INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

EB-2012-0139

RESPONSE TO INTERROGATORIES

February 13, 2013

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SUMMARY OF CHANGES

IHDSL Overview of Changes for IRR for EB-2012-0139

IHDSL filed EB-2012-0139 on September 13, 2013. At the time of submission, the primary elements of IHDSL's bridge and test year were the capital components to build IHDSL's new facilities/operations headquarters by December 2013.

By the close of 2012 it became evident that the completion of the IHDSL's new corporate headquarters would not be completed in 2013. As such, IHDSL has removed the capital request for the new facility in 2013 and respectfully submits a modified 2013 capital plan. To support the modified capital plan IHDSL also submits the associated Fixed Asset Continuity and Depreciation & Amortization Expense schedules.

With respect to IHDSL's new facilities/operations headquarters IHDSL will submit an ICM – Incremental Capital Mechanism in conjunction with IHDSL's 2014 IRM. At the time of IHDSL IRR submission the estimated completed date for IHDSL's facilities/operations headquarters is now August 2014.

Capital Updates for 2012 and 2013

With the removal of the IHDSL's new facilities/operations headquarters from the capital work plan, IHDSL respectfully submits revised capital work plans.

IHDSL has presented the revised 2013 capital work plan to the Board of Directors to on January 21, 2013. The Board of Directors has approved the proposed changes with Resolution # 13-5.

The following tables identify the removals and additions to the previously submitted capital work plan schedules.

IHDSL has recorded the updates to the capital work plan in the Summary of Proposed Cumulative Changes in OEB Staff IR-5 and has updated the RRWF with the applicable changes.

Removals from EB-2012-0139 Capital Work Plan

Year	CAR #	Description	Gross Asset	Contribution	Net Asset	GL Account
2012	GO-010	New Building	(2,000,000)		(2,000,000)	1908
2012	DO-015	County Relocates IBR & 20th S.R.	(153,420)	55,171	(98,249)	1830
			(147,924)	65,112	(82,812)	1835
			(4,860)	2,150	(2,710)	1850
			(8,105)	-	(8,105)	1856
2012	DO-019	Urbanization 1 Pole Relocate Finish	(139,300)	34,740	(104,560)	1830
			(66,400)	16,560	(49,840)	1835
			(600)	150	(450)	1850
2012	DO-020	Urbanization 2A Lighting carry over	(258,000)	258,000	-	1845
2012	DO-021	Cookstown water main relocates	(19,700)	7,400	(12,300)	1830
			(12,050)	4,330	(7,720)	1835
2013	GB-001	Network infrastructure in new building	(87,500)		(87,500)	1908
2013	GB-002	Security for new building	(5,000)		(5,000)	1908
2013	GO-002	standup inside forklift	(30,000)		(30,000)	1930
2013	GO-010	New Building	(5,000,000)		(5,000,000)	1908
			(7,932,859)	**443,613**	**(7,489,246)**	

Additions from EB-2012-0139 Capital Work Plan

Year	CAR #	Description	Gross Asset	Contribution	Net Asset	GL Account
2013	DO-012	BBPT Line Ext. for BBPT Dev.& New 27.6kV	221,084		221,084	1830
		Substation	237,029		237,029	1835
			12,410		12,410	1845
2013	DO-013	Land Purchase for Lefroy 44-27.6kV Substation	450,000	(250,000)	200,000	1805
2013	DO-014	3 Ph. 27.6kV Conductoring 20th btwn.5th & 7th	68,713		68,713	1830
			215,770		215,770	1835
			5,632		5,632	1850
2013	DO-015	3 Ph. 44kV Repoling-reconductoring	157,196		157,196	1830
		20th btwn.6th & 7th	90,404		90,404	1835
			8,950		8,950	1850
2013	DO-011	County Relocate - 20th S.R. & IBR	292,720	(87,546)	205,174	1830
			214,224	(82,987)	131,237	1835
			6,260	(2,450)	3,810	1850
			8,105	-	8,105	1856
2012		WIP	1,075,000		1,075,000	2055
2013		WIP	4,000,000		4,000,000	2055
			7,063,497	**(422,983)**	**6,640,514**	

Updated Fixed Asset Continuity Schedules

IHDSL has updated the Fixed Asset Continuity Statements (from the Board Chapter 2 Appendices) based on the updated capital work plans for 2012 and 2013.

Table 1.1 Fixed Asset Continuity Schedule 2012 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	-$ 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					
		Total		**$ 54,353,342**	**$ 4,792,175**	**-$ 317,646**	**$ 58,827,871**	**-$ 28,293,279**	**-$ 2,171,755**	**$ 266,170**	**-$ 30,198,864**	**$ 27,554,007**

10		Transportation
8		Stores Equipment

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

Table 1.2 Fixed Asset Continuity Schedule 2012 MIFRS

				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

Table 1.3 Fixed Asset Continuity Schedule 2013 MIFRS

			Cost				Accumulated Depreciation				
OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)		$ 645,749	$ 278,500		$ 924,249	-$ 352,902	-$ 174,811		-$ 527,713	$ 396,536
1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
1805	Land		$ 738,770	$ 200,000		$ 938,770	$ -			$ -	$ 938,770
1806	Land Rights		$ 982,703			$ 982,703	-$ 572,858	-$ 14,575		-$ 587,433	$ 395,270
1808	Buildings		$ -			$ -	$ -			$ -	$ -
1810	Leasehold Improvements		$ 86,252			$ 86,252	-$ 37,812	-$ 3,312		-$ 41,124	$ 45,128
1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV		$ 4,394,009	$ 194,422		$ 4,588,431	-$ 2,413,754	-$ 93,752		-$ 2,507,506	$ 2,080,925
1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
1830	Poles, Towers & Fixtures		$ 9,837,491	$ 1,657,866	-$ 105,000	$ 11,390,357	-$ 4,385,195	-$ 211,514	$ 89,250	-$ 4,507,459	$ 6,882,898
1835	Overhead Conductors & Devices		$ 14,130,821	$ 1,880,970	-$ 157,500	$ 15,854,291	-$ 7,494,973	-$ 170,292	$ 133,875	-$ 7,531,390	$ 8,322,901
1840	Underground Conduit		$ 2,072,771	$ 38,205		$ 2,110,976	-$ 536,511	-$ 49,686		-$ 586,197	$ 1,524,779
1845	Underground Conductors & Devices		$ 11,867,856	$ 169,983	-$ 52,500	$ 11,985,339	-$ 4,609,384	-$ 317,451	$ 44,625	-$ 4,882,210	$ 7,103,129
1850	Line Transformers		$ 9,132,436	$ 670,342	-$ 10,500	$ 9,792,278	-$ 5,786,022	-$ 221,701	$ 8,925	-$ 5,998,798	$ 3,793,480
1855	Services (Overhead & Underground)		$ 4,216,436	$ 225,017		$ 4,441,453	-$ 1,836,830	-$ 83,893		-$ 1,920,722	$ 2,520,731
1860	Meters		$ 287,258			$ 287,258	-$ 78,526	-$ 11,490		-$ 90,016	$ 197,242
1860	Meters (Smart Meters)		$ 2,236,521	$ 116,170		$ 2,352,691	-$ 474,117	-$ 152,968		-$ 627,085	$ 1,725,606
1875	Street Lighting		$ -			$ -	$ -			$ -	$ -
1905	Land		$ 201,049			$ 201,049	$ -			$ -	$ 201,049
1908	Buildings & Fixtures		$ 764,631	$ 35,000		$ 799,631	-$ 302,778	-$ 29,466		-$ 332,244	$ 467,387
1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)		$ 334,155	$ 35,000		$ 369,155	-$ 245,184	-$ 15,561		-$ 260,745	$ 108,410
1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware		$ 637,806	$ 128,000		$ 765,806	-$ 462,746	-$ 75,182		-$ 537,928	$ 227,878
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment		$ 1,174,196	$ 80,000		$ 1,254,196	-$ 619,934	-$ 167,800		-$ 787,734	$ 466,462
1935	Stores Equipment		$ 35,824	$ 4,200		$ 40,024	-$ 20,126	-$ 2,364		-$ 22,490	$ 17,534
1940	Tools, Shop & Garage Equipment		$ 514,684	$ 20,000		$ 534,684	-$ 220,349	-$ 34,462		-$ 254,811	$ 279,873
1945	Measurement & Testing Equipment		$ 41,497	$ 19,000		$ 60,497	-$ 16,857	-$ 4,006		-$ 20,863	$ 39,634
1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment		$ 1,775,243	$ 266,697		$ 2,041,940	-$ 886,326	-$ 118,418		-$ 1,004,744	$ 1,037,196
1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants		-$ 8,355,287	-$ 555,506		-$ 8,910,793	$ 1,790,548	$ 237,924		$ 2,028,472	-$ 6,882,321
etc.			$ -			$ -				$ -	$ -
	WIP		$ 1,075,000	$ 4,000,000		$ 5,075,000				$ -	$ 5,075,000
	Total		**$ 58,827,871**	**$ 9,463,866**	**-$ 325,500**	**$ 67,966,237**	**-$ 29,562,634**	**-$ 1,714,781**	**$ 276,675**	**-$ 31,000,740**	**$ 36,965,497**

	Transportation
	Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 167,800
Stranded Meters	
Net Depreciation	-$ 1,546,981

Updated Depreciation and Amortization Expense Schedules

IHDSL has updated the Depreciation and Amortization Expense Schedules (from the Board Chapter 2 Appendices) based on the updated capital work plans for 2012 and 2013.

Table 1.4 Depreciation and Amortization Expense Schedule 2012 GCAAP

Appendix 2-CF
Depreciation and Amortization Expense
Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)		Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 363,599	$ 162,914	-$ 660,571	$ 200,685	$ 282,150	$ 341,760	3.00	33.33%	$ 113,920.00	$ 113,920.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ 273,770	$ -	$ -	$ 273,770	$ 465,000	$ 506,270	-	0.00%	$ -	$ -	$ -
1806	Land rights	$ 982,703	$ 239,103	$ 8,449	$ 743,600	$ -	$ 743,600	50.00	2.00%	$ 14,872.00	$ 14,872.00	$ 0.00
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ 86,252	$ 3,452	$ 3,452	$ 82,800	$ -	$ 82,800	25.00	4.00%	$ 3,312.00	$ 3,312.00	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,358,561	$ 1,353,335	-$ 23,664	$ 3,005,226	$ 35,448	$ 3,022,950	25.00	4.00%	$ 120,918.00	$ 120,918.00	$ -
1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,077,888	$ 726,325	$ 626,640	$ 8,351,564	$ 859,603	$ 8,781,365	25.00	4.00%	$ 351,254.60	$ 351,254.60	$ -
1835	Overhead Conductors & Devices	$13,192,946	$ 6,253,571	$ 734,767	$ 6,939,376	$1,087,875	$ 7,483,313	25.00	4.00%	$ 299,332.52	$ 299,332.52	$ -
1840	Underground Conduit	$ 2,035,571	$ 297,546	$ 184,991	$ 1,738,025	$ 37,200	$ 1,756,625	25.00	4.00%	$ 70,265.00	$ 70,265.00	-$ 0.00
1845	Underground Conductors & Devices	$11,721,156	$ 546,406	$ 499,861	$ 11,174,750	$ 196,700	$ 11,273,100	25.00	4.00%	$ 450,924.00	$ 450,924.00	$ 0.00
1850	Line Transformers	$ 8,602,786	$ 609,566	$ 556,561	$ 7,993,220	$ 539,650	$ 8,263,045	25.00	4.00%	$ 330,521.80	$ 330,521.80	$ -
1855	Services (Overhead & Underground)	$ 4,017,136	$ 309,264	$ 307,036	$ 3,707,873	$ 199,300	$ 3,807,523	25.00	4.00%	$ 152,300.90	$ 152,300.90	$ -
1860	Meters	$ 287,258	$ -	$ -	$ 287,258	$ -	$ 287,258	25.00	4.00%	$ 11,490.32	$ 11,490.32	$ -
1860	Meters (Smart Meters)	$ 2,162,281	$ -	$ -	$ 2,162,281	$ 74,240	$ 2,199,401	15.00	6.67%	$ 146,626.73	$ 146,621.68	$ 5.05
1875	Street Lighting	$ 7,646	$ 7,646	$ 7,646	$ -	$ -	$ -	25.00	4.00%	$ -	$ -	$ -
1905	Land	$ 201,049	$ -	$ -	$ 201,049	$ -	$ 201,049	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 739,631	$ 30,481	$ 30,481	$ 709,150	$ 25,000	$ 721,650	25.00	4.00%	$ 28,866.00	$ 28,866.00	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 308,655	$ 196,045	$ 44,658	$ 112,610	$ 25,500	$ 125,360	10.00	10.00%	$ 12,536.00	$ 12,536.00	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 515,306	$ 263,231	-$ 301,927	$ 252,075	$ 122,500	$ 313,325	5.00	20.00%	$ 62,665.00	$ 62,665.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 1,174,196		$ -	$ 1,174,196	$ -	$ 1,174,196	7.35	13.61%	$ 159,754.56	$ 159,800.00	-$ 45.44
1935	Stores Equipment	$ 31,824	$ 14,284	$ 2,803	$ 17,540	$ 4,000	$ 19,540	10.00	10.00%	$ 1,954.00	$ 1,954.00	$ -
1940	Tools, Shop & Garage Equipment	$ 487,684	$ 180,064	$ 23,255	$ 307,620	$ 27,000	$ 321,120	10.00	10.00%	$ 32,112.00	$ 32,112.00	$ -
1945	Measurement & Testing Equipment	$ 32,997	$ 10,937	$ 7,094	$ 22,060	$ 8,500	$ 26,310	10.00	10.00%	$ 2,631.00	$ 2,631.00	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,407,393	$ 132,313	$ 132,313	$ 1,275,080	$ 367,850	$ 1,459,005	15.00	6.67%	$ 97,267.00	$ 97,267.00	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 7,714,946	-$ 739,898	-$ 551,331	-$ 6,975,048	-$ 640,341	-$ 7,295,219	25.00	4.00%	-$ 291,808.74	-$ 291,808.74	$ -
etc.					$ -		$ -		0.00%	$ -		$ -
					$ -		$ -		0.00%	$ -		$ -
	Total	$54,353,342	$ 10,596,583		$ 43,756,759	$3,717,175	$ 45,615,346			$2,171,714.70	$ 2,171,755.08	-$ 40.38
	Original Submission	$54,353,342	$ 10,566,102		$ 43,787,240	$6,083,921	$ 46,829,200			$2,220,268.86	$ 2,179,090.00	$ 41,178.86

