total Bill (including OCEB)				**$ 4,013.65**			**$ 4,378.71**	**$ 365.06**	**9.10%**

	Consumption	100	kW							
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 42.4400	1	$ 42.44	$ 226.6000	1	$ 226.60	$ 184.16	433.93%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 5.3520	1	$ 5.35	$ -	1	$ -	-$ 5.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 4.6338	100	$ 463.38	$ 3.3398	100	$ 333.98	-$ 129.40	-27.93%
Low Voltage Rate Adder	per kWh	$ 1.1697	100	$ 116.97	$ 0.7099	100	$ 70.99	-$ 45.98	-39.31%
Volumetric Rate Adder(s)		$ -	100	$ -	$ -	100	$ -	$ -	
Volumetric Rate Rider(s)		$ -	100	$ -	$ -	100	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	100	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	100	$ -	$ 0.3481	100	$ 34.81	$ 34.81	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 1.0997	100	$ 109.97	$ 4.9202	100	$ 492.02	$ 382.05	347.41%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	100	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 739.11**			**$ 1,160.21**	**$ 421.10**	**56.97%**
RTSR - Network		$ 2.0227	105.54	$ 213.48	$ 2.4575	104.21	$ 256.10	$ 42.63	19.97%
RTSR - Line and Transformation Connection		$ 0.4787	105.54	$ 50.52	$ 1.2953	104.21	$ 134.98	$ 84.46	167.17%
Sub-Total B - Delivery (including Sub-Total A)				**$ 1,003.11**			**$ 1,551.30**	**$ 548.19**	**54.65%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	105.54	$ 0.55	$ 0.0052	104.21	$ 0.54	-$ 0.01	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	105.54	$ 0.14	$ 0.0011	104.21	$ 0.11	-$ 0.02	-16.45%
Special Purpose Charge		$ -	105.54	$ -	$ -	104.21	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	52770	$ 369.39	$ 0.0070	52105	$ 364.74	-$ 4.65	-1.26%
Energy		$ 0.0560	52770	$ 2,955.12	$ 0.0560	52105	$ 2,917.88	-$ 37.24	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 4,328.56**			**$ 4,834.82**	**$ 506.26**	**11.70%**
HST		13%		$ 562.71	13%		$ 628.53	$ 65.81	11.70%
Total Bill (including Sub-total B)				**$ 4,891.27**			**$ 5,463.34**	**$ 572.07**	**11.70%**
Ontario Clean Energy Benefit [1]				**-$ 489.13**			**-$ 546.33**	**-$ 57.20**	**11.69%**
Total Bill (including OCEB)				**$ 4,402.14**			**$ 4,917.01**	**$ 514.87**	**11.70%**

	Consumption	500	kW						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 42.4400	1	$ 42.44	$ 226.6000	1	$ 226.60	$ 184.16	433.93%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 5.3520	1	$ 5.35	$ -	1	$ -	-$ 5.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 4.6338	500	$ 2,316.90	$ 3.3398	500	$ 1,669.88	-$ 647.02	-27.93%
Low Voltage Rate Adder	per kWh	$ 1.1697	500	$ 584.85	$ 0.7099	500	$ 354.94	-$ 229.91	-39.31%
Volumetric Rate Adder(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Volumetric Rate Rider(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	500	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	500	$ -	$ 0.3481	500	$ 174.05	$ 174.05	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 1.0997	500	$ 549.85	$ 4.9202	500	$ 2,460.10	$ 1,910.25	347.41%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	500	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 3,500.39**			**$ 4,887.39**	**$ 1,387.00**	**39.62%**
RTSR - Network		$ 2.0227	527.7	$ 1,067.38	$ 2.4575	521.05	$ 1,280.51	$ 213.13	19.97%
RTSR - Line and Transformation Connection		$ 0.4787	527.7	$ 252.61	$ 1.2953	521.05	$ 674.90	$ 422.29	167.17%
Sub-Total B - Delivery (including Sub-Total A)				**$ 4,820.38**			**$ 6,842.80**	**$ 2,022.42**	**41.96%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	527.7	$ 2.74	$ 0.0052	521.05	$ 2.71	-$ 0.03	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	527.7	$ 0.69	$ 0.0011	521.05	$ 0.57	-$ 0.11	-16.45%
Special Purpose Charge		$ -	527.7	$ -	$ -	521.05	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	52770	$ 369.39	$ 0.0070	52105	$ 364.74	-$ 4.65	-1.26%
Energy		$ 0.0560	52770	$ 2,955.12	$ 0.0560	52105	$ 2,917.88	-$ 37.24	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 8,148.57**			**$ 10,128.95**	**$ 1,980.37**	**24.30%**
HST		13%		$ 1,059.31	13%		$ 1,316.76	$ 257.45	24.30%
Total Bill (including Sub-total B)				**$ 9,207.89**			**$ 11,445.71**	**$ 2,237.82**	**24.30%**
Ontario Clean Energy Benefit [1]				**-$ 920.79**			**-$ 1,144.57**	**-$ 223.78**	**24.30%**
Total Bill (including OCEB)				**$ 8,287.10**			**$ 10,301.14**	**$ 2,014.04**	**24.30%**

