INNISFIL HYDRO
DISTRIBUTION SYSTEMS LIMITED

2073 Commerce Park Drive
Innisfil ON L9S 4A2
(S/E Corner Hwy 400 & Innisfil Beach Road)

Tel (705) 431-4321
Fax (705) 431-5901
Tel (705) 458-4329
Toll Free From 775 Exchange

March 15, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON, M4P 1E4

Re: Innisfil Hydro Distribution Systems Limited 2013 COS Rate Application EB-2012-0139

Dear Ms. Walli:

Innisfil Hydro Distribution Systems Limited (IHDSL) is pleased to submit to the Ontario Energy Board it Response to Supplemental Interrogatories as filed by Board Staff, Energy Probe, School Energy Coalition and the Vulnerable Energy Consumers Coalition.

This application is being filed pursuant to the Board's e-Filing Services. Two hard copies of Responses will be delivered to the Board over the next two business days.

Excel versions in support of the Responses to Interrogatories that are being filed pursuant to the Board's e-Filing Services include;

- Innisfiol_RRWF_20130315
- Innisfil_RTSR-Updated_20130315
- Innisfil_Smeter_20130315
- Innisfil_Costallocation_WF equal 1_20130315
- Innisfil_Costallocation_Updated_20130315
- Innisfil_LCDMAWF_20130315

We would be pleased to provide any further information or details relative to this application, by contacting me at 705-431-6870 Ext 262 or brendap@innisfilhydro.com.

Respectfully submitted,

Brenda L Pinke
Regulatory/Conservation Manager

.cc Laurie Ann Cooledge, CFO IHDSL

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

EB-2012-0139

RESPONSE TO INTERROGATORIES

Round 2 – March 15, 2013

Table of Contents

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1.0-Staff-67s - RRWF and Updated Revenue Requirement

Ref: 1-Staff-3 and 1-Staff-5

Please provide updated versions of the RRWF and the response to 1.0-Staff-5 reflecting all updates made as a response of supplemental interrogatories. In doing these updates, also reflect the updated Return on Equity and deemed Short-term and Long-term Debt Rates as communicated by the Board on February 14, 2013 for 2013 Cost of Service applications with an effective date of May 1, 2013.

Please file the RRWF in working Microsoft Excel format. Use columns I and M of the RRWF to reflect the further changes made; do not change the Initial Application.

IHDSL Response:

IHDSL has revised the RRWF reflecting all updates made as a response to the supplemental interrogatories including the updated Return on Equity as communicated by the Board on February 14, 2013 with an effective date of May 1, 2013. The RRWF has also been submitted in Excel format and the file name is as follows: Ex 1 Appendix 1 Ref 3.0-Staff-86s b).

IHDSL would like to clarify the calculation of PILs within the Summary of Proposed Changes (Appendix A) and the RRWF. IHDSL has adjusted PILs from a refund of $23,708.00 to a nil balance.

Following is the Summary of Changes Appendix A reflecting all significant changes resulting from interrogatories.

Innisfil Hydro Distribution Systems Limited
Summary of Proposed Cumulative Changes

	Exhibit #	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Service Revenue Requirement	Base Revenue Requirement	Gross Revenue Deficiency	Reference
Original Submission		**$1,386,640**	**9.12%**	**$38,010,954**	**$29,715,660**	**$3,863,036**	**$1,611,954**	**$25,788**	**$5,465,072**	**$9,419,635**	**$8,862,687**	**$761,836**	
IR# EP 27d	**4**	$1,386,640	9.12%	$38,010,954	$29,715,660	$3,863,036	$1,611,954	$19,623	$5,465,072	$9,413,470	$8,856,522	$755,671	Ist round IR
Computer Hardward s/b CCA class 50								-$6,165		-$6,165	-$6,165	-$6,165	
IR# Staff 28a	**2**	$1,386,640	9.12%	$38,010,954	$29,715,660	$3,863,036	$1,611,954	$19,623	$5,465,072	$9,455,637	$8,898,689	$797,838	Ist round IR
Removal ROE adj										$42,167	$42,167	$42,167	
IR# Staff 9e	**2**	$1,236,796	9.12%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	$41,182	$5,465,072	$9,148,460	$8,591,512	$490,661	Ist round IR
2012 & 2013 Capital expenditure changes		-$149,844		-$4,107,551			-$64,973	$21,559		-$307,177	-$307,177	-$307,177	
IR# EP 30a	**5**	$1,211,030	8.93%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	$36,455	$5,465,072	$9,117,967	$8,561,019	$460,168	Ist round IR
Rate of return updated to 8.93% from 9.12%		-$25,766	-0.19%					-$4,727		-$30,493	-$30,493	-$30,493	
IR# Staff 67	**5**	$1,217,810	8.98%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	$37,698	$5,465,072	$9,125,991	$8,569,043	$468,192	2nd round IR
Rate of return updated to 8.98% from 8.93%		$6,780	0.05%					$1,243		$8,024	$8,024	$8,024	
IR# Staff 71c	**2**	$1,217,810	8.98%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	$37,698	$5,465,072	$9,126,900	$8,569,952	$469,101	2nd round IR
Updated Appendix B-2012 forecast continuity schedules										$909	$909	$909	
IR# Staff 94a	**4**	$1,217,810	8.98%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	-$35,591	$5,465,072	$9,053,611	$8,546,662	$445,811	2nd round IR
SRED tax credit								-$73,289		-$73,289	-$23,290	-$23,290	
IR# EP 56a	**3**	$1,217,810	8.98%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	-$35,591	$5,465,072	$9,053,611	$8,516,662	$415,811	2nd round IR
Retail Services revenue											-$30,000	-$30,000	
IR# EP 59b	**4**	$1,217,810	8.98%	$33,903,403	$29,715,660	$3,863,036	$1,546,981	-$23,591	$5,465,072	$9,065,611	$8,528,662	$427,811	2nd round IR
Apprendice Tax credit								$12,000		$12,000	$12,000	$12,000	
IR# EP 52	**2**	$1,217,173	8.98%	$33,885,655	$29,579,137	$3,845,288	$1,546,981	-$23,708	$5,465,072	$9,064,330	$8,527,381	$426,530	2nd round IR
RPP & Non RPP update		-$637		-$17,748	-$136,523	-$17,748		-$117		-$1,281	-$1,281	-$1,281	
Adjustment		$1,217,173	8.98%	$33,885,655	$29,579,137	$3,845,288	$1,546,981	$0	$5,465,072	$9,088,038	$8,551,089	$450,238	2nd round IR
Tax adjusted to zero								$23,708		$23,708	$23,708	$23,708	
Proposed at		**$1,217,173**	**8.98%**	**$33,885,655**	**$29,579,137**	**$3,845,288**	**$1,546,981**	**$0**	**$5,465,072**	**$9,088,038**	**$8,551,089**	**$450,238**	
Change - Proposed vs. Original		**-12%**		**-11%**	**0%**	**0%**	**-4%**	**-100%**	**0%**	**-4%**	**-4%**	**-41%**	
		-$169,467		**-$4,125,299**	**-$136,523**	**-$17,748**	**-$64,973**	**-$25,788**	**$0**	**-$331,597**	**-$311,598**	**-$311,598**	

1.0-Staff-68s

Ref: 1.0 Energy Probe #3

In response to Energy Probe IR #3, IHDSL indicated that it will not convert to IFRS on January 1, 2013 IHDSL will take the deferral to January 1, 2014 for the full conversion to IFRS.

Since then, the Accounting Standards Board has extended the option to adopt IFRS to January 1, 2015.

a) When is IHDSL planning to convert to IFRS?

IHDSL Response:

IHDSL has not yet determined when it will be converting to IFRS.

b) Please confirm that the current rate application is fully based on MIFRS for the 2013 rate year. If not, please update your evidence accordingly.

IHDSL Response:

IHDSL has prepared the 2013 rate application based on MIFRS.

1.0 Energy Probe #41

Ref: Response to Interrogatories, Summary of Changes & Exhibit 2

a) Please confirm that the Table 1.1 (2012 CGAAP) and Table 1.2 (2012 MIFRS) reflect either actual or preliminary actual capital expenditures in 2012. If this cannot be confirmed, please provide an updated version of Tables 1.1 and 1.2 that reflect actual or preliminary actual capital expenditures for 2012 if more data is now available. If not, please indicate how many months of actual capital expenditures are reflected in Tables 1.1 and 1.2.

IHDSL Response:

Please see response to 1.0-Staff-69 b).

b) Please explain why there is no Net Book Value for WIP shown in Table 1.1.

IHDSL Response:

IHDSL is providing an updated Table 2.1 from Exhibit 2 that reflects the 2012 continuity schedule from 41a) representing actual capital expenditures.

Table 2.1 - Summary of Rate Base

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP/MIFRS	2013 Test MIFRS
Gross Fixed Assets	$ 47,925,891	$ 45,430,084	$ 50,156,160	$ 52,269,144	$ 58,236,689	$ 67,966,237
Less WIP	$ -	$ -	$ -	$ 110,616	$ 1,288,668	$ 5,075,000
Accumulated Depreciation	$ 26,893,025	$ 25,719,208	$ 27,555,404	$ 27,938,673	$ 29,418,106	$ 31,000,740
Net Book Value	$ 21,032,867	$ 19,710,876	$ 22,600,756	$ 24,219,855	$ 27,529,915	$ 31,890,497
Average Net Book Value	$ 19,436,442	$ 18,584,299	$ 21,155,816	$ 23,410,306	$ 25,874,885	$ 29,710,206
Working Capital	$ 22,890,322	$ 22,604,720	$ 24,323,497	$ 25,744,664	$ 28,943,819	$ 29,715,660
Working Capital Allowance	$ 3,433,548	$ 3,390,708	$ 3,648,525	$ 3,861,700	$ 4,341,573	$ 3,863,036
Rate Base	$ 22,869,990	$ 21,975,007	$ 24,804,341	$ 27,272,005	$ 30,216,458	$ 33,573,242

c) Please provide and updated Table 2.1 from Exhibit 2 that reflects the continuity schedules provided in the Summary of Changes or the updated tables requested in part (a).

IHDSL Response:

IHDSL is providing an updated Appendix B based on the asset continuity schedules provided 1.0 Energy Probe #41 a).

Appendix B
IHDSL Accounting Change in 2012 and files Cost of Service Application in 2013

	2012	2013 Rebasing Year	2014	2015	2016
Basis of Rates	IRM	COS	IRM	IRM	IRM
Forecast vs. Actual Used in COS Application	Forecast	Forecast			
	$	$	$	$	$
PP&E Values assuming previous CGAAP Accounting Polices Continued					
Opening net PP&E	26,060,063				
Additions	4,211,012				
Depreciation	-2,112,987				
Closing net PP&E	28,158,088				
PP&E Values assuming Accounting Changes under CGAAP in 2012					
Opening net PP&E	26,060,063				
Additions	4,211,012				
Depreciation	-1,452,492				
Closing net PP&E	28,818,583				
Difference in Closing net PP&E, "Previous" CGAAP vs "Changed" CGAAP	-660,495				
Account 1576 - PP&E Changes Under CGAAP					
Opening balance	-	- 660,495	- 495,371	- 330,248	- 165,124
Amounts added in the year	- 660,495				
Sub-total	- 660,495	- 660,495	- 495,371	- 330,248	- 165,124
Amount of amortization, included in depreciation expense - Note 1		165,124	165,124	165,124	165,124
Closing balance in deferral account	- 660,495	- 495,371	- 330,248	- 165,124	-

Effect on Revenue Requirement		
Annual disposition amount		- 165,124
Disposition Period - Years (note 2)		4

d) Please provide an updated IFRS-CGAAP Transitional PP&E Amounts schedule, as shown in Exhibit 2, Tab 5, Schedule 4 that is based on the continuity schedules provided in the Summary of Changes or the updated tables requested in part (a).

IHDSL Response:

IHDSL is providing an updated Appendix B based on the asset continuity schedules provided 41a).

Appendix B
IHDSL Accounting Change in 2012 and files Cost of Service Application in 2013

	2012	2013 Rebasing Year	2014	2015	2016
Basis of Rates	**IRM**	**COS**	**IRM**	**IRM**	**IRM**
Forecast vs. Actual Used in COS Application	**Forecast**	**Forecast**			
	$	$	$	$	$
PP&E Values assuming previous CGAAP Accounting Polices Continued					
Opening net PP&E	26,060,063				
Additions	4,211,012				
Depreciation	-2,112,987				
Closing net PP&E	28,158,088				
PP&E Values assuming Accounting Changes under CGAAP in 2012					
Opening net PP&E	26,060,063				
Additions	4,211,012				
Depreciation	-1,452,492				
Closing net PP&E	28,818,583				
Difference in Closing net PP&E, "Previous" CGAAP vs "Changed" CGAAP	-660,495				
Account 1576 - PP&E Changes Under CGAAP					
Opening balance	-	- 660,495	- 495,371	- 330,248	- 165,124
Amounts added in the year	- 660,495				
Sub-total	- 660,495	- 660,495	- 495,371	- 330,248	- 165,124
Amount of amortization, included in depreciation expense - Note 1		165,124	165,124	165,124	165,124
Closing balance in deferral account	- 660,495	- 495,371	- 330,248	- 165,124	-

Effect on Revenue Requirement

Annual disposition amount	- 165,124
Disposition Period - Years (note 2)	4

1.0 Energy Probe #42

Ref: 1.0-Energy Probe #1

The interrogatory was not fully answered. The deemed capital structure currently includes 56% long term debt, 4% short term debt and 40% equity. Innisfil appears to have asked for a debt ratio (short and long term) of 75%.

a) Please confirm that the above is accurate.

IHDSL Response:

Innisfil Hydro respectfully submits that the interrogatory was fully answered. Within the 4 year planning horizon, the debt equity ratio is expected to exceed 60%. This is because economic evaluations have to be debt financed and paid back over 20 years and new capital for growth requirements is debt financed and depreciated over 45 years. LDCs that had experienced substantial growth prior to year 2000 had their infrastructure paid for by their customers. LDCs after year 2000 have lost the ability to collect development charges and are required to up-front capital costs for new infrastructure and for economic development payments. Innisfil Hydro's 20 year long range planning indicates that the debt equity ratio is expected to exceed 75% in 2024. Innisfil Hydro is asking for the debt equity ceiling of 60% to be raised to 75%.

b) If the above is accurate, please confirm that the requested equity ratio is 25%.

IHDSL Response:

Please refer to 1.0 Energy Probe #42 a).

c) If the above is accurate, please provide the requested split of the 75% debt ratio into a short term and long term debt component.

IHDSL Response:

Innisfil Hydro is respectfully notifying the OEB that the 60% debt equity ratio ceiling is unsustainable for high growth LDCs like Innisfil Hydro. The short and long term debt components for a debt equity ratio of 75% have not been developed yet.

d) If the above is not accurate, why does IHDSL believe it requires approval to increase the "debt ceiling" to 75%?

IHDSL Response:

Please refer to 1.0 Energy Probe #42 a).

1.0 Energy Probe #43

Ref: 1.0-Energy Probe #3

The response indicates that IHDSL will not be converting to IFRS until 2014. Does IHDSL still propose to adjust its capitalization policy and depreciation rates effective January 1, 2012? If not, please revise the evidence and revenue requirement to reflect the continuation of the existing capitalization policy and depreciation rates in 2012.

IHDSL Response:

IHDSL still proposes to adjust its capitalization policy and depreciation rates effective January 1, 2012.

EX 1 APPENDIX 1 REF 1.0-STAFF-67s

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$761,836		$450,240		$450,240
2	Distribution Revenue	$8,100,851	$8,100,851	$8,100,851	$8,100,851	$8,100,851	$8,100,851
3	Other Operating Revenue Offsets - net	$556,948	$556,948	$536,948	$536,948	$536,948	$536,948
4	**Total Revenue**	$8,657,799	$9,419,635	$8,637,799	$9,088,039	$8,637,799	$9,088,039
5	Operating Expenses	$6,929,560	$6,929,560	$6,865,497	$6,865,497	$6,865,497	$6,865,497
6	Deemed Interest Expense	$1,119,814	$1,119,814	$1,005,369	$1,005,369	$1,005,369	$1,005,369
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($42,167) **(2)**	($42,167)	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$8,007,207	$8,007,207	$7,870,866	$7,870,866	$7,870,866	$7,870,866
9	**Utility Income Before Income Taxes**	$650,592	$1,412,428	$766,933	$1,217,173	$766,933	$1,217,173
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,246,052)	($1,246,052)	($805,837)	($805,837)	($805,837)	($805,837)
11	**Taxable Income**	($595,460)	$166,376	($38,904)	$411,336	($38,904)	$411,336
12	Income Tax Rate	15.50%	15.50%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	($92,296)	$25,788	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$742,888	$1,386,640	$766,933	$1,217,173	$766,933	$1,217,173
16	**Utility Rate Base**	$38,010,954	$38,010,954	$33,885,655	$33,885,655	$33,885,655	$33,885,655
17	Deemed Equity Portion of Rate Base	$15,204,382	$15,204,382	$13,554,262	$13,554,262	$13,554,262	$13,554,262
18	Income/(Equity Portion of Rate Base)	4.89%	9.12%	5.66%	8.98%	5.66%	8.98%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.98%	8.98%	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	-4.23%	0.00%	-3.32%	0.00%	-3.32%	0.00%
21	Indicated Rate of Return	4.90%	6.59%	5.23%	6.56%	5.23%	6.56%
22	Requested Rate of Return on Rate Base	6.59%	6.59%	6.56%	6.56%	6.56%	6.56%
23	Deficiency/Sufficiency in Rate of Return	-1.69%	0.00%	-1.33%	0.00%	-1.33%	0.00%
24	Target Return on Equity	$1,386,640	$1,386,640	$1,217,173	$1,217,173	$1,217,173	$1,217,173
25	Revenue Deficiency/(Sufficiency)	$643,752	$ -	$450,240	$0	$450,240	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$761,836 **(1)**		$450,240 **(1)**		$450,240 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement Workform

Version 3.00

Utility Name	Innisfil Hydro Dist. Systems Limited
Service Territory	
Assigned EB Number	EB-2012-0139
Name and Title	Brenda L Pinke Regulatory/CDM Manager
Phone Number	705-431-6870 Ext 262
Email Address	brendap@innisfilhydro.com

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

#	Item	Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$64,467,293		($4,145,239)	(12)	$ 60,322,054			$60,322,054	
	Accumulated Depreciation (average)	($30,319,374)	(5)	$37,687	(12)	($30,281,687)			($30,281,687)	
	Allowance for Working Capital:									
	Controllable Expenses	$5,477,572				$ 5,477,572			$5,477,572	
	Cost of Power	$24,238,088		($136,523)	(13)	$ 24,101,565			$24,101,565	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)		13.00%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$8,100,851		$0		$8,100,851		$0	$8,100,851	
	Distribution Revenue at Proposed Rates	$8,862,687		($311,596)		$8,551,091		$0	$8,551,091	
	Other Revenue:									
	Specific Service Charges	$154,100		$0		$154,100		$0	$154,100	
	Late Payment Charges	$113,700		$0		$113,700		$0	$113,700	
	Other Distribution Revenue	$222,633		$30,000		$252,633	###	$0	$252,633	
	Other Income and Deductions	$66,515		($50,000)		$16,515	###	$0	$16,515	
	Total Revenue Offsets	$556,948	(7)	($20,000)		$536,948		$0	$536,948	
	Operating Expenses:									
	OM+A Expenses	$5,465,072				$ 5,465,072			$5,465,072	
	Depreciation/Amortization	$1,451,988	(10)	($64,063)	(12)	$ 1,387,925			$1,387,925	
	Property taxes	$12,500				$ 12,500			$12,500	
	Other expenses									
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($1,246,052)	(3)			($805,837)			($805,837)	
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$21,791				$ -	###		$ -	
	Income taxes (grossed up)	$25,788				$ -			$ -	
	Federal tax (%)	11.00%				0.00%			0.00%	
	Provincial tax (%)	4.50%				0.00%			0.00%	
	Income Tax Credits								$ -	
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)									
		100.0%				100.0%			100.0%	
	Cost of Capital									
	Long-term debt Cost Rate (%)	5.11%				5.15%			5.15%	
	Short-term debt Cost Rate (%)	2.08%				2.08%			2.08%	
	Common Equity Cost Rate (%)	9.12%				8.98%	###		8.98%	
	Prefered Shares Cost Rate (%)									
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($42,167)	(11)	$42,167		$ -		$0	$ -	(11)

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(12) Capital expenditures changes IRR# Staff 9e
(13) RPP & non RPP price update IRR# EP 52
(14) Updated equity rate IRR# EP 30a & Staff 67
(15) Tax adjustment to nil
(16) Retail Services revenue IRR# 56a
(17) SRED correction IRR#94a

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$64,467,293	($4,145,239)	(4)	$60,322,054	$ -	$60,322,054
2	Accumulated Depreciation (average)	(3)	($30,319,374)	$37,687	(4)	($30,281,687)	$ -	($30,281,687)
3	Net Fixed Assets (average)	(3)	$34,147,919	($4,107,552)		$30,040,367	$ -	$30,040,367
4	Allowance for Working Capital	(1)	$3,863,036	($17,748)		$3,845,288	$ -	$3,845,288
5	**Total Rate Base**		$38,010,954	($4,125,299)		$33,885,655	$ -	$33,885,655

Allowance for Working Capital - Derivation

(1)

Line No.			Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$5,477,572	$ -	$5,477,572	$ -	$5,477,572
7	Cost of Power		$24,238,088	($136,523)	$24,101,565	$ -	$24,101,565
8	Working Capital Base		$29,715,660	($136,523)	$29,579,137	$ -	$29,579,137
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$3,863,036	($17,748)	$3,845,288	$ -	$3,845,288

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

(4) Capital changes IRR# Staff 9e

Revenue Requirement Workform

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$8,862,687	($311,596)	$8,551,091	$ -	$8,551,091
2	Other Revenue (1)	$556,948	($20,000)	$536,948	$ -	$536,948
3	Total Operating Revenues	$9,419,635	($331,596)	$9,088,039	$ -	$9,088,039
	Operating Expenses:					
4	OM+A Expenses	$5,465,072	$ -	$5,465,072	$ -	$5,465,072
5	Depreciation/Amortization	$1,451,988	($64,063)	$1,387,925	$ -	$1,387,925
6	Property taxes	$12,500	$ -	$12,500	$ -	$12,500
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$6,929,560	($64,063)	$6,865,497	$ -	$6,865,497
10	Deemed Interest Expense	$1,119,814	($114,445)	$1,005,369	$ -	$1,005,369
11	Total Expenses (lines 9 to 10)	$8,049,374	($178,508)	$7,870,866	$ -	$7,870,866
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($42,167)	$42,167	$ -	$ -	$ -
13	**Utility income before income taxes**	$1,412,428	($195,255)	$1,217,173	$ -	$1,217,173
14	Income taxes (grossed-up)	$25,788	($25,788)	$ -	$ -	$ -
15	**Utility net income**	$1,386,640	($169,466)	$1,217,173	$ -	$1,217,173

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$154,100	$ -	$154,100	$ -	$154,100
	Late Payment Charges	$113,700	$ -	$113,700	$ -	$113,700
	Other Distribution Revenue	$222,633	$30,000	$252,633	$ -	$252,633
	Other Income and Deductions	$66,515	($50,000)	$16,515	$ -	$16,515
	Total Revenue Offsets	$556,948	($20,000)	$536,948	$ -	$536,948

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$1,386,640	$1,217,173	$1,217,173
2	Adjustments required to arrive at taxable utility income	($1,246,052)	($805,837)	($805,837)
3	Taxable income	$140,588	$411,336	$411,336
	Calculation of Utility income Taxes			
4	Income taxes	$21,791	$ -	$ -
6	Total taxes	$21,791	$ -	$ -
7	Gross-up of Income Taxes	$3,997	$ -	$ -
8	Grossed-up Income Taxes	$25,788	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$25,788	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	11.00%	0.00%	0.00%
12	Provincial tax (%)	4.50%	0.00%	0.00%
13	Total tax rate (%)	15.50%	0.00%	0.00%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$21,286,134	5.11%	$1,088,189
2	Short-term Debt	4.00%	$1,520,438	2.08%	$31,625
3	**Total Debt**	60.00%	$22,806,573	4.91%	$1,119,814
	Equity				
4	Common Equity	40.00%	$15,204,382	9.12%	$1,386,640
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$15,204,382	9.12%	$1,386,640
7	**Total**	100.00%	$38,010,954	6.59%	$2,506,454
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$18,975,967	5.15%	$977,176
2	Short-term Debt	4.00%	$1,355,426	2.08%	$28,193
3	**Total Debt**	60.00%	$20,331,393	4.94%	$1,005,369
	Equity				
4	Common Equity	40.00%	$13,554,262	8.98%	$1,217,173
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,554,262	8.98%	$1,217,173
7	**Total**	100.00%	$33,885,655	6.56%	$2,222,542
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$18,975,967	5.15%	$977,176
9	Short-term Debt	4.00%	$1,355,426	2.08%	$28,193
10	**Total Debt**	60.00%	$20,331,393	4.94%	$1,005,369
	Equity				
11	Common Equity	40.00%	$13,554,262	8.98%	$1,217,173
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$13,554,262	8.98%	$1,217,173
14	**Total**	100.00%	$33,885,655	6.56%	$2,222,542

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$5,465,072		$5,465,072		$5,465,072	
2	Amortization/Depreciation	$1,451,988		$1,387,925		$1,387,925	
3	Property Taxes	$12,500		$12,500		$12,500	
5	Income Taxes (Grossed up)	$25,788		$ -		$ -	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,119,814		$1,005,369		$1,005,369	
	Return on Deemed Equity	$1,386,640		$1,217,173		$1,217,173	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($42,167)		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$9,419,635		$9,088,039		$9,088,039	
9	Revenue Offsets	$556,948		$536,948		$536,948	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$8,862,687		$8,551,091		$8,551,091	
11	Distribution revenue	$8,862,687		$8,551,091		$8,551,091	
12	Other revenue	$556,948		$536,948		$536,948	
13	**Total revenue**	$9,419,635		$9,088,039		$9,088,039	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$0	**(1)**	$0	**(1)**

Notes

(1) Line 11 - Line 8

EXHIBIT 2 – RATE BASE

2.0-Staff-69s

Ref: Updated Fixed Asset Continuity Schedules, Tables 1.1-1.3 and 2.0-Staff-28 – PP&E Deferral Account

In IHDSL's updated fixed continuity schedule:

a) IHDSL included CWIP in the schedules. Please confirm that the 2012 CGAAP ending net book value of $27,554,007 does not include WIP.

IHDSL Response:

The 2012 CGAAP ending net book value of $27,554,007 does not include WIP.

b) Please update the 2012 CGAAP fixed asset continuity schedule to include CWIP in the ending net book value so that the inclusion of WIP is consistent with the 2012 MIFS and 2013 MIFS fixed asset continuity schedules.

IHDSL Response:

The following 2012 CGAAP fixed asset continuity schedule is updated to include CWIP in the ending net book value.

Fixed Asset Continuity Schedule

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 120,918		-$ 2,443,794	$ 1,950,215
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 859,603	-$ 100,000	$ 9,837,491	-$ 4,286,653	-$ 351,255	$ 85,000	-$ 4,552,908	$ 5,284,583
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,087,875	-$ 150,000	$ 14,130,821	-$ 7,476,921	-$ 299,333	$ 127,500	-$ 7,648,754	$ 6,482,067
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 70,265		-$ 558,032	$ 1,514,739
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 196,700	-$ 50,000	$ 11,867,856	-$ 4,339,016	-$ 450,924	$ 42,500	-$ 4,747,440	$ 7,120,416
47	1850	Line Transformers		$ 8,602,786	$ 539,650	-$ 10,000	$ 9,132,436	-$ 5,587,946	-$ 330,522	$ 8,500	-$ 5,909,968	$ 3,222,468
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 199,300		$ 4,216,436	-$ 1,757,180	-$ 152,301		-$ 1,909,481	$ 2,306,955
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 25,000		$ 764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 640,341		-$ 8,355,287	$ 1,570,218	$ 291,809		$ 1,862,027	-$ 6,493,260
	etc.			$ -			$ -				$ -	$ -
		WIP		$ -	$ 1,075,000		$ 1,075,000					$ 1,075,000
		Total		**$ 54,353,342**	**$ 4,792,175**	**-$ 317,646**	**$ 58,827,871**	**-$ 28,293,279**	**-$ 2,171,755**	**$ 266,170**	**-$ 30,198,864**	**$ 28,629,007**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 2,054,955

	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Original submission	**$ 54,353,342**	**$ 6,083,921**	**-$ 317,646**	**$ 60,119,617**	**-$ 28,293,279**	**-$ 2,179,090**	**$ 266,170**	**-$ 30,206,199**	**$ 29,913,418**
Variance	-	(1,291,746)	-	(1,291,746)	-	7,335	-	7,335	(1,284,411)

c) Please confirm that IHDSL implemented accounting policy changes for capitalization and depreciation as at January 1, 2012 under CGAAP.

IHDSL Response:

IHDSL has implemented accounting policy changes for capitalization and depreciation as at January 1, 2012 under CGAAP.

d) Please indicate if IHDSL has implemented other changes to fixed assets besides the change in capitalization and depreciation as at January 1, 2012.

i. If there are no other changes to fixed assets, please explain why the 2012 CGAAP fixed asset continuity schedule is different than the 2012 MIFRS fixed asset continuity schedule. Please update the 2012 CGAAP or MIFRS fixed asset continuity schedules and all relevant evidence as appropriate.

IHDSL Response:

IHDSL has implemented no other changes to fixed assets besides the change in capitalization and depreciation as at January 1, 2012. When IHDSL filed the 2013 rate application we provided the 2012 CGAAP fixed asset continuity schedule reflecting the previous asset useful lives. The 2012 MIFRS fixed asset continuity schedule is reflecting the updated asset useful lives. IHDSL is providing the 2012 CGAAP fixed asset continuity schedule reflecting the updated useful lives.

Appendix 2-B
CGAAP Fixed Asset Continuity Schedule

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 90,878		-$ 2,413,754	$ 1,980,255
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 859,603	-$ 100,000	$ 9,837,491	-$ 4,286,653	-$ 183,542	$ 85,000	-$ 4,385,195	$ 5,452,296
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,087,875	-$ 150,000	$ 14,130,821	-$ 7,476,921	-$ 145,552	$ 127,500	-$ 7,494,973	$ 6,635,848
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 48,744		-$ 536,511	$ 1,536,260
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 196,700	-$ 50,000	$ 11,867,856	-$ 4,339,016	-$ 312,868	$ 42,500	-$ 4,609,384	$ 7,258,472
47	1850	Line Transformers		$ 8,602,786	$ 539,650	-$ 10,000	$ 9,132,436	-$ 5,587,946	-$ 206,576	$ 8,500	-$ 5,786,022	$ 3,346,414
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 199,300		$ 4,216,436	-$ 1,757,180	-$ 79,650		-$ 1,836,830	$ 2,379,606
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 25,000		$ 764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 640,341		-$ 8,355,287	$ 1,570,218	$ 220,330		$ 1,790,548	-$ 6,564,739
	etc.			$ -			$ -				$ -	$ -
		WIP		$ -	$ 1,075,000		$ 1,075,000				$ -	$ 1,075,000
		Total		**$ 54,353,342**	**$ 4,792,175**	**-$ 317,646**	**$ 58,827,871**	**-$ 28,293,279**	**-$ 1,535,525**	**$ 266,170**	**-$ 29,562,634**	**$ 29,265,237**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 1,418,725

	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Original Submission	**$ 54,353,342**	**$ 6,083,921**	**-$ 317,646**	**$ 60,119,617**	**-$ 28,293,279**	**-$ 1,539,226**	**$ 266,170**	**-$ 29,566,335**	**$ 30,553,282**
Variance	-	(1,291,746)	-	(1,291,746)	-	3,701	-	3,701	(1,288,045)

2.0-Staff-70s

Ref: 2.0-Staff-6; Updated Fixed Asset Continuity Schedules, Tables 1.1-1.3 and 2.0-Staff-25

In response to 2.0-Staff-6, IHDSL indicated there were no changes to the Summary of Rate Base table except for the column headings.

a) IHDSL has indicated on page 24 and 35 of the IRRs that there are no changes to the balances in calculating rate base. However, the fixed asset continuity schedules have been updated as per pages 3-5 of IHDSL's IR responses. Please update the Summary of Rate Base table accordingly, with a separate line indicating the exclusion of WIP in the calculation of rate base.

IHDSL Response:

IHDSL is providing an update Table 2.1 reflecting the 2012 and 2013 fixed asset continuity changes with a separate line indicating the exclusion of WIP in the calculation of rate base.

Table 2.1 - Summary of Rate Base

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP/MIFRS	2013 Test MIFRS
Gross Fixed Assets	$ 47,925,891	$ 45,430,084	$ 50,156,160	$ 52,269,144	$ 58,827,871	$ 67,966,237
Less WIP	$ -	$ -	$ -	$ 110,616	$ 1,075,000	$ 5,075,000
Accumulated Depreciation	$ 26,893,025	$ 25,719,208	$ 27,555,404	$ 27,938,673	$ 29,562,634	$ 31,000,740
Net Book Value	$ 21,032,867	$ 19,710,876	$ 22,600,756	$ 24,219,855	$ 28,190,237	$ 31,890,497
Average Net Book Value	$ 19,436,442	$ 18,584,299	$ 21,155,816	$ 23,410,306	$ 26,205,046	$ 30,040,367
Working Capital	$ 22,890,322	$ 22,604,720	$ 24,323,497	$ 25,744,664	$ 28,943,819	$ 29,715,660
Working Capital Allowance	$ 3,433,548	$ 3,390,708	$ 3,648,525	$ 3,861,700	$ 4,341,573	$ 3,863,036
Rate Base	$ 22,869,990	$ 21,975,007	$ 24,804,341	$ 27,272,005	$ 30,546,619	$ 33,903,403

b) In Table 2.1, the 2012 column has been titled 2012 CGAAP/MIFRS. Please explain what this means and why the column is both CGAAP and MIFRS.

IHDSL Response:

Please see response to 2.0-Staff-69 d).

c) In Table 2.1, please explain why the 2012 CGAAP net book value would be the same as the 2012 MIRS net book value when the 2012 CGAAP fixed asset continuity schedule is different from the 2012 MIFRS fixed asset continuity schedule.

IHDSL Response:

Please see response to 2.0-Staff-69d).

2.0-Staff-71s

Ref: 2.0-Staff-28 – PP&E Deferral Account; 2.0-Staff-29 – Depreciation; Updated Fixed Asset Continuity and Depreciation Schedules Table 1.1 to 1.6

In response to 2.0-Staff-28, IHDSL provided an updated Appendix B and to reflect the accounting policy change of useful lives as at January 1, 2012. The PP&E values used in calculating the amount in Account 1576 has not been updated to reflect the update in fixed assets. The depreciation schedules in the IRR have also not been updated to reflect the update in fixed assets.

a) Please provide the 2012 CGAAP fixed asset continuity schedule where the change in capitalization and depreciation policy was not implemented to support the amounts under "PP&E Values assuming previous CGAAP Accounting Policies Continued" used in calculating the amount for Account 1576.

IHDSL Response:

The following 2012 fixed asset continuity schedule reflects where the change in capitalization and depreciation policy was not implemented.