Table 1.5 Depreciation and Amortization Expense Schedule 2012 MIFRS

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year **2012** **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 119,195	$ 282,150	1.78	3.00	33.33%	$ 66,895	$ 47,025	$ 113,920	$ 113,920	-$ 0	$ 94,050	$ 32,550	$ 128,395
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 273,770	$ 465,000			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land rights	$ 424,717	$ -	28.56	50.00	2.00%	$ 14,872	$ -	$ 14,872	$ 14,872	$ 0	$ -	$ 297	$ 14,575
1808	Buildings	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ 51,752	$ -	15.63	25.00	4.00%	$ 3,312	$ -	$ 3,312	$ 3,312	$ 0	$ -		$ 3,312
1815	Transformer Station Equipment >50 kV	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 2,035,685	$ 35,448	22.51	40.00	2.50%	$ 90,435	$ 443	$ 90,878	$ 90,878	-$ 0	$ 886		$ 91,321
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 4,791,235	$ 859,603	27.54	45.00	2.22%	$ 173,990	$ 9,551	$ 183,541	$ 183,542	-$ 0	$ 19,102		$ 193,092
1835	Overhead Conductors & Devices	$ 5,716,025	$ 1,087,875	41.88	60.00	1.67%	$ 136,486	$ 9,066	$ 145,551	$ 145,552	-$ 0	$ 18,131		$ 154,617
1840	Underground Conduit	$ 1,547,804	$ 37,200	32.06	40.00	2.50%	$ 48,279	$ 465	$ 48,744	$ 48,744	$ 0	$ 930		$ 49,209
1845	Underground Conductors & Devices	$ 7,382,140	$ 196,700	23.78	40.00	2.50%	$ 310,409	$ 2,459	$ 312,868	$ 312,868	$ 0	$ 4,918		$ 315,327
1850	Line Transformers	$ 3,014,840	$ 539,650	15.09	40.00	2.50%	$ 199,830	$ 6,746	$ 206,576	$ 206,576	$ 0	$ 13,491		$ 213,322
1855	Services (Overhead & Underground)	$ 2,259,956	$ 199,300	29.09	50.00	2.00%	$ 77,677	$ 1,993	$ 79,670	$ 79,650	$ 20	$ 3,986		$ 81,663
1860	Meters	$ 220,222	$ -	19.17	25.00	4.00%	$ 11,490	$ -	$ 11,490	$ 11,490	-$ 0	$ -		$ 11,490
1860	Meters (Smart Meters)	$ 1,834,786	$ 74,240	12.73	15.00	6.67%	$ 144,147	$ 2,475	$ 146,621	$ 146,622	-$ 0	$ 4,949		$ 149,096
1875	Street Lighting	$ 4,976	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1905	Land	$ 201,049	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 465,719	$ 25,000	16.28	50.00	2.00%	$ 28,616	$ 250	$ 28,866	$ 28,866	-$ 0	$ 500		$ 29,116
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 76,007	$ 25,500	6.75	10.00	10.00%	$ 11,261	$ 1,275	$ 12,536	$ 12,536	$ 0	$ 2,550		$ 13,811
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 115,225	$ 122,500	2.29	5.00	20.00%	$ 50,415	$ 12,250	$ 62,665	$ 62,665	-$ 0	$ 24,500	$ 12,533	$ 62,382
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 714,062	$ -	4.47	5.00	20.00%	$ 159,800	$ -	$ 159,800	$ 159,800	$ 0	$ -		$ 159,800
1935	Stores Equipment	$ 13,652	$ 4,000	7.79	10.00	10.00%	$ 1,754	$ 200	$ 1,954	$ 1,954	-$ 0	$ 400		$ 2,154
1940	Tools, Shop & Garage Equipment	$ 299,447	$ 27,000	9.73	10.00	10.00%	$ 30,762	$ 1,350	$ 32,112	$ 32,112	$ 0	$ 2,700		$ 33,462
1945	Measurement & Testing Equipment	$ 18,771	$ 8,500	8.51	10.00	10.00%	$ 2,206	$ 425	$ 2,631	$ 2,631	-$ 0	$ 850		$ 3,056
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 618,334	$ 367,850	7.27	15.00	6.67%	$ 85,005	$ 12,262	$ 97,267	$ 97,267	-$ 0	$ 24,523		$ 109,528
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 6,144,728	-$ 640,341	29.28	35.00	2.86%	-$ 209,897	-$ 9,148	-$ 219,045	-$ 220,330	$ 1,286	-$ 18,295		-$ 228,192
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 26,054,641	$ 3,717,175				$ 1,437,744	$ 99,086	$ 1,536,831	$ 1,535,525	$ 1,306	$ 198,172	$ 45,380	$ 1,590,535
	Original Submission	$ 26,054,641	$ 4,083,921				$ 1,437,744	$ 101,481	$ 1,539,226	$ 1,539,226	$ 0	$ 202,961	$ 45,380	$ 1,595,325

Table 1.6 Depreciation and Amortization Expense Schedule 2013 MIFRS

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	278,500	3.00	33.33%	$ 174,811	$ 174,811	$ 0
1612	Land Rights (Formally known as Account 1906)	-	-	0.00%	$ -	$ -	$ -
1805	Land	200,000	-	0.00%	$ -	$ -	$ -
1806	Land rights	-	-	0.00%	$ 14,575	$ 14,575	$ 0
1808	Buildings	-	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	-	25.00	4.00%	$ 3,312	$ 3,312	$ 0
1815	Transformer Station Equipment >50 kV	-	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	194,422	40.00	2.50%	$ 93,751	$ 93,752	-$ 1
1825	Storage Battery Equipment	-	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	1,657,866	45.00	2.22%	$ 211,513	$ 211,514	-$ 1
1835	Overhead Conductors & Devices	1,880,970	60.00	1.67%	$ 170,292	$ 170,292	-$ 0
1840	Underground Conduit	38,205	40.00	2.50%	$ 49,687	$ 49,686	$ 1
1845	Underground Conductors & Devices	169,983	40.00	2.50%	$ 317,452	$ 317,451	$ 1
1850	Line Transformers	670,342	40.00	2.50%	$ 221,701	$ 221,701	-$ 0
1855	Services (Overhead & Underground)	225,017	50.45	1.98%	$ 83,893	$ 83,893	$ 0
1860	Meters	-	25.00	4.00%	$ 11,490	$ 11,490	$ 0
1860	Meters (Smart Meters)	116,170	15.00	6.67%	$ 152,968	$ 152,968	$ 0
1875	Street Lighting	-	-	0.00%	$ -	$ -	$ -
1905	Land	-	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	35,000	50.00	2.00%	$ 29,466	$ 29,466	-$ 0
1910	Leasehold Improvements	-	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	35,000	10.00	10.00%	$ 15,561	$ 15,561	$ 0
1915	Office Furniture & Equipment (5 years)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	128,000	5.00	20.00%	$ 75,182	$ 75,182	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	80,000	5.00	20.00%	$ 167,800	$ 167,800	$ 0
1935	Stores Equipment	4,200	10.00	10.00%	$ 2,364	$ 2,364	-$ 0
1940	Tools, Shop & Garage Equipment	20,000	10.00	10.00%	$ 34,462	$ 34,462	$ 0
1945	Measurement & Testing Equipment	19,000	10.00	10.00%	$ 4,006	$ 4,006	-$ 0
1950	Power Operated Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	-	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	-	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	-	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	266,697	15.00	6.67%	$ 118,418	$ 118,418	$ 0
1985	Miscellaneous Fixed Assets	-	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	- 555,506	28.54	3.50%	-$ 237,923	-$ 237,924	$ 0
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$ 5,463,866			$ 1,714,781	$ 1,714,781	-$ 0
	Depreciation expense adjustment resulting from amortization of Account 1575				-$ 159,966.00		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,554,815**		

GENERAL

1.0-OEB Staff-1 – Responses to Letters of Comment

Following publication of the Notice of Application, the Board received one letter of comment. Please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information except for the name is redacted. If not confirmed, please explain why a response was not sent and confirm if the applicant intends to respond.

IHDSL Response:

At the time of this IRR response IHDSL has investigated and can confirm that no letter of comment has been received following the publication of the Notice of Application. As no letter of comment has been received by IHDSL, no response has been generated.

1.0-OEB Staff-2 – Conditions of Service (CoS)

a) Please identify any rates and charges that are included in the applicant's conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

IHDSL Response:

IHDSL confirms that there are no rates and/or charges included in the conditions of service that do not appear on the Board approved tariff sheet.

b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2009 and the revenue forecasted for the 2012 bridge and 2013 test years.

IHDSL Response:

IHDSL has not provided a schedule outlining revenues as there were no rates and/or charges collected that were not on the Board approved tariff sheet.

c) Please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

IHDSL Response:

Not applicable based on the response to b) above.

1.0-OEB Staff-3 – Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

IHDSL Response:

IHDSL has enclosed a proposed list of changes in response to various interrogatories. The proposed list of changes reconciles to the amounts as submitted in the updated RRWF.

IHDSL has provided the updated RRWF in the Exhibit 1 Appendices –Ex1 Appendix A IR Ref OEB Staff-3.

1.0-OEB Staff-4 – Updated Appendix 2-2, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

IHDSL Response:

IHDSL has updated the Bill Impacts on the completion of all interrogatories. Appendix 2-W has been filed electronically as IHDSL_IR Revised Bill Impacts_20130213.xlsm.

The table summarizing the changes in bill impacts as a result of the interrogatories is located in the Exhibit 1 appendices – Ex1 Appendix 1 IR Ref OEB Staff-4.