	Consumption	1000	kW						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 42.4400	1	$ 42.44	$ 226.6000	1	$ 226.60	$ 184.16	433.93%
Smart Meter Rate Adder	Monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Smart Meter IRR	Monthly	$ -	1	$ -	$ 1.4700	1	$ 1.47	$ 1.47	
Service Charge Rate Rider(s)		$ 5.3520	1	$ 5.35	$ -	1	$ -	-$ 5.35	-100.00%
Distribution Volumetric Rate	per kWh	$ 4.6338	1000	$ 4,633.80	$ 3.3398	1000	$ 3,339.76	-$ 1,294.04	-27.93%
Low Voltage Rate Adder	per kWh	$ 1.1697	1000	$ 1,169.70	$ 0.7099	1000	$ 709.89	-$ 459.81	-39.31%
Volumetric Rate Adder(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1000	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
LRAM & SSM Rate Rider	Monthly	$ -	1000	$ -	$ 0.3481	1000	$ 348.10	$ 348.10	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 1.0997	1000	$ 1,099.70	$ 4.9202	1000	$ 4,920.19	$ 3,820.49	347.41%
Global Adjustment Disposition	Monthly	$ -		$ -	$ -	1000	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 6,951.99**			**$ 9,546.36**	**$ 2,594.37**	**37.32%**
RTSR - Network		$ 2.0227	1055.4	$ 2,134.76	$ 2.4575	1042.1	$ 2,561.01	$ 426.25	19.97%
RTSR - Line and Transformation Connection		$ 0.4787	1055.4	$ 505.22	$ 1.2953	1042.1	$ 1,349.80	$ 844.58	167.17%
Sub-Total B - Delivery (including Sub-Total A)				**$ 9,591.97**			**$ 13,457.18**	**$ 3,865.21**	**40.30%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	1055.4	$ 5.49	$ 0.0052	1042.1	$ 5.42	-$ 0.07	-1.26%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	1055.4	$ 1.37	$ 0.0011	1042.1	$ 1.15	-$ 0.23	-16.45%
Special Purpose Charge		$ -	1055.4	$ -	$ -	1042.1	$ -	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	52770	$ 369.39	$ 0.0070	52105	$ 364.74	-$ 4.65	-1.26%
Energy		$ 0.0560	52770	$ 2,955.12	$ 0.0560	52105	$ 2,917.88	-$ 37.24	-1.26%
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 12,923.59**			**$ 16,746.61**	**$ 3,823.02**	**29.58%**
HST		13%		$ 1,680.07	13%		$ 2,177.06	$ 496.99	29.58%
Total Bill (including Sub-total B)				**$ 14,603.66**			**$ 18,923.67**	**$ 4,320.01**	**29.58%**
Ontario Clean Energy Benefit [1]				**-$ 1,460.37**			**-$ 1,892.37**	**-$ 432.00**	**29.58%**
Total Bill (including OCEB)				**$ 13,143.29**			**$ 17,031.30**	**$ 3,888.01**	**29.58%**

d) Based on their usage patterns over the most recent 12 months how many of the 17 GS>50-999 customers will see bill impacts greater than 10%? (Note: There is no need to provide customers' names or usage levels)