Fixed Asset Continuity Schedule-Old useful lives

Year 2012

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 363,599	$ 282,150		$ 645,749	-$ 238,982	-$ 113,920		-$ 352,902	$ 292,847
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 273,770	$ 465,000		$ 738,770	$ -			$ -	$ 738,770
CEC	1806	Land Rights		$ 982,703			$ 982,703	-$ 557,986	-$ 14,872		-$ 572,858	$ 409,845
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 34,500	-$ 3,312		-$ 37,812	$ 48,440
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,358,561	$ 35,448		$ 4,394,009	-$ 2,322,876	-$ 120,918		-$ 2,443,794	$ 1,950,215
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 9,077,888	$ 859,603	-$ 100,000	$ 9,837,491	-$ 4,286,653	-$ 351,255	$ 85,000	-$ 4,552,908	$ 5,284,583
47	1835	Overhead Conductors & Devices		$ 13,192,946	$ 1,087,875	-$ 150,000	$ 14,130,821	-$ 7,476,921	-$ 299,333	$ 127,500	-$ 7,648,754	$ 6,482,067
47	1840	Underground Conduit		$ 2,035,571	$ 37,200		$ 2,072,771	-$ 487,767	-$ 70,265		-$ 558,032	$ 1,514,739
47	1845	Underground Conductors & Devices		$ 11,721,156	$ 196,700	-$ 50,000	$ 11,867,856	-$ 4,339,016	-$ 450,924	$ 42,500	-$ 4,747,440	$ 7,120,416
47	1850	Line Transformers		$ 8,602,786	$ 539,650	-$ 10,000	$ 9,132,436	-$ 5,587,946	-$ 330,522	$ 8,500	-$ 5,909,968	$ 3,222,468
47	1855	Services (Overhead & Underground)		$ 4,017,136	$ 199,300		$ 4,216,436	-$ 1,757,180	-$ 152,301		-$ 1,909,481	$ 2,306,955
47	1860	Meters		$ 287,258			$ 287,258	-$ 67,036	-$ 11,490		-$ 78,526	$ 208,732
47	1860	Meters (Smart Meters)		$ 2,162,281	$ 74,240		$ 2,236,521	-$ 327,495	-$ 146,622		-$ 474,117	$ 1,762,404
47	1875	Street Lighting		$ 7,646		-$ 7,646	$ -	-$ 2,670		$ 2,670	$ -	$ -
N/A	1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
47	1908	Buildings & Fixtures		$ 739,631	$ 25,000		$ 764,631	-$ 273,912	-$ 28,866		-$ 302,778	$ 461,853
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 308,655	$ 25,500		$ 334,155	-$ 232,648	-$ 12,536		-$ 245,184	$ 88,971
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 515,306	$ 122,500		$ 637,806	-$ 400,081	-$ 62,665		-$ 462,746	$ 175,060
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,174,196			$ 1,174,196	-$ 460,134	-$ 159,800		-$ 619,934	$ 554,262
8	1935	Stores Equipment		$ 31,824	$ 4,000		$ 35,824	-$ 18,172	-$ 1,954		-$ 20,126	$ 15,698
8	1940	Tools, Shop & Garage Equipment		$ 487,684	$ 27,000		$ 514,684	-$ 188,237	-$ 32,112		-$ 220,349	$ 294,335
8	1945	Measurement & Testing Equipment		$ 32,997	$ 8,500		$ 41,497	-$ 14,226	-$ 2,631		-$ 16,857	$ 24,640
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,407,393	$ 367,850		$ 1,775,243	-$ 789,059	-$ 97,267		-$ 886,326	$ 888,917
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 7,714,946	-$ 640,341		-$ 8,355,287	$ 1,570,218	$ 291,809		$ 1,862,027	-$ 6,493,260
	etc.			$ -			$ -				$ -	$ -
		WIP		$ -	$ 1,075,000		$ 1,075,000					$ 1,075,000
		Total		**$ 54,353,342**	**$ 4,792,175**	**-$ 317,646**	**$ 58,827,871**	**-$ 28,293,279**	**-$ 2,171,755**	**$ 266,170**	**-$ 30,198,864**	**$ 28,629,007**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 159,800
Stranded Meters	$ 43,000
Net Depreciation	-$ 2,054,955

b) Please update the calculation of the Account 1576 balance to reflect the updated fixed asset continuity schedules, excluding WIP, provided in IRR pages 3 to 4.

IHDSL Response:

IHDSL is providing an updated Appendix B reflecting the updates to the 2012 fixed asset continuity schedules.

Appendix B
IHDSL Accounting Change in 2012 and files Cost of Service Application in 2013

	2012	2013 Rebasing Year	2014	2015	2016
Basis of Rates	**IRM**	**COS**	**IRM**	**IRM**	**IRM**
Forecast vs. Actual Used in COS Application	**Forecast**	**Forecast**			
	$	$	$	$	$
PP&E Values assuming previous CGAAP Accounting Polices Continued					
Opening net PP&E	26,060,063				
Additions	4,792,175				
Depreciation	-2,171,755				
Closing net PP&E	28,680,483				
PP&E Values assuming Accounting Changes under CGAAP in 2012					
Opening net PP&E	26,060,063				
Additions	4,792,175				
Depreciation	-1,535,525				
Closing net PP&E	29,316,713				
Difference in Closing net PP&E, "Previous" CGAAP vs "Changed" CGAAP	-636,230				
Account 1576 - PP&E Changes Under CGAAP					
Opening balance	-	- 636,230	- 477,172	- 318,115	- 159,057
Amounts added in the year	- 636,230				
Sub-total	- 636,230	- 636,230	- 477,172	- 318,115	- 159,057
Amount of amortization, included in depreciation expense - Note 1		159,057	159,057	159,057	159,057
Closing balance in deferral account	- 636,230	- 477,172	- 318,115	- 159,057	-

Effect on Revenue Requirement		
Annual disposition amount		- 159,057
Disposition Period - Years (note 2)		4

c) Please update the depreciation schedules Appendix 2-CH (IRR pages 6-8, 42) Review Requirement Workform and any other applicable evidence to reflect the updated fixed asset continuity schedules and revised depreciation adjustment resulting from Account 1576.

IHDSL Response:

IHDSL will submit an updated RRWF included for the change in the Appendix B annual disposition amount for account 1576 from the 1st round of interrogatory submission of $159,966 to $159,057 resulting in a change of the reduced revenue requirement of $909. There are no further changes to the depreciation schedules 2-CH submitted as these schedules reflected the updated capital changes.

d) In response to 2.0-Staff-29, IHDSL updated the depreciation schedule Appendix 2-CH to reconcile to the Revenue Requirement Workform. In reconciling depreciation expense on Appendix 2-CH to depreciation expense on the Revenue Requirement Workform, IHDSL removes Rolling Stock/Transportation depreciation. Please explain what this adjustment in depreciation is for.

IHDSL Response:

The rolling stock depreciation expense is not posted to the depreciation expense account. The rolling stock depreciation is redistributed to jobs with vehicle costs for the applicable timeframe.

2.0-Staff-72s

Ref: 6.0-VECC

In the table provided in response to 6.0-VECC, IHDSL shows a capital project costs of $1,370,674 for reliability in the 2013 test year. IHDSL also shows $557,150 in the 2012 bridge year and $356,000 in the 2013 test year for Hardware and Software.

a) Please provide a table listing the projects and costs included the reliability category.

IHDSL Response:

The following table provides the project costs and project overview for the 2013 Reliability capital projects which are estimated to be $1,370,674.

IHDSL Capital Project Overview – 2013

2013 Distribution & General Plant Reliability Capital Projects

ID	Total	Description	Category	Project Overview
DO-001	$207,300	Station Recloser	Reliability	Four (4) sets of G&W electronically controlled reclosers are to replace the Big Bay Point D.S. and Sandy cove D.S. hydraulic reclosers. These low maintenance units utilize vacuum break technologies rather than hydraulic oil versions. This technology dramatically reduces the cost of maintenance over the life of the asset. These units will be providing remote communication via the SCADA network which improves the efficiencies and restoration times during outages. and allows recording of momentary and operational data. The electronic reclosers play a compulsory role in the Self-healing, smart grid system of the future. Also as part of the project, costs for refurbishment of reclosers due in the 4 year cycle rotation.
DO-002	$144,500	44kV Aiduti Ruptor	Reliability	Two (2) switches in total. Each of these switches shall replace an aging and obsolete current airbreak or MSO location. Each will provide remote switching capability and real time data acquisition to better manage outage reporting numbers to the OEB. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing considerations within the 44kV subtransmission system.
DO-003	$181,180	27.6kV Mechanized Scada Controlled Load Interpt	Reliability	Install 27.6 kV vacuum line recloser/switch, connect it with SCADA and implement distribution system automation. Total 3 sets to be installed at strategic locations. These switches will be SCADA operated and distribution automation equipped. This is a step forward towards Smart Grid. When commissioned into the future smart grid, they will provide automatic isolation of faulty line sections and automatic power restoration to unaffected sections. They will also provide enhanced reliability and safety.
DO-008	$724,294	27kV Extension 20th SR, BBPt to 13th Line	Reliability	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR from 10th line to 13th line and E on 13th line from 20th SR to Fairway Rd. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Big Bay Point. Also in this scope will be the Installation of a 44 kV circuit (556 kcmil conductor) and 27.6 kV circuit (336 kcmil conductor) on 13th line,

ID	Total	Description	Category	Project Overview
				from Fairway Rd. to the intersection of 25th Sideroad just west of the south Entrance of the proposed BBPT development (Friday Harbour resort). Without this line, the future BBPT Station will be islanded without redundancy in an emergency or for maintenance.
GO-007	$62,000	System Supervisory	Reliability	Implementation of new fault indicating and switching devices in the distribution system. Solution for communications from repeater locations to Innisfil Hydro office. Some lead acid battery replacement to gelled batteries as required and low voltage electronic board and module replacements as required.
GO-008	$51,400	Capacitor Intelilink to Scada	Reliability	Innisfil Hydro has installed a number of capacitor banks for voltage/ VAR improvements. With the implementation of the new SCADA system and using GIS system capabilities; these capacitor banks can be controlled via SCADA. Better voltage management and VAR control will enhance power quality.
TOTAL Reliability Projects:	**$1,370674**			

b) Please state if any capital cost for software and hardware included in the 2013 capital budget relate to IFRS transition.

i. If so, please explain if these cost are incremental to cost recovered for IFRS transition.

IHDSL Response:

The General Plant capital schedule refers to project "GO-010 Engineering topobase & IFRS enhancement" which consists of an estimated $18,000 of the forecasted spend of $171,000 to modify our GIS application to manage componentization requirements due to the accounting change that IHDSL has implemented. The componentization is not a direct IFRS requirement however this cost is incremental to costs recovered for the IFRS transition.

2.0-Staff-73s Land purchase

Ref: 2.0-Staff-7, 2.0-Staff-11 and Updated Fixed Asset Continuity Schedules, Tables 1.1-1.3

The updated continuity schedules include $465,000 capital additions for a transformer station site in the 2012 rate year and a $200,000 capital addition in the 2013 test year.

a) Please explain why a capital addition of $465,000 should be included in rate base given that the property will be neither used nor useful in the 2013 test year.

IHDSL Response:

The OEB has established a Process Planning Working Group to develop a Regional Infrastructure Planning Process. The presentation to the OEB from the Working Group contains the following objectives inter alia;

- *A more structured and transparent approach to regional infrastructure planning;*
- *Support LDC rate applications;*
- *Support transmitter rate and LTC applications;*
- *Timely implementation of required regional infrastructure;*
- *Coordinated regional planning to ensure cost effective and efficient wires expansion;*
- *Assessment and planning started early enough to support cost effective identification and implementation of solutions.*

Innisfil Hydro is a high growth LDC and has completed long range regional planning with neighbouring LDCs and the transmitter. The plan has identified the need for a transformer station in North Innisfil. The property purchased is the last vacant parcel available adjacent to the Hydro One ROW with appropriate zoning. Innisfil Hydro submits that if it waits to purchase property until immediately required, it would not be available and Innisfil Hydro would be criticised for not taking prudent action as recommended in the long range planning report. Innisfil Hydro submits that the property purchased is not for speculation; it is required for infrastructure purposes. It is understandable why speculation properties would not be included in the rate base as they are outside of the mandate of distributing electricity. The property purchased is required for the distribution of electricity. Properties need to be purchased first so that planning and engineering can occur to build the required infrastructure. Innisfil Hydro submits that the capital addition of $465k is an asset that was identified in the Regional Infrastructure Planning Process and therefore should be included in the rate base.

b) Please explain the capital addition of $200,000 under account 1805 in the 2013 test year.

IHDSL Response:

The $200k property acquisition is for a transformer station site in the village of Lefroy. The transformer station is expected to be operational in 2015.

c) Please explain why IHDSL did not include the purchase of $650,000 for the 2147 Innisfil Beach Rd. property in capital additions in account 1805 for the 2012 bridge year.

IHDSL Response:

IHDSL did not include the land purchase in the capital additions in account 1805 as the building has been delayed from December 2013 occupancy to August 2014 occupancy.

2.0-Staff-74s New Office Building

Ref: 2.0-Staff-8 and Appendix 3IR Ref OEB Staff-8a – Options Analysis

a) Please state why Option #5 did not include Land costs in IHDSL analysis of various options.

IHDSL Response:

Option 5 was originally contemplated to be a land lease arrangement.

b) Please confirm that IHDSL is including a land value of $650,000 in its estimated cost for the new headquarter.

IHDSL Response:

Yes, submitted via the ICM as non-depreciating.

c) Please comment on why IHDSL selected to Option #5.

IHDSL Response:

Option #5 was chosen for the following main reasons:

- *recommended by the Architect's Report,*
- *closer to the urban centre for customer dispatch response improvement,*
- *on the Town Administrative Campus for improved convenience to customers,*
- *accessible to GO bus service unlike the existing location,*
- *fully serviced land unlike the existing location,*
- *less expensive land as compared to the existing location, and*
- *closer to fueling and fleet maintenance services.*

2.0-Staff-75s

Ref: 2.0-Staff-12

a) Please provide a disaggregation of the 2012 meter additions of $74,240 reference in part a) of 2.0-Staff-12 between:

i. Smart meters for Residential and GS < 50 kW customers;
ii. Meters for other metered customers (e.g. GS > 50 kW); and
iii. Wholesale meters.

Also, indicate the number of meters acquired for deployment and inventory in each of the above categories.

IHDSL Response:

Category	Allocation	Deployment	Inventory
Res & GS < 50 Smart Meters	**$ 20,203.72**	**$ 16,971.15**	**$ 3,232.57**
		172 meters plus installation	44 meters
GS > 50	**$ 30,590.40**	**$ 30,590.40**	
	inlcudes service upgrades	10 meters plus installation, incl IT's (instrument transfermers)	
Wholesale	**$ -**	**n/a**	**n/a**
Total	**$ 50,794.12**	**$ 47,561.55**	**$ 3,232.57**

Note: the cost of the installation includes the CT's and/or PT's.

2.0-Staff-76s

Ref: 2.0-Staff-29 Depreciation

IHDSL has included depreciation expenses of $170,800 for Rolling Stock. Please explain what is included in rolling stock.

IHDSL Response:

The depreciation for rolling stock is the depreciation for all the vehicles listed in the table below.

YEAR	VEHICLE
1993	GMC BUCKET TRUCK MODEL WG64 - #301
2000	GMC PICK-UP WITH DUMP BOX - #94
2004	CHEVY SILVERADO PICK-UP - #84
2005	DODGE RAM PICK-UP - #87
2005	DODGE RAM PICK-UP - #91
2006	FORD F150 - #93
2008	FORD ESCAPE (HYBRID) - #92
2008	FORD ESCAPE (HYBRID) - #85
2009	FORD ESCAPE (HYBRID) - #88
2009	FORD ESCAPE (HYBRID) - #89
2010	POSI PLUSSINGLE BUCKET MODEL FM2 - #302
2010	FORD ESCAPE (HYBRID) - #95
2010	REEL TRAILER - #402
2010	PORTABLE TRAFFIC SIGNALERS (2) - #404 (BOTH)
2011	CHEVY SILVERADO HYBRID - #96
2011	FORD SRW F350 PICK UP - #101
2011	FLOAT TRAILER - #403
2011	POLE TRAILER - #401
2011	FREIGHTLINER RBD - #201

2.0-Staff-77s

Ref: 2-SEC-4 and 2.0 Energy Probe #13

a) Please provide an update to table 2.6 for the most recent year-to-date actuals.

IHDSL Response:

IHDSL has updated the table submitted in response to Energy Probe IR #13 with December 31, 2012 year end actuals. IHDSL's capital project process extends beyond the physical in service date in terms of reporting. Dependant on the phase of a capital project IHDSL has limited visibility to report on specific components of a capital project as it progresses through the capital project phases. Adding to the visibility issue is that 90% of IHDSL's capital projects are categorized as "In-Service" and "Closed" in the later portion of the 4th quarter of a year end. The phases of the capital projects are as follows,

1. *WIP – capital project planned and started*
2. *In Service – project has been physically completed*
3. *Closed – all related invoices received, validated and forwarded to Finance for processing*
4. *Completed – processed through IHDSL's financial system. It is at this phase that IHDSL has full visibility to actual costs and contributions*

From the actual in-service date of a project to the completed status of a Capital Project, the lapsed time frame can range from 90 to 120 days.

IHDSL 2012 Capital Projects - Final Year End Costs

Projects	Category	Budget 2012 -Net of Contributions	Budget Forecasted Contributions	2012 YEAR END ACTUALS Actual Cost	Actual Contributions	2012 Actual Spend (Net of Contributions)
2012 Distribution Plant						
DO-005 - 2012 Pole Replacement Program	Infrastructure Replacement	389,270		446,005		446,005
DO-006 - Infrastructure Replacements	Infrastructure Replacement	166,850		163,797		163,797
DO-007- Reclosurer automation	Reliability	33,186		33,443		33,443
DO-009 - 27.6kv Mechanized SCADA Load Interpt	Reliability	157,808		124,767		124,767
DO-010 - 44kv Mechanized SCADA Load Interpt	Reliability	144,906		149,065		149,065
DO-012 - UG padmount TX replacements	Infrastructure Replacement	67,600		16,873		16,873
DO-013-Substandard trnasformer rehabs	Infrastructure Replacement	172,110		27,623		27,623
DO-015-County relocates IBR & 20th SDRD	Customer Demand	191,876	122,433	203		203
DO-016-County relocated 7th Line & 20th SDRD	Customer Demand	197,173	91,986	297,101	92,157	204,945
DO-017-County relocates IBR & 10th SDRD	Customer Demand	379,402	185,055	441,029	123,041	317,988
DO-018-Urbanization carry forward	Customer Demand	24,000	24,000	119,210	49,934	69,276
DO-019-Urbanization 1 Pole Relocate Finish	Customer Demand	154,850	51,450	-		-
DO-021-Cookstown water main relocates	Customer Demand	20,020	11,730	-		-
DO-022-TS Land	Customer Demand	465,000		526,913		526,913
DB-001- Retail meters	Meters	74,000		50,794		50,794
Base	Customer Demand	583,370	339,300	1,016,719	638,348	378,371
Sub-Total Distribution Plant		**3,221,421**	**825,954**	**3,413,544**	**903,480**	**2,510,064**
2012 General Plant						
Account 1908						
GO-010 New Building	Facility	2,000,000		662,562	-	662,562
GO-002 Replace & Improve building/fixtures	Facility	25,000		-		-
Account 1915						-
GB-003 Furniture & Equipment		25,500		4,162		4,162
Account 1920						-
GB-001 Hardware General		120,000		73,117		73,117
GF-001 Hardware Finance scanner		2,500		-		-
Account 1925						-
GB-001 Software General		73,000		18,090		18,090
GF-002 GP Upgrade		45,000		32,668		32,668
GO-012 Eng topobase &IFRS enhancement		164,150		11,947		11,947
Account 1935						-
GO-008 Stores Equipment	Hardware & Software	4,000		4,461	-	4,461
Account 1940						-
GO-007 Fleet tools		27,000		13,151		13,151
Account 1945					-	-
GO-009 Measurement & Testing tools		8,500		7,377	-	7,377
Account 1980						
Base		11,000		-		-
GO-004 System Supervisory		36,300		19,208		19,208
GO-005 Radio repeated faulted indicators		35,600		3,800		3,800
GO-011 Scada program conversion		200,100		253,248		253,248
DO-009 - 27.6kv Mechanized SCADA Load Interpt		68,700		69		69
DO-010 - 44kv Mechanized SCADA Load Interpt		16,150		2,375		2,375
Contributions Recognized in 2012 for prior year						
2011 Projects-capitalized 2011 contribution recog 2012					45,205	(45,205)
Pratt Alcon North Economic Evaluation				942,138	649,247	292,891
County of Simcoe 2011 Project-capitalized 2011 contribution recog 2012					90,811	(90,811)
Sub-Total General Plant		2,862,500		2,048,373	785,263	1,263,109
2012 Grand Total		**6,083,921**		**5,461,917**	**1,688,744**	**3,773,173**

b) Please explain why IHDSL's capital expenditure is $2,398,262 below its forecasted levels as of November 2012 and provide IHDSL level of capital expenditure by December 31, 2012.

IHDSL Response:

With the 2012 actuals, IHDSL's capital spend is $2,310,748 below the forecasted 2012 capital spend. The following table summarizes the breakdown of the $2,310,748.

2012 Capital Project Analysis - Forecast to Spend

Over Forecast		Under Forecast		Cancelled		Deferred		Total
$	229,722	-$	747,530	-$	20,020	-$	1,929,796	-$ 2,467,623
				Pratt Alcona North Economic Evaluation				292,891
				2011 Contributions recognized in 2012				(136,016)
								-$ 2,310,748

IHDSL will address the largest variances amounts in each of the respective categories contributing to the underspend:

<u>Over Forecast</u>

*DO-005 - **$56,735.19** of 2011 project costs closed in 2012.*

*DO-022 - **$61,913 .00** additional land costs, $51.426.24 for lands at 675 Big Bay Point Rd and an additional $10,486.76 in costs associated with the transformer lands 22 Saunders Rd, Barrie.*

*DO-018 - **$45,276.45** of 2011 project costs closed in 2012.*

*GO-011 - **$53,147.97** of costs due to vendor program costs higher than the initial budget and unforeseen involvement from operations required in the field for automation testing.*

The remaining overages apply to DO-007, DO-010, DO-008, and DO-016 for the amount of $12,649.62.

<u>Under Forecast</u>

*DO-017 **- $61,414.0**9 under forecast due to below estimate tender bids received and awarded.*

*DO-012 - **$50,727.45** due to decisions undertaken to repair and paint a greater number of transformers than estimated rather than replace with new transformer units and shortfall of available contractor resources.*

*DO-013 - **$144,486.63** due to shortfall of available contractor resources.*

*Base - **$204,999.08** due to the following factors:*

- *Less customer initiated trespass locates*
- *Fewer customer demand jobs*
- *Less storm related capital replacement due to favorable weather conditions in 2012*
- *Less developer initiated Economic Evaluation reimbursement*
- *Higher contributions due to 2011 projects recognized in 2012*

*GB-001 Account 1920 - **$46,883.40** due to competitive pricing on hardware purchases and the delay of purchases due to the extension of the move to the new operations/headquarters facility until 2014.*

*GB-001 Account 1925 - **$ 54,909.94** due to the delay of 2 projects, ePost and North Star (customer CIS application) upgrade until 2013.*

*DO-009 - **$33,040.88** as the original estimate contained more expensive switching apparatus and due to the installation location changes planned pole replacements were not required.*

*DB-001 - **$23,205.88** due to fewer than anticipated new services and no new wholesale meters to install.*

*GB-002 - **$25,000.00** due to minimized repairs on existing buildings in anticipation of move to the new operations/headquarters facility.*

*GB-003 - **$17,092.05** due to purchases minimized/deferred in anticipation of the move to the new building end of 2013.*

*GO-005 - **$31,800.06** due to the planned indicator for use was discovered on investigation to not be suitable due to a design flaw.*

Cancelled

*DO-021 - **$20,020.00** due to anticipated utility relocates not required due to water main installation design change.*

Deferred

*DO-015 - **$191,673.22** due to County of Simcoe project deferred in 4th quarter of 2012.*

*DO-019 - **$154,850.00** due to County of Simcoe project deferred in 4th quarter of 2012.*

*DO-010 - **$1,337,438.36** due to the extension (move in date) of the new operations/facility headquarters.*

*GO-012 - **$152,203.03** project deferred as existing vendor/contractor relationship dissolved in 2012.*

*DO-009 - **$68,630.89** project deferred due to the impending implementation of an entirely new communication infrastructure which takes advantage of a dedicated licenced frequency throughout Canada.*

2.0-Staff-78s

Ref: 2.0-Staff-16 – Base

IHDSL noted that in 2012 $293k payment was part of the Economic Evaluation payout, which impacted the base budget.

a) Please provide a detailed explanation of this expense.

IHDSL Response:

In 2012, Pratt Developments requested an updated Economic Evaluation be completed for Pratt Alcona North subdivision. This requirement of distributors is part of the Distribution Code. Based on the 170 connections made to request date and within the five year connection horizon and the costs of the electrical infrastructure and other inputs prescribed by the Distribution code, an updated economic evaluation was completed using the CHEC model. Capital assets of $942,138 were capitalized, offset by contribution of $649,247, the difference of which was the payment to Pratt $292,891, as a result of the economic evaluation. The infrastructure cost and contribution breakdown by OEB asset category is as follows:

	Capital Cost	*Capital Contribution*
1840	*$404,742*	*$278,917*
1845	*$191,914*	*$132,252*
1856	*$63,689*	*$43,889*
1851	*$281,793*	*$194,190*

b) Please provide the 2012 actual capital expenditure under the Base category.

IHDSL Response:

Please refer to table provided in 2.0-Staff-77s above.

2.0-Staff-79s

Ref: 2.0-Staff-17

IHDSL's response to 2.0-Staff-17 b) and e) stated:
This load calculation is based on the total load and DG on the entire feeder, including the HONI portion as applicable.
It should be noted that the table referred to in this question pertains only to micro-FiT projects. Hence, the limits presented in the table also apply only to micro-FiT projects. Unless the feeder's minimum load increases, additional micro-FiT projects cannot be connected on this feeder (as discussed above, based on HONI guidelines). However, this does not limit the installation of projects larger than 10kW.

a) Since the "remaining capacity" calculation is based on the total load and DG on the entire feeder, including the HONI portion, what is the capacity available to IHDSL (i.e. excluding the portion that would be available to HONI)?

IHDSL Response:

As background information to this answer, we would like to preface our response noting that any LDC that is not embedded to HONI is responsible to provide both transmission and distribution capacity on DG connectivity to its customers. Due to the fact that we are embedded into HONI, where HONI owns transmission supply lines, IHDSL is only responsible to provide distribution level thresholds to its customers.

The above note on "remaining capacity" applies to the data presented in Table 6 on Page 9, which pertains to the available capacity on sub-transmission feeders owned and operated by HONI, and not IHDSL owned distribution feeders. We have presented the following scenario to illustrate our answer.

Scenario 1:
If the given sub-transmission feeder has an available capacity of 20 MW, and we (an imbedded LDC) receive a request from a customer to connect a 10 MW DG to the given sub-transmission feeder in our service area, it is likely that we would get approval from HONI for this project. However, if HONI receives a request directly from one of their customers for a 15 MW DG connection on the given sub-transmission feeder while our application is being processed, HONI may choose to reject the application we submitted on behalf of our 10 MW customer to make way for a larger size DG to get connected to their sub-transmission grid.

Hence, the portion available to IHDSL for DG connectivity on HONI owned and operated sub-transmission feeders, noted in table 6 on page 9, would theoretically be all of what is presented in our table, excluding only what HONI would choose to limit based solely on the application connections that are strictly with HONI as they are reviewed and processes by HONI for which we currently do not have visibility.

Scenario 2:
IHDSL has a few distribution feeders with shared ownership with HONI, where we own and operate a section of the feeder, serving IHDSL customers, while another section is owned and operated by HONI which serves HONI customers.

In this scenario the capacity for DG connection by IHDSL customers is calculated by subtracting DG connection by HONI customers from the total DG capacity of the given feeder.

Prior to approving a DG connection on one of these feeders we contact HONI and request an update on their DG connectivity to check available capacity. This is done on an on-going basis as we are not kept up-to-date on HONI's DG project queue and status. However, IHDSL provides notifications to HONI on all DG connections on a quarterly basis.

b) Please explain why it is that the limit referred to above applies to micro-FiT projects (<10 kW) but the limit does not apply to projects larger than 10 kW. Please explain the technical basis for the limitation on the Innisfil station F3 feeder.

IHDSL Response:

In preparation of the review of the IR response IHDSL feels that there may be confusion of the "DG" terminology. In previous responses IHDSL did not clearly elude to the factors that differentiate FiT from micro-FiT. The following points may assist in providing greater clarity:

i. *The table on page 8 of our initial submission presents information solely on micro-FiT connections, and not the overall DG connections (that would otherwise include DG projects greater than 10 kW).*

ii. *The limitations on DG connectivity noted on this table (and on the revised table submitted in the first interrogatory response) apply only to micro-FiT connections.*

iii. *The DG connectivity limits are calculated using different criteria for micro-FiT's and FiT's.*

iv. *For micro-FiT connectivity determination, among other variants, the minimum load on the feeder sets the threshold for maximum connectivity. Based on HONI guidelines we have decided to limit micro-FiT connectivity to 50% of the minimum load of each feeder.*

v. *A set of separate criteria apply to DG projects larger than 10 kW.*

vi. *Although it might seem intuitively proper to limit ALL connectivity to within 50% of a feeder's minimum load, the reason why we apply this load related criterion only to micro-FiT connections is as follows:*

- *a. We typically do not have the capability to disconnect micro-FiT generators when a feeder breaker is tripped. When such an event occurs it is paramount that we limit total DG to within half of the load on the feeder. By imposing this limit the LDC is able to limit the risk posed by inoperable or tampered control devices/inverter controls which would allow for power to flow back into the grid or to feed a fault during an outage., adversely affecting other customers.*
- *b. Given this scenario we have implemented a blanket limit for micro-FiT connections based on the criteria noted above.*

vii. *On DG connections larger than 10 kW, we have the option to install an isolation device (an automated switch at the "Point of Common Coupling": a cost-prohibitive option for micro-FiT connections) that can drop a generator off the grid if and when the feeder breaker trips. We also have the option to request the installation of various monitoring and control systems at the DG site during the CCA process to ensure the quality of generated power. This capability allows us to permit the connection of DG's (greater than 10 kW) past the threshold limitations used on micro-FiT connections.*

viii. *The limitation on connecting generators greater than 10 kW, on the other hand, is determined using multiple variants including short-circuit limits. In addition, on the sub-transmission grid (please note that all micro-FiT data presented on page 8 pertains to our Distribution system) which is owned and operated by HONI, an on-line spreadsheet is available on their website where imbedded LDC's can check available DG capacity. The table 6 on page 9, which shows available DG connectivity capacity, applies strictly to HONI's sub-transmission feeders which supply our Distribution Stations.*

a. Although a sub-transmission feeder may have available DG capacity, it is possible for distribution feeders, which are supplied by such sub-transmission feeders, to have DG connectivity limitations imposed by circuit parameters specific to each distribution feeder as we have discussed above.

b. Alternatively, if a HONI sub-transmission feeder has reached its DG capacity, then all new DG connectivity to our distribution feeders which are supplied by such a sub-transmission feeder will need to be put on hold until such time as HONI increases DG capacity on the given sub-transmission feeder.

2.0-Staff-80s

Ref: 2.0-Staff-18

IHDSL's response to 2.0-Staff-18 b) did not answer the question of what expected infrastructure upgrades are likely be required to accommodate the expected new DG.

In response to 2.0-Staff-18 d), IHDSL indicated that "the proposed additional technician will be carrying out work outlined in our GEA……." and that " the scope of work outlined for the new technician pertains to infrastructure upkeep (including capital)…."

a) For the five distribution feeders that have already reached maximum capacity or are nearing their maximum capacity for DG connectivity, please indicate the expected infrastructure upgrades that will likely be required to accommodate the expected new DG.

IHDSL Response:

First, please allow us to explain infrastructure upgrades geared towards accommodating new DG projects.

In the past we have NOT limited any DG connections to our distribution grid, and do not have immediate plans on imposing any limitations on DG connections for generators larger than 10 kW in size. Hence, we have not laid out specific projects for the "enabling" of new micro-FiT connections. However, should DG (greater than 10 kW) connectivity opportunities require upgrades to our grid in the future, and as noted in our earlier submittal "infrastructure upgrades will be designed and completed to meet the specific requirements of each DG project (greater than 10 kW) as and when they come in." As we look ahead, over the next two to three years we are anticipating DG connection requests to amount to 2 - 3 MW in total. As such requests are received it is very likely that our aging infrastructure would need to be upgraded to accommodate the anticipated DG connection applications. Depending on which distribution feeder(s) would carry the generated power an accurate estimate of the extent of system upgrades and associated costs will then be identified. In the interim, as we continue to expand our in-house technical capabilities to conduct substation and feeder based studies, and implement communication and SCADA system upgrades, it is imperative that we have the opportunity to employ an additional technician starting in 2013 to adequately support these efforts.

Let us now address why we are not planning infrastructure upgrades to remove the limitations on select distribution feeders that have reached the limit for micro-FiT connections. One of the limiting factors of *micro-FiT connections is a customer driven circuit parameter – namely, the load on the circuit. Although we do not control power consumption, if and when the load on the feeder increases we would revise our decision on allowing micro-FiT DG connectivity. We want to reiterate our unresolved commitment to our customers and the Ministry to continue to work towards enabling DG connectivity to our grid.*

b) With respect to the role of the proposed additional technician, please confirm whether IHDSL considers work pertaining to infrastructure upkeep (including capital) to be part its GEA plan and if so please explain.

IHDSL Response:

Yes, it does, to the extent that the infrastructure noted here refers predominantly to the assets pertaining to the installation, commissioning, and upkeep of the GEA plan specific to our Smart Grid. Existing infrastructure will continue to be maintained by our existing forces to execute our 5-year plan as previously documented.

The work scope for the proposed additional technician includes:

a. Recloser Automation & Replacement: Maintenance and Upkeep
b. 44kV SCADA Controlled Load Interrupting Gang Switch: Maintenance and Upkeep
c. 27.6kV SCADA Controlled Load Interrupting Gang Switch: Maintenance and Upkeep
d. Automated Sectionalization and Restoration (ASR): maintenance & trouble shooting
e. Fault Current Indicator: maintenance & trouble shooting
f. SCADA system: maintenance, upkeep, & trouble shooting
g. Radio Communication system: maintenance, upkeep, & trouble shooting
h. Communication protocol upgrade, maintenance & trouble shooting
i. Distribution Station Maintenance
j. SCADA equipment battery check & equipment inspection

Other opportunities for technical support:

1. Green Energy projects: site surveys, interfacing with customer electrician, prepare layout, etc
2. Fiber communication system maintenance and trouble shooting
3. OMS data review and correction, & outage follow up
4. FDIR system: assist Smart Grid Engineer with system check and trouble shooting
5. Water and Waste Water - Radio System: maintenance and trouble shooting
6. Miscellaneous field surveys, patrols, data verification, etc.

The proposed new technician is expected to spend less than 10 percent of his/her time on DG work. A majority of his/her focus will be on executing work pertaining to the GEA related to the "Smart Grid". The breakdown of hours was noted on the second table on pg 13, Appendix C; however it should be noted that these pertain to opportunities for the future - once the position has been stabilized.

2.0-Staff-81s

Ref: 2.0-Staff-19 and 2.0-Staff-22

2.0-Staff-19 a) and 22 c) related to whether the contents of Tables 8 and 9 in Exhibit 2 Appendix C pertain to IHDSL's Green Energy Act Plan. It is not clear from the responses whether the contents of Tables 8 and 9 pertain to requirements under the Green Energy Act Plan.

a) Please confirm whether IHDSL considers each of the items listed in Tables 8 and 9 referenced above to be part of its Green Energy Act Plan and provide the rationale for it.

IHDSL Response:

Yes, the contents noted in Tables 8 and 9 are intended to satisfy, either in part or in its entirety, the requirements of the GEA plan.

> *The rationale used to determine whether a specific project would qualify to be part of the GEA plan was based on the contents of EB-2009-0397 "Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence", and the "Minister's Directive". Each project listed in tables 8 and 9 was developed per the guidelines outlined in the above referenced documents.*

Based on the contents of the Minister's Directive, the projects noted below contribute towards meeting the requirements of the Directive by:

- *helping to improve the efficiency of grid operation,*
- *enhancing customer value,*
- *complying with coordination and interoperability requirements,*
- *enhancing safety and security,*
- *providing opportunity for economic development within Ontario, and*
- *helping to improve reliability.*

1. *Recloser Automation, Replacement, & Line Recloser Maintenance (4 year cycle),*
2. *44kV SCADA Controlled Load Interrupting Gang Switches,*
3. *27.6kV SCADA Controlled Load Interrupting Gang Switches,*
4. *Automated Sectionalization and Restoration (ASR),*
5. *Fault Current Indicators,*
6. *SCADA*
7. *Radio system*

Furthermore, the intended scope of these projects will help (1) ensure the flexibility of our power system while meeting some of the objectives noted in Appendix B of the Minister's Directive; and (2) ensure compliance with the adaptive infrastructure objectives noted in Appendix C of the Minister's Directive.

The remaining three cost items, namely the Smart Grid/Green Energy Engineer, Tech Support, and software upkeep, provide the resources needed to support the works outlined above.