1.0-OEB Staff-5 – Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

IHDSL Response:

IHDSL has enclosed a Summary of Proposed Changes resulting from the responses to all 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
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
Computer Hardward s/b CCA								(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
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
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
Rate of return updated to 8.93% from 9.12%		-$25,766	-0.19%					-$4,727		-$30,493	-$30,493	-$30,493
IR#		$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
Description & amount												
IR#		$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
Description & amount												
IR#		$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
Description & amount												
Proposed at		**$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**
Change - Proposed vs. Original		**-13%**		**-11%**	**0%**	**0%**	**-4%**	**41%**	**0%**	**-3%**	**-3%**	**-40%**
		-$175,610		**-$4,107,551**	**$0**	**$0**	**-$64,973**	**$10,667**	**$0**	**-$301,668**	**-$301,668**	**-$301,668**

1-SEC-1

Please confirm that there are 14 schools in the applicant's franchise area and please advise the number of schools in each of the GS <50 and GS>50 classes.

IHDSL Response:

IHDSL does not confirm that there are 14 schools in our franchise area. IHDSL can confirm nine schools in our franchise area, of which eight are in the GS >50 class and one is in the GS<50 class. IHDSL also confirms one private school in our franchise area which is in the GS<50 class.

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1.0 – Energy Probe #1

Ref: Exhibit 1, Tab 1, Schedule 3

At pages 2 and 3, IHDSL submits that a debt ceiling of 60% is not sustainable for high growth LDCs like IHDSL and requests that the debt ceiling be raised to 75%.

Please indicate what specific request IHDSL is making regarding the deemed capital structure for the 2013 test year. If IHDSL is not requesting a change in the deemed capital structure, what specific request is IHDSL making?

IHDSL Response:

IHDSL has a service territory that is 292 sq. Km currently designated as rural (low population density) that is transitioning to an urban territory (high density population). IHDSL's long term growth plan speaks to the future growth and infrastructure requirements that will be required to enable this transition.

IHDSL is required to connect new customers and to undertake economic evaluations for new developments. Economic evaluation payments for new growth need to be paid up-front by IHDSL which are then paid back by those customers over a 20 year period. LDCs are required to outlay up-front capital requirements and get reimbursed over the life of the asset. The aforementioned increases IHDSL's requirement to borrow thus impacting the current 60% debt ceiling. IHDSL's long term financial plan indicates that the 60% debt ceiling will be breached in the near future and requests that the debt ceiling be raised to 75% throughout the transition to urban territory.

1.0-VECC

IHDSL states it held two public consultations (Rotary Club and Chamber of Commerce). Please provide a summary of the comments received at these meetings.

IHDSL Response:

IHDSL conducted the public consultations to obtain feedback on both IHDSL's long range plan and the preliminary impacts to rates with the COS application, especially with the impact of the new operations/facility headquarters.

The Innisfil Rotary Club and Innisfil Chamber of Commerce sessions were conducted in August and September, respectively, with approximately 22-25 people in attendance for each session.

After the presentation the following questions were put forth to the audience for comment. Comments/questions are summarized following the individual question.

1. *Are IHDSL's distribution rates reasonable?*

    - *Positive comments received that the distribution rates are reasonable based on the 4 year plan presented.*
    - *Confusion re the components of the bill that Innisfil Hydro directly impacts (distribution rates).*
    - *Significant improvement on outages, great job.*
    - *Why are there hydro vehicles other than Innisfil Hydro in our service area?*
    - *When will the Debt Retirement come off the bill?*
    - *When will the OCEB credit come off the bill?*
    - *What contributes to the loss factor?*

2. *Is IHDSL's capital plan reasonable to meet growth requirements?*

    - *Positive comments received; both consultations fully aware of Big Bay Point development and Innisfil/South Barrie identified as a growth area.*

3. *Is the new operations/facilities headquarter plan reasonable?*

    - *Required.*
    - *Existing building not very accessible*
    - *Colocation with the Town Campus will be a plus for the community.*

4. *Would it be reasonable for the four year rate application to be spread out over 4 years to smooth out the rate impact?*

- *Agreement.*
- *Why the spike in the first year after approval of the COS application.*

Overall feedback from both consultations was very positive in terms of IHDSL's long range plan and the proposed distribution rates resulting from EB-2012-0139.

1.0 - Energy Probe #2

Ref: Exhibit 1, Tab 1, Schedule 3

a) **Please explain why IHDSL did not prepare a 2013 COS application for rates effective January 1, 2013?**

IHDSL Response:

IHDSL did not prepare a 2013 COS Application for rates effective January 1, 2013 primarily due to resource restraints from projects that were underway in the Regulatory (EB-2011-0176, EB-2011-0435), Operations, Customer Service/IT and Finance departments.

b) **What would be the significant changes (if any) in the evidence that would be required for a test year that is equivalent to the calendar year?**

IHDSL Response:

IHDSL does not foresee any significant changes in the evidence that would be required for a test year that is equivalent to the calendar year. IHDSL recognizes that, due to the timeline changes, it may not be possible to include actual information on the bridge year at the time of filing. However, it is typically part of the interrogatory process to update bridge year data which could include actuals to June 30.

c) **What are the cost increases and/or cost savings (egg. simplified financial reporting) that IHDSL expects will occur as a result of moving to a calendar year fiscal year in 2014?**

IHDSL Response:

IHDSL does not foresee any cost savings and/or cost increases with aligning the fiscal and rate year. The initial implementation of the alignment will require a shifting of work priorities/activities to achieve but there will be no increased costs.

28.0-VECC

Reference: Exhibit 1, Tab 1, Schedule 3, pg. 3

a) **The evidence states that IHDSL may seek to raise its debt component to above the Board deemed 60%. Please clarify IHDSL's intent.**

IHDSL Response:

Please refer to the response provided in IR 1.0- Energy Probe #1.

1.0 – Energy Probe #3

Ref: Exhibit 1, Tab 1, Schedule 10

Please confirm that IHDSL will convert to IFRS on January 1, 2013. If this cannot be confirmed, please indicate when IHDSL will convert to IFRS.

IHDSL Response:

At the time of this IR response, IHDSL can confirm that we will not convert to IFRS on January 1, 2013. Following the IASB direction, IHDSL will take the deferral to January 1, 2014 for the full conversion to IFRS.

1.0 – Energy Probe #4

Ref: Exhibit 1, Tab 1, Schedule 13

What is the status of EB-2007-0031 and any Board recommendations as a result of it?

IHDSL Response:

IHDSL has undertaken the distribution rate classifications and rate design as mandated by the OEB.

2.0–VECC

Ref: Exhibit 1, Tab 1, Appendix D pg. 68 – Conditions of Service

a) **Please file Policies 6.0 (Security Deposit); Policy 6.2 (Billing and Payment); Policy 8.1 (Disconnection).**

IHDSL Response:

The requested policies are enclosed in the Exhibit 1 Appendices – Ex1 Appendix 2 IR Ref VECC-2a.

b) Are these policies available on IHDSL's website? If not please explain why not.

IHDSL Response:

Yes, the policies are posted on our website, under Publications – All. The link has been enclosed for your review.

http://www.innisfilhydro.com/Publications/AllPublications/tabid/214/Default.aspx

c) Has IHDSL implemented the Board's requirements for low-income energy consumers, including the security deposit provisions?

IHDSL Response:

IHDSL can confirm implementation of the Board's requirements for LEAP, including the security deposit provisions.

d) If not please explain why not. If yes, please explain how these policies and the availability of assistance are communicated to the public

IHDSL Response:

These policies are communicated to our customer base:

- *as part of our credit and collection procedures;*
- *through our Conservation programmes and community events , specifically the Home Assistance Program;*
- *stated on all notices of pending disconnection;*
- *verbally by our Customer Service Staff;*
- *via our 3rd party agency – United Way of Simcoe County and Barrie (Simcoe County) Housing;*
- *OEB brochure inserted in all customer bills in May, 2012; and*
- *on our website.*

1.0 Energy Probe #5

Ref: Exhibit 1, Tab 1, Schedule 15

Are any costs associated with the Board of Directors of Innisfil Energy Services Limited included in the revenue requirement of IHDSL? If yes, please quantify.

IHDSL Response:

There are no associated costs with the Board of Directors of Innisfil Energy Services Limited included in IHDSL's revenue requirement.

3.0-VECC

Ref: Exhibit 1, Tab 3, Schedule 1, Appendix E

a) **Please explain why under section 4 of the 2010 financial statement it lists Electrical Services billed to the Town of Innisfil as being $2,017,772, whereas in the 2011 statement it states that for 2010 the amount billed for this service was $1,862,558?**

   IHDSL Response:

   The note in Section 4 of the 2011 financial statements listing 2010 Electric services billed to the town are incorrectly stating $1,862,558, while the narrative correctly states the 2010 billed electricity is $2,017,772.

2.0-OEB Staff-24

Ref: Updated evidence filed Oct. 22, 2012, Exhibit 1, Tab 6, Schedule 5, Page 6

a) **Please reconcile the IFRS useful lives by UsoA provided in the application to the useful lives of the assets in the Kinetrics Study in which IHDSL has adhered to for 2012 and 2013.**

   IHDSL Response:

   The following table provides a comparison of capital asset useful lives for the OEB, Kinetrics Study and IHDSL.

USA Account # and Description	OEB Prescribed Useful life	Kinectics Study	IHDSL proposed useful life
1805 Land	NA	NA	NA
1806 Land Rights	50	50	50
1808 Buildings and Fixtures	50	50	50
1815 Station Equip (above 50kV)	25-40	30	30
1820 Station Equip (below 50kV)	25-30	40-50	40-50
1830 Poles, Towers, Fixtures	25	40-60	40-60
1835 OH Conductors & Devices	25	60	60
1840 Underground Conduit	25	50	50
1845 UG Conductors & Devices	25	40	40
1850 Line Transformers	25	40	40
1855 Services	25	40	40
1860 Meters	25	25-35	25
1860 Smart Meters	15	5-10	15
1905 Land	NA	NA	NA
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	5-15	10
1940 Tools, Shop & Garage Equip	10	5-10	10
1945 Measurement & Testing Equip	10	5-10	10
1980 System Supervisor Equip	15	20	15

4.0-VECC

Ref: Exhibit 1, Appendix H, pg. 3

a) **Innisfil Hydro has a negative free cash flow but continues to pay dividends. Please explain why this is a prudent financial policy and provide the financial analysis which supports this policy.**

IHDSL Response:

Appendix 1 of the Business Plan is the Innisfil Hydro - Rate Base, Debt, Equity and ROE analysis from 2009 to 2031. The long range analysis shows that a prudent mix between dividends and internally generated funds required for the acquisition of new assets is sustainable.

5.0-VECC

Ref: Exhibit 1, Appendix H, pg. 132 (3of9) - Review of Asset Management Plan

a) Have all the recommendations listed in section 3 of the Review of the Asset Plan been addressed? If not please identify which items were not addressed and why.

IHDSL Response:

The following two recommendations were not addressed:

1) *Item 3.1 i) recommended a minimum three year forecast with the test year and two subsequent years for capital expenditures. Innisfil Hydro chose to provide the full five year forecast without the test year or two subsequent years.*

2) *Item 3.1 iv) suggested documentation of maintenance practices within the Asset Management Plan. Innisfil Hydro does not feel the sheer volume of maintenance records should be attached to the plan. The maintenance records are available as required within software tracking systems.*

EXHIBIT 1 APPENDICES

Appendix Ex1 Appendix A IR OEB Staff 3 - RRWF

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		$1,387,015		$1,387,015	
3	Property Taxes	$12,500		$12,500		$12,500	
5	Income Taxes (Grossed up)	$25,788		$36,455		$36,455	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,119,814		$1,005,895		$1,005,895	
	Return on Deemed Equity	$1,386,640		$1,211,030		$1,211,030	
	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		$9,117,967		$9,117,967	
9	Revenue Offsets	$556,948		$556,948		$556,948	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$8,862,687		$8,561,019		$8,561,019	
11	Distribution revenue	$8,862,687		$8,561,019		$8,561,019	
12	Other revenue	$556,948		$556,948		$556,948	
13	**Total revenue**	$9,419,635		$9,117,967		$9,117,967	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$0	(1)	$0	(1)

Notes

(1) Line 11 - Line 8

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]

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$64,467,293		($4,145,239)	$ 60,322,054			$60,322,054	
	Accumulated Depreciation (average)	($30,319,374)	(5)	$37,687	($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			$ 24,238,088			$24,238,088	
	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		($301,668)	$8,561,019		$0	$8,561,019	
	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		$0	$222,633		$0	$222,633	
	Other Income and Deductions	$66,515		$0	$66,515		$0	$66,515	
	Total Revenue Offsets	$556,948	(7)	$0	$556,948		$0	$556,948	
	Operating Expenses:								
	OM+A Expenses	$5,465,072			$ 5,465,072			$5,465,072	
	Depreciation/Amortization	$1,451,988	(10)	($64,973)	$ 1,387,015			$1,387,015	
	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			$30,805			$30,805	
	Income taxes (grossed up)	$25,788			$36,455			$36,455	
	Federal tax (%)	11.00%			11.00%			11.00%	
	Provincial tax (%)	4.50%			4.50%			4.50%	
	Income Tax Credits				($32,000)			($32,000)	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	5.11%			5.15%			5.15%	
	Short-term debt Cost Rate (%)	2.08%			2.08%			2.08%	
	Common Equity Cost Rate (%)	9.12%			8.93%			8.93%	
	Prefered Shares Cost Rate (%)								
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($42,167)	(11)	$42,167	$ -	(11)	$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.