- ***Any customer with a billed demand greater than 100 kW will be impacted greater than 10%.***
- ***The following table details by month how many customers in the last year were billed demand greater than 100 kW.***

Count of demand_billed		
year	month	Total
2011	7	6
	8	7
	9	7
	10	7
	11	7
	12	7
2011 Total		41
2012	1	7
	2	7
	3	7
	4	6
	5	5
	6	5
	7	6
2012 Total		43
Grand Total		84

69. Reference: Exhibit 11, Tab 1, Schedule 2

a) Please explain why the cost of mitigation is all recovered through a fixed charge as opposed to being recovered through both fixed and variable charges.

- ***ETPL calculated the cost of recovery in a simple manner to allow for easy application in billing different rates across the various service territories and customer sub classes. ETPL is flexible on the manner of recovery provided no extensive billing complications are created.***

b) Please recalculate the fixed and volumetric mitigation rate riders required assuming the mitigation costs for each class are recovered using the fixed-variable split for the class.

	Total Remaining Customers		Total Refund	Fixed %	Variable %	Fixed Amount	Variable Amount	Fixed Rate	Variable Rate
Residential	15,047	147,767,075	(97,396.32)	58.84%	41.16%	(57,305.26)	(40,091.06)	0.32	0.0003
GS<50	1,639	50,460,667	(32,632.86)	37.66%	62.34%	(12,288.92)	(20,343.94)	0.62	0.0004
GS>50 to 999	158	227,921	(34,853.40)	38.47%	61.53%	(13,407.04)	(21,446.36)	7.07	0.0941
			(164,882.58)						

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Appendix 2-O
Cost Allocation

Please complete the following four tables.

a) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 3,921,806	51.65%	$ 5,105,794	57.24%
GS < 50 kW	$ 939,275	12.37%	$ 1,234,833	13.84%
GS > 50 to 999 kW	$ 1,018,541	13.41%	$ 1,182,361	13.25%
GS > 1000 kW, if applicable	$ 975,336	12.85%	$ 442,385	4.96%
Large User, if applicable	$ 296,120	3.90%	$ 288,569	3.23%
Street Lighting	$ 265,430	3.50%	$ 379,194	4.25%
Sentinel Lighting	$ 22,227	0.29%	$ 31,077	0.35%
Unmetered Scattered Load (USL)	$ 13,089	0.17%	$ 87,106	0.98%
		0.00%		0.00%
		0.00%		0.00%
Embedded distributor, if applicant is a host distributor	$ 141,163	1.86%	$ 169,394	1.90%
Total	$ 7,592,987	100.00%	$ 8,920,714	100.00%

Notes

Customer Classification

Host Distributors: Provide information on embedded distributor(s) as a separate class, even if your proposal is to bill the embedded distributor(s) as (a) General Service customer(s).

If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

Class Revenue Requirements

If using the Board-issued model, enter data from Worksheet O-1, row 39 in the 2012 model.

For the Embedded Distributor(s), the Service Revenue Requirement does not include Account 4750 - Low Voltage (LV) Costs

Exclude costs in deferral and variance accounts.

Include Smart Meter costs only to the extent that they are being included in Rate Base and Revenue Requirement (i.e. being transferred from accounts 1555 and 1556 as a result of a prudence review).

b) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 4,868,699	$ 5,168,260.82	$ 5,081,212	$ 597,067
GS < 50 kW	$ 1,016,184	$ 1,078,707.88	$ 1,228,883	$ 130,812
GS > 50 to 999 kW	$ 926,213	$ 983,201.13	$ 1,176,662	$ 98,451
GS > 1000 kW, if applicable	$ 488,158	$ 518,193.44	$ 483,215	$ 38,759
Large User, if applicable	$ 349,473	$ 370,975.41	$ 287,182	$ 17,262
Street Lighting	$ 385,197	$ 408,897.44	$ 377,369	$ 31,623
Sentinel Lighting	$ 20,837	$ 22,119.06	$ 30,927	$ 2,742
Unmetered Scattered Load (USL)	$ 13,889	$ 14,743.56	$ 86,688	$ 11,941
0		$ -		
		$ -		
Embedded distributor, if applicant is a host distributor	$ 114,965	$ 122,038.58	$ 168,577	$ 4,399
Total	$ 8,183,615	$ 8,687,137	$ 8,920,714	$ 933,056