2.0-Staff-82s

Ref: 2.0-Staff-23

In response to 2.0-Staff-23 IHDSL shows the derivation of the weighted average calculation of the direct benefit as follows:

Table 6.1

Average Net Fixed Assets	Direct Benefit %	2012	2013	2014
Renewable Connections Capital - Expansions	17%	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects	100%	$ -	$ 405,000	$ 360,000
		$ 123,611	$ 773,056	$ 966,944
Direct Benefit		$ 7,417	$ 427,083	$ 396,417
Weighted Average Direct Benefit %		0.00%	55.25%	41.00%

Please explain why the Feeder Automation Project, which is considered a 100% direct benefit to IHDSL customer, should be considered for provincial rate protection through a weighting of the direct benefit in the 2013 and 2014 rate years.

IHDSL Response:

Table 6.1 only reflects the derivation of the weighted Average Direct Benefit % which is then utilized to determine the overall Direct Benefit amount.

Average Net Fixed Assets	Direct Benefit %	2013	2014	2015
Renewable Connections Capital - Expansions	17%	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ 123,611	$ 368,056	$ 606,944
Feeder Automation Projects	100%	$ -	$ 405,000	$ 360,000
		$ 123,611	$ 773,056	$ 966,944
Direct Benefit		$ 7,417	$ 427,083	$ 396,417
Weighted Average Direct Benefit %		0.00%	55.25%	41.00%

The value reflected in 2014 and 2015 (updated as a response to Staff IR # 23 a), represents the average net fixed assets resulting from the 2013 capital investment for feeder automation in 2013 of $450,000.

IHDSL is of the position that the average net fixed assets resulting from the Feeder Automation Projects in 2013 should be considered for the provincial rate protection through the weighting process as the feeder automation provides not only benefits to IHDSL but the infrastructure for interoperability supporting the smart grid initiatives.

Feeder Automation Projects

SCADA		**2013**	**2014**	**2014**
Opening Capital Investment		$ -	$ 450,000	$ 450,000
Capital Investment		$ 450,000	$ -	$ -
Closing Capital Investment		$ 450,000	$ 450,000	$ 450,000
Opening Accumulated Amortization		$ -	$ 22,500	$ 67,500
Amortization Year One	10 years	$ 22,500	$ -	$ -
Amortization Thereafter		$ -	$ 45,000	$ 45,000
Closing Accumulated Amortization		$ 22,500	$ 67,500	$ 112,500
Opening Net Fixed Assets		$ -	$ 427,500	$ 382,500
Closing Net Fixed Assets		$ 427,500	$ 382,500	$ 337,500
Average Net Fixed Assets		$ 213,750	$ 405,000	$ 360,000

The net fixed assets were then utilized in determining the revenue requirement for the GEA Rate Adder.

2.0-Staff-83s

Ref: 2.0-Staff-24

In response to 2.0-Staff-24, IHDSL provided a comparison of capital asset useful lives. Please map the proposed useful lives by the specific asset category/component/type identified in the Kinetics Study (i.e. page 17 of the Kinetics Report) and explain any departure from the Kinetics Study.

IHDSL Response:

IHDSL is resubmitting the proposed useful lives by specific asset category/component/type/ as identified from the Kinetics Study within the following table:

Capital Assets Useful Life Comparison					
		Kinectrics Study			
USA Account # and Description	OEB Prescribed Useful life	Min	Typical	Max	IHDSL
1808 Buildings and Fixtures	50	50		75	50
1815 Station Equip (above 50kV)	25-40	30			
1820 Station Equip (below 50kV)					
-Transformers	25	30	45	60	45
-Switchgear	25	30	40	60	40
-Switchs	25	30	50	60	50
-Buildings	25	50		75	50
1830 Poles-Wood	25	35	45	75	45
1830 Poles-Concrete	25	50	60	80	60
1835 OH Conductors & Devices	25	50	60	75	60
1840 UG Conduit-Switchgear	25	20	30	45	30
1840 UG Conduit-Ducts & foundatio	25	30	50	80	50
1845 UG Conductors-Primary TR	25	35	40	55	40
1850 Line Transformers	25	30	40	60	40
1855 Services-OH & UG	25	25-35	35-40	40-60	40
1860 Wholesale Meters	25	25-35	25-35	25-35	25
1860 Smart Meters	15	5		20	15
1908 Buildings and Fixtures	50	50		75	50
1915 Office Furniture & Equip	10	5		15	10
1920 Computer Equip Hardware	5	3		5	5
1925 Computer Software	3	2		5	3
1930 Trucks Less Than 3 Tonnes	5	5		10	5
1930 Bucket & Other Large Trucks	10	5		15	10
1935 Stores Equipment	10	5		10	10
1940 Tools, Shop & Garage Equip	10	5		10	10
1945 Measurement & Testing Equip	10	5		10	10
1980 System Supervisor Equip	15	15	20	30	15

IHDSL has utilized the typical useful life provided within the Kinectrics Study for Distribution Plant assets. IHDSL has compared the range of min-max useful lives as provided by the Kinectrics Study for the General Plant assets and has applied useful lives within that range.

2.0 Energy Probe #44

Ref: 2.0-Energy Probe #6

a) Please confirm that since the property to be sold will not be sold until 2014, that this property remains in rate base in the test year.

IHDSL Response:

IHDSL confirms that the property will not be sold until 2014 and that the property remains in IHDSL's rate base for the test year. The impact to the rate base will be addressed in IHDSL's ICM application for the new operations/facility headquarters.

b) What is the amount included in rate base associated with the land that is scheduled to be sold in 2014?

IHDSL Response:

The associated value of the land currently in rate base for the 3 lots is $201,049. There are also buildings on the 3 lots with a current NBV, (December 2012 financial records) value of $458, 897.

c) Does IHDSL agree that as part of the ICM application for 2014 to reflect the addition of the new land and building costs, the value of the land being sold would need to be removed from rate base?

IHDSL Response:

IHDSL agrees that the value of the land being sold would be removed from rate base.

d) How does IHDSL propose to treat any capital gain realized on the sale of the land in February, 2014 in the ICM application?

IHDSL Response:

Innisfil Hydro confirms that it will pay any capital gains taxes as appropriate. Innisfil Hydro proposes that the revenue from the sale of the existing properties will be used to offset the cost of the new property and building.

2.0 Energy Probe #45

Ref: 2.0-OEB OEB Staff-7

a) Please confirm that the $650,000 associated with the land for the new administration building referred to the in the response has not been included in rate base in either 2012 or 2013.

IHDSL Response:

IHDSL confirms that the $650,000 associated with the land for the new administration building has not been included in rate base for 2012 nor 2013.

b) The response to part (c) indicates that the $925,000 value of the existing land remains in rate base for 2013. Please confirm whether the value of the existing land included in rate base is $925,000 or the original purchase price. If the latter, please provide the amount included in the 2013 rate base.

IHDSL Response:

The amounts included in the 2013 rate base are as follows, land NBV (3 lots) $201,049 and buildings with a NBV (as of the December 2012 financial records) of $458,897.

2.0 Energy Probe #46

Ref: Energy Probe #7 & 2.0-OEB Staff-6 & 2.0-OEB Staff-26

a) Please explain how the 2012 column shown in Table 2.1 in the response to 2.0-OEB Staff-6 can be labelled both CGAAP and MIFRS given the different depreciation rates are different in 2012 under CGAAP and MIFRS.

IHDSL Response:

Please see response to Staff 69d). IHDSL is submitting the change in asset useful life is an accounting policy change and will be effective January 1, 2012. The effect of the change in useful life is the same for CGAAP and MIFRS. IHDSL had inadvertently submitted asset continuity schedules reflecting the change in useful life as a MIFRS impact.

b) The responses provided to parts of the question are not complete. There is no change to the numbers in the revised Table 2.1 provided in the response to 2.0-OEB Staff-6a. As a result there are still differences between the 2011 and 2012 net book values shown in Tables 2.1, 24, 2.5 and 2.6. The response to 2.0-OEB Staff-26 indicates that the differences in the 2011 figures are due to WIP not being included in Table 2.4. Is this also the explanation for the difference between the figures shown for 2012 in Tables 2.1 and 2.6?

IHDSL Response:

Please see response to Staff 70a).

c) Based on the response to part (b) above, does this mean that IHDSL has included WIP in the calculation of the net book values used in Table 2.1 for the calculation of rate base? If so, why does IHDSL believe this is appropriate?

IHDSL Response:

IHDSL did not include WIP within the calculation of the net book values used in Table 2.1 for the calculation of rate base. IHDSL does not believe it is appropriate to include WIP in the calculation of the net book value and rate base.

2.0 Energy Probe #47

Ref: 2.0 Energy Probe #9

Please explain how the continuity schedules for 2013 would be the same under CGAAP and MIFRS. Would this not imply that the depreciation expense and rates would be identical under CGAAP and MIFRS? If this is not the case, please provide the requested continuity schedule under CGAAP.

IHDSL Response:

The asset continuity schedules for 2013 would be the same under CGAAP and MIFRS because the change in useful life is an accounting policy change not a change due to the transition of MIFRS as per OEB's July 2012 FAQ.

2.0 Energy Probe #48

Ref: 2.0 Energy Probe #10b

The response indicates that the $465,000 in account 1805 is for the purchase of land for a future required transformer station.

Was this land purchased in 2012? If so, what was the actual cost of the land purchased?

IHDSL Response:

Yes, the land was purchased in 2012. The actual cost of the land purchased was $475,487.15.

2.0 Energy Probe #49

Ref: 2.0 Energy Probe #11 & Exhibit 2, Tab 2, Schedule 1

a) **Please explain why the contributions shown in the response to part (d) do not add up to the figures shown in Tables 2.1 through 2.6 in Exhibit 2, Tab 2, Schedule 1. If a revised response is required, please include it also in the response to part (b) below.**

IHDSL Response:

a) The contributions in response to Energy Probe IR #11 d) did not match the figures shown in Tables 2.1 – 2.6 due to a calculation error combining the values for account 1850 &1851 and 1860 & 1861.

Annual Contributions & Grants by OEB Account					
OEB Account	**2009**	**2010**	**2011**	**2012**	**2013**
1830 - Poles, Towers & Fixtures	46,760	108,933	13,839	653,458	116,816
1835 - Overhead Conductors & Devices	48,171	79,014	21,210	523,367	106,300
1840 - Underground Conduit	15,485	2,150	136,065	126,217	4,108
1845 - Underground Conductors & Devices	368,587	1,382,463	124,276	100,886	40,762
1850/1 - Line Transformers	146,324	109,478	145,905	150,396	127,692
1855/6 - Services (Overhead & Underground)	197,196	117,040	88,339	43,442	126,682
1860 - Meters	2,670	1,774	- 325	21,122	-120
Total by Year	**825,193**	**1,800,852**	**529,309**	**1,618,888**	**522,240**

b) **Please confirm that the following table is accurate. If this cannot be confirmed, please provide a revised table with the corrected figures. Please also include any changes necessary based on the responses to part (a) an (c).**

IHDSL Response:

b) IHDSL has revised the table based on the corrections identified in response a).

		2009	2010	2011	2012	2013
1830 - Poles, Towers & Fixtures	**Contributions**	**46,760**	**108,933**	**13,839**	**653,458**	**116,816**
	Gross Additions	**792,949**	**811,713**	**935,010**	**1,172,023**	**1,657,866**
	Ratio	**5.9%**	**13.4%**	**1.5%**	**55.8%**	**7.0%**
1835 - Overhead Conductors & Devices	**Contributions**	**48,171**	**79,014**	**21,210**	**523,367**	**106,300**
	Gross Additions	**1,549,227**	**736,529**	**1,491,019**	**1,314,249**	**1,880,970**
	Ratio	**3.1%**	**10.7%**	**1.4%**	**39.8%**	**5.7%**
1840 - Underground Conduit	**Contributions**	**15,485**	**2,150**	**136,065**	**126,217**	**4,108**
	Gross Additions	**11,848**	**26,610**	**225,131**	**37,200**	**38,205**
	Ratio	**130.7%**	**8.1%**	**60.4%**	**339.3%**	**10.8%**
1845 - Underground Conductors & Devices	**Contributions**	**368,587**	**1,382,463**	**124,276**	**100,886**	**40,762**
	Gross Additions	**1,795,662**	**3,834,252**	**251,456**	**454,700**	**169,983**
	Ratio	**20.5%**	**36.1%**	**545110.0%**	**22.2%**	**24.0%**
1850/1 - Line Transformers	**Contributions**	**146,324**	**109,478**	**145,905**	**150,396**	**127,692**
	Gross Additions	**247,676**	**291,950**	**487,484**	**545,110**	**670,342**
	Ratio	**59.1%**	**37.5%**	**29.9%**	**27.6%**	**19.0%**
1855/6 - Services (Overhead & Underground)	**Contributions**	**197,196**	**117,040**	**88,339**	**43,442**	**126,682**
	Gross Additions	**167,287**	**141,283**	**306,192**	**207,405**	**225,017**
	Ratio	**117.9%**	**82.8%**	**28.9%**	**20.9%**	**56.3%**
1860 - Meters	**Contributions**	**2,670**	**1,774**	**-325**	**21,122**	**-120**
	Gross Additions	**71,174**	**0**	**10,308**	**74,240**	**116,170**
	Ratio	**3.8%**	**0%**	**-3.2%**	**28.5%**	**-0.1%**
Total	**Contributions**	**825,193**	**1,800,852**	**529,309**	**1,618,888**	**522,240**
	Gross Additions	**4,635,823**	**5,842,337**	**3,706,600**	**3,804,927**	**4,758,553**
	Ratio	**17.8%**	**30.8%**	**14.3%**	**42.5%**	**11.0%**

c) Please update the table found in part (b) to reflect the Summary of Changes in 2012 and 2013.

IHDSL Response:

The tables in part a) and b) have been updated to reflect the Summary of Changes for 2012 and 2013.

2.0 Energy Probe #50

Ref: 2.0-OEB Staff-14

Will the line discussed in part (a) of the response be completed and placed into service in 2013 or will it not be placed into service until Big Bay Station is in service?

IHDSL Response:

Yes, the line will be constructed and placed into service in 2013.

2.0 Energy Probe #51

Ref: 2.0 Energy Probe #13b

a) Please update the table found in the response to part (b) to reflect actual data for 2012. If no more data is available relative to the year-to-date figures for November, 2012 as found in the response, please provide a table based on the best estimate of the actual expenditures for 2012 that is currently available.

IHDSL Response:

2012 actuals have been provided; please refer to the response provided for OEB Staff IR # 77s.

b) Please add two lines to the table found in the response to part (a), or if no update is available, to the original response found in 2.0 Energy Probe #13b, that shows the capital expenditures closed to rate base and the amount included in WIP at the end of year.

IHDSL Response:

The amount reflected in WIP for 2012 is $1,288,668.

2.0 Energy Probe #52

Ref: 2.0 Energy Probe #15 & 2.0-OEB Staff-3 & 2.0-OEB Staff-5

The response to the Energy Probe interrogatory states that the RRWF has been updated to reflect the change in the cost of power in the WCA calculation shown in the response. However, a review of the RRWF provided in response to 2.0-OEB Staff-3 and in the summary of proposed changes provided in response to 2.0-OEB Staff-5 appears to indicate that no such change has been made. Please reconcile.

IHDSL Response:

IHDSL did state in the response to the Energy Probe IR 15 that the RRWF had been updated. This change is now reflected in the current RRWF and referenced as Energy Probe IR 52.

2-SEC-23

[Update, p.2]

Please provide details and justification for each addition to the Applicant's 2013 capital work plan.

IHDSL Response:

The following capital projects were added to the 2013 Capital Work Plan:

ID	Total	Description	Category	Project Overview
DO-012	$470,523	BBPT Dev & New 27.6kV Substation	Customer Demand	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR from 10th line to 13th line and E on 13th line from 20th SR to Fairway Rd. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Big Bay Point. Also in this scope will be the Installation of a 44 kV circuit (556 kcmil conductor) and 27.6 kV circuit (336 kcmil conductor) on 13th line, from Fairway Rd. to the intersection of 25th Sideroad just west of the south Entrance of the proposed BBPT development (Friday Harbour resort). Without this line, the future BBPT Station will be islanded without redundancy in an emergency or for maintenance.
DO-013	$450,000	Land Purchase Lefroy 44-27.6kV Substation		IHDSL is looking to secure land for the purpose of constructing a new 44kV to 27.6kV substation that is required for load growth in the Lefroy area. A property located near the center of the customer growth and demand has recently been obtained through an unsolicited offer. The property is larger than needed so it can provide access to two streets since nine feeders are projected to require power line egress. Innisfil Hydro is looking to acquire the

ID	Total	Description	Category	Project Overview
				property with a sale price of approximately $450,000 plus associated costs. The new substation requires approximately 1 acre of land so the remaining 3.7 acres will be severed and sold leaving a capital out lay of approximately $200,000 after this transaction.
DO-014	$290,115	3 Ph 27.6kV Conductoring 20th btwn 5th & 7th	Customer Demand	Installation of a circuit of 27.6 kV (336 kcmil conductor) on 20th SR, from 7th line to 5th line. Previous projects have set the foundation for this project to link the Brian Wilson D.S. to a future 27.6 kV Station in Lefroy. Without this line the new Lefroy Station will be islanded without redundancy in an emergency or for maintenance. Scope also includes the install of an approximate 10 poles (27.6 kV circuit) on 5th line, from 20th SR to new residential LSAMI entrance.
DO-015	$256,550	3 Ph 44kV Repooling-reconductoring 20th betwn 6th & 7th	Infrastructure	A pole and conductor replacement is necessary on 20th SR, from 6th line to 7th line. This is the final piece to create a 27.6kV tie between the Brian Wilson D.S. and new 27.6kV Lefroy D.S. An upgrade of the existing 44kV circuit from 336 MCM to 556 MCM conductor will also occur to maximize the feeder capability of 600 amps. Without this section of line the new Lefroy Station will be islanded without redundancy in an emergency or for maintenance.
DO-011	$521,309	County Relocate 20th SR & IBR	Customer Demand	County is rebuilding and widening the 20th SR and IBR intersection to tie in with the finished Precinct 1 Urbanization. Relocation of Innisfil Hydro infrastructure in this area will have to be done. As reviewed from the County of Simcoe engineering plan, an approximate 6 spans of 44kV double circuit subtransmission and 27.6kV distribution wire and apparatus are in this scope of work. As Precinct one (1) still exists in a partially finished state due to property acquisition, County of Simcoe and Metro Links (GO train) involvement, Innisfil Hydro has been advised the County of Simcoe will go ahead with finalization of the IBR and 20th Sideroad. This project scope will finish the remaining portion of Precinct 1.
TOTAL	**$1,988,497**			

2-SEC-24

[Update, p.2]

Please explain why the Applicant removed certain projects from its capital work plan.

IHDSL Response:

The majority of capital projects removed from the 2012/2013 capital work plan are related to IHDSL's new operations/facility headquarters. With the move in date extended to August 2014 these capital plans needed to be removed from the bridge and test year.

2-VECC-36

Reference: 2.0-OEB -6 (see also OEB 2.0-Staff-70s)

Please update Tables 2.1 and 2.2 so as to be consistent with the revised RRWF.

IHDSL Response:

Please refer to 2.0-Staff-70s a).

2-VECC-37

Reference: 2-OEB-Staff-11

What is the lot size of the 13M3 transformer station property? Where is the property located?

IHDSL Response:

The lot size is 3 acres. It is located at 22 Saunders Road in Barrie Ontario.

Given the anticipated date for use is 2022 what, if any, plan does Innisfil have to derive income from this property in the interim?

IHDSL Response:

Since the City of Barrie had annexed 5,000 acres from Innisfil, Barrie City Planners have indicated that the population growth in that area will increase from 500 in 2011 to 39,000 in 2031. This translates into a 70MW demand increase for that area. Innisfil Hydro may require a 44kV-27.6kV distribution station on the property before the 230kV - 27.6kV transformer station gets built. While income earning opportunities are being investigated, none have been engaged at this time.

2-VECC-38

Reference: 2-Energy Probe – 13

Has Innisfil's rate base calculations been updated to reflect the deferment to 2014 of Capital Projects DO-015 ($191,876) and DO-019 ($154,850) and DO-21 ($20,200)?

IHDSL Response:

IHDSL rate base calculations have been updated to reflect the deferment of capital projects to 2014. Please see response to Staff-70a) for the updated Table 2.1 reflecting the changes to 2012 and 2013 capital.

If not please provide this update in a revised RRWF filed with the supplementary interrogatories.

IHDSL Response:

n/a

2-VECC-39

Reference: 13-VECC

Do the SAIDI and SAIFI targets (or 2013 "expectations") relate in any manner to compensation or incentives. If yes, please explain how.

IHDSL Response:

No, the SAIDI/SAIFI targets/expectations do not relate in any manner to compensation or incentives.

EXHIBIT 3 – LOAD FORECAST AND OPERATING REVENUES

3.0-Staff-84s

Ref: 3.0-Staff-35

Please confirm the estimated occupancy of the 1600 units forecasted for the Big Bay Point development as 2014. Please confirm that this customers and associated load are not accounted for in the customer or load forecast for the 2013 test year.

IHDSL Response:

In the 5 year plan submitted by IHDSL the first 200 connections were to occur in 2014. In discussion with the Big Bay Point developer IHDSL has been informed that the first 200 units are projected to be connected in the later part of 2015. Based on this information the full allotment of the 1600 connections will not be completed until 2020.

IHDSL assumed a growth factor of 0.6% within the load forecast for the initial connections that were originally forecasted to occur in 2014.

3.0-Staff-85s

Ref: 3.0-Staff-31

a) IHDSL stated that it was unable to update Table 3.4 as 2012 were not available at the time that it responded to the initial interrogatories. Can IHDSL provide an update to Table 3.4 as requested. In the alternative, please explain.

IHDSL Response:

Table 3-4: Annual Usage per Customer/Connection by Rate Class						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**
Energy Usage per Customer/Connection (kWh per customer/connection)						
2009 Board Approved	11,382	37,485	555,556	569	518	7,059
2002 Actual	11,485	26,625	547,243	556	748	
2003 Actual	11,983	29,293	538,389	431	752	
2004 Actual	11,866	30,395	497,310	536	739	
2005 Actual	12,144	31,204	553,123	617	697	
2006 Actual	11,588	34,117	497,886	610	698	3,242
2007 Actual	11,446	34,754	553,811	601	679	5,839
2008 Actual	11,295	33,971	620,129	593	668	6,050
2009 Actual	11,112	32,881	659,351	601	632	5,948
2010 Actual	10,867	33,744	751,894	588	581	6,020
2011 Actual	10,893	34,095	745,100	534	490	6,041
2012 Actual	**10,392**	**33,807**	**751,471**	**550**	**448**	**6,329**
2013 Test	**10,329**	**34,559**	**769,813**	**521**	**439**	**7,626**

b) **With respect to part c) of 3.0-Staff-31, IHDSL has not explained why the historical decline in the average consumption per street lighting connection has decreased by 9.2%, nor has it explained why the forecasted decrease of 1.2% per annum for 2012 and 2013 is reasonable. Please provide an explanation for the decline.**

IHDSL Response:

The historical decline in the average consumption per street lighting connection in 2011 by 9.2% is attributable to a correction in the number of connections provided by the Town of Innisfil to 2786 from 2685.

c) **Similarly, the response to part d) of 3.0-Staff-31 does not explain the rationale that would support the estimated decline in per sentinel light consumption in 2011 and the continuing forecasted declines for 2012 and 2013. Please provide a response, similar to that requested in b) above, with respect to part d) of 3.0-Staff-31.**

IHDSL Response:

As IHDSL does not maintain sentinel lights and connections have not increased our assumption for the decline in consumption is through the replacement of older lights with newer energy efficient lights with lower wattage ratings contributing to the decline.

d) **Similarly, the response to part e) of 3.0-Staff-31 does not explain the rationale that would support the estimated increase in per USL consumption for 2012 and 2013. Please provide a response, similar to that forecasted in b) above, with respect to part e) of 3.0-Staff-31.**

IHDSL Response:

IHDSL first connected USL in July of 2007. The geometric mean calculation for the USL rate class included 2007 as a full year thus generating an artificially high estimated increase. The geometric calculation should have utilized 2008 as the starting year versus 2007.

3.0-Staff-86s

Ref: 3.0-Staff-67, 17.0-VECC

a) In the update to Table 3-16 provided in the response to 3.0-Staff-67, IHDSL shows 592,454 kWh as the annualized impact of 2011 CDM programs for all years from 2011 to 2014. These are explained as being the final verified CDM results as reported by the OPA. In the 2011 final CDM Report filed as Exhibit 3/Appendix 2 in response to 17.0-VECC b), IHDSL's 2011 CDM results are shown as 0.56 GWh for each of 2011, 2012 and 2013, and 0.54 GWh for 2014. Please confirm and reconcile the numbers provided in the updated Table 3-16.

IHDSL Response:

IHDSL has reconciled the numbers in Table 3.16 and has enclosed the revised table below.

Table 3-16: Schedule for 4 Year kWh CDM Target - Updated with 2011 Final CDM Results
4 Year 2011 to 2014 kWh target
9,200,000

	2011	**2012**	**2013**	**2014**	**Total**
2011 Programs	6.04%	6.04%	6.04%	6.04%	24.17%
2012 Programs		12.6%	12.6%	12.6%	37.9%
2013 Programs			12.6%	12.6%	25.3%
2014 Programs				12.6%	12.6%
	6.04%	18.7%	31.3%	44.0%	100.0%
kWh					
2011 Programs	555,895	555,895	555,895	555,895	2,223,580
2012 Programs		1,162,737	1,162,737	1,162,737	3,488,210
2013 Programs			1,162,737	1,162,737	2,325,473
2014 Programs				1,162,737	1,162,737
	555,895	**1,718,632**	**2,881,368**	**4,044,105**	**9,200,000**

b) If available, please provide the 2011 CDM report in its Microsoft Excel format.

IHDSL Response:

The 2011 Final CDM Results have been enclosed in Excel format. The file name is as follows Ex 3 Appendix 1 Ref 3.0-Staff-86 b).

3.0-Staff-87s

Ref: 3.0-Staff-67, 17.0-VECC

One approach for dealing with the CDM adjustment for the purposes of establishing the base amount for the LRAMVA for 2013 and the corresponding (but not equal adjustment) the load forecast is to take into account the 2011 results and their persistence, as measured and reported by the OPA for IHDSL, and then to assume an equal increment for each of 2012, 2013, and 2014 so as to achieve THI's CDM target of 9,200,000 kWh. The response to 3.0-Staff-67 reflects this approach.

Based on the final 2011 OPA results provided in response to 17.0-VECC and also in 3.0-Staff-67, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)

Innisfil Hydro Distribution System Ltd. *EB-2012-0139*

4 Year (2011-2014) kWh Target:					
9,200,000					
	2011	*2012*	*2013*	*2014*	*Total*
%					
2011 CDM Programs	*6.09%*	*6.09%*	*6.09%*	*5.87%*	*24.13%*
2012 CDM Programs		*12.64%*	*12.64%*	*12.64%*	*37.93%*
2013 CDM Programs			*12.64%*	*12.64%*	*25.29%*
2014 CDM Programs				*12.64%*	*12.64%*
Total in Year	*6.09%*	*18.73%*	*31.38%*	*43.80%*	*100.00%*
kWh					
2011 CDM Programs	*560,000*	*560,000*	*560,000*	*540,000*	*2,220,000*
2012 CDM Programs		*1,163,333*	*1,163,333*	*1,163,333*	*3,490,000*
2013 CDM Programs			*1,163,333*	*1,163,333*	*2,326,667*
2014 CDM Programs				*1,163,333*	*1,163,333*
Total in Year	*560,000*	*1,723,333*	*2,886,667*	*4,030,000*	*9,200,000*
				Check	*9,200,000*

Net-to-Gross Conversion	*"Gross"*	*"Net"*	*Difference*	*"Net-to-Gross" Conversion Factor ('g')*
2006 to 2011 OPA CDM programs: Persistence to 2013	*1*	*1*	*0*	*0.00%*

	2011	*2012*	*2013*	*2014*	*Total for 2013*
Amount used for CDM threshold for LRAMVA	*560,000*	*1,163,333*	*1,163,333*		*2,886,667*
Manual Adjustment for 2013 Load Forecast	*560,000*	*1,163,333*	*581,667*		*2,305,000*
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

The methodology for this is as follows:

For the top table

- **The 2011-2014 CDM target is input into cell B4;**
- **Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;**
- **Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.**

The second table is to calculate the conversion from "net" to "gross" results. While the LRAMVA is based on the "net" OPA-reported results, the load forecast is impacted also by CDM savings of "free riders" and "free drivers". While Board staff has input values of "1" in each of cells D24 and E24, in the absence of information, these should be populated with the measured "gross" and "net" CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- **The "Amount used for CDM threshold for LRAMVA" is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and**
- **"Manual Adjustment for 2013 Load Forecast" represents the amount to be reflected in the 2013 load forecast. This amount uses the "gross" impact, which is calculated by multiplying each year's CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 "actual" consumption is divided by 2 to reflect a "half year" rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the "annualized"**

results reported in the OPA report will overstate the "actual" impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a "half-year" rule may proxy the impact.

a) Please input the "gross" and "net" cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24.

IHDSL Response:

IHDSL has input the gross and net cumulative kWh CDM savings from 2006-2011 into the respective cells.

b) Please verify the inputs and results of the model.

IHDSL Response:

IHDSL has verified that the inputs and the results of the model provided by Board staff.

		Net-to-Gross Conversion			
		"Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013		46,960	29,187	17773.26	60.89%
	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	560,000	1,163,333	1,163,333		2,886,667
Manual Adjustment for 2013 Load Forecast	901,011	1,871,742	935,871		3,708,624
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

c) Please derive the class CDM kWh and kW savings that would correspond with the "net" CDM savings above.

IHDSL Response:

The following table reflects the derivation of the class CDM kWh and kW savings that would correspond with the "NET" savings calculated in response b).

Table 3-17: 2013 Expected Savings for LRAM Variance Account Updated LFCDMAWF (IR 87s)							
	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
kWh	1,833,200	393,218	633,400	18,357	1,270	7,221	2,886,667
kW where applicable			1,822	54	3.5		1,879

d) Please provide IHDSL's comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What refinements to this approach should be considered? As one consideration, 2011 actuals would be impacted by the 2011 CDM programs, but the impact would not be the total annualized amount as the 2011 CDM programs were not in place for the full year. Would it be appropriate to consider that, for the load forecast adjustment, the 2011 CDM should be a manual adjust of using a half-year rule, on the basis that half of the annualized amount is already reflected in the actual data on which the base forecast from the regression model is derived.

IHDSL Response:

IHDSL's Comment on Methodology:

IHDSL supports the methodology used to determine the CDM savings that will underlie the 2013 CDM amount for the LRAMVA.

IHDSL's Comment on 2011 Impact for2013 Manual CDM Adjustment:

With respect to the manual CDM adjustment for the 2013 test year load forecast, IHDSL supports a value that represents the gross level excluding the 2011 values. The results of the 2011 programs and related existence have already been reflected in the CDM Activity variable, which has been based on the actual 2011 power purchases used in the regression analysis. By including the 2011 value in the CDM manual adjustment would be a "double" count. The full suite of 2011 OPA programs may not have been place for the entire year however it should be noted that even in 2013 the full suite of programs designed by the working groups have still not been implemented. CDM programs that were in place in 2010 and with no changes to design still continued into the 1st and 2nd quarter of 2011, for example, peaksaver, DR programs, ERIP (prior to ERII), GRR (prior to Appliance retirement) thus still contributing to energy reductions in 2011. IHDSL has enclosed the 2011 Q2 OPA CDM results As Ex 3 Appendix 1 Ref 3.0-Staff-87s to support the aforementioned statement and which also indicates that measures are not reported until the OPA inputs into their reporting system. Savings are not back dated as to when they actually occurred but as to when the results are input.

IHDSL's Comment on "half year rule":

IHDSL does not support the "half year rule" as the approach is not consistent as to how the LRAMVA threshold is derived and the proposed adjustment to the load forecast. If a full year amount is utilized in the LRAMVA threshold 2013 calculation then the full amount should be utilized in the manual CDM adjustment.

3.0 Energy Probe #53

Ref: 3.0 Energy Probe #20 & Exhibit 3, Tab 2, Schedule 1, Table 3-9

The actual number of residential and GS < 50 customers shown in the interrogatory response are significantly higher than they forecast for 2012 shown in Table 3-9. Please provide any reasons why this is the case.

IHDSL Response:

The volumes reported in Table 3.9 were actual 2012 customer connections. The numbers reported in the forecast for 2012 are year-end averages. The following table provides the year end average connections versus the forecasted connections:

	Res	GS<50	GS<50	Street Lights	Sentinel	USL
Year-End Average	13,943	914	68	2728	223	79
Forecast	13,983	903	68	2807	231	79

3.0 Energy Probe #54

Ref: 16.0-VECC

How does IHDSL deal with the losses associated with the billed volumes associated with the 55 Hydro One customers? In particular, does it bill Hydro One for the billed energy as well as for the lost volumes based on the IFDSL loss factor? If not, why not?

IHDSL Response:

We bill Hydro One annually on receipt of the kWh by rate class, for the loss adjusted volumes as applicable, on our annual Long Term Load Transfer invoice based on our approved loss factor.

Yes, IHDSL bills for all applicable fixed variable energy costs plus the loss factor. Please refer to the enclosed Hydro One invoice for LTLT's.

2011 HI LTLT

Distribution Rates - Residential				
January to April 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0161	259,214	4,173.35	1.20.4080.100.000
PILs Rates incl in rate order	0.0025	259,214	648.04	1.20.4080.100.001
LV Charges	0.0022	259,214	570.27	1.10.4075.900.000
LRAM Rider	0.0008	259,214	207.37	1.20.4080.100.000
Global Adj Rider (nonrpp) (use 2011)	0.0024	259,214	622.11	1.00.1595.800.103
DVA 2009 Rider	0.0005	259,214	129.61	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0023	259,214	596.19	1.00.1595.800.103
	0.0268		6,946.94	

Distribution Rates - Residential				
May to December 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0161	518,429	8,346.70	1.20.4080.100.000
PILs Rates incl in rate order	0.0025	518,429	1,296.07	1.20.4080.100.001
LV Charges	0.0022	518,429	1,140.54	1.10.4075.900.000
LRAM Rider	0.0000	518,429	-	1.20.4080.100.000
Global Adj Rider (nonrpp) (use 2011)	0.0032	518,429	1,658.97	1.00.1595.800.103
DVA 2009 Rider	0.0005	518,429	259.21	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0000	518,429	-	1.00.1595.800.103
DVA 2011 Rider	-0.0015	518,429	(777.64)	1.00.1595.800.103
Tax Change 2011 Rider	-0.0003	518,429	(155.53)	1.20.4080.100.000
	0.0227		11,768.33	

Distribution Rates - General Service				
January to April 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0080	68,854	550.84	1.20.4080.110.000
PILs Rates incl in rate order	0.0012	68,854	82.62	1.20.4080.110.001
LV Charges	0.0020	68,854	137.71	1.10.4075.900.000
LRAM Rider	0.0000	68,854	-	1.20.4080.110.000
Global Adj Rider (nonrpp) (use 2011)	0.0024	68,854	165.25	1.00.1595.800.103
DVA 2009 Rider	0.0004	68,854	27.54	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0023	68,854	158.36	1.00.1595.800.103
	0.0163		1,122.33	

Distribution Rates - General Service				
May to December 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0074	137,708	1,019.04	1.20.4080.110.000
PILs Rates incl in rate order	0.0011	137,708	151.48	1.20.4080.110.001
LV Charges	0.0020	137,708	275.42	1.10.4075.900.000
LRAM Rider	0.0000	137,708	-	1.20.4080.110.000
Global Adj Rider (nonrpp) (use 2011)	0.0032	137,708	440.66	1.00.1595.800.103
DVA 2009 Rider	0.0004	137,708	55.08	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0000	137,708	-	1.00.1595.800.103
DVA 2011 Rider	-0.0015	137,708	(206.56)	1.00.1595.800.103
Tax Change 2011 Rider	-0.0002	137,708	(27.54)	1.20.4080.110.000
	0.0124		1,707.57	

3.0 Energy Probe #55

Ref: 3.0 Energy Probe #21 & 20.0 VECC

The question in 3.0 Energy Probe #21a refers to Table 3.3.9 in Exhibit 3, Tab 3, Schedule 3, whereas the response provided to VECC 20c appears to refer to Table 3.3.9 in Exhibit 3, Tab 3, Schedule 2.

a) Please provide a response to Energy Probe #21a based on the Other Revenue Table 3.3.9 in Exhibit 3, Tab 3, Schedule 3.