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)	$60,322,054	$ -	$60,322,054
2	Accumulated Depreciation (average)	(3)	($30,319,374)	$37,687	($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	$ -	$3,863,036	$ -	$3,863,036
5	**Total Rate Base**		$38,010,954	($4,107,552)	$33,903,403	$ -	$33,903,403

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		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	$ -	$24,238,088	$ -	$24,238,088
8	Working Capital Base		$29,715,660	$ -	$29,715,660	$ -	$29,715,660
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$3,863,036	$ -	$3,863,036	$ -	$3,863,036

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.

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	($301,668)	$8,561,019	$ -	$8,561,019
2	Other Revenue (1)	$556,948	$ -	$556,948	$ -	$556,948
3	Total Operating Revenues	$9,419,635	($301,668)	$9,117,967	$ -	$9,117,967
	Operating Expenses:					
4	OM+A Expenses	$5,465,072	$ -	$5,465,072	$ -	$5,465,072
5	Depreciation/Amortization	$1,451,988	($64,973)	$1,387,015	$ -	$1,387,015
6	Property taxes	$12,500	$ -	$12,500	$ -	$12,500
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$6,929,560	($64,973)	$6,864,587	$ -	$6,864,587
10	Deemed Interest Expense	$1,119,814	($113,919)	$1,005,895	$ -	$1,005,895
11	Total Expenses (lines 9 to 10)	$8,049,374	($178,892)	$7,870,482	$ -	$7,870,482
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	($164,943)	$1,247,485	$ -	$1,247,485
14	Income taxes (grossed-up)	$25,788	$10,667	$36,455	$ -	$36,455
15	**Utility net income**	$1,386,640	($175,610)	$1,211,030	$ -	$1,211,030

Notes

Other Revenues / Revenue Offsets

		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	$ -	$222,633	$ -	$222,633
	Other Income and Deductions	$66,515	$ -	$66,515	$ -	$66,515
	Total Revenue Offsets	$556,948	$ -	$556,948	$ -	$556,948

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	$1,211,030	$1,211,030
2	Adjustments required to arrive at taxable utility income	($1,246,052)	($805,837)	($805,837)
3	Taxable income	$140,588	$405,193	$405,193
	Calculation of Utility income Taxes			
4	Income taxes	$21,791	$30,805	$30,805
6	Total taxes	$21,791	$30,805	$30,805
7	Gross-up of Income Taxes	$3,997	$5,651	$5,651
8	Grossed-up Income Taxes	$25,788	$36,455	$36,455
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$25,788	$36,455	$36,455
10	Other tax Credits	$ -	($32,000)	($32,000)
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

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%	$18,985,906	5.15%	$977,688
2	Short-term Debt	4.00%	$1,356,136	2.08%	$28,208
3	**Total Debt**	60.00%	$20,342,042	4.94%	$1,005,895
	Equity				
4	Common Equity	40.00%	$13,561,361	8.93%	$1,211,030
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,561,361	8.93%	$1,211,030
7	**Total**	100.00%	$33,903,403	6.54%	$2,216,925
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$18,985,906	5.15%	$977,688
9	Short-term Debt	4.00%	$1,356,136	2.08%	$28,208
10	**Total Debt**	60.00%	$20,342,042	4.94%	$1,005,895
	Equity				
11	Common Equity	40.00%	$13,561,361	8.93%	$1,211,030
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$13,561,361	8.93%	$1,211,030
14	**Total**	100.00%	$33,903,403	6.54%	$2,216,925

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 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		$460,168		$460,168
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	$556,948	$556,948	$556,948	$556,948
4	**Total Revenue**	$8,657,799	$9,419,635	$8,657,799	$9,117,967	$8,657,799	$9,117,967
5	Operating Expenses	$6,929,560	$6,929,560	$6,864,587	$6,864,587	$6,864,587	$6,864,587
6	Deemed Interest Expense	$1,119,814	$1,119,814	$1,005,895	$1,005,895	$1,005,895	$1,005,895
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	$7,870,482	$7,870,482	$7,870,482	$7,870,482
9	**Utility Income Before Income Taxes**	$650,592	$1,412,428	$787,317	$1,247,485	$787,317	$1,247,485
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	($18,520)	$441,648	($18,520)	$441,648
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	($92,296)	$25,788	($2,871)	$68,455	($2,871)	$68,455
14	**Income Tax Credits**	$ -	$ -	($32,000)	($32,000)	($32,000)	($32,000)
15	**Utility Net Income**	$742,888	$1,386,640	$822,187	$1,211,030	$822,187	$1,211,030
16	**Utility Rate Base**	$38,010,954	$38,010,954	$33,903,403	$33,903,403	$33,903,403	$33,903,403
17	Deemed Equity Portion of Rate Base	$15,204,382	$15,204,382	$13,561,361	$13,561,361	$13,561,361	$13,561,361
18	Income/(Equity Portion of Rate Base)	4.89%	9.12%	6.06%	8.93%	6.06%	8.93%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.93%	8.93%	8.93%	8.93%
20	Deficiency/Sufficiency in Return on Equity	-4.23%	0.00%	-2.87%	0.00%	-2.87%	0.00%
21	Indicated Rate of Return	4.90%	6.59%	5.39%	6.54%	5.39%	6.54%
22	Requested Rate of Return on Rate Base	6.59%	6.59%	6.54%	6.54%	6.54%	6.54%
23	Deficiency/Sufficiency in Rate of Return	-1.69%	0.00%	-1.15%	0.00%	-1.15%	0.00%
24	Target Return on Equity	$1,386,640	$1,386,640	$1,211,030	$1,211,030	$1,211,030	$1,211,030
25	Revenue Deficiency/(Sufficiency)	$643,752	$ -	$388,842	$0	$388,842	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$761,836 **(1)**		$460,168 **(1)**		$460,168 **(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

Ex1 Appendix 1 IR Ref OEB Staff-4

Ex1 Appendix # IR Ref VECC 2a - COS Policies

CORNERSTONE HYDRO ELECTRIC CONCEPTS ASSOCIATION

POLICIES

CONDITIONS OF SERVICE

May 31, 2011

Table of Contents

6.0.1 PURPOSE:

This policy describes the terms and conditions distributors will use for collection, maintaining and returning customer security deposits while complying with the applicable legislation and codes.

6.0.2 POLICY STATEMENT:

A distributor will comply with the deposit requirements as defined in the Distribution System Code, Retail Settlement Code, Standard Supply Service Code, and the Distribution Rate Handbook but may waive these requirements in favor of a customer or potential customer.

6.0.3 MINIMUM REQUIREMENTS:

A distributor's security deposit policy shall include at a minimum the following:

- a list of all potential types/forms of security accepted;
- a detailed description of how the security is calculated;
- limits on the amount of security required;
- the planned frequency, process and timing of updating security;
- a description of how interest payable to customers is determined;
- criteria customer must meet to have security deposit waived and/or returned; and
- methods of enforcements where a security deposit is not paid *(Ref: DSC 2.4.6.1)*.

In managing customer non-payment risk, a distributor shall not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code *(Ref: DSC 2.4.6.2)*.

6.0.4 CRITERIA FOR WAIVER OR RETURN OF SECURITY DEPOSIT:

The distributor may require a security deposit from a customer who is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of:

- 1 year in the case of a residential customer,
- 5 years in the case of a non-residential customer in < 50 kW demand rate class, or
- 7 years in the case of a non-residential customer in any other rate class.

The time period that makes up the good payment history must be the most recent period of time and some of the time period must occur in the previous 24 months. A distributor shall provide a customer with the specific reasons for requiring a security deposit from the customer *(Ref: DSC 2.4.9)*.

A customer is deemed to have a good payment history, unless, during the relevant time period:

- the customer has received more than one disconnection notice from the distributor;
- more than one cheque given to the distributor by the customer has been returned for insufficient funds;
- more than one pre-authorized payment to the distributor has been returned for insufficient funds;
- a disconnection/collection trip has occurred; or
- a distributor had to apply a security deposit to the arrears on the account and required the customer to repay the security deposit.

If any of the preceding events occur due to an error by the distributor, the customer's good payment history shall not be affected *(Ref: DSC 2.4.10)*.

The distributor shall not require a security deposit where:

- the customer provides a letter from another electricity distributor or gas distributor in Canada confirming a good payment history with that distributor for the most recent relevant time period, where some of the time period which makes up the good payment history has occurred in the previous 24 months; or,
- a customer, other than a customer in a >5,000 kW demand rate class, that provides a satisfactory credit check made at the customer's expense *(Ref: DSC 2.4.11).*

6.0.5 METHOD OF CALCULATION AND LIMIT OF SECURITY DEPOSIT:

The maximum amount of the security deposit which a distributor may require a customer to pay shall be calculated in the following manner:

- The "***Billing Cycle Factor***" times the estimated bill based on the customer's average monthly consumption/load with the distributor in the most recent 12 consecutive months within the past two years; or
- Where relevant usage information is not available for the customer for 12 consecutive months within the past two years or the billing system is not capable of making the calculation, the customer's average monthly consumption/load shall be based on a reasonable estimate made by the distributor *(Ref: DSC 2.4.12)*.

Where a non-residential customer in any rate class other than a <50kW demand rate class has a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by the distributor shall be reduced in accordance with the following table *(Ref: DSC 2.4.13)*:

Credit Rating (Using Standard and Poor's Rating Terminology)	Allowable Reduction
AAA- and above or equivalent	100%
AA-, AA, AA+ or equivalent	95%
A-, A, A+ or equivalent	85%
BBB-, BBB, BBB+ or equivalent	75%
Below BBB- or equivalent	0%

For the purposes of calculating the estimated bill for a consumer who is billed under SSS or distributor consolidated billing and who is:

- a low-volume consumer or designated consumer, the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for distributors, low-volume consumers and designated consumers.
- other than a low-volume consumer or designated consumer, the price estimated used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for market participants other than distributors, low-volume consumers and designated customers *(Ref: DSC 2.4.14)*.

A distributor may in its discretion reduce the amount of a security deposit which it requires a customer to pay for any reason including where the customer pays under an interim payment arrangement and where the customer makes pre-authorized payments *(Ref: DSC 2.4.15)*.

The **"*Billing Cycle Factor*"** is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly *(Ref: DSC 2.4.16).*

Where a customer, other than a residential electricity customer, has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of the security deposit *(Ref: DSC 2.4.17)*.

6.0.6 FORM OF SECURITY DEPOSIT:

Residential – The form of payment of a security deposit for a residential customer shall be cash or cheque at the discretion of the customer or such other form as is acceptable to the distributor *(Ref: DSC 2.4.18)*.

The distributor shall permit a residential customer to pay the security deposit in equal instalments paid over a period not exceeding six (6) months, including where a new security deposit is required due to the distributor having applied the existing security deposit against amounts owing. The customer may elect to pay the security deposit over a shorter period of time *(Ref: DSC 2.4.20A)*.

General Service – The form of payment of a security deposit for a non-residential customer shall be cash, cheque or an automatically renewing, irrevocable letter of credit from a bank as defined in the *Bank Act 1991*, *c46*, at the discretion of the customer. The distributor may also accept other forms of security such as surety bonds and third party guarantees *(Ref: DSC 2.4.19)*.