Notes:

Columns 7B to 7D

LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, **and** kWh or kW, as applicable)

Exclude revenue from rate adders and rate riders. For Embedded Distributor(s): exclude revenue in account 4075.

Columns 7C and 7D:

Column total in each column should equal the Base Revenue Requirement.

For Embedded Distributor(s), Base Revenue Requirement does not include Account 4750 - Low Voltage Costs

Column 7C:

The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

Column 7E:

If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-

1, row 19.

c) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2008	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	101.00	200.74	111.21	85 - 115
GS < 50 kW	101.00	186.87	110.11	80 - 120
GS > 50 to 999 kW	101.00	182.67	107.84	80 - 120
GS > 1000 kW, if applicable	101.00	226.37	117.99	80 - 120
Large User, if applicable	101.00	228.08	105.50	85 - 115
Street Lighting	70.00	207.35	107.86	70 - 120
Sentinel Lighting	101.00	170.69	108.34	80 - 120
Unmetered Scattered Load (USL)	101.00	116.45	113.23	80 - 120
0				
Embedded distributor, if applicant is a host distributor	101.00	171.56	102.11	

Notes:

Previously Approved Revenue-to-Cost Ratios

For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2008 with further adjustments over 2 years, the Most recent year is 2010.

For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

Status Quo Ratios

The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1.

Status Quo means "No Rebalancing" or "Before Rebalancing".

d) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2012	2013	2014	
	%	%	%	%
Residential	111.21			85 - 115
GS < 50 kW	110.11			80 - 120

GS > 50 to 999 kW	107.84			80 - 120
GS > 1000 kW, if applicable	117.99			80 - 120
Large User, if applicable	105.50			85 - 115
Street Lighting	107.86			70 - 120
Sentinel Lighting	108.34			80 - 120
Unmetered Scattered Load (USL)	113.23			80 - 120
0				
Embedded distributor, if applicant is a host distributor	102.11			

The applicant should complete Table (d) if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2012 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that

November 14, 2011

Re: Estimated allocation of 2006-2010 provincial conservation results to Local Distribution Company service territories – detailed: Clinton Power Corporation

Dear Chris White,

The Ontario Power Authority (OPA) is pleased to provide the enclosed report as a more detailed version to the Final 2010 Conservation and Demand Management (CDM) Summary Results report which was distributed to LDCs on Friday September 16, 2011.

About this report

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The OPA welcomes inquiries regarding the determination of these province-wide CDM program results and/or allocation of these results to individual LDC territories. However the OPA is unable to provide any technical or regulatory advice to LDCs regarding specific treatment of these OPA-funded

CDM program savings for the purposes of Lost Revenue Adjustment Mechanism or other filings by LDCs to the OEB. Such inquiries should be directed to the OEB.

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4) Programs run exclusively in a particular LDC territory: All energy and demand savings were allocated to the particular LDC.

Report structure

The structure of the enclosed spreadsheet-based report is consistent with past reports. It includes the following tabs:

1) **Allocation Methodology**: Provides an initiative-by-initiative summary of the allocation methodology applied to arrive at your specific Local Distribution Company share of the total provincial results.
2) **Summary - LDC**: Provides a portfolio-level summary of the annual resource savings (demand and energy, net and gross for each) for the 2006–2010 program portfolios at your specific Local Distribution Company level.
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With kind regards,

Sorana Ionescu
Director, Evaluation and Awareness

November 14, 2011

Re: Estimated allocation of 2006-2010 provincial conservation results to Local Distribution Company service territories – detailed: Erie Thames Powerlines Corporation

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