IHDSL Response:

IHDSL has updated the appropriate Table 3.3.9, Ex 3, Tab 3, Schedule 3 with 2012 actuals.

Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2012	2012	2013
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	Forecast	Actual	MIFRS
4235	Specific Service Charges	$ 142,194	$ 127,673	$ 166,067	$ 166,067	$ 149,670	$ 150,081	$ 154,100
4225	Late Payment Charges	$ 105,597	$ 111,120	$ 104,841	$ 104,841	$ 110,402	$ 74,521	$ 113,700
4082	Retail Services Revenues	$ 35,349	$ 42,813	$ 78,272	$ 78,272	$ 54,203	$ 44,119	$ 55,033
4210	Pole Rental	$ 154,992	$ 161,381	$ 157,442	$ 157,442	$ 162,676	$ 137,509	$ 167,600
4305	Regulatory Debit	$ -	$ -	$ -	$ -	-$ 639,864	-$ 660,495	$ -
4325	Special Purpose Chg Reco		$ 49,901					
4355	Gain(Loss) on Disposal	$ 33,840	$ -	-$ 126,618	-$ 126,618	-$ 51,476	-$ 80,107	-$ 48,825
4375	Misc Non-Utility Income	$ 377,961	$ 287,996	$ 279,583	$ 279,583	$ 384,806	$ 318,150	$ 500,668
4380	Misc Non-Utility Expense	-$ 331,366	-$ 389,430	-$ 268,700	-$ 268,700	-$ 405,862	-$ 472,526	-$ 469,228
4390	Misc Non-Utility Income	$ 9,629	$ 52,823	$ 24,952	$ 24,952	$ 30,009	$ 6,807	$ 30,900
4405	Interest Income	$ 23,617	$ 36,839	$ 53,328	$ 53,328	$ 14,600	$ 35,182	$ 3,000
4406	SRED Revenue	$ -	$ -	$ 153,377	$ 153,377	$ 50,000	$ 84,575	$ 50,000
Specific Service Charges		$ 142,194	$ 127,673	$ 166,067	$ 166,067	$ 149,670	$ 150,081	$ 154,100
Late Payment Charges		$ 105,597	$ 111,120	$ 104,841	$ 104,841	$ 110,402	$ 74,521	$ 113,700
Other Operating Revenues		$ 190,341	$ 204,194	$ 235,714	$ 235,714	$ 216,879	$ 181,628	$ 222,633
Other Income or Deductions		$ 113,681	$ 38,129	$ 115,922	$ 115,922	-$ 617,787	-$ 768,414	$ 66,515
Total		$ 551,813	$ 481,116	$ 622,544	$ 622,544	-$ 140,836	-$ 362,184	$ 556,948

b) The response to part (b) of the Energy Probe interrogatory is incomplete since it asked for the 2012 actual data (or the most recent year-to-date actuals for 2012 and the corresponding figures for 2011 over the same period) in the same level of detail as shown in Table 3.3.9 (Other Revenue) in Exhibit 3, Tab 3, Schedule 3. The VECC response referred to only provides a response to part (c) of the Energy Probe interrogatory. Please provide the requested information for 2012 in the level of detail requested.

IHDSL Response:

IHDSL has modified the table to reflect Table 3.3.9, Ex 3, Tab 3, Schedule 3, with 2012 Actuals excluding account 4375 Misc. Non-utility Income and account 4380 Misc. Non-Utility Expense.

Appendix 2-F
Other Operating Revenue (removing 4375 & 4380)

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2012	2012	2013
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	Forecast	Actual	MIFRS
4235	Specific Service Charges	$ 142,194	$ 127,673	$ 166,067	$ 166,067	$ 149,670	$ 150,081	$ 154,100
4225	Late Payment Charges	$ 105,597	$ 111,120	$ 104,841	$ 104,841	$ 110,402	$ 74,521	$ 113,700
4082	Retail Services Revenues	$ 35,349	$ 42,813	$ 78,272	$ 78,272	$ 54,203	$ 44,119	$ 55,033
4210	Pole Rental	$ 154,992	$ 161,381	$ 157,442	$ 157,442	$ 162,676	$ 137,509	$ 167,600
4305	Regulatory Debit	$ -	$ -	$ -	$ -	-$ 639,864	$ 660,495	$ -
4325	Special Purpose Chg Reco		$ 49,901					
4355	Gain(Loss) on Disposal	$ 33,840	$ -	-$ 126,618	-$ 126,618	-$ 51,476	-$ 80,107	-$ 48,825
4390	Misc Non-Utility Income	$ 9,629	$ 52,823	$ 24,952	$ 24,952	$ 30,009	$ 6,807	$ 30,900
4405	Interest Income	$ 23,617	$ 36,839	$ 53,328	$ 53,328	$ 14,600	$ 35,182	$ 3,000
4406	SRED Revenue	$ -	$ -	$ 153,377	$ 153,377	$ 50,000	$ 84,575	$ 50,000
Specific Service Charges		$ 142,194	$ 127,673	$ 166,067	$ 166,067	$ 149,670	-$ 150,081	$ 154,100
Late Payment Charges		$ 105,597	$ 111,120	$ 104,841	$ 104,841	$ 110,402	$ 74,521	$ 113,700
Other Operating Revenues		$ 190,341	$ 204,194	$ 235,714	$ 235,714	$ 216,879	$ 181,628	$ 222,633
Other Income or Deductions		$ 113,681	$ 38,129	$ 115,922	$ 115,922	-$ 617,787	$ 706,952	$ 66,515
Total		$ 551,813	$ 481,116	$ 622,544	$ 622,544	-$ 140,836	$ 813,020	$ 556,948

3.0 Energy Probe #56

Ref: 20.0-VECC

a) Please provide a breakdown of the revenues in account 4082 - Retail Services Revenues into each of its components, including microFit revenues, SSS Admin charges (account 4080) and retail services for 2009 through 2013, including actual data for 2012.

IHDSL Response:

IHDSL is providing a breakdown of the revenues in account 4082. Through this analysis IHDSL has determined it inadvertently omitted a digit when estimating the retail services revenue for the 2012 bridge year and 2013 test year. IHDSL is submitting the retail services revenue for the 2013 test year should be $39,533 based on the 2009 to 2012 actual average. IHDSL will reflect this change within the Summary of Changes.

Breakdown of Account 4082 - Retail Services						
	2009	2010	2011	2012 Bridge	2012 Actual	2013 Test
Microfit	-	-	1,879	2,000	3,333	2,500
SSS	45,485	46,359	41,362	42,500	45,958	43,000
Retail Services	35,349	42,813	35,031	9,703	44,476	9,533
Total	**80,834**	**89,172**	**78,272**	**54,203**	**93,767**	**55,033**

b) Please provide the gain and loss and net gain/loss on the disposition of assets for 2012 on an actual basis.

IHDSL Response:

The actual loss on disposition of assets for 2012 is $80,107.

c) How has IHDSL adjusted the PP&E accounts to reflect the loss of the disposition of assets that are fully depreciated or not yet fully depreciated?

IHDSL Response:

IHDSL has removed the asset cost and associated accumulated depreciation and therefore removing the loss of disposition of assets from the PP&E accounts.

3.0 – VECC – 40

Reference: Staff #67 a) & b); VECC #17 b)

a) The purported 2011 final reported CDM results shown in Staff #67 a) and b) do not match those from the OPA's final 2011 CDM report (see VECC #17 b)) which shows a net 2011 CDM savings from 2011 programs of 555,895 kWh. Please provide corrected responses.

IHDSL Response:

IHDSL has reconciled the numbers in Table 3.16 and has enclosed the revised table below.

Table 3-16: Schedule for 4 Year kWh CDM Target - Updated with 2011 Final CDM Results 4 Year 2011 to 2014 kWh target 9,200,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 Programs	6.04%	6.04%	6.04%	6.04%	24.17%
2012 Programs		12.6%	12.6%	12.6%	37.9%
2013 Programs			12.6%	12.6%	25.3%
2014 Programs				12.6%	12.6%
	6.04%	18.7%	31.3%	44.0%	100.0%
kWh					
2011 Programs	555,895	555,895	555,895	555,895	2,223,580
2012 Programs		1,162,737	1,162,737	1,162,737	3,488,210
2013 Programs			1,162,737	1,162,737	2,325,473
2014 Programs				1,162,737	1,162,737
	555,895	**1,718,632**	**2,881,368**	**4,044,105**	**9,200,000**

3.0 – VECC-41

Reference: VECC #16 a) & b)

a) **Please update the 2013 load forecast (both purchases and sales by customer class so as to include Hydro One Load Transfer for 2013.**

Rate Class	kWh	MicroFit Generation
Residential	873,386	
GS < 50	195,189	
MicroFit	5	18,753
Sentinel Lights	3,542	
Total:	**1,072,122**	**18,753**

b) **How are the annual payments received from HON accounted for (i.e., with reference to Application Table 3.1 where are they recorded and formally what USOA account is used)?**

We bill Hydro One annually on receipt of the kWh by rate class, for the loss adjusted volumes as applicable, on our annual Long Term Load Transfer invoice based on our approved loss factor.

On receipt of IHDSL payment from the generated invoice, we utilize the same charge codes as for direct customer billings as indicated on the enclosed 2011 Hydro One invoice:

2011 HI LTLT

Distribution Rates - Residential				
January to April 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0161	259,214	4,173.35	1.20.4080.100.000
PILs Rates incl in rate order	0.0025	259,214	648.04	1.20.4080.100.001
LV Charges	0.0022	259,214	570.27	1.10.4075.900.000
LRAM Rider	0.0008	259,214	207.37	1.20.4080.100.000
Global Adj Rider (nonrpp) (use 2011)	0.0024	259,214	622.11	1.00.1595.800.103
DVA 2009 Rider	0.0005	259,214	129.61	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0023	259,214	596.19	1.00.1595.800.103
	0.0268		6,946.94	

Distribution Rates - Residential				
May to December 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0161	518,429	8,346.70	1.20.4080.100.000
PILs Rates incl in rate order	0.0025	518,429	1,296.07	1.20.4080.100.001
LV Charges	0.0022	518,429	1,140.54	1.10.4075.900.000
LRAM Rider	0.0000	518,429	-	1.20.4080.100.000
Global Adj Rider (nonrpp) (use 2011)	0.0032	518,429	1,658.97	1.00.1595.800.103
DVA 2009 Rider	0.0005	518,429	259.21	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0000	518,429	-	1.00.1595.800.103
DVA 2011 Rider	-0.0015	518,429	(777.64)	1.00.1595.800.103
Tax Change 2011 Rider	-0.0003	518,429	(155.53)	1.20.4080.100.000
	0.0227		11,768.33	

Distribution Rates - General Service				
January to April 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0080	68,854	550.84	1.20.4080.110.000
PILs Rates incl in rate order	0.0012	68,854	82.62	1.20.4080.110.001
LV Charges	0.0020	68,854	137.71	1.10.4075.900.000
LRAM Rider	0.0000	68,854	-	1.20.4080.110.000
Global Adj Rider (nonrpp) (use 2011)	0.0024	68,854	165.25	1.00.1595.800.103
DVA 2009 Rider	0.0004	68,854	27.54	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0023	68,854	158.36	1.00.1595.800.103
	0.0163		1,122.33	

Distribution Rates - General Service				
May to December 2011	**Rate**	**Usage**	**Cost**	**Account**
Distribution Rates w/o PILs - Base	0.0074	137,708	1,019.04	1.20.4080.110.000
PILs Rates incl in rate order	0.0011	137,708	151.48	1.20.4080.110.001
LV Charges	0.0020	137,708	275.42	1.10.4075.900.000
LRAM Rider	0.0000	137,708	-	1.20.4080.110.000
Global Adj Rider (nonrpp) (use 2011)	0.0032	137,708	440.66	1.00.1595.800.103
DVA 2009 Rider	0.0004	137,708	55.08	1.00.1595.800.101
DVA 2010 Rider (use 2011)	0.0000	137,708	-	1.00.1595.800.103
DVA 2011 Rider	-0.0015	137,708	(206.56)	1.00.1595.800.103
Tax Change 2011 Rider	-0.0002	137,708	(27.54)	1.20.4080.110.000
	0.0124		1,707.57	

3.0 – VECC – 42

Reference: VECC #17 c) & d)

a) Please confirm that, for any given year, the difference between gross and net OPA reported savings does not reflect all of the CDM activity that will take place without any incentive being provided. If not confirmed, please explain why.

IHDSL Response:

IHDSL can confirm that for any given year the difference between gross and net OPA reported savings is not reflective of all the CDM activity in IHDSL's service territory.

b) Does Innisfil agree that the historical consumption values for each customer class will have been impacted by the total CDM activity that has occurred each year without any incentive being provided (and not just that associated with OPA CDM programs)?

IHDSL Response:

Yes

c) Can Innisfil provide any estimates of the total savings in each year 2002-2011 from CDM activity that has would have taken place in its service area without any incentive (as opposed to just that associated with OPA programs)? If so, please do so and indicate how the savings amounts were determined.

IHDSL Response:

IHDSL feels that the CDM variables in the load forecast attest to CDM activities that have occurred in our service territory beyond the OPA Provincial Programs

3.0 – VECC – 43

Reference: VECC #19 a)

a) Please provide as schedule setting out the derivation of the 251.1 GWh purchase value for 2013.

IHDSL Response:

The following provides a schedule setting out the derivation of the 251.1 GWh purchase value for 2013.

2013 Weather Normal	
Predicted kWh Purchases	256.2
CDM adjustment including losses @ 8.63%	(4.1)
Hydro One transfer adjustment including losses @ 8.63%	(1.0)
Total	251.1

3.0 – VECC – 44

Reference: Staff #36 a) & b)

a) Please explain why it is appropriate for Innisfil to change the useful lives used for depreciation purposes in the middle of an IRM period – since its rates for the IRM period are anchored on a revenue requirement rebased using the pre-existing service lives.

IHDSL Response:

IHDSL is implementing an accounting policy change within the IRM period due to updated information provided by the Kinetics Study and guidelines provided by the OEB July 2012 FAQs'. IHDSL is recognizing the excess depreciation collected within the 2012 distribution rates to a DVA account that will be refunded to its ratepayers over the next 4 years.

3.0 – VECC – 45

Reference: Energy Probe #21 b) & VECC #20 c)

a) There are two versions of Table 3.3.9 in the Application – one at Exhibit 3, Tab 3, Schedule 2, page 5 and another at Exhibit 3, Tab 3, Schedule 3, page 1. Both information requests asked for an update of the second table based on 2012 actual results. Please provide.

IHDSL Response:

Please refer to the Tables provided in Energy Probe IR 55 for the 2012 updates.

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b)

save on energy™

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

LDC: Innisfil Hydro Distribution Systems Limited

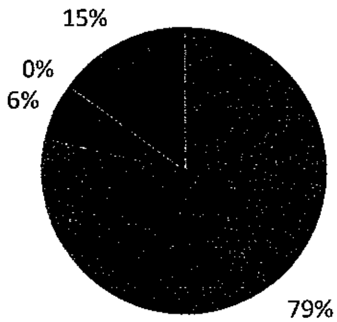
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.3	**5.3%**	**11.0%**
Net Cumulative Energy Savings (GWh)	0.6	**23.9%**	**24.0%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

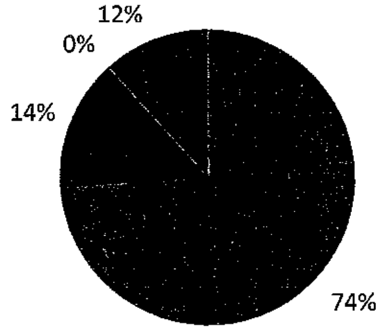
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

2011 Incremental Peak Demand Savings (MW)



2011 Incremental Energy Savings (GWh)

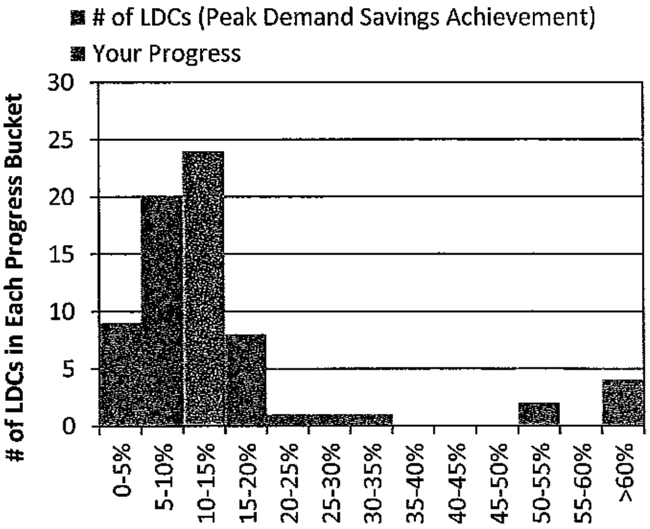


- Consumer Program Total
- Industrial Program Total
- Pre-2011 Programs completed in 2011 Total
- Business Program Total
- Home Assistance Program Total

Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

% of OEB Peak Demand Savings Target Achieved



% of OEB Energy Savings Target Achieved

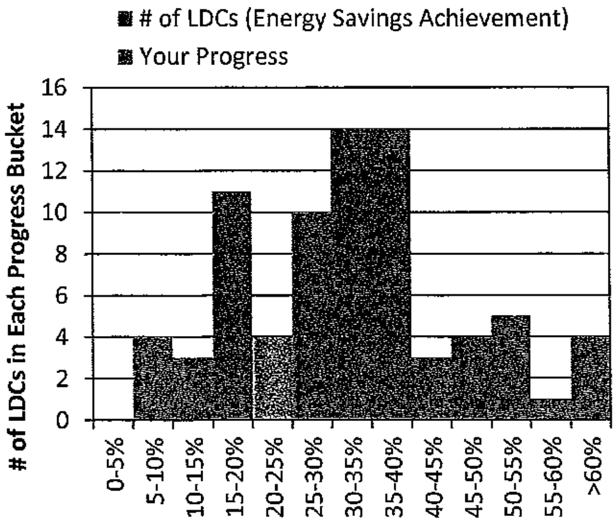


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	250
2	Appliance Exchange	Appliances	17
3	HVAC Incentives	Equipment	188
4	Conservation Instant Coupon Booklet	Products	2,095
5	Bi-Annual Retailer Event	Products	3,439
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	233
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	1
10	Direct Install Lighting	Projects	11
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	1
14	Commercial Demand Response (part of the Residential program schedule)	Devices	5
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	1
23	High Performance New Construction	Projects	1
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Table 3: OPA Province Wide Evaluation Findings

#	Initiative	OPA Province-Wide Key Evaluation Findings
Consumer Program		

1	Appliance Retirement	* Overall participation continues to decline year over year
		  * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011)
		* 97% of net resource savings achieved through the home pick-up stream
		  * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners
		* 3% of net resource savings achieved through the Retailer pick-up stream
		  * Measure Breakdown: 90% refrigerators, 10% freezers
		* Net-to-Gross ratio for the initiative was 50%
		  * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream
		  * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream

2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to
		  * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers
		* Dehumidifiers and window air conditioners contributed almost equally to the net energy
		  * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners
		* Window air conditioners contributed to 64% of the net peak demand savings achieved
		* Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit)
		* Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)

3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011)
		  * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15)
		  * Measure breakdown did not change from 2010 to 2011
		* The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program
		  * Furnaces accounted for over 91% of energy savings achieved for this initiative
		* Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in
		  * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)

4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products
		  * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%)
		  * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%)
		* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed

		* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%)

#	Initiative	OPA Province-Wide Key Evaluation Findings

5	Bi-Annual Retailer Event	* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		  * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings
		  * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.

6	Retailer Co-op	* Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings

7	Residential Demand Response	* Approximately 20,000 new devices were installed in 2011
		  * 99% of the new devices enrolled controlled residential central AC (CAC)
		* 2011 only saw 1 atypical event (in both weather and timing) that had limited participation
		  * The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device

8	Residential New Construction	* Initiative was not evaluated in 2011 due to limited uptake * Business case assumptions were used to calculate savings
Business Program		

9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and
		* Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes
		  * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions
		  * Low realization rates for engineered lighting projects due to overstated operating hour assumptions
		* Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan
		* The final realization rate for summer peak demand was 94%
		  * 84% was a result of different methodologies used to calculate peak demand savings
		  * 10% due to the benefits from reduced air conditioning load in lighting retrofits
		* Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios

10	Direct Install Lighting	* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity
		* 70% of province-wide resource savings persist to 2014
		  * Over 35% of the projects for 2011 included at least one CFL measure
		  * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years
		* Since 2009 the overall realization rate for this program has improved
		  * 2011 evaluation recorded the highest energy realization rate to date at 89.5%

#	Initiative	OPA Province-Wide Key Evaluation Findings
		* The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in "as needed" areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
11	Existing Building Commissioning Incentive	* Initiative was not evaluated in 2011, no completed projects in 2011
12	New Construction and Major Renovation Incentive	* Initiative was not evaluated in 2011 due to low uptake * Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio)
13	Energy Audit	* The evaluation is ongoing. The sample size for 2011 was too small to draw reliable conclusions.
14	Commercial Demand Response (part of the Residential program schedule)	* See residential demand response (#7)
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
16	Process & System Upgrades	* Initiative was not evaluated in 2011, no completed projects in 2011
17	Monitoring & Targeting	* Initiative was not evaluated in 2011, no completed projects in 2011
18	Energy Manager	* Initiative was not evaluated in 2011, no completed projects in 2011
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% * Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively * Program continues to diversify but still remains heavily concentrated with less than 5% of * By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase
Home Assistance Program		
21	Home Assistance Program	* Initiative was not evaluated in 2011 due to low uptake * Business Case assumptions were used to calculate savings
Pre-2011 Programs completed in 2011		

#	Initiative	OPA Province-Wide Key Evaluation Findings
22	Electricity Retrofit Incentive Program	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio)
23	High Performance New Construction	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%)
24	Toronto Comprehensive	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
25	Multifamily Energy Efficiency Rebates	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
26	Data Centre Incentive Program	* Initiative was not evaluated
27	EnWin Green Suites	* Initiative was not evaluated

Table 5: Summarized Program Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)		Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	271	578,970		216	411,063
Business Program Total	16	103,630		17	79,964
Industrial Program Total	0	0		0	0
Home Assistance Program Total	0	0		0	0
Pre-2011 Programs completed in 2011 Total	80	129,699		41	64,868
Total OPA Contracted Province-Wide CDM Programs	**367**	**812,298**		**275**	**555,895**

#	Initiative	Realization Rate: Peak Demand Savings	Realization Rate: Energy Savings	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net-to-Gross Ratio: Peak Demand Savings	Net-to-Gross Ratio: Energy Savings	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	28	205,896	51%	51%	14	100,309
2	Appliance Exchange	100%	100%	4	4,632	52%	52%	2	2,387
3	HVAC Incentives	100%	100%	98	190,629	60%	60%	58	113,459
4	Conservation Instant Coupon Booklet	100%	100%	4	71,198	114%	111%	5	78,462
5	Bi-Annual Retailer Event	100%	100%	6	106,277	113%	110%	7	116,108
6	Retailer Co-op	-	-	0	0	-	-	0	0
7	Residential Demand Response	0%	0%	130	338	-	-	130	338
8	Residential New Construction	-	-	0	0	-	-	0	0
Business Program									
9	Efficiency: Equipment Replacement	-	-	0	64,914	-	-	0	44,014
10	Direct Install Lighting	108%	90%	13	38,704	93%	93%	14	35,938
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0
13	Energy Audit	-	-	0	0	-	-	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	3	12	-	-	3	12
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0
Industrial Program									
16	Process & System Upgrades	-	-	0	0	-	-	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0
18	Energy Manager	-	-	0	0	-	-	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0
Home Assistance Program									
21	Home Assistance Program	-	-	0	0	-	-	0	0
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	77%	77%	55	926	52%	52%	29	481
23	High Performance New Construction	100%	100%	25	128,773	50%	50%	13	64,386
24	Toronto Comprehensive	-	-	0	0	-	-	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	84	1,641,995
Business Program Total	8	301,396
Industrial Program Total	0	0
Home Assistance Program Total	0	0
Pre-2011 Programs completed in 2011 Total	41	259,471
Total OPA Contracted Province-Wide CDM Programs	**133**	**2,202,862**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	13	400,830
2	Appliance Exchange	1	8,711
3	HVAC Incentives	58	453,837
4	Conservation Instant Coupon Booklet	5	313,846
5	Bi-Annual Retailer Event	7	464,432
6	Retailer Co-op	0	0
7	Residential Demand Response	0	338
8	Residential New Construction	0	0
Business Program			
9	Efficiency: Equipment Replacement	0	176,058
10	Direct Install Lighting	8	125,326
11	Existing Building Commissioning Incentive	0	0
12	New Construction and Major Renovation Incentive	0	0
13	Energy Audit	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0	12
15	Demand Response 3 (part of the Industrial program schedule)	0	0
Industrial Program			
16	Process & System Upgrades	0	0
17	Monitoring & Targeting	0	0
18	Energy Manager	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	0	0
20	Demand Response 3	0	0
Home Assistance Program			
21	Home Assistance Program	0	0
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	29	1,926
23	High Performance New Construction	13	257,545
24	Toronto Comprehensive	0	0
25	Multifamily Energy Efficiency Rebates	0	0
26	Data Centre Incentive Program	0	0
27	EnWin Green Suites	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

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

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.27	0.14	0.14	0.13
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.13
nnisfil Hydro Distribution Systems Limited 2014 Annual CDM Capacity Target:				2.5
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				5.31%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.56	0.56	0.56	0.54	2.20
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					2.20
Innisfil Hydro Distribution Systems Limited 2011-2014 Cumulative CDM Energy Target:					9.2
Verified Portion of Cumulative Energy Target Achieved (%):					23.94%
LDC Milestone submitted for 2011					-%
Variance					

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,110
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,587
4	Conservation Instant Coupon Booklet	Products[4]	559,462
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement	Projects	2,516
10	Direct Installed Lighting	Projects	20,297
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	10
13	Energy Audit	Audits	103
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	433
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre-2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	2,023
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	553
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	5
27	EnWin Green Suites	Projects	3

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects*

[4] *209,693 valid coupons redeemed*

[5] *369,446 valid coupons redeemed*

Table P2: Province-Wide Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)		Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	73,757	192,379,633		49,123	133,519,668
Business Program Total	78,048	251,304,448		64,594	198,124,227
Industrial Program Total	68,648	41,493,145		57,099	31,947,577
Home Assistance Program Total	4	56,119		2	39,283
Pre-2011 Programs completed in 2011 Total	87,169	460,822,079		44,833	241,853,020
Total OPA Contracted Province-Wide CDM Programs	307,626	946,055,425		215,651	605,483,775

#	Initiative	Realization Rate: Peak Demand Savings	Realization Rate: Energy Savings	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net-to-Gross Ratio: Peak Demand Savings	Net-to-Gross Ratio: Energy Savings	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
	Consumer Program								
1	Appliance Retirement	100%	100%	6,750	45,971,627	51%	51%	3,299	23,005,812
2	Appliance Exchange	100%	100%	719	873,531	51%	51%	371	450,187
3	HVAC Incentives	100%	100%	53,209	99,413,430	60%	60%	32,037	59,437,670
4	Conservation Instant Coupon Booklet	100%	100%	1,184	19,192,453	114%	111%	1,344	21,211,537
5	Bi-Annual Retailer Event	100%	100%	1,504	26,899,265	112%	110%	1,681	29,387,468
6	Retailer Co-op	100%	100%	0.18	3,917	68%	68%	0	2,652
7	Residential Demand Response	n/a	n/a	10,390	23,597	n/a	n/a	10,390	23,597
8	Residential New Construction	100%	100%	0	1,813	41%	41%	0	743
	Business Program								
9	Efficiency: Equipment Replacement	106%	91%	34,201	184,070,265	72%	74%	24,467	136,002,258
10	Direct Installed Lighting	108%	93%	22,155	65,777,197	108%	93%	23,724	61,076,701
11	Existing Building Commissioning Incentive	-	-	-	-	-	-	-	-
12	New Construction and Major Renovation Incentive	50%	50%	247	823,434	50%	50%	123	411,717
13	Energy Audit	-	-	-	-	-	-	-	-
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	55	131	n/a	n/a	55	131
15	Demand Response 3 (part of the Industrial program schedule)	76%	n/a	21,390	633,421	n/a	n/a	16,224	633,421
	Industrial Program								
16	Process & System Upgrades	-	-	-	-	-	-	-	-
17	Monitoring & Targeting	-	-	-	-	-	-	-	-
18	Energy Manager	-	-	-	-	-	-	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	111%	91%	6,372	38,412,408	72%	75%	4,615	28,866,840
20	Demand Response 3	84%	n/a	62,276	3,080,737	n/a	n/a	52,484	3,080,737
	Home Assistance Program								
21	Home Assistance Program	100%	100%	4	56,119	70%	70%	2	39,283
	Pre-2011 Programs completed in 2011								
22	Electricity Retrofit Incentive Program	80%	80%	40,418	223,956,390	54%	54%	21,550	120,492,549
23	High Performance New Construction	100%	100%	10,197	52,371,183	49%	49%	5,098	26,185,591
24	Toronto Comprehensive	113%	113%	33,467	174,070,574	50%	52%	15,805	86,964,886
25	Multifamily Energy Efficiency Rebates	93%	93%	2,553	9,774,792	78%	78%	1,981	7,595,683
26	Data Centre Incentive Program	100%	100%	81	533,038	100%	100%	81	533,038
27	EnWin Green Suites	100%	100%	453	116,102	70%	70%	317	81,272

Assumes demand response resources have a persistence of 1 year

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	38,405	534,017,835
Business Program Total	41,048	767,657,790
Industrial Program Total	4,613	118,543,019
Home Assistance Program Total	2	157,134
Pre-2011 Programs completed in 2011 Total	44,833	967,412,079
Total OPA Contracted Province-wide CDM Programs	128,901	2,387,787,856

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	3,160	91,903,303
2	Appliance Exchange	181	1,930,651
3	HVAC Incentives	32,037	237,750,681
4	Conservation Instant Coupon Booklet	1,344	84,846,148
5	Bi-Annual Retailer Event	1,681	117,549,874
6	Retailer Co-op	0	10,607
7	Residential Demand Response	0	23,597
8	Residential New Construction	0	2,973
Business Program			
9	Efficiency: Equipment Replacement	24,438	543,856,392
10	Direct Installed Lighting	16,486	221,520,977
11	Existing Building Commissioning Incentive	-	-
12	New Construction and Major Renovation Incentive	123	1,646,869
13	Energy Audit	-	-
14	Commercial Demand Response (part of the Residential program schedule)	0	131
15	Demand Response 3 (part of the Industrial program schedule)	0	633,421
Industrial Program			
16	Process & System Upgrades	-	-
17	Monitoring & Targeting	-	-
18	Energy Manager	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	4,613	115,462,282
20	Demand Response 3	0	3,080,737
Home Assistance Program			
21	Home Assistance Program	2	157,134
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	21,550	481,970,197
23	High Performance New Construction	5,098	104,742,366
24	Toronto Comprehensive	15,805	347,859,545
25	Multifamily Energy Efficiency Rebates	1,981	30,382,733
26	Data Centre Incentive Program	81	2,132,152
27	EnWin Green Suites	317	325,086

Assumes demand response resources have a persistence of 1 year

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

Summary - Provincial Progress

Table P3: Province Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	215.7	136.4	135.7	128.9
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				128.9
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				9.69%

Table P4: Province Wide Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	605.5	601.6	599.6	580.9	2,388
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					2,388
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					39.79%

METHODOLOGY

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

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

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

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

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

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

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

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

EX 3 APPENDIX 1 REF 3.0-STAFF-86s b

ERII Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

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

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

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

EX 3 APPENDIX 2 REF 3.0-STAFF-87s

saveONenergy

Ontario Power Authority Q2 2011 Conservation & Demand Management Status Report (Revised)

April 1, 2011 to June 30, 2011

For LDC: ***Innisfil Hydro Distribution Systems Limited***

The OPA Conservation team is pleased to provide the Q2 2011 CDM Status Report. Not all data has been entered into the system at the OPA so please don't be discouraged by the results. With each quarter report the data will become more fulsome and provide clearer insight into the Tier 1 progress. We would like to thank LDCs for their constructive feedback. We have incorporated some comments and will continue to incorporate others into future reports. We invite you to continue to look for ways we can improve this report to meet your needs. If you are having any concerns with roll-out or have had particular success to share, please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca. We are here to help you and electricity consumers in Ontario achieve aggressive, yet achievable, conservation results.

- Andrew Pride
Vice President, Conservation
Ontario Power Authority

About this Report:

This report contains:

- Saving for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other conservation efforts undertaken by an LDC)
- Unverified quarterly results are discounted for assumed net-to-gross ratios. Once full Evaluation, Measurement & Verification (EM&V) occurs in the following year, results will be identified as final.
- Data entered into the OPA processing system on or before July 22, 2011 is represented in the data set if the project/participation was completed on or before June 30, 2011

Future reports will contain:

- Data from: Coupons, Bi-Annual Retailer Events, Appliance Exchange, Retrofit (currently unavailable)

New this quarter:

- Savings for OPA-Contracted Province-wide programs aggregated for the province
- Updates to the previous quarter's participation due to more data availability
- Unverified savings projections from pre-2011 programs completed in 2011 are included for your information
- Reports for Q2 - Q4 will communicate only changes to the total demand response (DR) under contract in the *Incremental (Current Quarter)* column. The total DR under contract will be reflected in the *Incremental (YTD)* column. If a facility is no longer providing DR or providing less megawatts in the LDC territory, a negative value may appear in the *Incremental (Current Quarter)* column.

saveONenergy

2011-2014 Summary

2011 Quarter 2 *April 1, 2011 to June 30, 2011*

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

Table 1 presents net peak demand savings results from 2011 to date by implementation period and results status (i.e. reported or verified). This table also presents expected net annual peak demand savings in 2014 from programs implemented to date.

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

#	Implementation Period	Annual			
		2011	2012	2013	2014
1	2011 - Reported - Quarter 1	0.01	0.01	0.01	0.01
2	2011 - Reported - Quarter 2	0.03	0.03	0.03	0.03
3	2011 - Reported - Quarter 3				
4	2011 - Reported - Quarter 4				
5	2012				
6	2013				
7	2014				
Annual Reported (Unverified)		0.05			
Annual Final (Verified)					
Projected Net Annual Peak Demand Savings in 2014:					**0.05**
2014 Annual CDM Capacity Target:					**2.50**
Projected Portion of Target Achieved (%):					**1.8%**

Table 2 presents net annual energy savings results from 2011 to date by implementation period and results status (i.e. reported or verified). This table also presents expected net cumulative energy savings in 2014 from programs implemented to date.

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

#	Implementation Period	Annual				Cumulative
		2011	2012	2013	2014	2011-2014
1	2011 - Reported - Quarter 1	0.03	0.03	0.03	0.03	0.13
2	2011 - Reported - Quarter 2	0.04	0.04	0.04	0.04	0.14
3	2011 - Reported - Quarter 3					
4	2011 - Reported - Quarter 4					
5	2012					
6	2013					
7	2014					
Annual Reported (Unverified)		0.07				
Annual Final (Verified)						
Projected 2011-2014 Net Cumulative Energy Savings in 2014						**0.27**
2011-2014 Cumulative CDM Energy Target:						**9.20**
Portion of Target Achieved (%):						**2.9%**

2011-2014 Summary

2011 Quarter 2 *April 1, 2011 to June 30, 2011*

Figure 1 graphically represents the projected net annual peak demand savings to 2014 from programs implemented to date. The 2014 annual peak demand savings target as per OEB is also presented.