The distributor shall permit a General Service customer to provide a security deposit in equal instalments paid over a period not exceeding four (4) months. A customer may, in its discretion, choose to pay the security deposit over a shorter period of time *(Ref: DSC 2.4.20).*

6.0.7 INTEREST PAYABLE:

Interest shall accrue monthly on security deposits made by way of cash or cheque commencing on receipt of the total deposit required by the distributor. The interest shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid out at least once every 12 months, on return or application of the security deposit, or closure of the account, whichever comes first, and may be paid by crediting the account of the customer or otherwise *(Ref: DSC 2.4.21)*.

6.0.8 PLANNED FREQUENCY, PROCESS AND TIMING OF UPDATING SECURITY DEPOSITS:

The distributor shall review every customer’s security deposit at least once every calendar year to determine whether the entire amount of the security deposit is to be returned to the customer or adjusted based on a re-calculation of the maximum amount of the security deposit *(Ref: DSC 2.4.22)*.

> **Residential Customer** – Where a residential customer has paid a security deposit in instalments, a distributor shall conduct a review of the customer’s security deposit in the calendar year following the first anniversary of the initial instalment and thereafter at the next review as required by this policy *(Ref: DSC 2.4.22A)*.

A customer may, no earlier than 12 months after payment of a security deposit or the making of a prior demand for a review, demand in writing that a distributor undertake a review to determine whether the entire amount of the security deposit is to be returned to the customer as the customer is now in a position that it would be exempt from paying a security deposit or whether the amount of the security deposit is to be adjusted based on a recalculation of the maximum amount of the security deposit *(Ref: DSC 2.4.23)*.

> **Residential Customer** – Where a residential customer has paid a security deposit in instalments, the customer shall not be entitled to request a review of the security deposit until 12 months after the first installment was paid *(Ref: DSC 2.4.23A)*.

Where the distributor determines in conducting a review that some or all of the security deposit is to be returned to the customer, the distributor shall promptly return this amount to the customer by crediting the customer's account or otherwise.

> **>5000kW** – In the case of a customer in a >5000 kW demand rate class, where the customer is now is a position that it would be exempt from paying a security deposit, the distributor is only required to return 50% of the security deposit held by the distributor.

Where the distributor determines in conducting a review that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time the customer's next regular bill comes due *(Ref: DSC 2.4.25)*.

> **Residential** – Where a residential electricity customer is required to adjust the security deposit upwards, a distributor shall permit the customer to pay the adjustment amount in equal installments paid over a period of at least 6 months. A customer may elect to pay the security deposit over a shorter period of time *(Ref: DSC 2.4.25A)*.

A distributor shall promptly return any security deposit received from the customer upon closure of the customer's account, subject to the distributor's right to use the security deposit to off-set other amounts owing by the customer to the distributor. The security deposit shall be returned within six weeks of the closure of an account *(Ref: DSC 2.4.26)*.

> **Residential** – A distributor shall not issue a disconnection notice to a residential customer for non-payment unless the distributor has first applied any security deposit held on account for the customer against any amounts owing at that time and the security deposit was insufficient to cover the total amount owing *(Ref: DSC 2.4.26A)*.
>
> **Residential** – Where a distributor applies all or part of a security deposit to off-set amounts owing by a residential customer, the distributor may request that the customer repay the amount of the security deposit that was so applied. The distributor shall allow the residential customer to repay the security deposit as per the requirements of this policy *(Ref: DSC 2.4.26B)*.

A distributor shall apply a security deposit to the final bill prior to the change in service where a customer changes from SSS to a competitive retailer that uses retailer-consolidated billing or a customer changes billing options from distributor-consolidated billing to split billing or retailer-consolidated billing. A distributor shall promptly return any remaining amount of the security deposit to the customer. A distributor shall not pay any portion of a customer's security deposit to a competitive retailer. Where a change is made from distributor-consolidated billing to split billing, a distributor may retain a portion of the security deposit amount that reflects the non-payment risk associated with the new billing option *(Ref: DSC 2.4.27)*.

Where all or part of a security deposit has been paid by a third party on behalf of a customer, the distributor shall return the amount of the security deposit paid by the third party, including interest, where applicable, to the third party. This obligation shall apply where and to the extent that:

- the third party paid all or part (as applicable) of the security deposit directly to the distributor;
- the third party has requested, at the time the security deposit was paid or within a reasonable time thereafter, that the distributor return all or part (as applicable) of the security deposit to it rather than to the customer; and
- there is not then any amount overdue for payment by the customer that the distributor is permitted by this Code to offset using the security deposit *(Ref: DSC 2.4.28)*.

6.0.9 METHOD OF ENFORCEMENT WHERE SECURITY DEPOSIT IS NOT PAID:

Failure to pay the security deposit as required will result in the immediate implementation of the distributor's Collection Policy which may lead to the discontinuation of electrical service.

6.0.10 RESPONSIBILITIES:

Distributor management is responsible for ensuring this policy is implemented and adhered to by the employees of the distributor.

6.2.1 PURPOSE:

This policy describes the terms and conditions distributors will use for billing and receiving payments on customer accounts while complying with the applicable legislation and codes.

6.2.2 POLICY STATEMENT:

A distributor will comply with the billing and payment of account requirements as defined in the Distribution System Code, Retail Settlement Code, Standard Supply Service Code, and the Distribution Rate Handbook.

6.2.3 BILLING:

A distributor shall include on each bill issued to a customer the date on which the bill is printed *(Ref: DSC 2.6.1)*.

A bill will be deemed to have been issued to a customer:

- if sent by mail, on the third day after the date on which the bill was printed by the distributor;
- if made available over the internet, on the date on which an e-mail is sent to the customer notifying the customer that the bill is available for viewing over the internet;
- if sent by e-mail, on the date on which the e-mail is sent; or
- if sent by more than one of the methods above, on whichever date of deemed issuance occurs last *(Ref: DSC 2.6.4)*.

Except as may be permitted or directed by the Ontario Energy Board, a distributor shall not include on or with a bill submitted to a standard supply service customer any marketing information or promotional materials of or relating to a third party and that relate to electricity supply *(Ref: SSS 2.6.3)*.

6.2.4 BILLING CYCLE:

The distributor may, at its option, render bills to its customers on either a monthly equal payment, monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service. Pro-rating of service and demand charges will be performed at the discretion of the Distributor.

Despite the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service, in managing customer non-payment risk a distributor may:

(a) bill a customer on a bi-weekly basis, if the value of that customer's electricity bill over 12 consecutive months falls between 51% and 100% of the distributor's approved distribution revenue requirement over that 12-month period; or
(b) bill a customer on a weekly basis, if the value of that customer's electricity bill over 12 consecutive months exceeds 100% of the distributor's approved distribution revenue requirement over that 12-month period.

For the purposes of determining whether this section applies in relation to a customer, a distributor may consider the value of the customer's electricity bill in the 12-month period preceding the coming into force of this section *(Ref: DSC 2.4.32)*.

A distributor shall not bill a customer on a bi-weekly or weekly basis unless the distributor has given the customer at least 42 days' notice before issuance of the first bi-weekly or weekly bill, as the case may be *(Ref: DSC 2.4.33)*.

Where a distributor is billing a customer on a bi-weekly, weekly or an alternatively negotiated arrangement, the distributor shall resume billing the customer in accordance with the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service if the value of that customer's annual electricity bill over 12 consecutive months falls below 51% of the distributor's distribution revenue over that 12-month period *(Ref: DSC 2.4.34)*.

Where a distributor is billing a customer on a weekly basis, the distributor shall bill the customer as follows if the value of that customer's annual electricity bill over 12 consecutive months falls between 51% and 100% of the distributor's distribution revenue over that 12-month period:

(a) in accordance with the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service; or
(b) on a bi-weekly or alternatively negotiated arrangement *(Ref: DSC 2.4.35)*.

Despite any other provision of this policy, a distributor that intends to bill or is billing a customer on a bi-weekly or weekly basis may, in lieu of such billing, negotiate alternative arrangements with the customer, including in relation to a lesser frequency of billing or in relation to the giving or retention of security deposits *(Ref: DSC 2.4.36)*.

6.2.5 EQUAL PAYMENT PLAN (SSS RESIDENTIAL CUSTOMERS ONLY):

A distributor shall offer an equal monthly payment plan option to all residential customers receiving standard supply service. The equal monthly payment plan option shall meet the minimum requirements as specified in the Standard Supply Service Code *(Ref: SSS 2.6.2)*.

6.2.6 PAYMENT:

Except as otherwise permitted by this policy, a distributor shall not treat a bill issued to a customer as unpaid, and shall not impose any late payment or other charges associated with non-payment, until a minimum payment period of 16 days from the date on which the bill was issued to the customer has passed. A distributor may provide for longer minimum payment periods, provided that any such longer minimum payment periods are documented in the distributor's Conditions of Service, Section 2.4.5 *(Ref: DSC 2.6.2, 2.6.3)*.

A distributor shall apply the following rules for purposes of determining the date on which payment of a bill has been received from a customer:

- if paid by mail, three days prior to the date on which the distributor receives the payment
- if paid at a financial institution or electronically, on the date on which the payment is acknowledged or recorded by the customer's financial institution or;
- if paid by credit card issued by a financial institution, on the date and at the time that the charge is accepted by the financial institution *(Ref: DSC 2.6.5)*.

Residential – Where a bill issued to a residential customer includes charges for goods or services other than electricity charges, a distributor shall allocate any payment made by the customer first to the electricity charges and then, if funds are remaining, to the charges for other goods or services *(Ref: DSC 2.6.6)*.

6.2.7 COMPUTATION OF TIME:

A distributor shall apply the following rules relating to the computation of time:

- where there is reference to a number of days between two events, the days shall be counted by excluding the day on which the first event happens and including the day on which the second event happens;
- where the time for doing an act expires on a day that is not a business day, the act may be done on the next day that is a business day;
- where an act, other than payment by a customer, occurs on a day that is not a business day, it shall be deemed to have occurred on the next business day;
- where an act, other than payment by a customer, occurs after 5:00 p.m., it shall be deemed to have occurred on the next business day; and
- receipt of a payment by a customer is effective on the date that the payment is made, including payments made after 5:00 p.m. *(Ref: DSC 2.6.7)*.

6.2.8 METHOD OF ENFORCEMENT WHERE PAYMENT IS NOT RECEIVED:

Failure to pay bills on the due date will result in the immediate implementation of the distributor's Collection Policy which may lead to the discontinuation of electrical service.

6.2.9 RESPONSIBILITIES:

Distributor management is responsible for ensuring this policy is implemented and adhered to by the employees of the distributor.

8.1.1 PURPOSE:

This policy describes the terms and conditions distributors will use when disconnecting and/or reconnecting the electrical service of a consumer while complying with the applicable legislation and codes.

8.1.2 POLICY STATEMENT:

A distributor will comply with the disconnection and reconnection requirements as defined in the Distribution System Code, Retail Settlement Code, Standard Supply Service Code, and the Distribution Rate Handbook.

8.1.3 GENERAL REQUIREMENTS:

The distributor shall have the right to limit or discontinue service without further notification to the customer for payment default, including default of payment arrangements, bankruptcy, receivership, or property foreclosure.

8.1.4 PLANNED INTERRUPTIONS

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

8.1.5 DISCONNECTION BY REQUEST:

Customers may make a written request (written, telephone, e-mail) to the distributor for temporary disconnection of electrical service. A distributor shall make every reasonable effort to respond promptly to a customer's request for disconnection. A charge for temporary disconnection and reconnection may apply.

8.1.6 DISCONNECTION WITH NOTIFICATION:

Prior to disconnecting a property for non-payment, a distributor shall provide to any person that, according to the distributor's Conditions of Service, receives notice of the disconnection:

- the Fire Safety Notice of the Office of the Fire Marshal; and
- any other public safety notices or information bulletins issued by public safety authorities and provided to the distributor, which provide information to consumers respecting dangers associated with the disconnection of electricity service *(Ref: DSC 4.2.1.1)*.

A distributor shall include a copy of the notices or bulletins referred to above along with any notice of disconnection that is left at the property at the time of actual disconnection for non-payment *(Ref: DSC 4.2.1.2)*.