Figure 1: Net Peak Demand Savings (MW)

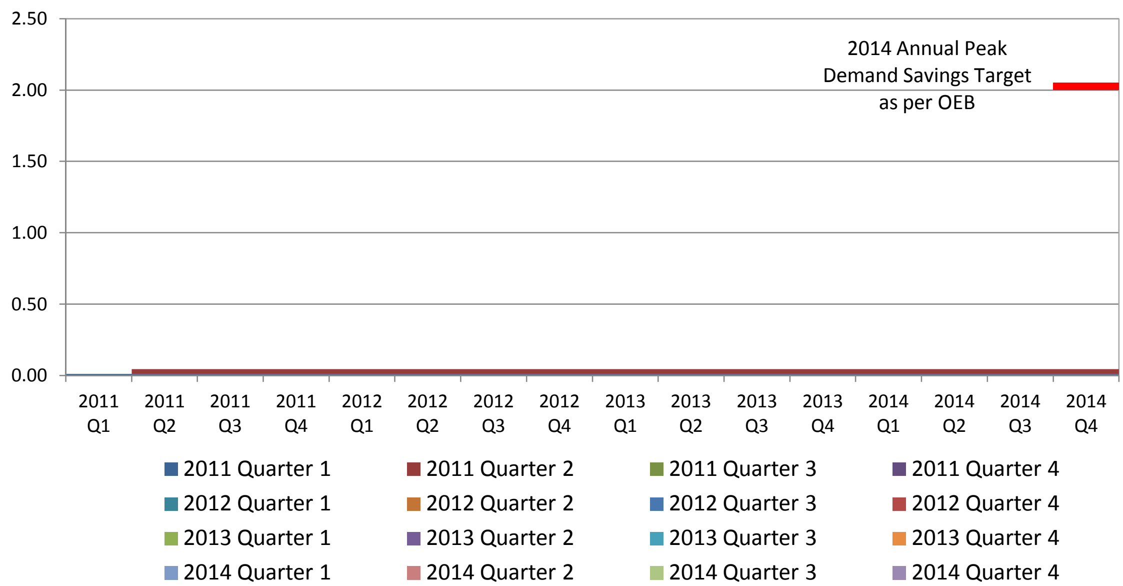
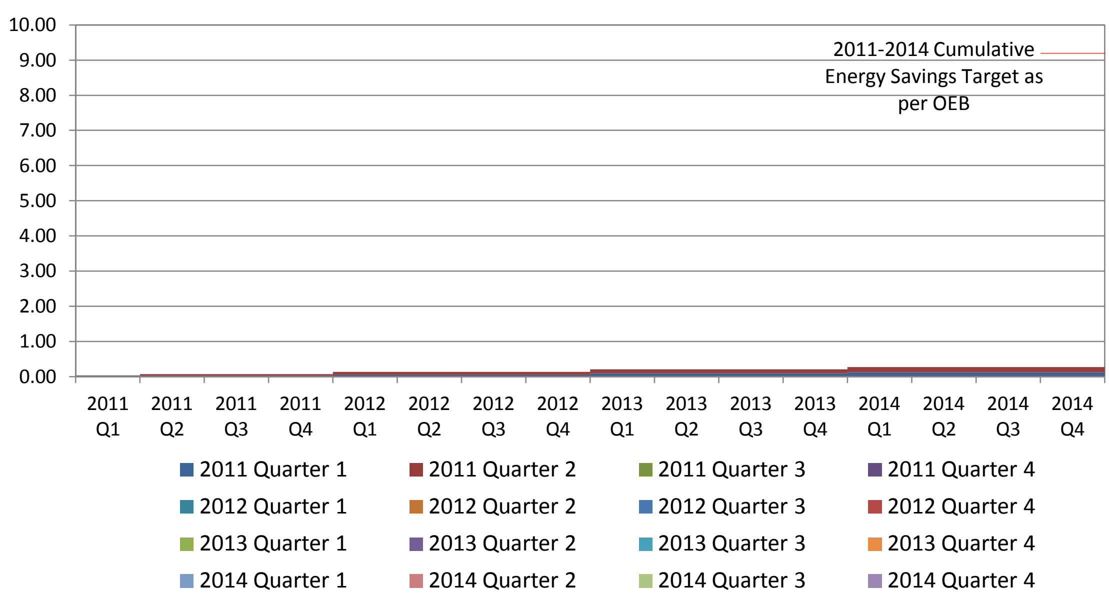


Figure 2 graphically represents the projected net cumulative energy savings to 2014 from programs implemented to date. The 2011-2014 cumulative energy savings target as per OEB is also presented.

Figure 2: Net Cumulative Energy Savings (GWh)



Initiative Detail: Innisfil Hydro Distribution Systems Limited

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

Table 3: Initiative and Program Level Savings Innisfil Hydro Distribution Systems Limited

Table 3: Initiative and Program Level Savings

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date:	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: projected annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: projected cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	62	101	4.7	7.7	7.7	32,356	52,815	211,260
2	Appliance Exchange	Appliances								
3	HVAC Incentives	Equipment	7	30	1.9	8.5	8.5	3,113	14,301	57,204
4	Conservation Instant Coupon Booklet	Items								
5	Bi-Annual Retailer Event	Items								
6	Residential Demand Response	Devices	30	33	23.4	25.7	25.7	467	514	2,055
7	Midstream Electronics	Items	0	0	0.0	0.0	0.0	0	0	0
8	Midstream Pool Equipment	Items	0	0	0.0	0.0	0.0	0	0	0
9	Residential New Construction	Houses	0	0	0.0	0.0	0.0	0	0	0
Consumer Program Total					**30.0**	**41.9**	**41.9**	**35,936**	**67,630**	**270,520**
Business Program										
10	Electricity Retrofit Incentive	Items								
11	Direct Installed Lighting	Items	0	0	0.0	0.0	0.0	0	0	0
12	Direct Service Space Cooling	Equipment	0	0	0.0	0.0	0.0	0	0	0
13	Building Commissioning	Buildings	0	0	0.0	0.0	0.0	0	0	0
14	New Construction	Buildings	0	0	0.0	0.0	0.0	0	0	0
15	Small Commercial Demand Response	Devices	2	2	3.3	3.3	3.3	67	67	266
16	Demand Response 1	Facilities	0	0	0.0	0.0	0.0	0	0	0
17	Demand Response 3	Facilities	0	0	0.0	0.0	0.0	0	0	0
Business Program Total					**3.3**	**3.3**	**3.3**	**67**	**67**	**266**
Industrial Program										
18	Process & System Upgrades	Projects	0	0	0.0	0.0	0.0	0.0	0	0
19	Monitoring & Targeting	Projects	0	0	0.0	0.0	0.0	0.0	0	0
20	Energy Manager	Managers	0	0	0.0	0.0	0.0	0.0	0	0
21	Industrial Electricity Retrofit	Measures								
22	Demand Response 1	Projects	0	0	0.0	0.0	0.0	0.0	0	0
23	Demand Response 3	Projects	0	0	0	0	0	0	0	0
Industrial Program Total					**0**	**0**	**0.0**	**0**	**0**	**0**
Home Assistance Program										
24	Home Assistance Program	Units	0	0	0.0	0.0	0.0	0	0	0
Home Assistance Program Total					**0.0**	**0.0**	**0.0**	**0**	**0**	**0**
Tier 1 Portfolio Total					**33**	**45**	**45**	**36,003**	**67,697**	**270,787**
Pre-2011 Programs completed in 2011		Projects	0	0	0.6	1.7	1.7	3,568	14,216	56,863

EX 3 APPENDIX 2 REF 3.0-STAFF-97S

Initiative Detail: Province-Wide

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

Shaded areas indicate data is not yet available

Table 4: Initiative and Program Level Savings Province-Wide

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date:	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: projected annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: projected cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	12,934	21,168	1,001	1,638	1,638	6,808,506	11,134,002	44,536,009
2	Appliance Exchange	Appliances								
3	HVAC Incentives	Equipment	4,368	22,824	931	5,509	5,509	1,411,718	8,748,891	34,995,565
4	Conservation Instant Coupon Booklet	Items								
5	Bi-Annual Retailer Event	Items								
6	Residential Demand Response	Devices	1,860	4,119	1,448	3,207	3,207	28,960	64,133	256,531
7	Midstream Electronics	Items	0	0	0	0	0	0	0	0
8	Midstream Pool Equipment	Items	0	0	0	0	0	0	0	0
9	Residential New Construction	Houses	0	0	0	0	0	0	0	0
Consumer Program Total					**3,380**	**10,354**	**10,354**	**8,249,183**	**19,947,026**	**79,788,105**
Business Program										
10	Electricity Retrofit Incentive	Items								
11	Direct Installed Lighting	Items	84,087	89,337	2,852	2,994	2,994	21,305,133	22,369,783	89,479,131
12	Direct Service Space Cooling	Equipment	0	0	0	0	0	0	0	0
13	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
14	New Construction	Buildings	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response	Devices	2	25	3	42	42	67	833	3,330
16	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
17	Demand Response 3	Facilities	0	10	145	8,962	0	4,524	279,614	279,614
Business Program Total					**3,000**	**11,998**	**3,036**	**21,309,724**	**22,650,230**	**89,762,076**
Industrial Program										
18	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
19	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
20	Energy Manager	Managers	0	0	0	0	0	0	0	0
21	Industrial Electricity Retrofit	Measures								
22	Demand Response 1	Projects	0	0	0	0	0	0	0	0
23	Demand Response 3	Projects	10	76	10,337	43,603	0	107,505	453,471	453,471
Industrial Program Total					**10,337**	**43,603**	**0**	**107,505**	**453,471**	**453,471**
Home Assistance Program										
24	Home Assistance Program	Units	0	0	0	0	0	0	0	0
Home Assistance Program Total					**0**	**0**	**0**	**0**	**0**	**0**
Tier 1 Portfolio Total					**16,717**	**65,955**	**13,390**	**29,666,412**	**43,050,727**	**170,003,652**
	Pre-2011 Programs completed in 2011	Projects	193	525	3,438	9,254	9,254	21,232,407	53,509,456	214,037,823

Glossary

Annual – the resource savings attributable in a particular year to activity procured in a particular reporting period

Annual Savings – peak demand savings or energy savings that are deemed to have taken place in a particular year

Contribution to Target (for demand) - the projected net annual peak demand savings persisting in 2014 attributable to resources acquired since the first quarter of 2011

Contribution to Target (for energy) - the projected net cumulative energy savings attributable to resources acquired since the first quarter of 2011

Current Reporting Period – the last calendar year and quarter that has been completed

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

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

Implementation Period – the particular calendar quarter or calendar year and quarter that conservation activity is achieved

Incremental – the annual resource savings attributable to activity procured in a particular reporting period

Initiative – a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use

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

Net Peak Demand Savings (MW) – demand savings attributable to conservation and demand management activities that are considered to be coincident with the power system peak net of free-riders, etc

Program-to-Date Reporting Period – the period of time from January 1, 2011 until the end of the Current Reporting Period

Program – a group of initiatives that target a particular market sector

Reported Savings – savings achieved that are based on reported activity and forecasted savings assumptions, have not undergone the Evaluation, Measurement & Verification processes

Unit – for a specific initiative the relevant type of activity acquired in the market place

saveONenergy

Savings Calculations & Methodology - Detailed by Initiative

The assumed implementation or 'start' date of resource savings varies by initiative. The table below illustrates the 'trigger point' or event that the OPA currently uses as start date for savings and the methodology to assign results to each LDC for each initiative.

Initiative	Savings 'start' Date	LDC-specific savings determination
Consumer Program		
Instant coupon booklets	Invoice date from coupon clearinghouse	1) LDC coded booklets direct allocation to LDC 2) Generic coded booklets provincially allocated based on LDC CDM target/Provincial CDM Target
Bi-annual retail event (In-store coupons)		Provincially allocated based on LDC CDM target/Provincial CDM Target
Appliance exchange initiative	Event date	1) Where LDC name and/or unique postal code identifies single LDC direct allocation to LDC 2) Where no direct identifiable data exists (i.e. no LDC name and postal code served by more than one LDC; or no customer survey submitted) provincially allocated based on LDC CDM target/Provincial CDM Target
Retailer co-op activities	Will vary by specific project	1) Where LDC name and/or unique postal code identifies single LDC direct allocation to LDC 2) Where no direct identifiable data exists provincially allocated based on LDC CDM target/Provincial CDM Target
Mid-stream electronics	TBD	Provincially allocated
Fridge & Freezer pickup (including retailer and municipality streams)	Pick-up date	Direct allocation to LDC (based on location of installation/pick-up/etc.)
Heating & Cooling incentive	Install date	
peaksaver extension/residential DR	Device install date	
New construction	Project completion	
Mid-stream pool incentive	Install date	
Business (Commercial & Institutional) Program		
Small business direct install lighting	Device Installation Date/Project Completion Date	Assigned based on LDC identified in application form
Direct services space cooling		
Electricity retrofit incentive		
High performance new construction		
Process & Systems Upgrades		

saveONenergy

Savings Calculations & Methodology - Detailed by Initiative

Business (Commercial & Institutional) Program Cont...		
Initiative	**Savings 'start' date**	**LDC-specific savings determination**
Demand Response (DR1, DR3)	Facility is available under contract	DR-1: Regular application--assigned based on LDCs identified in application form, Head-office application—assigned to LDC based on address in application DR-3: Assigned based on LDCs identified in application form
peaksaver extension/ small comm. demand response	Device installation Date	Direct allocation to LDC (based on location of installation)
Industrial Program		
Process & Systems Upgrades	In Service Date	Assigned based on LDC identified in application form.
Monitoring & Targeting	2nd year Report	Assigned based on LDC identified in 2nd year report
Demand Response (DR1, DR3)	Facility is available under contract	DR-1: Regular application--assigned based on LDCs identified in application form, Head-office application--assigned to LDC based on address in application. DR-3: Assigned based on LDCs identified in application form;
Industrial Electricity retrofit	Device Installation Date/ Project Completion Date	Assigned based on LDC identified in Icon application form.
Energy Managers	Quarterly Report Date	Assigned based on LDC identified in Energy Manager Quarterly Report
Home Assisstance Program		
Home Assisstance Program	Project Completion Date	Assigned based on LDC identified in application form

Initiative/Measure:	Prescriptive	Non-prescriptive
Reported Savings *"what we think happened"*	Program Input Assumptions[1] X Actual[2] program participants	• Sum of calculated savings from custom/ engineered worksheets from each participant • Using program-design assumptions for NTG factors[1]
Verified Savings *"what really happened"*	Reviewed Program Input Assumptions X Verified # of program participants	Based on either: • on-site verification of installed equipment and usage patterns; OR • application of savings 'realization rate' based on on-site visits to representative sample of participants/ projects; AND • verified net-to-gross factors

[1]Default values based on program design; may be updated when previous years' evaluation results become available

[2]Based on reported participation numbers as of a particular date (when data is collected); updated in the following quarterly report as more data becomes available

EXHIBIT 4 – OPERATING COSTS

4.0-Staff-88s

Ref: 4.0-Staff-42 – Procurement and Inventory Officer

Please compare the additional operational expenditure for an additional procurement and inventory officer with the savings achieved by the redundancy of the student assistance. Please state how the cost savings resulting from the elimination of the student role is reflected in this application.

IHDSL Response:

The savings resulting from the elimination of the student role will be reflected in the capital budget as part of the cost of inventory that is capitalized when constructing distributions assets.

4.0-Staff-89s

Ref: 4.0-Staff-45 – Regulatory Costs

Please update the total regulatory costs to include any consultant fees incurred at the settlement process.

IHDSL Response:

IHDSL's has updated Appendix 2-M to reflect the forecasted $16,000 of consultant fees related to the settlement process in the projected costs for consultant fees versus the expert witness cost category.

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 49,990	$ 46,951	$ 48,000	2.23%	$ 49,000	2.08%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 4,000	$ 6,546	$ 8,000	22.21%	$ 8,000	0.00%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 4,000	$ 6,546	$ 8,000	22.21%	$ 8,000	0.00%
4	Expert Witness costs for regulatory matters			On-Time					$ -	
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5655		On-Time	$ 28,700	$ -	$ -		$ 41,000	
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs			On-Time	$ 8,000				$ 9,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 94,690	$ 60,043	$ 64,000	6.59%	$ 115,000	79.69%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 94,690	$ 60,043	$ 64,000	6.59%	$ 115,000	79.69%

4.0-Staff-90s

Ref: 4.0-Staff-49 – Maintenance of Poles, Towers and Fixtures

Given that the Board approved OM&A for account 5120 in the amount of $44,680 in the IHDSL's 2009 cost of service application, please explain IHDSL lower level of spending in this category in the 2010, 2011 and 2012 rate years. Please explain why IHDSL only undertook pole replacement on an emergency basis only.

IHDSL Response:

Pole testing costs were removed from the 5120 expense line in 2010. A re-allocation of these expense funds were leveraged and moved in the 5005 and 5085 accounts in 2010 onward, thus reducing the 5120 account. The pole testing costs were moved to the pole replacement capital program as the replacement of failed poles is directly derived from these results. On page 48 of the Asset Management Plan, and E4/T2/S3, p. 6, the maintenance program described directly relates to the identified secondary issues that don't require a pole replacement but do require some form of remediation. These items have only been done intermittently, based on severity or emergency. Every year Innisfil Hydro tests an approximate 1/8 of the 10,000 poles in its distribution territory. Poles that are found in need of replacement are capitalized; however poles that are tested and pass often are in the need of maintenance. Approximately 200-215 poles per year receive comments back to Innisfil Hydro from the pole testers indicating deficiencies. Items such as slack or loose guy wires, guy strain insulators pulled apart or broken, guy guards out of position or missing, loose grounding connections and missing nomenclature are a few examples. A program of this scope has not been budgeted before in the past; however with an Annual Pole Maintenance Program, Innisfil Hydro would be able to address the issues raised by our contractor and remediate potential hazards to the public and staff. The annual maintenance cost of $13,440.00 has been included in the 5120 account in the 2013 budget. A full Pole replacement program is completed yearly in the capital projects listing.

4.0-Staff-91s

Ref: 4.0 Energy Probe #22

In response to part a) IHDSL provided a year-to-date update as of November 2012. Part b) of the interrogatory response seems to be missing.

a) Please explain why IHDSL spending in the Maintenance category is $246,271 below the budgeted amount as of November 30, 2012.Please provide IHDSL spending as of December 31, 2012.

IHDSL Response:

IHDSL has provided updated Tables reflecting 2012 actual spend to December 31, 2012. With the 2012 actuals the revised underspend in the Maintenance category is now $127,900. The reduction from the $246,271 in November to $127,900 in December is directly related to IHDSL's overall cycle process in closing out jobs.

Table 4.1 Summary of OM&A Expenses - Updated 2012 Actuals

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2012 Actuals	2013 Test
Operations	778,575	694,259	870,153	947,441	1,159,195	1,314,678	1,423,862
Maintenance	657,080	544,762	436,208	528,873	601,800	473,900	713,650
Billing & Collections	1,010,600	970,447	922,744	925,296	955,500	983,742	1,106,020
Community Relations	11,700	10,826	9,114	17,892	18,400	8,370	23,900
Aministrative General Expense	1,439,785	1,476,117	1,620,369	1,776,253	1,899,865	2,093,718	2,197,640
Total OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,874,408**	**5,465,072**
Total Recoverable OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,874,408**	**5,465,072**
Year Over Year Variance $	**-**	**201,329**	**162,177**	**337,167**	**439,005**	**239,648**	**830,312**
Year Over Year Variance %		**-5%**	**4%**	**9%**	**10%**	**5%**	**18%**

The resulting underspend of $127,900 in the maintenance category is mainly attributable to the following explanations,

Account 5125 -$31,521

- *fewer inclement weather events thus reducing trouble and emergency response costs*
- *delay in hiring Smart Grid Engineer from Jan 2012 to June 2012*

Account 5135 - $23,462

- *fewer inclement weather events played a substantial role in lowering trouble and emergency response costs involving tree contracts*
- *1 year (RFQ) tender bids came in lower than anticipated*

Account 5155 - $40,893

- *above average weather conditions left little to no frost settlement in the ground, which saw a substantial reduction of underground secondary faults from prior normalized weather years*

Account 5160 - $13,524

- *fewer inclement weather events lowered trouble and emergency response costs in the transformer area*

Account 5175 - $6,844

- *fewer than anticipated repairs required*
- *repairs to one wholesale metering cabinet not completed in 2012; deferred to 2013*

b) Please file the answer to part b) of the interrogatory.

IHDSL Response:

IHDSL has provided the response to part b), in Energy Probe IR # 57.

4.0-Staff-92s

Ref: 4-SEC-11 – IFRS/Financial Analyst

Please state why additional expertise of an IFRS/Financial Analyst is required since IHDSL submitted that the current Finance Department has received IFRS training to develop the required knowledge and skill set. Please explain why this FTE is required at this point, given the late stage of IHDSL's IFRS transition.

IHDSL Response:

The IHDSL Finance Department received training and has developed knowledge and skills to support the new processes, procedures and analysis required from the change due to IFRS. The software and procedural changes were well under way with the expectation of IFRS, and substantially complete prior to the announcement of deferral options for IFRS. Deferral of all but the useful life/componentization changes have been chosen to ensure that we are able to participate in any first time adoption options. As a result, we are employing the new processes and analysis to ensure proper componentization, capitalization, additions, disposals, amortization and gains and losses. As an electricity distributor we are in an industry where capital assets are not limited to plant floor machinery, a building and vehicles. IHDSL assets are being added, improved or disposed of on a daily basis and encompass kilometers of conductor, thousands of meters, poles and transformers. Although current staff has acquired the required skillset the issue is one of resource capacity. The new processes resulting from the useful life componentization is just one of the major strains on time for the current staff. IHDSL also have additional reporting and performance measurements to assist the various departments, our distribution customers are increasing which results in additional economic evaluation analysis, and IHDSL has been experiencing its own growth internally which results in increased demands for our support services.

4.0-Staff-93s

Ref: 4.0-Staff-43 – Maintenance for Office building

Please state which, if any, OM&A cost were included in tables 4.6 to 4.10 for the new Headquarters on 2147 Innisfil Beach Rd. Please remove any expenses and update the relevant tables, if necessary.

IHDSL Response:

OM&A costs for the new headquarters are not included in tables 4.6 to 4.1.

4.0-Staff-94s

Ref: 4.0 Energy Probe #29 c)

In response to part c) IHDSL submitted that no other tax credits other than Apprenticeship Training Tax credits and Co-Operative Education Tax credits have been claimed by IHDSL. In E3/T3/S3 p. 1, table 3.3.9 IHDSL used account 4406 – SRED Revenue as a revenue offset.

a) Please explain the nature of this other revenue and state why the SRED has not been applied as a tax credit.

IHDSL Response:

IHDSL has reflected the estimated $50k SRED tax credit within the test year as other revenue. IHDSL also inadvertently adjusted the tax return for the SRED expenditures as well. IHDSL is submitting the SRED tax credit should be removed from other income and included within the test year tax return. IHDSL will be resubmitted an updated Test Year PILs Workform and reflecting the correction within the Summary of Changes.

4.0 Energy Probe #57

Ref: 4.0 Energy Probe #22

The response to part (a) appears to be incomplete.

a) Please confirm that the figures provided in the table for 2012 Nov YTD include 11 months of actuals, and do not represent an estimate for all of 2012 based on 11 months of actual and 1 month of forecast.

IHDSL Response:

The figures provided in the Summary of OM&A Expenses in response to Energy Probe IR#22 were year to date November 2012 actuals.

b) Please complete the response by providing the 2011 Nov YTD figures in the same level of detail as shown in the response.

IHDSL Response:

IHDSL has updated the Summary of OM&A Expenses to reflect Nov 11, 2011 actuals. The Table is enclosed:

Table 4.1 Summary of OM&A Expenses - Updated Nov YTD Compared to Nov 2011

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Nov YTD	2012 Bridge	2012 Nov YTD	2013 Test
Operations	778,575	694,259	870,153	891,689	1,159,195	1,226,090	1,423,862
Maintenance	657,080	544,762	436,208	453,298	601,800	355,529	713,650
Billing & Collections	1,010,600	970,447	922,744	853,991	955,500	931,026	1,106,020
Community Relations	11,700	10,826	9,114	17,017	18,400	16,468	23,900
Aministrative General Expense	1,439,785	1,476,117	1,620,369	1,743,944	1,899,865	2,011,919	2,197,640
Total OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**3,959,939**	**4,634,760**	**4,541,032**	**5,465,072**
Total Recoverable OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**3,959,939**	**4,634,760**	**4,541,032**	**5,465,072**
Year Over Year Variance $	**-**	**201,329**	**162,177**	**101,351**	**674,821**	**- 93,728**	**830,312**
Year Over Year Variance %		**-5%**	**4%**	**3%**	**17%**	**-2%**	**18%**

c) Part (b) of the response has not been answered. Please provide a response.

IHDSL Response:

Cost driver # 1 as reflected on Appendix 2-J based on the 2012 Bridge Year closing balance of $4,634,760 changes from $139,043 at 3% to $92,695 at 2%.Lowering the overall forecast of recoverable OM&A by $46,347.

d) Are OM&A figures now available based on year end costs? If so, please provide the actual data for 2012 in the same format at that shown in the response to the interrogatory.

IHDSL Response:

IHDSL has provided an updated Table 4.1 Summary of OM&A Expenses with 2012 Actuals.

Table 4.1 Summary of OM&A Expenses - Updated 2012 Actuals

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2012 Actuals	2013 Test
Operations	778,575	694,259	870,153	947,441	1,159,195	1,314,678	1,423,862
Maintenance	657,080	544,762	436,208	528,873	601,800	473,900	713,650
Billing & Collections	1,010,600	970,447	922,744	925,296	955,500	983,742	1,106,020
Community Relations	11,700	10,826	9,114	17,892	18,400	8,370	23,900
Aministrative General Expense	1,439,785	1,476,117	1,620,369	1,776,253	1,899,865	2,093,718	2,197,640
Total OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,874,408**	**5,465,072**
Total Recoverable OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,874,408**	**5,465,072**
Year Over Year Variance $	**-**	**201,329**	**162,177**	**337,167**	**439,005**	**239,648**	**830,312**
Year Over Year Variance %		**-5%**	**4%**	**9%**	**10%**	**5%**	**18%**

4.0 Energy Probe #58

Ref: 4.0 Energy Probe #24

A response has not been provided. Please provide a response and the requested change to Table 4.16, if required.

IHDSL Response:

Table 4.16 – Management category does not include members of the Board of Directors.

4.0 Energy Probe #59

Ref: 4.0 Energy Probe #26-29 &
1.0-OEB Staff-3

a) Please provide an updated income tax PILs Workform that results in the income tax of $36,455 shown in the updated RRWF provided in 1.0-OEB Staff-3.

IHDSL Response:

Please see response to 4.0-Staff-99a). IHDSL will be submitting an updated PILs model in conjunction with the updated Summary of Changes as of the 2nd round of interrogatories.

b) It appears that IHDSL has claimed investment tax credits of $20,000 and miscellaneous tax credits of $12,000 in the 2013 test year. Please explain how these figures have been determined, and provide the corresponding credits for each of 2009 through 2012.

IHDSL Response:

Please see response to 4.0-Staff-94a). IHDSL was claiming tax credits for SRED investments and Apprentice Tax credits for the 2013 Test year. IHDSL is submitting revised PILs model to reflect the updated $50k SRED tax credit for taxation years ending 2012 and 2013. IHDSL has subsequently determined the Apprentice Tax credit would only be available up to 2012 and will update the Summary of Changes and PILs model for the 2013 Test Year accordingly.

IHDSL tax credits							
				Originally Submitted		Revised Submission	
	2009	2010	2011	2012 Bridge	2013 Test	2012 Bridge	2013 Test
Investment Tax Credit	-	75,903	53,048	20,000	20,000	50,000	50,000
Apprenticeship Tax Credit	-	-	12,192	12,000	12,000	12,000	-
Total	**-**	**75,903**	**65,240**	**32,000**	**32,000**	**62,000**	**50,000**

4-SEC-25

[4-SEC-11]

Please explain why the proposed IFRS/Financial Analyst position is still required considering the Applicant is delaying implementation of IFRS until January 1, 2014.

IHDSL Response:

The IHDSL Finance Department received training and has developed knowledge and skills to support the new processes, procedures and analysis required from the change due to IFRS. The software and procedural changes were well under way with the expectation of IFRS, and substantially complete prior to the announcement of deferral options for IFRS. Deferral of all but the useful life/componentization changes have been chosen to ensure that we are able to participate in any first time adoption options. As a result, we are employing the new processes and analysis to ensure proper componentization, capitalization, additions, disposals, amortization and gains and losses. As an electricity distributor we are in an industry where capital assets are not limited to plant floor machinery, a building and vehicles. IHDSL assets are being added, improved or disposed of on a daily basis and encompass kilometers of conductor, thousands of meters, poles and transformers. Although current staff has acquired the required skillset the issue is one of resource capacity. The new processes resulting from the useful life componentization is just one of the major strains on time for the current staff. IHDSL also have additional reporting and performance measurements to assist the various departments, our distribution customers are increasing which results in additional economic evaluation analysis, and IHDSL has been experiencing its own growth internally which results in increased demands for our support services.

4-VECC-46

Reference: 27.0 VECC

Please provide the EDA (Electricity Distributor Association) membership fees for the years 2009 through 2013.

IHDSL Response:

The following table provides the EDA (Electricity Distributor Association) membership fees for the years 2009 through to 2013.

Year	Fee	
2009	$	25,000.00
2010	$	26,100.00
2011	$	26,950.00
2012	$	28,450.00
2013	$	29,800.00
Total	$	136,300.00

4-VECC-47

Reference: 22.0-VECC

Please respond to the original interrogatory.

22.0-VECC

Reference: Exhibit 4, Appendix 2-G

a) Please explain why account 6205 Donations is included in recovery for rates.

IHDSL Response:

IHDSL has copied the bottom portion of Appendix 2-G (lines 85-119), which reflects the 6205 Donations being adjusted from recoverable OM&A. IHDSL has not included donations in recovery for rates.

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ 209,979	$ 209,923	$ 218,153	$ 218,153	$ 227,875	$ 227,875	$ 233,375
5610 Management Salaries and Expenses	$ 189,103	$ 201,551	$ 214,395	$ 214,395	$ 225,025	$ 225,025	$ 232,247
5615 General Administrative Salaries and Expenses	$ 486,302	$ 576,121	$ 673,158	$ 673,158	$ 699,800	$ 699,800	$ 849,125
5620 Office Supplies and Expenses	$ 67,522	$ 73,767	$ 86,725	$ 86,725	$ 94,000	$ 94,000	$ 107,000
5625 Administrative Expense Transferred - Credit							
5630 Outside Services Employed	$ 64,876	$ 93,488	$ 104,144	$ 104,144	$ 148,500	$ 148,500	$ 152,895
5635 Property Insurance	$ 39,448	$ 75,239	$ 57,252	$ 57,252	$ 59,470	$ 59,470	$ 61,254
5640 Injuries and Damages	$ 34,487	$ 30,319	$ 34,561	$ 34,561	$ 37,000	$ 37,000	$ 38,110
5645 OMERS Pensions and Benefits	$ 28,828	$ 3,555	$ 3,461	$ 3,461	$ 4,400	$ 4,400	$ 4,500
5646 Employee Pensions and OPEB							
5647 Employee Sick Leave							
5650 Franchise Requirements							
5655 Regulatory Expenses	$ 99,623	$ 44,657	$ 56,135	$ 56,135	$ 56,000	$ 56,000	$ 107,000
5660 General Advertising Expenses							
5665 Miscellaneous General Expenses	$ 91,366	$ 104,035	$ 105,153	$ 105,153	$ 116,395	$ 116,395	$ 114,884
5670 Rent	$ 755	$ 319	$ 335	$ 335	$ 600	$ 600	$ 750
5672 Lease Payment Charge							
5675 Maintenance of General Plant	$ 155,401	$ 198,768	$ 181,370	$ 181,370	$ 221,000	$ 221,000	$ 286,500
5680 Electrical Safety Authority Fees	$ 8,427	$ 8,627	$ 8,928	$ 8,928	$ 9,800	$ 9,800	$ 10,000
5681 Special Purpose Charge Expense		$ 49,901					
5685 Independent Electricity System Operator Fees and Penalties							
5695 OM&A Contra Account							
6205 Donations	$ 844	$ 1,718	$ 531	$ 531	$ 1,000	$ 1,000	$ 1,000
6205 Donations, Sub-account LEAP Funding			$ 32,483	$ 32,483			
Total - Administrative and General Expenses	$ 1,476,961	$ 1,671,988	$ 1,776,784	$ 1,776,784	$ 1,900,865	$ 1,900,865	$ 2,198,640
Total OM&A	$ 3,697,255	$ 3,910,207	$ 4,196,286	$ 4,196,286	$ 4,635,760	$ 4,635,760	$ 5,466,072
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense		$ 49,901	$ -				
6205 Donations[1]	$ 844	$ 1,718	$ 531	$ 531	$ 1,000	$ 1,000	$ 1,000
Total Recoverable OM&A	$ 3,696,411	$ 3,858,588	$ 4,195,755	$ 4,195,755	$ 4,634,760	$ 4,634,760	$ 5,465,072

4-VECC-48

Reference: 23-VECC

We are unable to locate a response to this interrogatory.

IHDSL Response:

Reference: Exhibit 4, Appendix 2-G
Please explain the increase since 2009 in accounts:
5410 Community relations
Office supplies and Expenses
Miscellaneous Expenses

Account 5410 Community Relations:
The increase in account 5410 since 2009 is due to IHDSL incorrectly recording LEAP funding in account 5410 versus 6205 sub-account LEAP. This will be corrected by IHDSL with the closing of the 2012 financial records.

Account 5620 Office Supplies and Expenses:
Increases in account 5620 are directly attributable to head count increases from 2009 to 2012. IHDSL FTE's changed from 26.3 to 34.3 from 2009 to 2011.

Account 5665 Miscellaneous Expenses:
Increases in Account 5665 are directly attributable to the head count increases, for conferences, Health and Safety, and professional dues.

EXHIBIT 5 – COST OF CAPITAL

5.0-Staff-95s

Ref: 5.0 Energy Probe #31 and E5/T1/S2, p. 5

In E5/T1/S2, p. 5 IHDSL shows a demand loan of $13,843,930. In response to Energy Probe #31 g) IHDSL submitted that this demand loan was based on the completion of capital projects at the end of 2013 at which point it would be converted to long-term debt in 2014.

a) Please confirm the issuance date of the demand loan as January 1, 2013 and confirm the rate of 5.00%.

IHDSL Response:

The demand loan was not issued on January 1, 2013. IHDSL is estimating the demand load will be required by Q2 2013.

b) Please comment on IHDSL response to Energy Probe #31 g) given the delay in completion of the capital projects until August 2014.

IHDSL Response:

IHDSL current banking agreement facilitates a $3m line of credit. When the line of credit exceeds the $3m, the outstanding balance is converted to a demand or long term loan depending on the climate of interest rates. IHDSL is estimating by the end of 2013, based on the revised capital submissions, the demand or long term loan will be approximately $8m.

c) Please provide further explanation why IHDSL is not seeking a long term debt instrument for this expenditure given the nature of this capital project, and state why the Board's deemed long-term debt rate should not apply to this loan.

IHDSL Response:

IHDSL will be seeking long term debt instrument for this expenditure. The uncertainty is more of when. The cost of the new building project is estimated to be $5m by the end of 2013 and classified as WIP. This project is estimated to be setup as a demand loan until completion when long term financing will be reviewed to determine the best course of action.

5-VECC-49

Reference: 5-Energy Probe-31 (e) / VECC 29.0

a) Please identify the various bondholders associated with the Town of Innisfil loan?

IHDSL Response:

The remaining non matured debentures (15-20) are issued to CDS & Company.

Copies of the debentures were included in IHDSL's updated evidence on October 22, 2012. IHDSL has provided copies of the requested debentures in the Exhibit 5 appendices. Please refer to Ex5 Appendix A.

b) Is the loan made between Innisfil Hydro and the Town or the referred to debenture holders?

IHDSL Response:

The loan is between IHDSL and the Town of Innisfil. Please see the response provided to Energy Probe IR 31 in the 1st round of interrogatories.

The loan is not considered to be a loan from an affiliate because the debentures were issued to various bond holders for the Hydro expansion. These debentures are not considered part of the Municipality's debt covenants per the Power Corporation Act Chapter P.18.

IHDSL pays the principal and interest on the debentures to the Town of Innisfil. This is purely a pass through transaction as IHDSL was unable to obtain the required debentures in 1995. The town of Innisfil is not compensated for this service in any form.

c) VECC 29 is seeking to ascertain whether the loan is callable. The response was that IHSDL had not attempted to renegotiate the loan. Is the loan between Innisfil Hydro and the Town callable and/or are the terms between the Town and the lenders callable on demand?

IHDSL Response:

IHDSL would like to clarify the response provided in VECC IR 29. Inquiries were made to extinguish the existing debt and interest rates. It was determined that the cost was of no benefit whereby IHDSL would be required to pay the full amount of interest, thus we were not able to renegotiate the loan.