A distributor that intends to disconnect, pursuant to section 31 of the Electricity Act, 1998, the property of a residential customer for non-payment shall send or deliver a disconnection notice to the customer that contains, at a minimum, the following information:

- the date on which the disconnection notice was printed by the distributor;
- the earliest and latest dates on which disconnection may occur;
- the amount that is then overdue for payment, including all applicable late payment and other charges associated with non-payment to that date;
- the amount of any approved service charge(s) that may apply if disconnection occurs, and the circumstances in which each of these charges is payable;
- the forms of payment that the customer may use to pay all amounts that are identified as overdue in the disconnection notice, which must at least include payment by credit card issued by a financial institution and any other method of payment that the distributor ordinarily accepts and which can be verified within the time period remaining before disconnection;
- the time period during which any given form of payment listed under paragraph (e) will be accepted by the distributor;
- that in order to avoid disconnection if the distributor attends at the customer's property to execute the disconnection, a customer will only be able to pay by credit card issued by a financial institution, unless the distributor, in its discretion, will accept other forms of payment at the time and sets out the other forms of payment in the disconnection notice;
- that a disconnection may take place whether or not the customer is at the premises;
- that where applicable, the disconnection may occur without attendance at the customer's premises;
- that a Vital Services By-Law may exist in the customer's community and that the customer should contact their local municipality for more information;
- that a Board- prescribed arrears management program and equal monthly payment plan option may be available to all residential customers, along with the contact information for the distributor where the customer can obtain further information; and
- any additional option(s) that the distributor chooses, in its discretion, to offer to the customer to avoid disconnection and the deadline for the customer to avail himself or herself of such option(s) *(Ref: DSC 4.2.2)*.

A distributor that sends or delivers to a customer a disconnection notice, pursuant to section 31(2) of the Electricity Act, 1998, for non-payment shall not include that notice in the same envelope as a bill or any other documentation emanating from the distributor *(Ref: DSC 4.2.2.1)*.

A distributor shall, at the request of a residential customer, send a copy of any disconnection notice issued to the customer for nonpayment to a third party designated by the customer for that purpose provided that the request is made no later than the last day of the applicable minimum notice period set out in the distributors Billing and Payment Policy. In such a case:

- the distributor shall notify the third party that the third party is not, unless otherwise agreed with the distributor, responsible for the payment of any charges for the provision of electricity service in relation to the customer's property; and
- the rules set out in the distributors Billing and Payment Policy shall apply, with such modifications as the context may require, for the purposes of determining the date of receipt of the disconnection notice by the third party *(Ref: DSC 4.2.2.2)*.

A customer may, at any time prior to disconnection, designate a third party to also receive any future notice of disconnection and the distributor shall send notice of disconnection to such third party *(Ref: DSC 4.2.2.2A)*.

A distributor shall accept electronic mail (e-mail) or telephone communications from the customer for purposes of disconnection and reconnection with respect to a designated third party *(Ref: DSC 4.2.2.2B)*.

A disconnection notice issued for non-payment shall expire on the date that is 11 days from the last day of the applicable minimum notice period referred to in this policy, determined in accordance with the rules set out in the distributors Billing and Payment Policy. A distributor may not thereafter disconnect the property of the customer for non-payment unless the distributor issues a new disconnection notice *(Ref: DSC 4.2.2.3)*.

A distributor shall make reasonable efforts to contact, in person or by telephone, a residential customer to whom the distributor has issued a disconnection notice for non-payment at least 48 hours prior to the scheduled date of disconnection. At that time, the distributor shall:

- advise the customer of the scheduled date for disconnection;
- advise the customer that a disconnection may take place whether or not the customer is at the premises;
- where applicable, advise the customer that the disconnection may occur without attendance at the customer's premises;
- advise that the customer has the option to pay amounts owing by credit card issued by a financial institution, in addition to other forms of payment that the distributor will accept at that time and which can be verified within the time period remaining before disconnection; and advise during what hours such payments may be made;

- advise the customer that, if the distributor attends at the customer's property to execute the disconnection, the customer will only be able to pay by credit card issued by a financial institution, unless the distributor, in its discretion, will accept other forms of payment at that time;
- advise the customer that a Board-prescribed standard arrears management program and equal monthly payment plan option may be available to all residential customers; the distributor must be prepared to enter into an arrears payment agreement at that time if the customer is eligible; and
- advise the customer of any additional option(s) that the distributor, in its discretion, wishes to offer to the customer to avoid disconnection *(Ref: DSC 4.2.2.4)*.

Where a distributor issues a disconnection notice for non-payment in respect of the disconnection of a multi-unit, master-metered building, the distributor shall post a copy of the disconnection notice in a conspicuous place on or in the building promptly after issuance of the notice *(Ref: DSC 4.2.2.5)*.

A distributor shall suspend any disconnection action for a period of 21 days from the date of notification by a registered charity, government agency or social service agency that it is assessing a residential customer for the purposes of determining whether the customer is eligible to receive bill payment assistance, provided such notification is made within 10 days from the date on which the disconnection notice is received by the customer. Where a residential customer had requested prior to the issuance of the disconnection notice that the distributor also provide a copy of any disconnection notice to a third party, the distributor shall suspend any disconnection action for a period of 21 days from the date of notification by the third party that he or she is attempting to arrange assistance with the bill payment, provided such notification is made within 10 days from the date on which the disconnection notice is received by the customer *(Ref: DSC 4.2.2.6)*.

Upon notification by a registered charity, government agency or social service agency that a customer is not eligible to receive bill payment assistance, or if another third party who was considering the provision of bill assistance decides not to proceed, the distributor may continue its disconnection process. Distributors will have up to 11 days to act on the previous disconnection notice and must make a further reasonable effort to contact the customer in accordance with prior to executing disconnection *(Ref: DSC 4.2.2.7)*.

A distributor shall not disconnect a customer for non-payment until the following minimum notice periods have elapsed.

- 60 days from the date on which the disconnection notice is received by the customer, in the case of a residential customer that has provided the distributor with documentation from a physician confirming that disconnection poses a risk of significant adverse effects on the physical health of the customer or on the physical health of the customer's spouse, dependent family member or other person that regularly resides with the customer; or
- 10 days from the date on which the disconnection notice is received, in all other cases *(Ref: DSC 4.2.3)*.

Receipt of disconnection notice is determined as follows:

- where a disconnection notice is sent by mail, the disconnection notice shall be deemed to have been received by the customer on the third business day after the date on which the notice was printed by the distributor;
- where a disconnection notice is delivered by personal service, the disconnection notice shall be deemed to have been received by the customer on the date of delivery;
- where a disconnection notice is delivered by being posted on the customer's property, the disconnection notice shall be deemed to have been received by the customer on the date of such posting;
- "spouse" has the meaning given to it in section 29 of the Family Law Act;
- "dependent family member" means a "dependent" as defined in section 29 of the Family Law Act and also includes a grandparent who, based on need, is financially dependent on the customer; and
- the distributor shall apply the rules relating to the computation of time set out in section 8.1.10 of this policy *(Ref: DSC 4.2.3.1)*.

8.1.7 DISCONNECTION WITHOUT NOTICE:

A distributor may disconnect without notice in accordance with a court order or for emergency, safety or system reliability reasons *(Ref: DSC 4.2.4)*.

8.1.8 PAYMENT TO AVOID DISCONNECTION:

Disconnection can be avoided if payment is made as follows:

(a) Where a distributor has issued a disconnection notice to a residential customer for non-payment, the distributor shall ensure it has the facilities or staff available to permit the customer to pay all amounts that are then overdue for payment by credit card issued by a financial institution. This payment option must be offered during the regular business hours of the distributor, from the time the disconnection notice is delivered to a residential customer until the time the distributor's staff attends at the customer's premises to execute the disconnection.

(b) Where a distributor attends at a customer's property to execute a disconnection, whether during or after the distributor's regular business hours, the distributor shall ensure it has the facilities or staff available at that time to permit the customer to pay all amounts that are then overdue for payment by credit card issued by a financial institution. The distributor may, in its discretion, also accept other forms of payment at the time of disconnection.

(c) Where a distributor was unsuccessful in its attempt to contact a residential customer 48 hours before the planned disconnection and the distributor intends to execute the disconnection by attendance at the customer's premises, the distributor shall make a reasonable attempt to communicate with the customer, with due regard for the safety and security of the distributor's personnel, if the customer is at the property, to advise that disconnection will be executed and that payment may be made by credit card issued by a financial institution *(Ref: DSC 4.2.5)*.

The physical process by which a distributor disconnects or reconnects shall reflect good utility practice and consider safety as a primary requirement *(Ref: DSC 4.2.5.1)*.

A distributor may recover from the customer responsible for the disconnection reasonable costs associated with disconnection, including overdue amounts payable by the customer. A distributor may recover from the customer responsible for the disconnection reasonable costs for repairs of the distributor's physical assets attached to the property in reconnecting the property *(Ref: DSC 4.2.5.2)*.

8.1.9 RECONNECTION:

The distributor shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Notwithstanding the distributor reserves the right to require, an Electrical Safety Authority inspection certificate at any time prior to reconnection at the expense of the customer.

The distributor shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

A distributor may recover from the person requesting the reconnection any Board approved reconnection charges *(Ref: DSC 4.2.5.3)*.

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within 2 business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrears payment agreement with the distributor referred to in Policy 7.3 *(Ref: DSC 7.10.1)*.

8.1.10 COMPUTATION OF TIME:

A distributor shall apply the following rules relating to the computation of time:

- where there is reference to a number of days between two events, the days shall be counted by excluding the day on which the first event happens and including the day on which the second event happens;
- where the time for doing an act expires on a day that is not a business day, the act may be done on the next day that is a business day;
- where an act, other than payment by a customer, occurs on a day that is not a business day, it shall be deemed to have occurred on the next business day;

- where an act, other than payment by a customer, occurs after 5:00 p.m., it shall be deemed to have occurred on the next business day; and
- receipt of a payment by a customer is effective on the date that the payment is made, including payments made after 5:00 p.m. *(Ref: DSC 2.6.7)*.

8.1.11 RESPONSIBILITIES:

Distributor management is responsible for ensuring this policy is implemented and adhered to by the employees of the distributor.

Policy 9.3 – ENVIRONMENTAL POLICY	**Version 7.0**
	Created: September 2002 *Latest Revision: May 2011*

9.3.1 PURPOSE:

This policy describes the terms and conditions distributors will follow regarding the privacy requirements while complying with the applicable legislation and codes.

9.3.2 POLICY STATEMENT:

A distributor will comply with the environmental requirements as defined in the Distribution System Code, Retail Settlement Code, Standard Supply Service Code, and the Distribution Rate Handbook.

9.3.3 GENERAL:

CHEC member distributors are committed to a cleaner, healthier environment. We resolve to conduct our business in an environmentally responsible way and are committed to leading the industry in minimizing the impact of its activities on the environment.

Key points to achieve this strategy are:

- Minimize waste by evaluating operations and ensuring they are as efficient as possible.
- Minimize toxic emissions through the selection and use of its fleet and the source of its power requirement.
- Actively promote recycling both internally and amongst its customers and suppliers.
- Meet or exceed all the environmental legislation that relates to the distributor.
- Measure its impact on the environment and set targets for ongoing improvement.

9.3.5 RESPONSIBILITIES:

Distributor management is responsible for ensuring this policy is implemented and adhered to by the employees of the distributor.

APPENDICES

REFERENCES:

- ***The Electricity Act, 1998*** – Service Ontario e-Laws,
  http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm

- ***Distribution System Code*** – The Ontario Energy Board,
  http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf

- ***Retail Settlement Code*** – The Ontario Energy Board,
  http://www.oeb.gov.on.ca/documents/cases/RP-1999-0032/code_231104.pdf

- ***Standard Supply Service Code*** – The Ontario Energy Board,
  http://www.oeb.gov.on.ca/documents/cases/EB-2004-0205/sssc/rpp_sssc_revised_20070917.pdf

- ***Electricity Distribution Rates Handbook*** – The Ontario Energy Board,
  http://www.ontla.on.ca/library/repository/mon/11000/254984.pdf

- ***Electricity Gas and Inspection Act*** – Government of Canada
  http://laws-lois.justice.gc.ca/eng/acts/E-4/index.html

- ***Market Rules*** – The Independent Electricity Market Operator
  http://www.ieso.ca/imoweb/pubs/marketRules/mr_marketRules.pdf

- ***Conditions of Service*** – The Distributor

GLOSSARY OF TERMS

"**Business Day**" means any day that is not a Saturday, a Sunday, or a legal holiday in the Province of Ontario;

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"**Connection**" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

("**Customer**", "**Consumer**", and "**SSS Customer**" will be understood herein as one and the same.)