The loan between IHDSL and the Town and the lender is callable.

EXHIBIT 7 – COST ALLOCATION

7.0-Staff-96s – Weighting Factor – Billing and Collection

Ref: 7.0-Staff-57s

IHDSL noted that it "undertook the calculation to determine the billing and collecting weighting factors based on customer specific data as referenced on the Table on Exhibit 7, Schedule 1, Page 3." However, the weighting factors provided by IHDSL together with the number of bills issued result in the Residential class being allocated 99.34% of Accounts 5315,1520, 5330 and 5340 as compared to 92.03% of all bills issued, and 0% of those accounts being allocated to Street lighting and USL customers. Board staff questions whether the weighting factor inputs are appropriate."

a) Please confirm that the weighting factors provided by IHDSL reflect the size of IHDSL's customer classes, rather than the relative costs of preparing and collecting on each individual bill that is issued by IHDSL.

IHDSL Response:

The weighting factors were an attempt to allocate the forecasted costs for 2013 in accounts 5315-Billing and 5320-Collecting. The table provided in Exhibit 7 Schedule 1 and referred to in 7.0 – VECC – 51 indicates an allocation of the costs in both accounts. The Billing costs are allocated based on the number of customers in each class as a percentage of the total number of customers. The Collecting costs are allocated on an approximation of how IHDSL sees the effort required for collecting in each of the classes. The percentages or weighing factors when input on sheet I5.2 of the Cost Allocation Model produces the same results which are not what IHDSL expected. For example, the table in Exhibit 7 Schedule 1 shows no collection costs should be allocated to the Street Light, Sentinel Light, or Unmetered Scattered Load *customer classes. Rows 84 and 85 in the table are more representative of how IHDSL sees the allocation of those costs. However, when the percentage or weighting factor produced in the table is input on sheet I5.1 of the Cost Allocation model, the model applies that weighting to both the Billing and Collecting accounts producing an allocation not representative of column "Exhibit 7, Schedule 1" of the table.*

Rather than attempting to create a weighting factor to replicate the results on the row titled "Revised Tot of 5315 & 5320" in the Table, which is impossible when the weighting for Billing versus Collecting are not the same, IHDSL has input those results on row 30 of sheet "I6.2 Customer Data" of the Cost Allocation model. IHDSL would have preferred to Directly Allocate the resulting values for the two accounts separately using sheet "I9 Direct Allocation" of the CA Model but could not get the direct allocation to work.

b) Please provide a table with the rationale that compares the costs of preparing and issuing a single bill for all customer rate classes.

IHDSL Response:

Since IHDSL agrees the allocation of the Billing and Collecting costs in the original submission to be flawed, a table providing a rationale to support those weighting factors would be irrelevant at this time.

c) For comparison, please provide a version of the Cost Allocation model in which all Billing and Collecting Weighting Factors in worksheet I 5.2 are equal to 1.0.

IHDSL Response:

IHDSL has prepared a Cost Allocation model using Weighting Factors of 1.0 for all classes as requested. The model, in PDF format, is included with these responses as Ex 7 Appendix 1 Ref 7.0-Staff-96 c). The excel model will be submitted via the RESS portal and is named Innisfil_Costallocation_WF Equal1_20130315.

d) Please comment on whether IHDSL's original model or the version from part (d) is more appropriate, or alternatively whether another version with other weighting factors provided by IHDSL might be more appropriate than either. If the latter, please provide this version of the Cost Allocation model.

IHDSL Response:

As discussed in part a) above, IHDSL has attempted to allocate the costs on the same basis identified in the table included with Exhibit 7 Schedule 1. However, due to model constraints even though the total billing and collecting costs have been allocated to accounts 5315 and 5320 it would have been preferable to allocate the specific amounts on rows entitled "% of 5315" and "%of 5320" of the table.

Based on the last paragraph of IHDSL's response in part a) above, a revised CA model in excel format has been prepared and is included with these responses in PDF format as Ex 7 Appendix 2 Ref 7.0-Staff-96 d). The excel model will be submitted via the RESS portal and is named Innisfil_Costallocation_Updated_20131315.

7.0 – VECC – 50

Reference: **Staff #56 a)**
VECC #30 c)

a) Please confirm that the service connections for Street Light, Sentinel Light and USL customers are owned by the customer and that Innisfil is not responsible for maintenance or replacement.

IHDSL Response:

IHDSL can confirm that the service connections for Street Lights, Sentinel Light, and USL customers are owned by the customer and that IHDSL is not responsible for the maintenance or replacement.

7.0 – VECC – 51

Reference: **Staff #57 a) – c)**
VECC #30 d) & e)
CA Model Results, Sheet O5
Exhibit 7, Schedule 1, page 3

a) Please reconcile the following differences between the Billing and Collecting costs by class as set out in Exhibit 7 and those shown in Sheet O5, where the latter are based on the weighting factors calculated by Innisfil.

Customer Class	Allocated Billing & Collecting Costs	
	Exhibit 7, Schedule 1	CA Sheet O5
Residential	$704,521.13	$816,030
GS<50	$67,638.54	$5,023
GS>50	$41,378.78	$223
Street Light	$156.02	0
Sentinel Light	$7,413.47	$144
USL	$312.04	0
Total	$821,420	$821,420

IHDSL Response:

AS discussed in the response to 7.0-Staff-57s, the allocation of costs in CA Sheet O5 should have reflected the amounts to each class as shown in the column above titled "Exhibit 7, Schedule 1". It is difficult to replicate those results in the Board's CA model when there is an entirely different weighting factor *between Billing and Collecting. IHDSL has attempted to directly allocate the values in column "Exhibit 7, Schedule 1" above but has experienced CA model problems when attempting to "Directly Allocate" those costs.*

As a work around, IHDSL has directly input the values in column "Exhibit 7, Schedule 1" into row 30 sheet "I6.2 Customer Data" of the CA model. Although this does not allocate the correct amount to the two accounts within the customer class it does allocate the total amount to the appropriate class.

b) With respect to Staff #57 a), please explain why the size to the residential class is relevant when the weighting factors are supposed to be on a per customer per bill basis.

IHDSL Response:

As discussed in part a) above, and in response to 7.0-Staff-57s, IHDSL has attempted to correct the allocation of Billing and Collecting costs and has explained the issues and the constraints of the OEB CA Model. The OEB CA model attempts to allocate two accounts using the same weighting factor when in fact the costs incurred in the Collecting account does not in any way mirror that of the costs incurred for Billing.

c) Please confirm that based on the costs set out in Exhibit 7, Schedule 1 the unit cost of Billing and Collecting for a GS>50 customer is $627 ($41,378/66) whereas the unit cost for a Residential customer is $50 ($704,521/14,176).

IHDSL Response:

IHDSL has attempted to fairly allocate Billing and Collecting costs based on past experience. Using the table in Exhibit 7, Schedule 1 the unit cost for Billing is $31.20 for all customer classes as the Billing cost for each class is divided by the number of customers in that class. The Collecting costs are based on experience and have been allocated to three customer classes only.

d) If part c) is confirmed and both classes have 12 bills per customer per year please explain how the weighting factor for GS>50 can be 0.06 relative to a value of 1.0 for Residential.

IHDSL Response:

Please see response to part c) above.

e) Please correct the cost allocation weighting factors as required and provide a revised model run.

IHDSL Response:

Please see response to 7.0-Staff-57s.

7.0 – VECC – 52

Reference: VECC #30 f)

a) What is the estimated cost in 2013 of the meter reading services provided by Oshawa Hydro for GS>50 customers?

IHDSL Response:

Oshawa PUC undertakes the meter reading services for the interval GS>50 customers for IHDSL. The cost is a fixed contracted cost of $25.00 per month per customer read of which IHDSL currently have 17 customers. Therefore, the estimated costs for 2103 are $5,100.00.

b) In what USOA account are these costs recorded and are they all allocated to the GS>50 class? If yes, how is this accomplished?

IHDSL Response:

The costs for the interval meter reads for the GS>50 are recorded in account 5310. The meter read costs in 5310 associated with the interval GS>50 customers have been allocated to the entire GS>50 rate class.

EX 7 APPENDIX 1 REF 7.0-STAFF-96s c)

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet - Final Run September 10, 2012

Total kWhs from Load Forecast	231,119,409
Total kWs from Load Forecast	151,169
Deficiency from RRWF	- 761,836
Miscellaneous Revenue	556,948

			1	2	3	7	8	9
	ID	**Total**	**Residental**	**GS < 50**	**GS 50-4,999 kW**	**Street Light**	**Sentinel Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
Forecast kW	**CDEM**	151,169			146,480	4,400	289	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		27,858			27,858			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
kWh - 30 year weather normalized amount		-	-	-	-	-	-	-
Existing Monthly Charge			$21.08	$35.18	$320.64	$5.39	$7.64	$23.51
Existing Distribution kWh Rate			$0.0188	$0.0086				$0.0396
Existing Distribution kW Rate					$2.9751	$37.3061	$34.7951	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges								

Distribution Revenue from Rates		$8,117,566	$6,344,682	$654,387	$690,286	$351,024	$31,826	$45,361
Transformer Ownership Allowance		$16,715	$0	$0	$16,715	$0	$0	$0
Net Class Revenue	**CREV**	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		-	-	-	-	-	-	-

Weather Normalized Data from Hydro One

	Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
kWh - 30 year weather normalized amount	-						
Loss Factor							

2013 Cost Allocation Model

Sheet I8 Demand Data Worksheet - Final Run September 10, 2012

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	49,474	40,614	3,359	5,053	327	33	88
Bulk Delivery CP	BCP1	49,474	40,614	3,359	5,053	327	33	88
Total Sytem CP	DCP1	49,474	40,614	3,359	5,053	327	33	88

4 CP									
Transformation CP	TCP4	190,329	152,081	14,772	21,676	1,312	131	357
Bulk Delivery CP	BCP4	190,329	152,081	14,772	21,676	1,312	131	357
Total Sytem CP	DCP4	190,329	152,081	14,772	21,676	1,312	131	357
12 CP									
Transformation CP	TCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Bulk Delivery CP	BCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Total Sytem CP	DCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	53,456	40,614	4,947	7,438	332	33	92
Primary NCP	PNCP1	53,456	40,614	4,947	7,438	332	33	92
Line Transformer NCP	LTNCP1	53,456	40,614	4,947	7,438	332	33	92
Secondary NCP	SNCP1	40,196	38,665	1,237		199	22	74
4 NCP									
Classification NCP from Load Data Provider	DNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Primary NCP	PNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Line Transformer NCP	LTNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Secondary NCP	SNCP4	152,249	146,533	4,544		796	87	290
12 NCP									
Classification NCP from Load Data Provider	DNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Primary NCP	PNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Line Transformer NCP	LTNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Secondary NCP	SNCP12	368,270	352,446	12,346		2,369	261	848

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Final Run September 10, 2012

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
			1	2	3	7	8	9
crev	Distribution Revenue at Existing Rates	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
mi	Miscellaneous Revenue (mi)	$556,948	$472,673	$34,455	$13,287	$31,372	$3,584	$1,577
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$8,657,799	**$6,817,355**	**$688,842**	**$686,858**	**$382,396**	**$35,411**	**$46,938**
	Factor required to recover deficiency (1 + D)	1.0940						
	Distribution Revenue at Status Quo Rates	$8,862,687	$6,941,361	$715,928	$736,916	$384,036	$34,819	$49,626
	Miscellaneous Revenue (mi)	$556,948	$472,673	$34,455	$13,287	$31,372	$3,584	$1,577
	Total Revenue at Status Quo Rates	$9,419,635	**$7,414,034**	**$750,383**	**$750,203**	**$415,408**	**$38,404**	**$51,203**
	Expenses							
di	Distribution Costs (di)	$1,689,663	$1,362,636	$101,223	$99,038	$112,491	$9,931	$4,343
cu	Customer Related Costs (cu)	$1,553,869	$1,384,334	$116,037	$27,594	$9,253	$15,751	$900
ad	General and Administration (ad)	$2,234,040	$1,888,624	$149,538	$88,654	$86,004	$17,537	$3,683
dep	Depreciation and Amortization (dep)	$1,451,988	$1,161,487	$101,447	$84,871	$92,387	$8,224	$3,572
INPUT	PILs (INPUT)	$25,788	$20,584	$1,733	$1,543	$1,710	$150	$67
INT	Interest	$1,119,814	$893,840	$75,272	$67,012	$74,275	$6,506	$2,909
	Total Expenses	$8,075,162	**$6,711,506**	**$545,251**	**$368,713**	**$376,120**	**$58,099**	**$15,475**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$1,344,473	$1,073,164	$90,373	$80,456	$89,176	$7,812	$3,492
	Revenue Requirement (includes NI)	$9,419,635	$7,784,669	$635,624	$449,169	$465,296	$65,911	$18,967
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$62,338,172	$49,715,995	$4,065,175	$3,784,749	$4,232,670	$375,170	$164,413
gp	General Plant - Gross	$11,119,283	$8,910,223	$725,412	$647,056	$742,468	$65,330	$28,793
accum dep	Accumulated Depreciation	($30,319,373)	($24,032,683)	($1,991,196)	($1,934,588)	($2,092,627)	($186,673)	($81,607)
co	Capital Contribution	($8,990,162)	($7,312,622)	($519,160)	($466,347)	($614,151)	($54,924)	($22,958)
	Total Net Plant	$34,147,920	**$27,280,913**	**$2,280,232**	**$2,030,870**	**$2,268,360**	**$198,904**	**$88,641**
	Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$24,238,088	$15,370,429	$3,296,927	$5,339,811	$157,890	$10,924	$62,108
	OM&A Expenses	$5,477,572	$4,635,594	$366,798	$215,286	$207,748	$43,219	$8,927
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$29,715,660*	***$20,006,023***	***$3,663,725***	***$5,555,097***	***$365,638***	***$54,143***	***$71,035***
	Working Capital	$3,863,036	**$2,600,783**	**$476,284**	**$722,163**	**$47,533**	**$7,039**	**$9,235**
	Total Rate Base	$38,010,956	**$29,881,696**	**$2,756,516**	**$2,753,032**	**$2,315,893**	**$205,942**	**$97,876**
		Rate Base Input equals Output						
	Equity Component of Rate Base	$15,204,382	**$11,952,678**	**$1,102,606**	**$1,101,213**	**$926,357**	**$82,377**	**$39,150**
	Net Income on Allocated Assets	$1,344,473	**$702,529**	**$205,132**	**$381,491**	**$39,288**	**($19,695)**	**$35,729**
	Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	$1,344,473	**$702,529**	**$205,132**	**$381,491**	**$39,288**	**($19,695)**	**$35,729**

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Final Run September 10, 2012

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

	Total	1	2	3	7	8	9
Rate Base Assets	**Total**	**Residental**	**GS < 50**	**GS 50-4,999 kW**	**Street Light**	**Sentinel Light**	**Unmetered Scattered Load**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**95.24%**	**118.05%**	**167.02%**	**89.28%**	**58.27%**	**269.96%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($761,836)**	($967,314)	$53,218	$237,689	($82,900)	($30,500)	$27,970
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**$0**	($370,635)	$114,759	$301,035	($49,888)	($27,507)	$32,236
RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	5.88%	18.60%	34.64%	4.24%	-23.91%	91.26%

2013 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Final Run September 10, 2012

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	**Residental**	**GS < 50**	**GS 50-4,999 kW**	**Street Light**	**Sentinel Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$7.63	$11.83	$22.92	$0.30	$4.70	$0.40
Customer Unit Cost per month - Directly Related	$12.72	$19.40	$38.20	$0.51	$7.94	$1.01
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$30.78	$33.04	$66.65	$15.17	$23.07	$14.06
Existing Approved Fixed Charge	$21.08	$35.18	$320.64	$5.39	$7.64	$23.51

EX 7 APPENDIX 2 REF 7.0-STAFF-96s d)

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet - Final Run September 10, 2012

Total kWhs from Load Forecast	231,119,409

Total kWs from Load Forecast	151,169

Deficiency from RRWF	- 761,836

Miscellaneous Revenue	556,948

			1	2	3	7	8	9
	ID	**Total**	**Residental**	**GS < 50**	**GS 50-4,999 kW**	**Street Light**	**Sentinel Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
Forecast kW	**CDEM**	151,169			146,480	4,400	289	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		27,858			27,858			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	231,119,409	146,562,898	31,437,455	50,917,130	1,505,545	104,161	592,220
kWh - 30 year weather normalized amount		-	-	-	-	-	-	-
Existing Monthly Charge			$21.08	$35.18	$320.64	$5.39	$7.64	$23.51
Existing Distribution kWh Rate			$0.0188	$0.0086				$0.0396
Existing Distribution kW Rate					$2.9751	$37.3061	$34.7951	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges								

Distribution Revenue from Rates		$8,117,566	$6,344,682	$654,387	$690,286	$351,024	$31,826	$45,361
Transformer Ownership Allowance		$16,715	$0	$0	$16,715	$0	$0	$0
Net Class Revenue	CREV	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		-	-	-	-	-	-	-

Weather Normalized Data from Hydro One

	Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
kWh - 30 year weather normalized amount	-						
Loss Factor							

2013 Cost Allocation Model

Sheet I8 Demand Data Worksheet - Final Run September 10, 2012

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	49,474	40,614	3,359	5,053	327	33	88
Bulk Delivery CP	BCP1	49,474	40,614	3,359	5,053	327	33	88
Total Sytem CP	DCP1	49,474	40,614	3,359	5,053	327	33	88

4 CP									
Transformation CP	TCP4	190,329	152,081	14,772	21,676	1,312	131	357
Bulk Delivery CP	BCP4	190,329	152,081	14,772	21,676	1,312	131	357
Total Sytem CP	DCP4	190,329	152,081	14,772	21,676	1,312	131	357
12 CP									
Transformation CP	TCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Bulk Delivery CP	BCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
Total Sytem CP	DCP12	480,144	366,099	43,931	66,891	1,967	196	1,060
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	53,456	40,614	4,947	7,438	332	33	92
Primary NCP	PNCP1	53,456	40,614	4,947	7,438	332	33	92
Line Transformer NCP	LTNCP1	53,456	40,614	4,947	7,438	332	33	92
Secondary NCP	SNCP1	40,196	38,665	1,237		199	22	74
4 NCP									
Classification NCP from Load Data Provider	DNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Primary NCP	PNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Line Transformer NCP	LTNCP4	201,924	153,921	18,174	28,009	1,327	131	362
Secondary NCP	SNCP4	152,249	146,533	4,544		796	87	290
12 NCP									
Classification NCP from Load Data Provider	DNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Primary NCP	PNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Line Transformer NCP	LTNCP12	504,538	370,216	49,384	79,538	3,948	392	1,060
Secondary NCP	SNCP12	368,270	352,446	12,346		2,369	261	848

Sheet O1 Revenue to Cost Summary Worksheet - Final Run September 10, 2012

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residental	2 GS < 50	3 GS 50-4,999 kW	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$8,100,851	$6,344,682	$654,387	$673,571	$351,024	$31,826	$45,361
mi	Miscellaneous Revenue (mi)	$556,948	$468,477	$36,018	$16,373	$31,363	$3,158	$1,559
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$8,657,799	$6,813,159	$690,405	$689,944	$382,387	$34,984	$46,920
	Factor required to recover deficiency (1 + D)	1.0940						
	Distribution Revenue at Status Quo Rates	$8,862,687	$6,941,361	$715,928	$736,916	$384,036	$34,819	$49,626
	Miscellaneous Revenue (mi)	$556,948	$468,477	$36,018	$16,373	$31,363	$3,158	$1,559
	Total Revenue at Status Quo Rates	$9,419,635	$7,409,838	$751,946	$753,289	$415,399	$37,977	$51,185
	Expenses							
di	Distribution Costs (di)	$1,689,663	$1,362,636	$101,223	$99,038	$112,491	$9,931	$4,343
cu	Customer Related Costs (cu)	$1,553,869	$1,323,683	$138,631	$72,205	$9,123	$9,586	$640
ad	General and Administration (ad)	$2,234,040	$1,848,229	$164,586	$118,366	$85,917	$13,432	$3,510
dep	Depreciation and Amortization (dep)	$1,451,988	$1,161,487	$101,447	$84,871	$92,387	$8,224	$3,572
INPUT	PILs (INPUT)	$25,788	$20,584	$1,733	$1,543	$1,710	$150	$67
INT	Interest	$1,119,814	$893,840	$75,272	$67,012	$74,275	$6,506	$2,909
	Total Expenses	$8,075,162	$6,610,460	$582,893	$443,036	$375,903	$47,829	$15,041
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,344,473	$1,073,164	$90,373	$80,456	$89,176	$7,812	$3,492
	Revenue Requirement (includes NI)	$9,419,635	$7,683,624	$673,266	$523,492	$465,079	$55,640	$18,534
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$62,338,172	$49,715,995	$4,065,175	$3,784,749	$4,232,670	$375,170	$164,413
gp	General Plant - Gross	$11,119,283	$8,910,223	$725,412	$647,056	$742,468	$65,330	$28,793
accum dep	Accumulated Depreciation	($30,319,373)	($24,032,683)	($1,991,196)	($1,934,588)	($2,092,627)	($186,673)	($81,607)
co	Capital Contribution	($8,990,162)	($7,312,622)	($519,160)	($466,347)	($614,151)	($54,924)	($22,958)
	Total Net Plant	$34,147,920	$27,280,913	$2,280,232	$2,030,870	$2,268,360	$198,904	$88,641
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,238,088	$15,370,429	$3,296,927	$5,339,811	$157,890	$10,924	$62,108
	OM&A Expenses	$5,477,572	$4,534,548	$404,441	$289,609	$207,531	$32,949	$8,494
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$29,715,660*	*$19,904,977*	*$3,701,368*	*$5,629,420*	*$365,421*	*$43,873*	*$70,601*
	Working Capital	$3,863,036	$2,587,647	$481,178	$731,825	$47,505	$5,703	$9,178
	Total Rate Base	$38,010,956	$29,868,560	$2,761,410	$2,762,694	$2,315,865	$204,607	$97,819
		Rate Base Input equals Output						
	Equity Component of Rate Base	$15,204,382	$11,947,424	$1,104,564	$1,105,078	$926,346	$81,843	$39,128
	Net Income on Allocated Assets	$1,344,473	$799,378	$169,053	$310,254	$39,496	($9,852)	$36,144
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,344,473	$799,378	$169,053	$310,254	$39,496	($9,852)	$36,144

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Final Run September 10, 2012

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	7	8	9
Rate Base Assets	**Total**	**Residental**	**GS < 50**	**GS 50-4,999 kW**	**Street Light**	**Sentinel Light**	**Unmetered Scattered Load**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**96.44%**	**111.69%**	**143.90%**	**89.32%**	**68.25%**	**276.17%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($761,836)**	($870,465)	$17,138	$166,453	($82,692)	($20,656)	$28,386
		Deficiency Input equals Output					
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	($273,786)	$78,680	$229,798	($49,680)	($17,663)	$32,652
RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	6.69%	15.30%	28.08%	4.26%	-12.04%	92.37%

2013 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Final Run September 10, 2012

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residental	GS < 50	GS 50-4,999 kW	Street Light	Sentinel Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$7.33	$13.58	$70.62	$0.30	$2.86	$0.16
Customer Unit Cost per month - Directly Related	$12.22	$22.34	$118.71	$0.51	$4.86	$0.61
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$30.18	$36.50	$161.37	$15.16	$19.46	$13.59
Existing Approved Fixed Charge	$21.08	$35.18	$320.64	$5.39	$7.64	$23.51

EXHIBIT 8 – RATE DESIGN

8.0-Staff-97s

Ref: 31.0-VECC

In response to VECC #31, IHDSL notes that it has enclosed the revised Table 8.3. Exhibit 8 Appendices states that there are no appendices in this section. Please file the revised Table 8.3.

IHDSL Response:

IHDSL has updated table as requested reflecting the current fixed variable split.

Distribution Rate Allocation Between Fixed & Variable Rates For 2013 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	7,234,973	81.63%	24.04	$0.0214	$ 4,092,953	$ 3,142,020		7,234,973	327,999	7,562,972
GS < 50 kW	629,481	7.10%	33.84	$0.0083	$ 369,409	$ 260,072		629,481	65,079	694,559
GS >50 to 4999 kW	518,208	5.85%	246.68	$2.3152	$ 195,793	$ 322,415	$ 16,715	534,923	111,034	645,956
Sentinel Lights	37,807	0.43%	9.08	$41.3339	$ 25,847	$ 11,961		37,807	170	37,977
Street Lighting	422,247	4.76%	6.48	$44.8755	$ 224,788	$ 197,460		422,247	3,822	426,070
Unmetered and Scattered	19,972	0.23%	10.35	$0.0174	$ 9,646	$ 10,326		19,972	1,226	21,198
TOTAL	8,862,688	100.00%			$ 4,918,436	$ 3,944,253	$ 16,715	$ 8,879,403	$ 509,329	$ 9,388,732
			Forecast Fixed/Variable Ratios		55.392%	44.420%	0.188%	100.000%		

8.0-Staff-98s

Ref: 33.0-VECC

Please file an updated RTSR model in Excel format reflecting the January 1, 2013 UTRs.

IHDSL Response:

The updated RTSR model reflecting the January 1, 2013 UTR's has been enclosed in Excel format in the Appendices section. The file name is Innisifl_RTSR_Updated_20130315.xls.

8.0 Energy Probe #60

Ref: 8.0 Energy Probe #37

No response was provided for part (b) of the question. Please provide a response.

IHDSL Response:

b) IHDSL does believe that it would be reasonable to consider a 3 year average for the loss factor due to the unusual loss in 2008. The enclosed table reflects the calculation of what a 3 year average loss factor would be.

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average	3-Year Average
		2007	2008	2009	2010	2011		
	Losses Within Distributor's System							
A(1)	"Wholesale" kWh delivered to distributor (higher value)	241,154,636	245,623,028	247,239,189	250,239,379	246,758,167	246,202,880	248,078,912
A(2)	"Wholesale" kWh delivered to distributor (lower value)	235,121,981	240,965,463	240,653,353	244,035,081	240,111,859	240,177,547	241,600,098
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-	
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	235,121,981	240,965,463	240,653,353	244,035,081	240,111,859	240,177,547	241,600,098
D	"Retail" kWh delivered by distributor	224,169,495	226,442,150	229,263,240	231,788,047	231,635,167	228,659,620	230,895,485
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-	
F	Net "Retail" kWh delivered by distributor = **D - E**	224,169,495	226,442,150	229,263,240	231,788,047	231,635,167	228,659,620	230,895,485
G	Loss Factor in Distributor's system = **C / F**	1.0489	1.0641	1.0497	1.0528	1.0366	1.0504	1.0464
	Losses Upstream of Distributor's System							
H	Supply Facilities Loss Factor	1.026	1.019	1.027	1.025	1.028	1.025	1.025
	Total Losses							
I	Total Loss Factor = **G x H**	1.0761	1.0844	1.0780	1.0792	1.0656	1.0766	1.0723

8.0 Energy Probe #61

Ref: 33.0-VECC

Please explain where the revised Table 8.3 referred to has been provided.

IHDSL Response:

IHDSL has updated table as requested reflecting the current fixed variable split.

Distribution Rate Allocation Between Fixed & Variable Rates For 2013 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	7,234,973	81.63%	24.04	$0.0214	$ 4,092,953	$ 3,142,020		7,234,973	327,999	7,562,972
GS < 50 kW	629,481	7.10%	33.84	$0.0083	$ 369,409	$ 260,072		629,481	65,079	694,559
GS >50 to 4999 kW	518,208	5.85%	246.68	$2.3152	$ 195,793	$ 322,415	$ 16,715	534,923	111,034	645,956
Sentinel Lights	37,807	0.43%	9.08	$41.3339	$ 25,847	$ 11,961		37,807	170	37,977
Street Lighting	422,247	4.76%	6.48	$44.8755	$ 224,788	$ 197,460		422,247	3,822	426,070
Unmetered and Scattered	19,972	0.23%	10.35	$0.0174	$ 9,646	$ 10,326		19,972	1,226	21,198
TOTAL	**8,862,688**	**100.00%**			**$ 4,918,436**	**$ 3,944,253**	**$ 16,715**	**$ 8,879,403**	**$ 509,329**	**$ 9,388,732**
			Forecast Fixed/Variable Ratios		**55.392%**	**44.420%**	**0.188%**	**100.000%**		

8.0 – VECC – 53

Reference: VECC #31

The revised version of Table 8.3 does not appear to have been included with the interrogatory responses. Please provide.

IHDSL Response:

IHDSL has updated table as requested reflecting the current fixed variable split.

Distribution Rate Allocation Between Fixed & Variable Rates For 2013 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	7,234,973	81.63%	24.04	$0.0214	$ 4,092,953	$ 3,142,020		7,234,973	327,999	7,562,972
GS < 50 kW	629,481	7.10%	33.84	$0.0083	$ 369,409	$ 260,072		629,481	65,079	694,559
GS >50 to 4999 kW	518,208	5.85%	246.68	$2.3152	$ 195,793	$ 322,415	$ 16,715	534,923	111,034	645,956
Sentinel Lights	37,807	0.43%	9.08	$41.3339	$ 25,847	$ 11,961		37,807	170	37,977
Street Lighting	422,247	4.76%	6.48	$44.8755	$ 224,788	$ 197,460		422,247	3,822	426,070
Unmetered and Scattered	19,972	0.23%	10.35	$0.0174	$ 9,646	$ 10,326		19,972	1,226	21,198
TOTAL	**8,862,688**	**100.00%**			**$ 4,918,436**	**$ 3,944,253**	**$ 16,715**	**$ 8,879,403**	**$ 509,329**	**$ 9,388,732**
			Forecast Fixed/Variable Ratios		**55.392%**	**44.420%**	**0.188%**	**100.000%**		

EXHIBIT 9 – Deferral and Variance Costs

9.0-Staff-99s – PILs

Ref: **4.0-Energy Probe - 27 d**
9.0 OEB - Staff 64a – PILS
Updated Fixed Asset Continuity Schedules Table 1.1 to 1.3

In response to Energy Probe IR #27d, IHDSL revised CCA schedules for 2012 and 2013.

a) The revised CCA schedules have not been updated to reflect the changes in fixed assets as per IRR pages 3-5. Please update the CCA schedules and the associated PILS model. Please update the Revenue Requirement Workform as necessary.

IHDSL Response:

IHDSL is submitting an updated PILs model and Revenue Requirement Workform reflecting the changes identified via the Summary of Changes Appendix.

b) The PILS also have not been updated to remove the additions and deductions of $81,910 of regulatory assets and regulatory liabilities to 2013 taxable income as requested in Board Staff IR #64a. Please update the PILS model and the Revenue Requirement Workform as necessary.

IHDSL Response:

Please see response to 9.0-Staff-99a) above.

9.0-Staff-100s - DVAs

Ref: **9.0-Staff-59**
6.0 VECC (page 26 of IRR)
Exhibit 9, Tab 2, Schedule 1, Page 6, Table 9.3

IHDSL is seeking disposition of a debit balance of Account 1508 for $308,464 as at December 31, 2011. IHDSL's current rate application is its first MIFRS rate application.

a) Has IHDSL been working with other distributors regarding the IFRS project and sharing the costs? If so, please list those distributors and explain the nature of the work that was jointly undertaken.

IHDSL Response:

IHDSL has worked collaboratively with LDCs' within CHEC. The LDCs' within CHEC collectively worked with BDO Accountants to individually obtain IFRS assessments of each LDC. IHDSL has also worked within the CHEC group with BDO to setup opening balances of assets as major components effective January 1, 2011. IHDSL has also worked with BDO Great Plains to develop, test and implement a process *within Great Plains financial software to setup assets by major components effective January 1, 2011. This process has been utilized by LDCs' utilizing Great Plains i.e. Wasaga Distribution, Lakefront Utilities, Cambridge Hydro, Wellington North Power, Essex Power, Erie Thames Power, Niagara on the Lake Hydro, and Orangeville Hydro.*

b) Per Table 9.3, please confirm that IHDSL spent a total of $356,133 ($103,354+$2,874+$249,905) in IFRS costs as at December 31, 2011.

i. Please confirm that the costs are one-time incremental, does not include labour cost which were included in the IHDSL's 2009 revenue requirement, and not already claimed by IHDSL in other parts of IHDSL's current application.

IHDSL Response:

IHDSL has spent a total of $356,133 in IFRS costs as at December 31, 2011.

i. The costs of $356,133 are one-time incremental and does not include labour cost which were included in the IHDSL's 2009 revenue requirement and not already claimed by IHDSL in other parts of IHDSL's current application.

c) Please confirm all the costs shown in Table 9.3 are only incurred by IHDSL and were not shared with any other distributors that IHDSL may have list in part (a) above.

IHDSL Response:

All costs shown in Table 9.3 totalling $356,133 are only incurred by IHDSL and were not shared with any other distributors that IHDSL may have worked with in question (a).

d) With regards to the $249,905 of initial set up costs incurred to develop and implement an identifiable asset process with GIS and financial reporting system for disposition referencing:

i. Please provide additional details on the nature of the system upgrade and the cost incurred. Please show how the work done was directly related to the IFRS project.

IHDSL Response:

IHDSL utilized Great Plains asset sub ledger to track asset purchased by year. IHDSL determined in conjunction with the mandatory conversion to IFRS an asset tracking by major component in order to reflect when disposition incurred was required. IHDSL determined it could utilize and link Great Plains with the GIS system via the job costing to identify assets that were setup or disposed of within the distribution territory. Inventory within Great Plains has been identified as a major component i.e. wood pole. The inventory is recorded to the job as well as any other applicable costs i.e. vehicles, internal labour and subcontractors. Once the job is finished and closed, an asset by major component (inventory) is setup and all non-major inventory costs are allocated to each major component within the applicable job. The asset is setup in Great Plains fixed asset sub ledger with the unique job number reference. This job number reference is also recorded within the GIS system of the major component. This facilitates the identification and recognition of assets disposed of subsequently.

ii. **Please provide a breakdown of this costs in terms of how much was incurred for consultant costs, system up-grade, GIS, financial reporting etc and explain how these cost were directly related to the IFRS implementation.**

IHDSL Response:

The following is the breakdown of costs by major category as requested by board staff:

Description of cost	***Amount***
Consultant costs	*$139,145.12*
Great Plains componentized fixed asset process	*43,110.00*
Financial Reporting	*33,750.00*
GIS	*33,900.00*
Total	*$249,905.12*

These costs are related to the IFRS implementation in order to have an identifiable componentized asset setup within Great Plains and the GIS system. IHDSL worked with consultants to develop, test and deploy the setup of componentized asset and subsequent disposal.

iii. **Please provide a copy of the report or study conducted by the vendor or consultant for IHDSL's system up-grade and provide an explanation on how the system up-grade is directly related to IHDSL's IFRS project.**

IHDSL Response:

IHDSL is providing a copy of the scope of works provided by the GIS vendor and BDO for the systems upgrade and financial reporting as it relates to the IFRS project. Please refer to Ex 9 Appendix 2 Ref 9.0-Staff-100s d) iii. The scope of work identifies the services the respective vendors provided in order to accomplish the end objective of being able to identify componentized assets in order to properly identify and reflect the useful lives of the assets deployed, reflect disposition by major component and the financial fixed asset reporting.

iv. **On page 27 of IRR to 6.0 VECC, capital project costs for hardware and software was $88,448, $64,210 and $86,927 for 2009 to 2011, respectively. Please indicate if any of the system upgrade costs included in Account 1508 has been included in the capital project costs on page 27 of IRR or has been capitalized.**

IHDSL Response:

None of the system upgrade costs included in Account 1508 has been included in the capital project costs on page 27 of IRR or has been capitalized to date.

e) As at December 31, 2011, please indicate the percentage of completion of IHDSL's IFRS project.

IHDSL Response:

As of December 31, 2011 IHDSL is estimating based on cost incurred as of 2011 for $356,133 it has completed over 80% of the IFRS project.

f) Please indicate the remaining costs IHDSL is expecting to incur in 2012 and beyond to complete the IFRS project.