"**Disconnection**" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

"**Disconnection/Collection Trip**" is a visit to a customer's premises by an employee or agent of the distributor to demand payment of an outstanding amount or to shut off or limit distribution of electricity of the customer failing payment.

"**Distributor-Consolidated Billing**" is when a retailer marketer who has signed contracts in the distributor service area and has opted for the distributor to do the billing and collection of the electricity commodity and all related non-competitive charges.

"Distribution System Code," means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

“Distributor” means a person who owns or operates a distribution system;

“**Electricity Charges**” are:

(a) charges that appear under the sub-headings “Electricity”, Delivery”, “Regulatory Charges” and “Debt Retirement Charge” as described in Ontario Regulation 275/04 (Information on Invoices to Low-volume Consumers of Electricity) made under the Act, and all applicable taxes on those charges;
(b) where applicable, charges prescribed by regulations under section 25.33 of the Electricity Act, 1998 and all applicable taxes on those charges; and
(c) Board-approved late payment fees, specific service charges and such other charges and applicable taxes associated with the consumption of electricity as may be designated by the Board for purposes of this section but not including security deposits.

“**Eligible Low-Income Customer**” means:

(a) a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service Agency or Government Agency; or
(b) a residential electricity customer who has been qualified for Emergency Financial Assistance;

“**Emergency Financial Assistance**” means any Board-approved emergency financial assistance program made available by a distributor to eligible low-income residential customers.

“**Errors and Omissions Excepted**” the distributor shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

“**General Service Customer**” – any customer who is not deemed to be a residential customer.

“Holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“**Late Payment Charge**” is an OEB approved interest charge that is applied after a specified date or a due date on a customer’s bill.

“**Licensed Competitive Retailer**” is a distributor that has a valid electricity retailer’s license from the Ontario Energy Board.

“**Load Control Device**” means a load limiter, timed load interrupter or similar device that limits or interrupts normal electricity service.

"**Load Limiter Device**" means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset.

"**Non-Competitive Charges**" is made up of the Wholesale Market Service charge, the Debt Retirement charge, Transmission Connection charge, Transmission Network charge and Distribution charges.

"Non-Payment Risk Mitigation" the distributor may use any risk mitigation options available to manage consumer non-payment risk.

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"**Residential Customer**" - the following customers shall be deemed to be residential customers:

- seasonal customers who are not classified as general service customers; and
- customers of a distributor with a farm rate class who have farms with a dwelling that is occupied as a residence continuously for at least 8 months of the year, where the customer has a < 50 kW demand.

"**Retail Customer**" means a person that has contracted with a company who retails electricity.

"**Retail Settlement Code**" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"**Retailer**" means a person who retails electricity;

"**Reconnection**" is when a property or premise has electrical service energized or re-established by the distributor.

"**Security Deposit**" is an amount collected by the distributor and is held by the distributor to ensure that all monies owed to the distributor are collected at the time of the final billing. Interest payments will be applied at least annually on all cash deposits.

"**Standard Supply Service Code**" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the manner in which a distributor must provide standard supply service to meet its obligation to sell electricity under section 29 of the Electricity Act or to give effect to rates determined by the Board under section 79.16 of the Act.

"**Social Service Agency or Government Agency**" means:

(a) a social service agency or government agency that partners with a given distributor to assess eligibility for Emergency Financial Assistance; or
(b) a social service agency or government agency that assesses eligibility for other energy financial assistance or low-income financial assistance programs, and partners with a given distributor to qualify customers for eligibility under these policies.

“**Standard Service Supply Customer**” is a company or person who purchases electricity at spot market price or statutory pricing from a distributor’s distribution system as a direct pass through from the IMO.

“**Timed Load Interrupter Device**” means a device that will completely interrupt the customer’s electricity intermittently for periods of time and allows full load capacity outside of the time periods that the electricity is interrupted.

EXHIBIT 2 – RATE BASE

2.0-OEB Staff-6 – Rate Base MIFRS

Ref: Exhibit 2/Tab 1/Schedule 1, p. 1, Table 2.1 and Table 2.2 and Exhibit 2/Tab 5/Sch 4, p. 3

a) Please update table 2.1 – Summary of Rate Base and table 2.2 – Summary of Working Capital to include a column showing the 2013 test year under MIFRS.

IHDSL Response:

IHDSL has updated the 2012 and 2013 column headings for tables 2.1 and 2.2. The column headings have been change to 2012 CGAAP/MIFRS and 2013 MIFRS. There are no other changes to tables.

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	$ 60,194,617	$ 68,814,969
Accumulated Depreciation	$ 26,893,025	$ 25,719,208	$ 27,555,404	$ 27,938,673	$ 29,566,335	$ 31,072,414
Net Book Value	$ 21,032,867	$ 19,710,876	$ 22,600,756	$ 24,330,471	$ 30,628,282	$ 37,742,555
Average Net Book Value	$ 19,436,442	$ 18,584,299	$ 21,155,816	$ 23,410,306	$ 27,386,569	$ 34,147,919
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	$ 31,728,141	$ 38,010,954

Table 2.2 - Summary of Working Capital

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP/MIFRS	2013 Test MIFRS
Cost of Power	$ 18,956,982	$ 18,877,111	$ 20,393,170	$ 21,570,056	$ 24,297,062	$ 24,238,088
Operations	$ 778,575	$ 694,257	$ 870,151	$ 947,441	$ 1,159,195	$ 1,423,862
Maintenance	$ 657,080	$ 544,761	$ 436,207	$ 528,872	$ 601,800	$ 713,650
Billing & Collecting	$ 1,010,600	$ 970,447	$ 922,742	$ 925,295	$ 955,500	$ 1,106,020
Community Relations	$ 11,700	$ 10,826.00	$ 9,114.00	$ 17,891.00	$ 18,400.00	$ 23,900.00
Administration & General Expense	$ 1,464,785	$ 1,476,113	$ 1,670,170	$ 1,743,770	$ 1,899,862	$ 2,197,640
Property Taxes	$ 10,600	$ 31,205	$ 21,943	$ 11,339	$ 12,000	$ 12,500
Working Capital	$ 22,890,322	$ 22,604,720	$ 24,323,497	$ 25,744,664	$ 28,943,819	$ 29,715,660

2.0-Energy Probe #6

Ref: Exhibit 2, Tab 1, Schedule 1, page 3 & Appendix 1

a) **Please explain why the purchase agreement price of $925,000 noted on page 3 does not include any value associated with the portables on the property noted in Appendix 1 of having a value of $36,000 to $40,000?**

IHDSL Response:

The existing site consists of three lots. Two lots will be sold and one will be kept as a substation/storage yard. The two portables will be relocated to the lot that is being kept.

b) **Why did IHDSL decide to sell the combined property for $925,000 when the estimated value shown in Appendix 1 would be $1,050,000 if the two properties would have been sold separately?**

IHDSL Response:

As the sale of property occurs between related parties, a third party appraisal was undertaken. The appraisal provided prices of the values of the two lots sold individually and one price for the value of the two lots sold together. Since the lots are to be sold together, the appropriate appraised value was used. A copy of the appraisal is located under Exhibit 2 Appendices – Ex2 Appendix 1 IR Ref Energy Probe-6b.

c) **Has the sale of the current property taken place? If not, when is the expected date of the sale? Is the property being sold to the town, an affiliate or to a third party?**

IHDSL Response:

The sale of the current property has not taken place. The purchase agreement has a closing in February 2014. The property is being sold to the Town of Innisfil.

A copy of the purchase agreement is enclosed in the Exhibit 2 Appendices – Ex2 Appendix 2 IR Ref Energy Probe-6b.

d) Does the purchase of the Old Town Hall site for $650,000 include the costs for demolition of the old building? If not, what is the cost associated with the demolition of the old building?

IHDSL Response:

The purchase of the Old Town Hall site for $650,000 does not include the costs for demolition of the old building. The cost associated with the demolition is approximately $125,000.

e) What is the status of the new site? Has the building been demolished?

IHDSL Response:

The new site is ready for construction. The building has been demolished.

f) When was construction of the new building started? Is it still on schedule to be completed by the end of 2013?

IHDSL Response:

Construction of the new building has not yet started. It will not be completed in 2013 and has been removed from the 2013 rate base. It is scheduled to be completed in 2014. Innisfil Hydro submits that the new building meets the criteria for an ICM and will make an application in due course.

6.0-VECC

Ref: Exhibit 2, Tab 1, Schedule 1, pg. 2

a) Please revise the table entitled "IHDSL Project Cost by Category (%)" replacing the percentages with actual dollar values and including a separate row to show the capital costs of facilities.

IHDSL Response:

IHDSL has provided the revised table reflecting the dollar values by capital category.

	IHDSL Project Costs by Category VECC IR #6						
Category	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Infrastructure Replacement	529,567	209,696	472,214	656,957	1,684,649	795,830	725,688
Reliability	210,551	448,352	1,172,996	157,559	264,262	404,600	1,370,674
Capacity	35,179	0	424,900	-	-	-	-
Security	-	362,911	136,224	-	20,030	-	-
Meter	43,048	72,069	189,324	-	-	74,000	115,900
Customer Demand	853,454	592,972	1,570,732	3,239,946	1,281,013	2,015,691	1,005,093
Substation	28,376	0	-	29,412	-	-	-
Facilities	56,911	103,837	-	-	-	-	-
Hardware and Software	282,348	125,799	88,448	64,210	86,927	557,150	356,000
Transportation	34,820	28,507	-	621,180	297,131	-	80,000
Regulatory	-	186,817	-	-	-	-	-
Communication	40,211	0	-	-	-	-	-
Tools & Equipment	13,377	14,825	-	260,656	58,448	-	-
Miscellaneous General Plant	-	0	257,437	188,227	201,860	236,650	279,997
Total w/o the New Building	2,127,842	2,145,785	4,312,275	5,218,147	3,894,319	4,083,921	3,933,352
Facilities						2,000,000	5,087,500
Total with the New Building						6,083,921	9,020,852

2.0-OEB Staff-7 – New Office Building 2147 Innisfil Beach Rd. – Land purchase

Ref: Exhibit 2/Tab 1/Schedule 1 p. 3-5, Exhibit 2/Tab 1/Schedule 2, Appendix 3 and Exhibit 2/Tab 2/Schedule 1 p. 10

On page 3 of E2/T2/S1 IHDSL states that "A purchase agreement was developed to sell 2.07 acres at the existing IHDSL site for $925k and purchase 3.5 acres at the Old Town hall site for $650k. All transactions are set at full appraised values".

The appraisal provided in Appendix 3 of E2/T1/S2 show property values for the continued use of the existing building in the amount of $650,000 and for redevelopment in the amount of $470,000.

a) **Page 1 of Appendix 3 provides two value estimates. The first for continued use of the building in the amount of $650,000 and a second for redevelopment in the amount of $470,000. Please confirm which value has been included in rate base and provide further justification for the purchase price, given that the site is being redeveloped.**

IHDSL Response:

For clarity, the appraiser was told about the intended use of the property and building and was asked to provide an updated appraisal with only one value. A revised appraisal was received at $650,000, which was utilized for the transaction.

A copy of the revised appraisal is enclosed in the Exhibit 2 Appendices – Ex2 Appendix 1 IR Ref Energy Probe-6b).

i. **Board staff noted an addition of $465,000 under account 1805 Land in the 2012 test year. Please confirm that this addition is related to the land purchase for the new office building. If not, please explain the addition and clarify under which account IHDSL has included the purchase of 2147 Innisfil Beach Rd.**

   IHDSL Response:

   There is a 2012 Bridge Year Land addition for $465,000 under account 1805 for the land purchase of a transformer station site. Due to inadvertence the land purchase for the new operations centre was included in 2012 within account 1908. No depreciation was calculated in 2012 but the half year rule was calculated in 2013. This has been corrected within the updated asset continuity and depreciation schedules.

b) **Please clarify if the existing purchase agreement includes the sale of the 2061 and 2073 Commerce Park Drive property. If so, please identify if the property is being sold to the town, an affiliate or a third person and identify the closing date. Please file the purchase agreement.**

IHDSL Response:

The existing sales agreement includes the sale of 2061 and 2073 Commerce Park Drive. The sale is to the Town with a closing date of February 2014.