IHDSL Response:

The costs incurred in 2012 for the IFRS project is $53k. IHDSL is estimating the remaining cost for the IFRS project post 2012 will be $25k to potential address the regulatory asset/liability issues of recording keeping, auditing and reporting.

g) Given the deferral of the adoption of IFRS until at least 2014 as stated by IHDSL, please confirm that IHDSL is still requesting the disposition of the transitional costs incurred to 2011

i. With regards to 1508, Other Regulatory Assets, "Sub-account IFRS Transition Costs Variance, APH FAQ October 2009 #2 states:

> **In the distributor's next cost of service rate application immediately after the IFRS transition period, the balance in this sub-account should be included for review and disposition.**

Please provide IHDSL justification for the disposition of the transitional costs in this rate application and not the rate application immediately after the IFRS transition period.

ii. If disposition is still requested, please indicate if IHDSL plans to continue accumulating costs in Account 1508 from 2012 onwards.

iii. If disposition is not requested, please update the relevant evidence in the application.

IHDSL Response:

Board staff is requesting confirmation from IHDSL if disposition of the transitional costs incurred to 2011 is still requested

i. IHDSL is still requesting disposition of the transitional costs incurred to 2011 as the majority of the IFRS project is completed. Also as an offset to the 2012 PP&E adjustment IHDSL is proposing to refund its customers and thus provide rate mitigation to its customers.

ii. IHDSL plans to continue accumulating costs in Account 1508 from 2012 onwards.

iii. Not applicable.

9.0-Staff-101s

Ref: 9.0-Staff-60
Exhibit 2, Tab 2, Schedule 1, Page 6

In response to 9.0-Staff-60, IHDSL provided the PST savings on capital purchases in Table 1. The asset purchase is indicated to be $708,411 annually from 2010 to 2013. Asset additions per 2009 fixed asset continuity schedule (Appendix 2-B) are $4,312,275. Please reconcile the proxy asset purchase of $708,411 used in the calculation of the amount recorded in Account 1592 to the 2009 additions of $4,312,275 per the fixed asset continuity schedule. Please update the evidence as necessary.

IHDSL Response:

IHDSL's proxy asset purchase of $708,411 was based on 2009 capital purchases. The majority of the 2009 capital costs are subcontractor costs that are not PSTable. The 2009 capital purchases of $708,411 are based on the PST that was incurred on material that was capitalized in 2009.

9.0-Staff-102s

Ref: 9.0-Staff-61

9.0-Staff-61 b) requested that IHDSL provide a schedule identifying all revenues and expense figures, listed by Uniform System of Account ("USoA") that were used to calculate the variances recorded in Account 1548. In response to this IR, IHDSL listed the USoA used. Please provide the revenue and expense figures and the calculation of the variance recorded in Account 1548 and reconcile these amounts to the amount recorded in Account 1548.

IHDSL Response:

IHDSL is providing the following table identifying the revenue and cost by USoA used to calculate the variance recorded in account 1548.

RCVA Analysis
as at December 31, 2011

Account	Name	2005	2006	2007	2008	2009	2010	2011	Total
1.20.4084.900.000	STR - Processing		(793.50)	(896.50)	(402.50)	(230.00)	(585.00)	(350.00)	
1.20.4084.901.000	STR - Request		(506.00)	(523.50)	(280.75)	(174.50)	(356.25)	(197.75)	
	Total STR revenue	-	(1,299.50)	(1,420.00)	(683.25)	(404.50)	(941.25)	(547.75)	(5,296.25)
1.40.5305.001.801	STR - BC Super		29.71	-	-	-	-	-	
1.40.5315.001.801	STR - Cust Bill	7,881.00	9,020.08	11,954.57	14,264.59	12,033.92	12,783.53	8,992.82	
	Total STR costs	7,881.00	9,049.79	11,954.57	14,264.59	12,033.92	12,783.53	8,992.82	76,960.22
	STR Variance	7,881.00	7,750.29	10,534.57	13,581.34	11,629.42	11,842.28	8,445.07	71,663.97
	Carrying Charges	7,765.00	2,138.90	894.86	1,269.74	469.91	449.28	985.41	13,973.10
	Cummulative Balance	15,646.00	25,535.19	36,964.62	51,815.70	63,915.03	76,206.59	85,637.07	85,637.07
	Grand Total								

9.0-Staff-103s

Ref: 9.0-Staff-63

In response to 9.0-Staff-63, IHDSL indicated that the RARA #1 from Hydro One for the period of May 2010 to December 2011 has been recorded in Account 2425 Other Deferred Credits. Please indicate the journal entries used to record the RARA #1 from Hydro One in Account 2425. Please also indicate the journal entry used to move the RARA#1 from Hydro One out of Account 2405 to Account 2425.

IHDSL Response:

IHDSL has enclosed the requested journal entries with respect to the Hydro One RAR-2010-General. Copies of the journal entries are enclosed in the appendices for Exhibit 9, as Ex 9 Appendix 1 Ref 9.0-Staff-103s.

9.0-Staff-104s – Stranded Meters

Ref: 9.0-Staff-65 and 9.0-Staff-66

a) **Please explain why the NBV of stranded meters for 2013 is estimated at $359,195 when the documented NBV of stranded meters as of December 31, 2012 is $334,628.**

IHDSL Response:

In EB-2011-0435 IHDSL did record an incorrect forecast NBV of $334,628 as of December 31, 2012. The correct value is $359,195 as recorded in Appendix 2-S Stranded Meter Treatment. Further to Appendix 2-3 filed in IHDSL's original submission, the $359,195 value is aligned to IHDSL SMTOU RRR filings for 2011 and 2012.

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009	Actual	$ 1,270,515	$ 1,068,807		$ 201,708		$ 201,708
2010	Actual	$ 426,641	$ 181,320		$ 245,321		$ 245,321
2011	Actual		$ 31,125		-$ 31,125		-$ 31,125
2012	Forecast		$ 42,532		-$ 42,532		-$ 42,532
2013	Forecast		$ 14,177		-$ 14,177		-$ 14,177
as at 12/31/11		$ 1,697,156	$ 1,281,252				
					$ 359,195		$ 359,195

b) **In the response to part b) of 9.0-Staff-66, IHDSL filed a copy of sheet I7.1 from its 2009 Cost Allocation study. That sheet shows a relative weighted meter cost of 1 for Residential and 5.26 for the GS < 50 kW class. Was that information taken into account in determining the proposed stranded meter rate riders ("SMRRs")? If so, please describe in detail, and provide the calculations. In the alternative, please explain.**

IHDSL Response:

IHDSL did not take into account the 2009 Cost Allocation weighted meter costs in determining the stranded meter rate riders. In determining the stranded meter rate riders IHDSL utilized actual NBV values of stranded meters by rate class to determine the allocation factor. The outcome determined an allocation of the NBV costs of 78.5% to the Residential rate class and 21.5% to the GS<50 rate class resulting in the following proposed rate riders,

	Residential	***GS<50***
Stranded Meter Rate Rider	*$0.83*	*$3.53*
Recovery Time Frame	*2 years*	*2 years*

c) **Please recalculate the stranded meter rate riders, on a class-specific basis for applicable customer classes, based on a December 31, 2012 NBV of $334,627.68. Please show the derivation, and file the calculations in an Excel spreadsheet if available.**

IHDSL Response:

As requested IHDSL has recalculated the stranded meter rate riders based on the NBV of $334,628 recorded in EB-2011-0435.In recalculating IHDSL utilized the same allocation factor which identified in Staff IR 104 b). IHDSL has enclosed the summary document in pdf form as Ex 9 Appendix 3 Ref 9.0-Staff-

104s c). (due to the size of this file, it will be transmitted directly to the OEB as Ex 9 Appendix 3 Ref 9.0-Staff-104s Innisfil Stranded Meters Rider). The resulting change to the proposed stranded meter rate rider is as follows:

	Residential	***GS<50***
Stranded Meter Rate Rider	*$0.77*	*$3.29*
Recovery Time Frame	*2 years*	*2 years*

9.0-Staff-108s - Stranded Meters

Ref: 35.0-VECC

No response is provided for 35-VECC. Please provide the response in full.

IHDSL Response:

The 2010 Continuity Schedule reflects $492,071 in meter disposals of which $65,430 was due to asset disposals for interval meters that were not related to the smart metering project. Table 9.11 (or Appendix 2-S) only reflects the disposals associated with the smart metering project for a value of $426,641.

9-VECC-53

Reference: 35.0-VECC

There does not appear to be a response to this interrogatory. Please respond or advise where the response may be found.

IHDSL Response:

Please refer to 9.0-Staff-108s above.

9-VECC-54

Reference: 34. 0 / 9.0-Staff 104s

In Board Staff Supplementary 104s Innisfil Hydro is asked to recalculate the stranded meter rate rider based on its 2009 cost allocation study. Please also show the riders that would result if stranded meters were allocated based on the average cost of installed smart meters for the residential and gs <50 class. Please show the calculation and comment as to which of the three methods Innisfil believes is most appropriate.

IHDSL Response:

Please see the response to Board Staff IR 104s b) for the 1st part of the IR.

The following table reflects the riders based on an average cost of the NBV of the stranded for the residential and GS<50.

Stranded Meter Calcualtion (Average)	Recovery period:				
Years:	**1 Year**	**2 Year**	**3 Year**	**4 Year**	**Defer**
Months:	12	24	36	48	0
Residential	$ 1.98	$ 0.99	$ 0.66	$ 0.50	0
GS <50kW	$ 1.98	$ 0.99	$ 0.66	$ 0.50	0

IHDSL feels that our original calculation for the stranded meter rate rider best reflects the costs by rate class as the calculation were based on the actual stranded meters by rate class.

EX 9 APPENDIX 1 REF 9.0-STAFF-103s

BOARD STAFF
IR 103s
Pg 1 of 5

Transaction Entry Zoom

File Edit Tools View Help

Innisfil Hydro Distribution Systems Limited 3/11/13

Journal Entry	329,639	Audit Trail Code	GLTRX00024108
Transaction Date	6/01/12	Batch ID	REALL H1 LV
Source Document	GJ	Reference	to reall H1 LV Rider
		Currency ID	

Account / Distribution Reference	Debit	Credit / Exchange Rate
1 .00 .2405 .900 .000	$66,050.63	$0.00
		0.0000000
1 .00 .2425 .805 .000	$0.00	$66,050.63
		0.0000000
Total	$66,050.63	$66,050.63
Difference		$0.00

Intercompany

OK

Routines

* Voided Journal Entry

Account: 1.00.2405.900.000 Other Regulatory Liabilities/Credits

Ranges:	From:	To:
Date	First	First
Source Document	First	First
Currency ID	First	First

Sorted By: Transaction Date Account Balance: $0.00

Trx Date	Jrnl No.	Source Doc	Audit Code	Reference	Currency ID	Debit	Credit
12/31/11	316,998	BBF	GLTRX00023323	Balance Brought Forward			$59,531.26
1/04/12	308,096	PMTRX	GLTRX00022560	Payables Trx Entry			$3,539.74
2/02/12	312,791	PMTRX	GLTRX00022960	Payables Trx Entry			$2,979.63
6/01/12	329,639	GJ	GLTRX00024108	to reall H1 LV Rider		$66,050.63	
					Totals:	$66,050.63	$66,050.63

Total Transactions: 4

* Voided Journal Entry

Account: 1.00.2405.900.000 Other Regulatory Liabilities/Credits

Ranges:	From:	To:
Date	First	First
Source Document	First	First
Currency ID	First	First

Sorted By: Transaction Date Account Balance: ($59,531.26)

Trx Date	Jrnl No.	Source Doc	Audit Code	Reference	Currency ID	Debit	Credit
12/31/10	267,138	BBF	GLTRX00019193	Balance Brought Forward			$21,416.96
1/14/11	260,702	PMTRX	GLTRX00018729	Payables Trx Entry			$2,798.32
2/14/11	263,843	PMTRX	GLTRX00018982	Payables Trx Entry			$3,686.14
3/02/11	268,410	PMTRX	GLTRX00019247	Payables Trx Entry			$3,633.88
4/15/11	272,150	PMTRX	GLTRX00019543	Payables Trx Entry			$3,883.48
5/03/11	275,672	PMTRX	GLTRX00019813	Payables Trx Entry			$3,086.16
6/02/11	279,423	PMTRX	GLTRX00020167	Payables Trx Entry			$2,574.29
7/04/11	283,315	PMTRX	GLTRX00020469	Payables Trx Entry			$2,920.42
8/03/11	288,582	PMTRX	GLTRX00020757	Payables Trx Entry			$2,937.06
9/01/11	292,316	PMTRX	GLTRX00021124	Payables Trx Entry			$3,639.66
10/03/11	295,943	PMTRX	GLTRX00021448	Payables Trx Entry			$3,154.65
11/01/11	299,824	PMTRX	GLTRX00021760	Payables Trx Entry			$2,734.17
12/01/11	304,092	PMTRX	GLTRX00022129	Payables Trx Entry			$2,543.02
12/31/11	311,432	GJ	GLTRX00022858	accrue H1 STLT Aug 2011			$523.05
					Totals:	$0.00	$59,531.26

Total Transactions: 14

* Voided Journal Entry

Account: 1.00.2405.900.000 Other Regulatory Liabilities/Credits

Ranges: From: To:
Date First First
Source Document First First
Currency ID First First

Sorted By: Transaction Date Account Balance: ($21,416.96)

Trx Date	Jrnl No.	Source Doc	Audit Code	Reference	Currency ID	Debit	Credit
12/31/09	227,246	BBF	GLTRX00016163	Balance Brought Forward			$23,071.88
1/01/10	224,690	GJ	GLREV00015974	Dec 09 A/P Accruals			$5,414.00
1/13/10	223,701	PMTRX	GLTRX00015844	Payables Trx Entry		$5,414.00	
2/11/10	225,612	PMTRX	GLTRX00016080	Payables Trx Entry		$5,414.00	
3/12/10	228,884	PMTRX	GLTRX00016266	Payables Trx Entry		$5,414.00	
4/15/10	231,711	PMTRX	GLTRX00016494	Payables Trx Entry		$5,323.08	
4/30/10	236,707	GJ	GLTRX00016878	Corr H1 Asset Recov coding		$90.92	
5/14/10	234,567	PMTRX	GLTRX00016747	Payables Trx Entry		$5,414.00	
5/31/10	239,650	GJ	GLTRX00017110	To corr g/l allocation H1Apri			$376.80
6/09/10	238,453	PMTRX	GLTRX00016980	Payables Trx Entry		$23.54	
7/13/10	241,585	PMTRX	GLTRX00017194	Payables Trx Entry			$3,076.73
8/12/10	244,235	PMTRX	GLTRX00017393	Payables Trx Entry			$2,835.75
9/14/10	247,737	PMTRX	GLTRX00017639	Payables Trx Entry			$2,910.83
10/14/10	250,607	PMTRX	GLTRX00017878	Payables Trx Entry			$5,411.41
11/15/10	253,808	PMTRX	GLTRX00018230	Payables Trx Entry			$2,417.25
12/14/10	257,525	PMTRX	GLTRX00018535	Payables Trx Entry			$2,995.85
					Totals:	$27,093.54	$48,510.50

Total Transactions: 16

System: 3/11/13 4:38:08 PM
User Date: 3/11/13

Innisfil Hydro Distribution Sy
SUMMARY INQUIRY FOR 2013
General Ledger

User ID: Jennifer

Account: 1.00.2425.805.000 Reg Liability - H1
Currency:

Period	Debit	Credit	Net Change	Period Balance
Beginning Balance		$66,050.63	($66,050.63)	($66,050.63)
Period 1			$0.00	($66,050.63)
Period 2			$0.00	($66,050.63)
Period 3			$0.00	($66,050.63)
Period 4			$0.00	($66,050.63)
Period 5			$0.00	($66,050.63)
Period 6			$0.00	($66,050.63)
Period 7			$0.00	($66,050.63)
Period 8			$0.00	($66,050.63)
Period 9			$0.00	($66,050.63)
Period 10			$0.00	($66,050.63)
Period 11			$0.00	($66,050.63)
Period 12			$0.00	($66,050.63)
Totals:	$0.00	$66,050.63	$66,050.63	$66,050.63

EX 9 APPENDIX 2 REF 9.0-STAFF-100s d)iii

Innisfil Hydro Distribution Systems Limited

IFRS Job Cost Fixed Assets Integration Proposal

BDO

Contact Information

Proposed by:	BDO Canada LLP Chartered Accountants and Advisors 60 Columbia Way, Suite 400 Markham, ON L3R 0C9 Canada
Contact persons:	Chris Johnsen, cjohnsen@bdo.ca Stephen Payne, spayne@bdo.ca
Reception:	(877) 236-4835
Fax:	(519) 824-5497
Date:	April 20, 2010
Directed to:	Laurie Ann Cooledge 2073 Commerce Park Drive Innisfil, ON L9S 4A2 Canada

BDO

April 20, 2010

Innisfil Hydro Distribution Systems Limited
2073 Commerce Park Drive
Innisfil, ON L9S 4A2
Canada

Attention: Laurie Ann Cooledge

Dear Laurie Ann,

We appreciate the opportunity to submit our revised proposal to assist with creating Fixed Asset records after a WennSoft Job is closed. The following proposal outlines the services we will provide to help you achieve your goals. Please review the details to understand our fees and terms of business.

We want our relationship to go beyond that of client/consultant and to become your partner in helping achieve your business objectives. Our goal will be to deliver value in everything we do.

We are excited about the prospect of working with **Innisfil Hydro Distribution Systems Limited** (IHDSL) on this important engagement and look forward to discussing our proposal in further detail. If there is any clarification or additional information you require, please do not hesitate to contact Stephen Payne - (416) 525-1762.

Yours truly,

BDO Canada LLP

Chris Johnsen, CMA, CMC
Partner

BDO

Overview

IHDSL has requested BDO automate the creation of Fixed Asset records after a job is closed. In addition IHDSL will be implementing WIP cost tracking and no longer use Job Cost division / Cost Element / Suffix accounts in the general ledger.

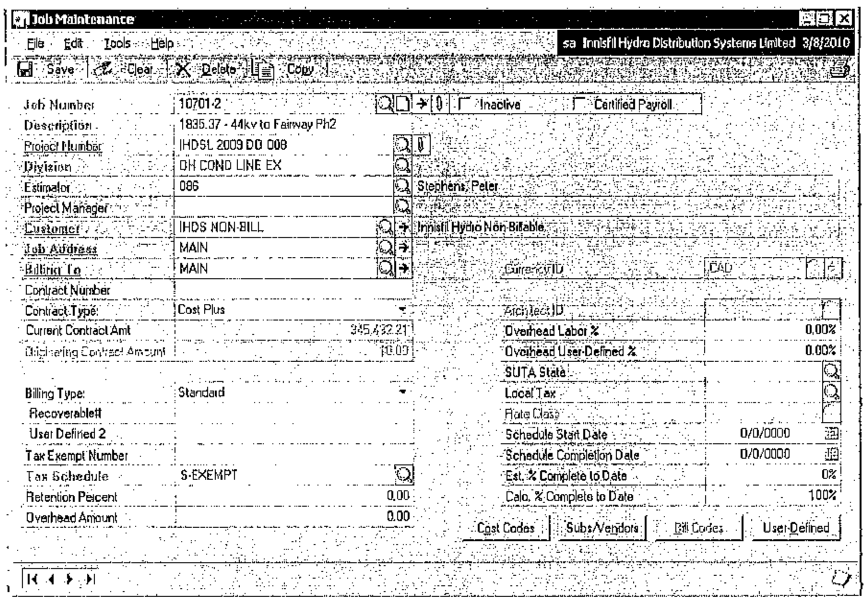
The process to create and setup project, jobs, and cost codes within WennSoft will not be altered.

Detailed Process

After a job is closed, an automated routine would be run to create the appropriate fixed assets for the job.

Step 1

The routine would prompt for a job number and request the fixed asset Acquisition Date. A confirmation window will be presented and the closed job will be located (example of a job below).



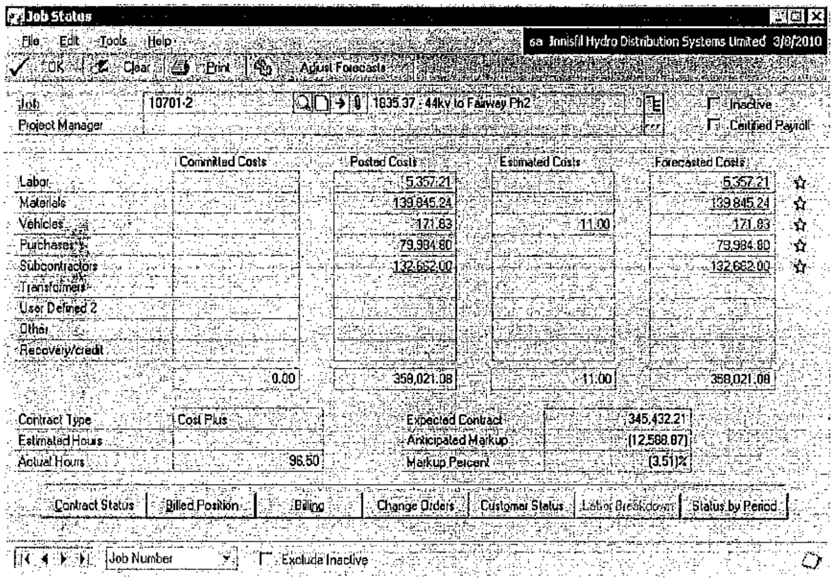
BDO

Step 2

The routine would cycle through the detailed job historical transactions (JC30201) for each cost element (example below).

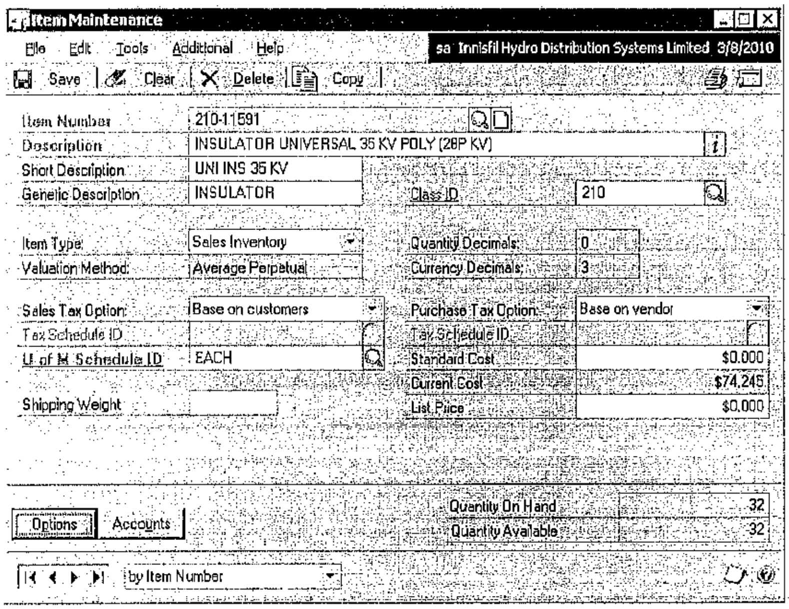
The item's master record is analysed to determine if the item is Fixed Asset related for the following material transaction types (Document Source):

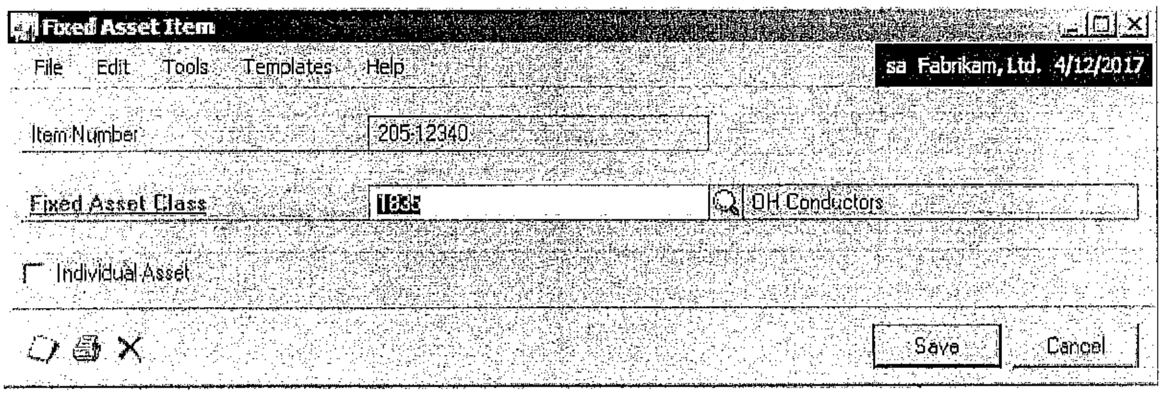
- IV - inventory adjustment
- REC - purchase order receiving



Step 3

An Extender window (example below) will be added to tag the asset class to the item. Items without asset classes are treated as overhead items.





The Individual Asset check box will instruct the utility to either pool the assets for the job or create unique individual assets for each item tagged to a Fixed Asset Class.

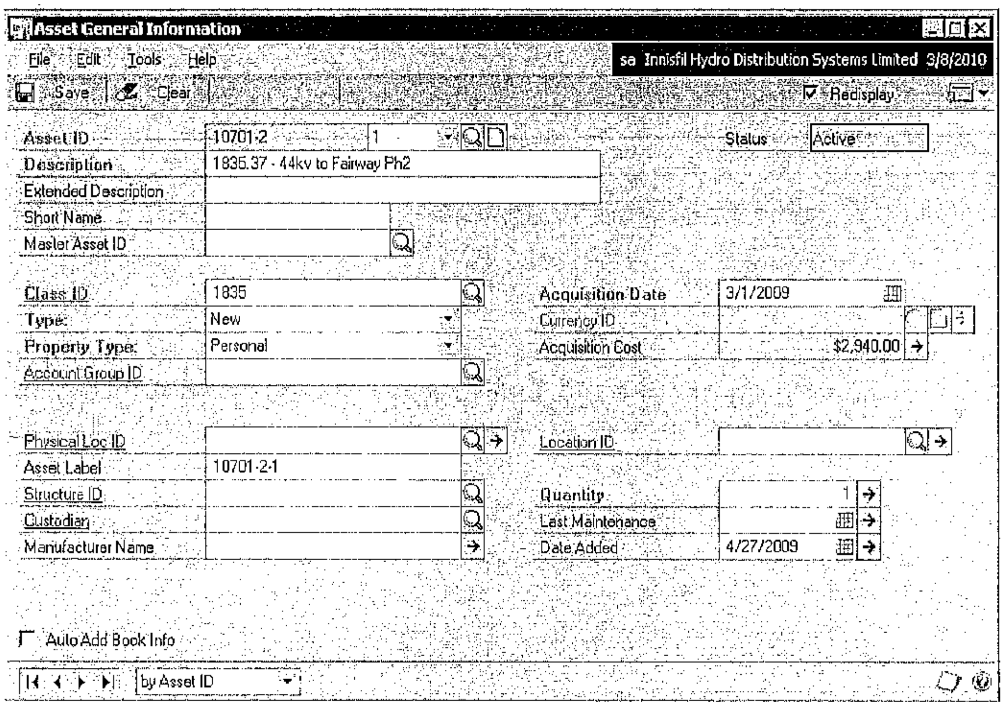
BDO

Step 4

The Fixed Asset record is created as follows:

Field	Source
Asset ID	Job Number
Asset Suffix	Default to 1 and increment for each asset to be created for the job.
Description	Job Description
Class ID	Item's fixed asset link class
Type	*Default in - New*
Property Type	*Default in - Personal*
Asset Label	Asset ID + suffix
Acquisition Date	Date value captured by the routine (step 1 above)
Quantity	Actual number of materials issued to the job
Acquisition Cost	Proportioned value based on the base cost of the material.
Date Added	System Date

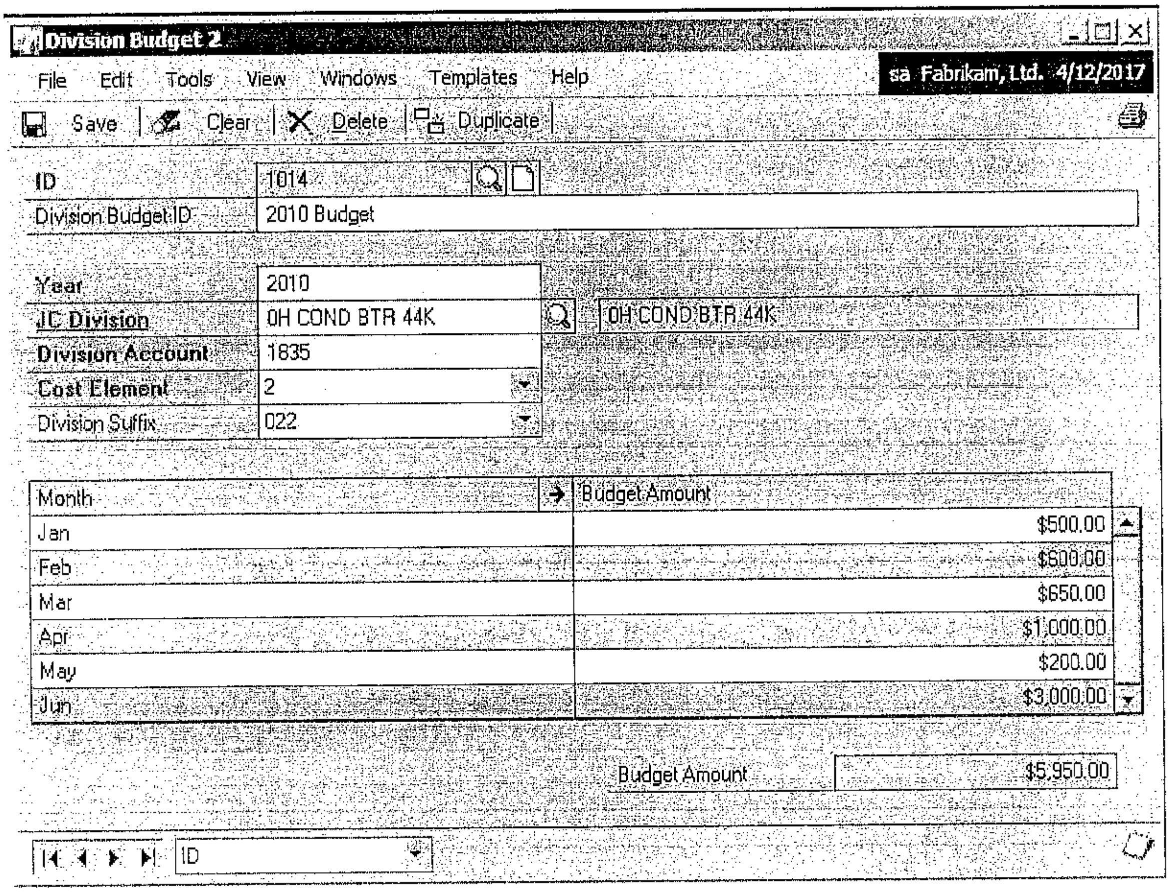
Note - the Fixed Asset book will automatically be added based on the configuration within Fixed Assets.



BDO

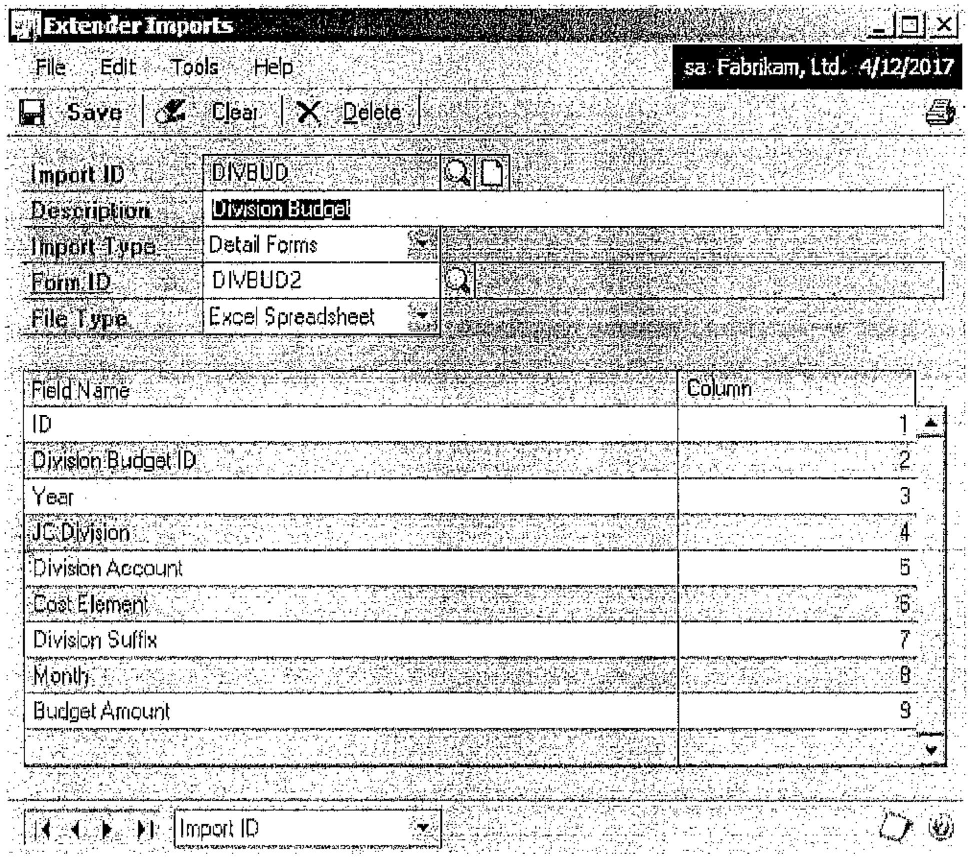
Job Cost WIP Implementation

In order to budget at the Division Account, Cost Element and Division Suffix level, the following Extender Window will be created:



BDO

The data to populate these windows would be manually keyed or imported from Excel using an Extender Import Window:



BDO

A Crystal report will be created to compare the budget data entered above to the actual transactions posted to Job Cost:

Innisfil Hydro Distribution Systems Limited

For the Twelve Months Ending December 31, 2008

Dec 2008	Dec Budget	Variance	Dec 2007	Variance			YTD 2008	2008 YTD Budget	Variance	YTD 2007	Variance	2008 Budget
						Distribution Plant Capital Expenditure - Detail						
8,826	0	8,826	0	8,826	1.00.1806.900.000	O Land	(1,319)	0	(1,319)	0	(1,319)	0
2,332	1,587	745	1,555	777	1.00.1800.000.000	O Land Rights	9,398	19,000	(9,602)	3,841	5,557	19,000
11,158	1,587	9,571	1,555	9,603		TOTAL LAND AND LAND RIGHTS	8,079	19,000	(10,921)	3,841	4,238	19,000
0	62	(62)	0	0	1.00.1820.001.???	F DS Equipment Labour	962	700	262	364	598	700
0	0	0	0	0	1.00.1820.002.050	O DS Equipment Materials Alcona	2	0	2	0	2	0
1,378	0	1,379	0	1,379	1.00.1820.002.051	O DS Equipment Materials Brian Wilson	1,570	25,000	(23,430)	0	1,570	25,000
0	163	(163)	0	0	1.00.1820.002.054	O DS Equipment Materials Innisfil	0	2,000	(2,000)	0	0	2,000
0	0	0	483	(483)	1.00.1820.002.057	O DS Equipment Materials Sandy Cove	0	0	0	483	(483)	0
0	0	0	0	0	1.00.1820.002.058	O DS Equipment Materials Stroud	0	1,200	(1,200)	0	0	1,200
0	0	0	0	0	1.00.1820.002.059	O DS Equipment Materials Commerce Park	0	0	0	669	(669)	0
0	0	0	0	0	1.00.1820.003.051	O DS Equipment Vehicles Brian Wilson	276	0	276	0	276	0
0	0	0	0	0	1.00.1820.003.058	O DS Equipment Vehicles Stroud	0	0	0	60	(60)	0
0	0	0	0	0	1.00.1820.004.051	O DS Equipment Purchases Brian Wilson	18,822	0	18,822	0	18,822	0
(482)	0	(482)	0	(482)	1.00.1820.004.052	O DS Equipment Purchases Big Bay	5,795	0	5,795	0	5,795	0
0	0	0	0	0	1.00.1820.004.057	O DS Equipment Purchases Sandy Cove	34	0	34	0	34	0
0	0	0	0	0	1.00.1820.005.051	O DS Equipment Subcontractor Brian Wils	6,296	5,000	1,296	0	6,296	5,000
1,491	0	1,491	0	1,491	1.00.1820.005.052	O DS Equipment Subcontractor Big Bay	1,491	0	1,491	0	1,491	0
0	0	0	0	0	1.00.1820.005.054	O DS Equipment Subcontractor Innisfil	0	8,000	(8,000)	0	0	8,000
0	0	0	0	0	1.00.1820.005.055	O DS Equipment Subcontractor Lefroy	378	0	378	10,478	(10,100)	0
0	0	0	0	0	1.00.1820.005.060	O DS Equipment Subcontractor Leonard Beach	0	0	0	6,754	(6,754)	0
0	0	0	0	0	1.00.1820.005.057	O DS Equipment Subcontractor Sandy Cov	218	0	218	1,026	(808)	0
0	0	0	0	0	1.00.1820.005.058	O DS Equipment Subcontractor Stroud	0	750	(750)	8,542	(8,542)	750
1,968	0	1,968	0	1,968	1.00.1820.005.059	O DS Equipment Subcontractor Commerce	1,968	0	1,968	0	1,968	0
0	0	0	(18,580)	18,580	1.00.1995.820.000	O DS Equipment Capital Contributions	0	0	0	(18,580)	18,580	0
4,357	225	4,132	(18,097)	22,454		TOTAL DS EQUIPMENT	37,812	42,650	(4,838)	9,795	28,017	42,650
3,626	5,346	(1,720)	1,584	2,042	1.00.1830.001.???	F PTF Labour	42,634	66,200	(23,566)	42,050	584	66,200
2,837	260	2,577	821	2,016	1.00.1830.002.020	O PTF Materials New Service	1,865	13,000	(11,135)	9,401	(7,536)	13,000
0	430	(430)	0	0	1.00.1830.002.022	O PTF Materials Major Betterment	1,644	8,600	(6,956)	1,216	428	8,600
3,178	0	3,178	0	3,178	1.00.1830.002.023	O PTF Materials Betterment 44kv	11,894	229,500	(217,606)	18,909	(7,015)	229,500
0	720	(720)	111	(111)	1.00.1830.002.024	O PTF Materials Minor Betterment	7,365	4,500	2,865	6,199	1,166	4,500
0	0	0	0	0	1.00.1830.002.029	O PTF Materials Volt Conversion	0	0	0	11,131	(11,131)	0
0	1,337	(1,337)	0	0	1.00.1830.002.035	O PTF Materials Replace 44kv	3,154	16,000	(12,846)	14,007	(10,853)	16,000
13,726	3,639	10,087	0	13,726	1.00.1830.002.036	O PTF Materials Replace	61,653	121,300	(59,647)	14,674	46,979	121,300
0	0	0	0	0	1.00.1830.002.037	O PTF Materials Line Ext	137,869	91,200	46,669	0	137,869	91,200
1,437	2,625	(1,188)	0	1,437	1.00.1830.002.038	O PTF Materials Relocates	7,044	31,500	(24,456)	34,305	(27,261)	31,500
24	44	(20)	0	24	1.00.1830.003.020	O PTF Vehicles New Service	(1,886)	500	(2,386)	91	(1,977)	500
48	36	12	0	48	1.00.1830.003.022	O PTF Vehicles Major Betterment	60	450	(390)	0	60	450
121	25	96	0	121	1.00.1830.003.023	O PTF Vehicles Betterment 44kv	327	300	27	1,025	(697)	300
0	0	0	5	(5)	1.00.1830.003.024	O PTF Vehicles Minor Betterment	4,260	0	4,260	7,045	(2,785)	0
0	0	0	0	0	1.00.1830.003.029	O PTF Vehicles Volt Conversion	0	0	0	596	(596)	0
0	0	0	0	0	1.00.1830.003.035	O PTF Vehicles Replace 44kv	224	200	24	141	83	200
555	132	423	0	555	1.00.1830.003.036	O PTF Vehicles Replace	1,592	1,650	(58)	404	1,188	1,650
72	56	16	0	72	1.00.1830.003.037	O PTF Vehicles Line Ext	2,695	700	1,995	(102)	2,797	700
0	25	(25)	0	0	1.00.1830.003.038	O PTF Vehicles Relocates	735	300	435	1,337	(601)	300
0	0	0	0	0	1.00.1830.004.023	O PTF Purchases Betterment 44kv	0	0	0	15,641	(15,541)	0
0	0	0	0	0	1.00.1830.004.024	O PTF Purchases Minor Betterment	3,499	0	3,499	0	3,499	0
0	0	0	0	0	1.00.1830.004.035	O PTF Purchases Replace 44kv	0	0	0	16	(16)	0
0	0	0	0	0	1.00.1830.004.036	O PTF Purchases Replace	365	0	365	133	231	0
3,377	270	3,107	1,560	1,817	1.00.1830.005.020	O PTF Subcontractor New Service	13,697	13,500	197	10,820	2,876	13,500
48,687	0	48,687	0	48,687	1.00.1830.005.022	O PTF Subcontractor Major Betterment	52,439	177,400	(124,961)	0	52,439	177,400
12,651	16,761	(4,110)	0	12,651	1.00.1830.005.023	O PTF Subcontractor Betterment 44kv	23,997	119,720	(95,723)	20,264	3,732	119,720
0	480	(480)	478	(478)	1.00.1830.005.024	O PTF Subcontractor Minor Betterment	8,586	3,000	5,585	3,094	5,491	3,000
0	0	0	0	0	1.00.1830.005.029	O PTF Subcontractor Volt Conversion	0	0	0	29,843	(29,843)	0

18

04/30/09

BDO

Software Costs

Module	Qty	Price	Extended Price
eOne			
SmartConnect	1	$ 4,500.00	$ 4,500.00
	18 % Maintenance Plan		$ 810.00
	Total		$ 5,310.00

Estimate of Implementation Services

Activity	Days
Planning & Project Management	3
Apply Dynamics GP SP4 and WennSoft 10.EX FP2	3
Implement WIP Accounting for Job Cost	4
Design Meetings with ASI	2
Fixed Asset Automation	10
Implement Division Budgeting and Importing	2
Create the Division Budget to Actual Crystal Report	4
Total Phase	28

BDO

Terms of Business

Pricing Confirmation

The terms outlined in this proposal are valid for 30 days.

Fees

Description		Price
eOne SmartConnect		$4,500.00
Software Maintenance		$810.00
Professional Services Estimate		$37,800.00
	Total	**$43,110.00**

Please note this is not a fixed fee assignment.

Disbursements

Costs that are billed separately from professional services include:

- Out-of-pocket expenses such as hotels, tolls, parking, telecommunications and meals.
- Local Travel charges will include the mileage reimbursement paid to the consultant
- 4% of total professional fees for project lifecycle administration.

Taxes

All costs referred to in this quotation are subject to relevant taxes.

Payment Terms

Software

- Due at proposal sign off.

Services

- BDO will invoice Innisfil Hydro Distribution Systems Limited on a bi-weekly basis.
- Our terms of business are net 20 days.
- Overdue accounts are subject to a 2% interest charge per month.

BDO

Acceptance

In order to confirm arrangements, please acknowledge your agreement by signing and returning to us a copy of this proposal.

If you have any questions, please do not hesitate to call Stephen Payne (416) 525-1762. We are delighted to have the opportunity to be of service and assure you that this engagement will be given our closest attention.

Accepted on behalf of Innisfil Hydro Distribution Systems Limited:

Innisfil Hydro Distribution Systems Limited	BDO CANADA LLP
Name LA Cooledge	Name CHRIS JOHNSEN
Signature	Signature
Title CFO/Treasurer	Title PARTNER
Date April 20/10	Date April 20, 2010

Innisfil Hydro Distribution Systems Limited

Proposal for SRS Report Design Services

To: **Lori Shirley**
20733 Commerce Park Drive
Innisfil, ON, L9S 4A2
705-431-6870 x226
loris@innisfilhyrdo.ca

From: **Les Wright, Senior Consultant**
512 Woolwich Street
Guelph, Ontario, N1H 3X7
519-589-0782
lwright@bdo.ca

BDO

Table of Contents

BDO

October 28, 2010

Innisfil Hydro Distribution Systems Limited
20733 Commerce Park Drive
Innisfil, ON, L9S 4A2

Attention: Lori Shirley

Dear Lori,

We appreciate the opportunity to submit our proposal to assist Innisfil Hydro Distribution Systems Limited with the design of SRS Reports for Microsoft Dynamics GP \ WennSoft. The following agreement outlines the assistance we can provide to help you achieve your goals. Please review the details to understand our methodology, fees and terms of business.

We want our relationship to go beyond client/consultant and to become your partner in helping achieve your business objectives. Our goal will be to deliver value in everything we do. We welcome the opportunity to demonstrate our abilities, commitment and enthusiasm.

We are excited about the prospect of working with Innisfil Hydro on this important engagement and look forward to discussing our agreement in further detail. If there is any clarification or additional information you require, please do not hesitate to contact Les Wright at 519-589-0782.

Yours truly,

BDO Canada LLP

Chris Johnsen, CMC, CMA
Partner

BDO

Our Understanding

Based on our discussions we understand Innisfil Hydro requires the following:

- Design of the following SRS reports:
  - Budget Indicator Report (a & b)
  - Deposit Report
  - Trued Up Deposit Report - Open Jobs
  - Trued Up Deposit Report - Closed Jobs
  - Recoverable Status Report
  - Capital Detail
  - Payroll Report
- The ability to export the above SRS reports to Excel for further analysis.
- Modifications/corrections made to stored procedures used as data sources for existing Crystal Reports. Details on these issues can be found under each report's 'Current Data Issues' section.

Note: The SRS reports will be designed to achieve clean exportability into Excel (i.e. minimal columns and rows); however, there are limits to how SRS reports will export to Excel and BDO cannot guarantee these results. In some cases, separate SRS reports may have to be created to summarize data in different ways (as you currently have in some Crystal Reports) in order to achieve clean exportability. In particular, SRS reports created with sub-reports do not export to Excel. Please review the Excel Exportability notes on each report below for more information.

SRS Report Design Details

The following tables summarize the key details relating to the SRS Reports to be designed. Samples of each report layout can be found in Appendix A.

Report 1a	**Budget Indicator Report* (Project Selection by Project Range)**
Business Reason	To understand difference between CAR and BASE jobs for budgeting/forecasting.
Current Crystal Report.rpt file	Budget Indicator Report for Capital Jobs.rpt
Sample	See Excel document and existing report.
Data Source	_usp_sel_BDO_JC_BudgetIndicator,1
Parameters	1) Date Range (Post Dated) 2) Open (Active/Inactive), Closed, All 3) Date Range (Posted Date) 4) Project Range
Data Notes	
Grouping	1) UserDefined1 (CAR/BASE) 2) Project Number 3) Job Number 4) GL Account

BDO

	5) Cost Code
Summarizing/Totaling	GrandTotal - Regular SubReport - Summary of all by UserDefined1 (CAR/BASE/Unassigned) SubReport - GrantTotal
Current Data Issues	Summarized Totals not summarized properly (accounts show up multiple times)
Other Notes	Need to add Cost Code column - To Report - Group - Summarized Totals This is intended to also replace Jobs by Project report.
Excel Exportability Notes	3 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summary Report by UserDefined1 (CAR/BASE/Unassigned) 3) Summary Report by GrantTotal

Report 1b	**Budget Indicator Report* (Project Selection by Discontinuous Projects)**
Business Reason	To understand difference between CAR and BASE jobs for budgeting/forecasting.
Current Crystal Report.rpt file	Budget Indicator Report for Capital Jobs.rpt
Sample	See Excel document and existing report.
Data Source	_usp_sel_BDO_JC_BudgetIndicator,1
Parameters	1) Date Range (Post Dated) 2) Open (Active/Inactive), Closed, All 3) Date Range (Posted Date) 4) Project (Discontinuous Projects)
Data Notes	
Grouping	1) UserDefined1 (CAR/BASE) 2) Project Number 3) Job Number 4) GL Account 5) Cost Code
Summarizing/Totaling	GrandTotal - Regular SubReport - Summary of all by UserDefined1 (CAR/BASE/Unassigned) SubReport - GrantTotal
Current Data Issues	Summarized Totals not summarized properly (accounts show up multiple times)
Other Notes	Need to add Cost Code column - To Report

BDO

	- Group - Summarized Totals This is intended to also replace Jobs by Project report. The discontinuous projects selected need to be reported back in a list somewhere on the report.
Excel Exportability Notes	3 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summary Report by UserDefined1 (CAR/BASE/Unassigned) 3) Summary Report by GrantTotal

Report 2	**Deposit Report**
Business Reason	Keeping track of cost to date against lay out deposits.
Current Crystal Report.rpt file	Deposit Report.rpt
Sample	See Excel document and existing report.
Data Source	Sp_BDO_JC_DepositReport, 1
Parameters	1)Payment Document Date (Post Dated) - leave at 1900-01-01, never changed 2) Job Transaction Date Filter
Data Notes	Only open jobs on this report, but not marked trued up or permanently recorded (Extender Field).
Grouping	1) RM Document Date (Doc Date) 2) Layout Number (Extender Field) 3) Customer/Project
Summarizing/Totaling	GrandTotal - Regular Summary of Debit/Credit showing GL (hard coded GL Account) and credit to 1995 accounts.
Current Data Issues	Sept Deposit, not costs = shows on Sept report. Oct costs posted, Sept rerun = doesn't show on Sept reprinted report. Oct report is fine.
Other Notes	1) Look at deposits for customers with Extender Project & Layout attached 2) Summarize above by customer, project and layout ID 3) For summarized values, use older deposit date 4) Cost Recorded Life to Date = LTD costs from WS 5) GL Accounts correspond to Contribution accounts. GL Account will be replaced with Cost Codes. A new list will be provided by

BDO

	Innisfil with cost codes and 1995 GL accounts. 6) Contribution Amount - Case 1: LTD Costs =< Deposit Amount, then contribution = LTD costs - Case 2: LTD Costs > Deposit Amount, Prorate LTD job cost by Deposit Amount 7) Outstanding Layout Balance = Deposit - Contribution (if neg, then 0) Other: All deposits should show on the report from the deposit date on until the job is closed (even if null records or $0 costs). Multiple deposits will show summarized amount as of original deposit date.
Excel Exportability Notes	2 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summary Report for Summary of Debit/Credit showing GL (hard coded GL Account) and credit to 1995 accounts.

Report 3	**Trued Up Deposit Report - Open Jobs**
Business Reason	Assist with completed, but unbilled jobs. Once engineering has completed the job, it is inactive and trued up, so no further costs can go on it. If job given OEB allowance, project Extender field marked 'trued up' and OEB allowance value populated.
Current Crystal Report.rpt file	Trued Up - Open Jobs.rpt
Sample	See Excel document and existing report.
Data Source	Sp_BDO_JC_DepositReportOpen,1
Parameters	1) Payment Document Date (Post Dated) - leave at 1900-01-01, never changed 2) Job Transaction Date Filter 3) Architect ID (= 2010 Trued Up) 4) Permanently Recorded (= No) 5) GST/HST
Data Notes	Only open jobs on this report that are marked trued up (Extender Field).
Grouping	1) RM Document Date (Doc Date) 2) Layout Number (Extender Field) 3) Customer/Project
Summarizing/Totaling	GrandTotal - Regular Summary of Debit/Credit showing GL (hard coded

BDO

	GL Account) and credit to 1995 accounts. Refer to existing Crystal Report.
Current Data Issues	OEB allowance (Extender field) not being picked up. OS Layout Balance should be added.
Other Notes	1) Look at deposits for customers with Extender Project & Layout attached 2) Summarize above by customer, project and layout ID 3) For summarized values, use older deposit date 4) Cost Recorded Life to Date = LTD costs from WS 5) GL Accounts correspond to Contribution accounts. GL Account will be replaced with Cost Codes. A new list will be provided by Innisfil with cost codes and 1995 GL accounts. 6) OEB uses 1995 accounts above. OEB allowance is not factored into Contribution on open report (only on closed report). 7) Contribution Amount - Case 1: LTD Costs =< Deposit Amount, then contribution = LTD costs - Case 2: LTD Costs > Deposit Amount, Prorate LTD job cost by Deposit Amount 8) Add: Outstanding Layout Balance = Deposit - Contribution (if neg, then 0) 9) Invoice to Customer = Cost LTD 10) Customer Invoice/Refund = Invoice to Customer - OEB Allowance - Deposit 11) HST @ 13% (be able to change value on field) 12) Total with Tax Other: All deposits should show on the report from the deposit date on until the job is closed (even if null records or $0 costs). Multiple deposits will show summarized amount as of original deposit date.
Excel Exportability Notes	2 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summary Report for Summary of Debit/Credit showing GL (hard coded GL Account) and credit to 1995 accounts.

BDO

Report 4	Trued Up Deposit Report - Closed Jobs
Business Reason	To show for the year what has been recognized as contributed capital. Only run for billed/closed jobs.
Current Crystal Report.rpt file	Trued Up - Closed Jobs.rpt
Sample	See Excel document and existing report.
Data Source	Sp_BDO_JC_DepositReportClosed,1
Parameters	1) Payment Document Date (Post Dated) - leave at 1900-01-01, never changed 2) Job Transaction Date Filter 3) Architect ID (= 2010 Trued Up) 4) Permanently Recorded (= Yes)
Data Notes	Only closed jobs on this report.
Grouping	1) RM Document Date (Doc Date) 2) Layout Number (Extender Field) 3) Customer/Project
Summarizing/Totaling	GrandTotal - Regular Summary of 1995 accounts. Refer to existing Crystal Report.
Current Data Issues	OEB allowance (Extender field) not being picked up. OS Layout Balance should be added.
Other Notes	1) Look at deposits for customers with Extender Project & Layout attached 2) Summarize above by customer, project and layout ID 3) For summarized values, use older deposit date 4) Cost Recorded Life to Date = LTD costs from WS 5) GL Accounts correspond to Contribution accounts. GL Account will be replaced with Cost Codes. A new list will be provided by Innisfil with cost codes and 1995 GL accounts. 6) OEB uses 1995 accounts above. OEB allowance is not factored into Contribution on open report (only on closed report). 7) Contribution Amount - All Cases: LTD Costs - OEB Allowance =< Deposit Amount, then contribution = LTD costs - OEB Allowance Other: All deposits should show on the report from the deposit date on if the job is closed (even if null records or $0 costs). Multiple deposits will show summarized amount as of original deposit date.

BDO

Excel Exportability Notes	2 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summary Report for Summary of 1995 accounts.

Report 5	**Recoverable Status Report**
Business Reason	Recoverable, but no mark up for billing. Job Name has .88 in it.
Current Crystal Report.rpt file	88Job Listing.rpt and Job Recoverable AC Reconciliation.rpt*
Sample	See Excel document and existing reports.
Data Source	JC00102 JC30001 JCTRNALL
Parameters	1) As at date 2) 88 vs 99
Data Notes	Only open jobs.
Grouping	1) Grouped by job
Summarizing/Totaling	GrandTotal - Regular
Current Data Issues	None.
Other Notes	JC00102.User_Define1 = "88" / "99" Only 99 gets marked up, with journal entry info.
Excel Exportability Notes	1 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total

Report 6	**Capital Detail**
Business Reason	For variance reporting at the cost code level for finished fixed assets.
Current FRx Report Catalogue	Unknown
Sample	See Excel document and existing FRx report.
Data Source	Cost Code Actual Budget (from Extender, still to be defined) Prior Year data will also come from Cost Codes (which causes a 'data problem' during the transition from old to new Cost Code structure Note: A new stored procedure will have to be created to facilitate this reports ability to Export to Excel. Otherwise, the use of sub-reports to pair actual transaction data with budgeted amounts at either cost code or project level would restrict the reports exportability.

BDO

Parameters	1) Pick a month end date (month to date)
Data Notes	Need to filter out old format cost codes (segment = blank or null).
Grouping	1) Grouped by Cost Code
Summarizing/Totaling	Grand Total - Regular Summarized by main OEB (from Cost Code) Summarized by Cost Element (from Cost Code)
Current Data Issues	n/a
Other Notes	Budget and prior year for full month. Discussed difficulty with prior year data under old cost code format, as not comparable to new cost format. Discussed brining in both Cost Code and GL accounts for this version of the report. An alternate version of the report can be scoped and proposed, if required.
Excel Exportability Notes	3 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total 2) Summarized by main OEB (from Cost Code) 3) Summarized by Cost Element (from Cost Code)

Report 7	**Payroll Report**
Business Reason	For detailed reporting on employee hours and job cost posted amounts based per job over a time period. The number of jobs on this report (columns) will be dynamic.
Current Crystal Report.rpt file	n/a
Sample	See Excel document.
Data Source	WennSoft TimeCard data and possibly Employee Master/Department
Parameters	1) Date Range (Post Date) 2) Department or Division (To Be Determined)
Data Notes	Jobs in columns is dynamic based on date range selected.
Grouping	1) By Employee
Summarizing/Totaling	Grand Total - Regular
Current Data Issues	
Other Notes	
Excel Exportability Notes	1 versions of this report will be required in order to facilitate export to Excel: 1) Detail Report with Regular Grand Total

BDO

Professional Fees Estimate

This professional fees summary is an estimate only, based on the information we currently have.

Professional Services	Estimated Days
Project Planning • Meeting to determine the scope for the project.	Completed
Project Management • Manage and coordinate efforts for engagement tasks.	1.0
SRS Report Design - Report 1: Budget Indicator Report (a & b, all 6 versions) • Design, deploy and test all versions of this report using the existing unmodified stored procedure currently used.	3.0
SRS Report Design - Report 2: Deposit Report (2 versions) • Creation and testing of new stored procedure (sproc), Sp_BDO_JC_SRSDepositReport, to meet the data requirements scoped. [2.0 days] • Design, deploy and test both versions of this report using the new stored procedure. [2.0 days]	4.0
SRS Report Design - Report 3: Trued Up Deposit Report - Open Jobs (2 versions) • Creation and testing of new stored procedure (sproc), Sp_BDO_JC_SRSDepositReportOpen, to meet the data requirements scoped. [2.0 days] • Design, deploy and test both versions of this report using the new stored procedure. [2.0 days]	4.0
SRS Report Design - Report 4: Trued Up Deposit Report - Closed Jobs (2 versions) • Creation and testing of new stored procedure (sproc), Sp_BDO_JC_SRSDepositReportClosed, to meet the data requirements scoped. [2.0 days] • Design, deploy and test both versions of this report using the new stored procedure. [2.0 days]	4.0
SRS Report Design - Report 5: Recoverable Status Report (1 version)	1.5

BDO

• Design, deploy and test both versions of this report using the existing SQL tables and views currently used.	
SRS Report Design - Report 6: Capital Detail (3 versions) • Creation and testing of new stored procedure (sproc), Sp_BDO_JC_SRSCapitalDetail, to meet the data requirements scoped. ***Note: This stored procedure be created until the relevant Extender window is created.*** [5.0 days] • Design, deploy and test all versions of this report using the new stored procedure. [3.0 days]	8.0
SRS Report Design - Report 7: Payroll Report (1 version) • Further report scoping and planning to determine exactly what data is required on this report. [0.5 days] ***Note: If the data and/or number of columns changes from the sample in Appendix A, then a change order may be required.*** • Planning and mapping the data required for this report. [0.5 days] • Design, deploy and test both versions of this report using existing SQL tables and views. [2.0 days]	3.0
Training • Training on running SRS Reports and exporting to Excel	0.5
Total Estimate	**25.0**

Notes:
In an effort to minimize the testing required by BDO, Innisfil Hydro will also be required to test reports and to submit cases where potential issues are identified in order to most efficiently resolve any potential data and/or SRS report issues.

The following are additional out of scope services not included in the above estimate:

- Any modifications or revisions to SRS report scope detailed within this proposal
- Any creation or modification or SRS security and/or security relating to SRS data source configuration
- Post Go-Live Support

BDO

Terms and Conditions

Pricing Confirmation

The terms outlined in this agreement are valid until August 31, 2010.

Fees

Description	*Price (CAD)*
Professional Services Estimate	33,750.00

- Implementation services have been estimated using a daily rate of $1,350/day and based on a 7.5 hour day.
- This is a fixed fee engagement.

Disbursements

Costs that are billed separately from professional services include:

- Out-of-pocket expenses associated with this engagement such as mileage, tolls, parking, and telecommunications.
- Local Travel charges will include the mileage reimbursement paid to the consultant.
- 4% of total professional fees for project lifecycle administration.

Taxes

All costs referred to in this quotation are subject to relevant taxes.

Payment Terms

Professional Services

- We will invoice Innisfil Hydro for this fixed fee project as follows:
  - ½ upon acceptance and
  - ½ upon completion of the services proposed.
- Our terms of business are net 10 days.
- Overdue accounts are subject to a 2% interest charge per month.

AUTOMATED SOLUTIONS International Inc.

Professional Services Order

DATE	March 30, 2010
PROJECT	IHD1001 - MSGP/Topobase Integration
CUSTOMER	Innisfil Hydro Distribution Systems Ltd.
LOCATION	2073 Commerce Park Dr., Innisfil, ON L9S 4A2
TERM	
PRICE	1.1 - $28,500. a) $9,000 b) $13,800 c) $5,700 1.2 - $ 5,400.

ACCEPTED: $33,900 Total Contract

Automated Solutions International Inc. ("ASI")	**Innisfil Hydro Distribution Systems Ltd. ("Customer")**
Signature	Signature
Printed Name	L A Cooledge Printed Name
Title	CFO / Treasurer Title
Date	June 4/10 Date

To accept this services order, please sign 2 original documents and send to the following:

Automated Solutions International Inc.
380 Jamieson Pkwy., Unit 1
Cambridge, Ontario N3C 4N4
T 519.220.0071 F 519.220.0061
Attention: Peter Krotky

One fully executed copy will be sent to the customer at the following address:
Innisfil Hydro Distribution Systems Ltd.
2073 Commerce Park Dr.
Innisfil ON L9S 4A2
T 705.431.6870 x 236 F 705.431.5901
Attention: Laurie Ann Cooledge

CUSTOMER ACKNOWLEDGES HAVING RECEIVED A COPY OF THE STATEMENT OF WORK ("SOW") AND THAT THE CUSTOMER HAS READ ALL THE TERMS AND CONDITIONS LISTED IN THE DESCRIPTION OF PROFESSIONAL SERVICES ATTACHED HERETO AND AGREES THAT SUCH TERMS AND CONDITIONS SHALL BE INCORPORATED AS PART OF SOW.

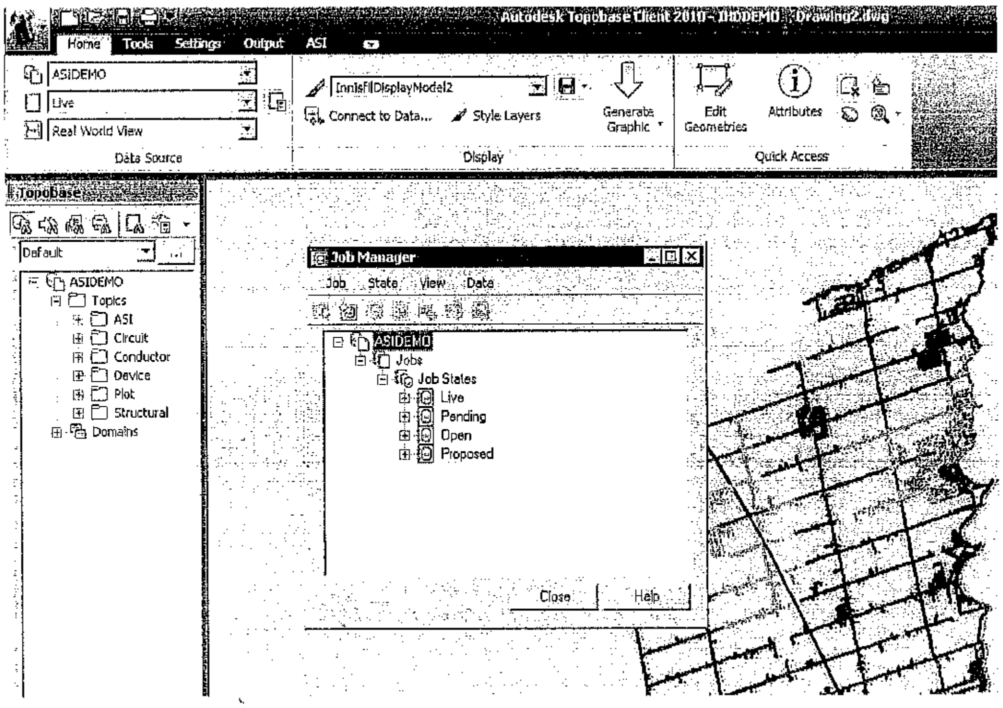
1.0 PROJECT SCOPE

The purpose of this implementation is to provide integration between MSGP and Topobase to support the requirements for IFRS reporting and disposal of assets. The tasks included in this Scope of Work (SOW) include the following deliverables:

1.1 MSGP – Topobase Integration

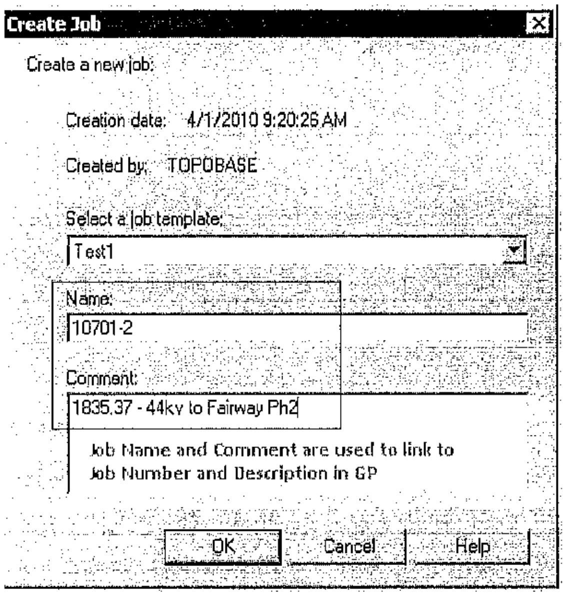
1.1.1 Deliverables

- Implement and configure Topobase Jobs function

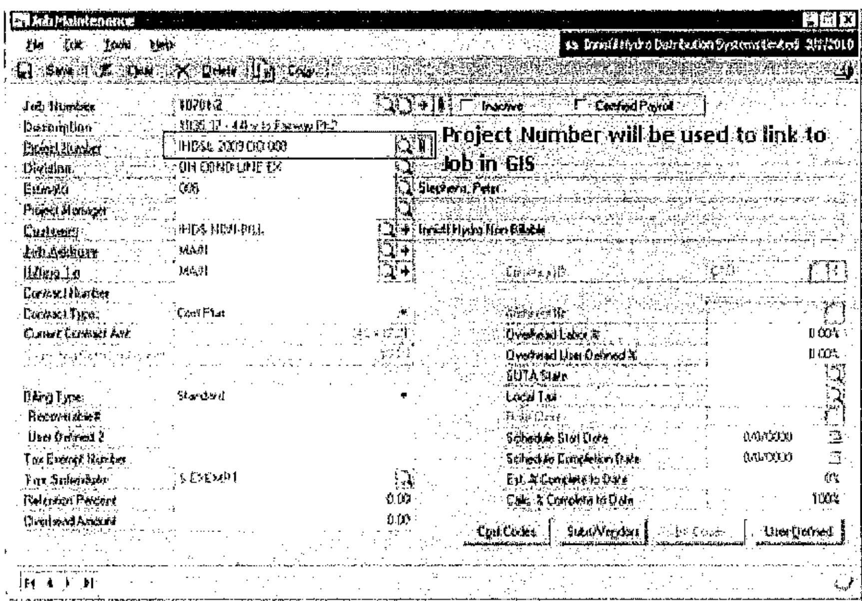


IHD1001 - MSGP/Topobase Integration

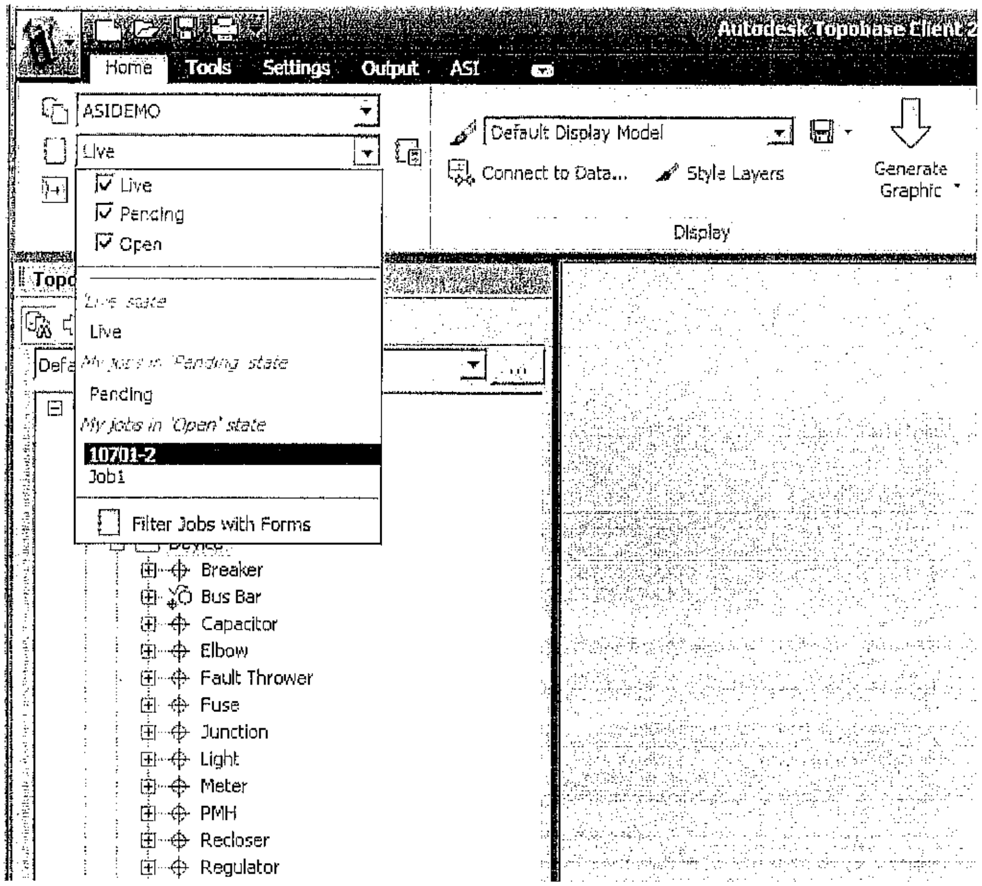
- Update Topobase forms to include required Job data from MSGP



- Workflow logic to determine/synchronize when a job is closed in both Topobase and MSGP – this will act as the "trigger" for the "data exchange"
- Tag "major" assets in Topobase with Job data from GP (poles, transformers, reclosers, etc)



- Topobase Retirement Report, indicating assets removed from the system and their associated installation project ID
- On-site implementation, validation and training of Topobase Jobs



1.1.2 Assumptions

The process for associating the Project data from MSGP to Topobase is a "single-shot" event. This means, any changes to this relationship requires the user to delete and re-associate..

1.2 goOutage Reconfiguration

The implementation of the IFRS integration will affect the current goOutage functionality. This will need to be modified to ensure co-existence of the two.

The IFRS implementation requires the enabling of Topobase Jobs.

When jobs are enabled, any data that is to be edited must be contained within a Job.

Topobase Jobs affects all tables in the Topobase structure including Outage tables. Work has to be done to separate goOutage from the TopoBase data structure to work with a Topobase Job enabled database.

EX 9 APPENDIX 3 REF 9.0-STAFF-104s

Stranded Meters Calculation:

Input cells are yellow

Capital Cost	$ 1,697,156			
Accumulated Depreciation (to 31-Dec-2011)	$ 1,281,252			
2012 Depreciation	$ 42,532			
2013 Depreciation	$ 14,177			
Net Book Value:	**$ 359,195**	**$ 334,627**	**Staff IR 104**	

Net Book Value Segregated by Rate Class:	**Residential**	**GS <50 kW**	**Total**	
	$ 262,781	$ 71,846	**$ 334,627**	
Allocated Weighting Based on Stranded Meters	78.5%	21.5%	**100%**	
Number of Metered Customers:	14189	910	**15,099**	Number of meters by class stranded
Rate Rider to Recover Stranded Meter Costs:	**$ 0.77**	**$ 3.29**		
Recovery period (years):	**2**	**2**		

	Recovery period:				
Years:	**1 Year**	**2 Year**	**3 Year**	**4 Year**	**Defer**
Months:	*12*	*24*	*36*	*48*	*0*
Residential	$ 1.54	$ 0.77	$ 0.51	$ 0.39	0
GS <50kW	$ 6.58	$ 3.29	$ 2.19	$ 1.65	0