The purchase agreement is enclosed in the Exhibit 2 Appendices – Ex2 Appendix 2 IR Energy Probe-6b.

c) **Please state if the value of $925,000 remains in IHDSL's 2013 rate base. If so, please explain why the old building should remain in rate base until IHDSL's next rebasing.**

IHDSL Response:

IHDSL can confirm that the value of $925,000 remains in IHDSL's rate base. The actual occupancy of the new operations headquarters was scheduled to occur in December of 2013 followed by the sale of the property in February 2014 which was beyond the test year.

With the removal of the new operations headquarters from the test year, IHDSL submits that the value of the existing facility should remain in rate base. The removal of the existing facility will be addressed in the forthcoming ICM (please refer to the Summary of Changes overview).

2.0 Energy Probe #7

Ref: Exhibit 2, Tab 1, Schedule 2 & Exhibit 2, Tab 2, Schedule 1

a) Please explain why the figures shown in Table 2.1 in Exhibit 2, Tab 1, Schedule 2 for 2011 do not match the figures shown in Table 2.4 of Exhibit 2, Tab 2, Schedule 1.

IHDSL Response:

Please refer to IR 2.0-OEB Staff-26.

b) Are the figures shown in Table 2.1 in Exhibit 2, Tab 1, Schedule 2 CGAAP or MIFRS based?

IHDSL Response:

Please refer to IR 2.0-OEB Staff-6a).

c) Please explain why the figures shown in Table 2.1 in Exhibit 2, Tab 1, Schedule 2 for 2012 do not match either of the CGAAP or MIFRS based figures shown in Tables 2.5 and 2.6 of Exhibit 2, Tab 2, Schedule 1.

IHDSL Response:

Please refer to IR 2.0-OEB Staff-6a).

d) Please confirm that the figures shown in Table 2.1 in Exhibit 2, Tab 1, Schedule 2 for 2013 are MIFRS based and not CGAAP based. If this cannot be confirmed, please explain why these figures match those in Table 2.7 of Exhibit 2, Tab 2, Schedule 1 which are shown as MIFRS based figures.

IHDSL Response:

Please refer to IR 2.0-OEB Staff-6a).

7.0-VECC

Ref: Exhibit 2, Tab 1, Schedule 1, pg. 5

a) Please provide the following for the new IHDSL office and Operations Center:

- **total estimated project costs as of year-end 2011;**
- **total amount spent to year-end 2012 and the total remaining to be spend in 2013;**
- **expected completion date of the project;**
- **total cost of new furnishings for office;**
- **total unoccupied office/commercial space (sq.ft.);**
- **amount of unoccupied office/commercial space currently leased (sq.ft.);**
- **estimated revenues in 2013 for leased space (including garage); and,**
- **estimated revenues in 2014 for leased space (including garage.**

IHDSL Response:

Please refer to Summary of Changes Overview.

2.0-OEB Staff-8 – New Office Building 2147 Innisfil Beach Rd. – Facilities & Buildings

Ref: Exhibit 2/Tab1/Schedule 1, p. 3

IHDSL noted that in 2009, an investigation was commissioned to McKnight Sharron Laurin Architects, which took an investigation of five options.

a) Please file reports or cost estimates for all alternatives including the option chosen.

IHDSL Response:

IHDSL has enclosed the Options Analysis in the Exhibit 2 Appendices – Ex2 Appendix 3 IR Ref OEB Staff-8a).

2.0 Energy Probe #8

Ref: Exhibit 2, Tab 1, Schedule 3

a) Please confirm that IHDSL has included $2 million associated with the new building facilities in the 2013 opening gross assets and a total of $7 million at the end of 2013 for rate base calculation purposes.

IHDSL Response:

Please refer to Summary of Changes Overview.

b) Please quantify the amount of accumulated depreciation at the beginning and ending of 2013 associated with the new building facilities used in the calculation of the test year rate base.

IHDSL Response:

Please refer to Summary of Changes Overview and 2.0 OEB Staff-7.

c) Please confirm the net book value associated with stranded meters has been removed from the calculation of the 2013 rate base in its entirety, meaning that the net book value was removed from the opening balance in 2013.

IHDSL Response:

IHDSL confirms that NBV of the stranded meter assets were reclassified from the asset account of 1860 to the approved smart meter regulatory account 1555 in 2009 and 2010. As such the NBV of the stranded meters was removed from the opening balance in 2013.

d) Please provide the net book value of the stranded assets as of the end of 2012.

IHDSL Response:

At the end of 2012 the NBV of the stranded meters is calculated to be $373,372. The value of $359,195 has been submitted in this application to reflect the forecasted depreciation to April 30, 2013.

Please refer to Exhibit 2 Appendices - Ex2 Appendix F IR Ref OEB Staff-26.

e) Has the net book value of the land and buildings of the current head office been removed from the value of the assets at the end of 2013? If not, please explain why not?

IHDSL Response:

Please refer to Summary of Changes Overview and IR 2.0 OEB Staff-7.

f) What is the forecasted net book value of the land and buildings associated with the current head office site at the end of 2013?

IHDSL Response:

Please refer to Summary of Changes Overview and IR 2.0 OEB Staff-9.

8.0-VECC

Reference: Exhibit 2, Tab 1, pg. 1

a) Please explain projects composed the $894,984 of capital projects not completed in 2009. When were these projects completed? Clarification of the IR was requested by IHDSL as the Schedule reference was omitted, reference is to Table 3.1 and the projects that are referenced in lines 9-11 contributing to the rate base variance.

IHDSL Response:

The largest capital project impacting the rate base variance was IHDSL's road widening (urbanization) project which was extended and completed in 2010 (please reference Exhibit 2, Tab 1, Schedule 3, page 2 lines 6-8).

2.0-OEB Staff-9 – Facilities & Buildings

Ref: Exhibit 2/Tab 2/Schedule 1, p. 9-11

In account 1908 – Building and Fixtures, IHDSL is showing an addition of $2,025,000 in the 2012 test year and $5,127,500 in the 2012 test year.

a) Please provide a breakdown of the cost and time table for the new head office.

IHDSL Response:

Please refer to Summary of Changes overview.

b) Please comment on the status of the new site.

IHDSL Response:

Please refer to Summary of Changes overview.

c) Please provide the cost per square foot as well as the square foot per employee.

IHDSL Response:

The building is budgeted for at an average of $200/sq.'. Removing warehouse and garage floor space, the square foot allocation per employee is: 2013 @ 38 employees =521 sq.'/employee. 2031 @ 75 employees = 264 sq.'/employee.

d) Please confirm that the building will be used and useful in the 2013 test year.

IHDSL Response:

IHDSL can confirm that the building will not be used in the 2013 test year. Please refer to Summary of Changes overview.

e) Please explain if any portion of the new building will be in use in the 2012 bridge year. If not, please explain the $2,025,000 addition to account 1908 in the 2012 bridge year.

IHDSL Response:

No portion of the new building will be in use in the 2012 bridge year. $2,000,000 of the 2012 asset additions within account 1908 relates to the new building. This was discovered before filing the application and the related depreciation for the $2,000.000 was removed from the 2012 continuity schedule. The 2012 continuity schedule inadvertently did not reflect the $2,000,000 addition reclassification to WIP. The $2,000,000 addition inadvertently has been included within the rate base calculation and will be reflected in revised continuity schedules and rate base schedules files located in the Summary of Changes Overview in this document.

2.0 Energy Probe #9

Ref: Exhibit 2, Tab 2, Schedule 1

On page 1, at lines 6 through 13 of the evidence, a number of table numbers are referenced that do not exist in the schedule. Further, the evidence implies that there is a continuity schedule for 2013 under CGAAP which does not appear to be included in the continuity schedules provided. Please provide the 2013 continuity schedule based on CGAAP.

IHDSL Response:

IHDSL concurs that the table numbers within the paragraph following the title "Continuity Statements" are misstated, the table references should have been corrected.

IHDSL wishes to clarify the continuity schedule for 2013 is the same for CGAAP and MIFRS. IHDSL will implement the accounting policy change in 2012.

9.0-VECC

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

a) Please explain what is meant by an increase in rate base "due to the internalization of IHDSL's line crew".

IHDSL Response:

To facilitate the internalization of the of IHDSL's line crew, capital expenditures of $881,836 were undertaken in 2010 for transportation and tools which contributed to the overall increase in the rate base. Further information on the internalization of the line crew is provided in Exhibit 4 of IHDSL's original submission for EB-2012-0139.

2.0-OEB Staff-10 – New Office Building 2147 Innisfil Beach Rd.

Ref: Exhibit 2/Tab 1/Schedule 1 p. 3-5

IHDSL noted on p. 5 of E2/T1/S1 that the "bottom floor is earmarked to be leased out as a medical centre and the top floor for a business development centre". HHDSL furthermore states that the Town of Innisfil has provided a letter of intent to lease five truck parking bays at the appraised value.

a) Please explain how this rental income for the medical and business development centres has been accounted for in this application.

IHDSL Response:

Please refer to Summary of Changes overview. IHDSL will address the forecasted revenues and offsets in the fore coming ICM for IHDSL's operations/facilities headquarters.

b) Please provide the estimated in service date for the garage area. Provide the forecasted rental income for the five truck parking bays and explain how this income has been reflected in other revenues.

IHDSL Response:

Please refer to Summary of Changes overview. IHDSL will address the forecasted revenues and offsets in the fore coming ICM for IHDSL's operations/facilities headquarters.

2.0 Energy Probe #16

Ref: Exhibit 2, Tab 5, Schedule 4 & Exhibit 2, Tab 2, Schedule 1

a) **Please reconcile the additions of $6,032,445 shown in Exhibit 2, Tab 5, Schedule 4 with the additions of $6,083,921 shown in Tables 2.5 and 2.6 of Exhibit 2, Tab 2, Schedule 1.**

IHDSL Response:

The value of $6,032,445 shown in Exhibit 2, Tab 5, Schedule 4 is a value that includes, total additions ($6,083,921) net 2012 disposals (-$317,646) and accumulated depreciation on disposals of ($266,170).

This appendix is being removed and replaced with Appendix B – Ex2 Appendix B IR Ref OEB Staff-28.

b) **Please confirm that the reference to Midland on page 2 of Exhibit 2, tab 5, Schedule 4 should be to IHDSL.**

IHDSL Response:

IHDSL confirms that the reference to Midland should in fact be IHDSL.

c) **Please provide a version of Table 2.5.5 that reflects the calculation of the revenue deficiency based on CGAAP.**

IHDSL Response:

The revenue deficiency table 2.5.5 is the same under MIFRS and CGAAP for IHDSL. IHDSL is electing to defer the MIFRS transition in line with the IASB direction to January 1, 2014.

2.0-OEB Staff-25

Ref: Exhibit 2/Tab 1/Schedule 2, Page 1

Per the 2012 and 2013 MIFRS schedules IHDSL filed in the rate application:

a) **Please confirm that the amounts in Table 2.1 Summary of Rate Base for 2012 and 2013 are MIFRS balances and not CGAAP balances as indicated by the title of the columns in the table.**

IHDSL Response:

Please see 2.0-OEB Staff IR 6 - Rate Base MIFRS.

b) **If the amounts for 2012 and 2013 are CGAAP balances in Table 2.1, please revise the balances to MIFRS and recalculate rate base accordingly.**

IHDSL Response:

Please see 2.0-OEB Staff IR 6 - there are no balance changes.

2.0-OEB Staff-26

Ref: Exhibit 2, Tab 2, Schedule 1, Pages 8, 11; Exhibit 1, Tab 3, Schedule1, Appendix E, 2011 Financial Statements Updated Evidence: 2013Balance Sheet

Board Staff summarized the references to PP&E and noted the following discrepancies as listed in Tables 1 and 2 below. For the following differences noted in Tables 1 and 2 below:

a) Please explain and reconcile the differences.

IHDSL Response:

The difference for Table 1 is due to the ending WIP balances not included within Appendix 2-B. The format of the 2012 and 2013 updated evidence was filed within the account descriptions and associated account balances on separate pages. IHDSL is filing an updated Appendix F, which is located in the Exhibit 2 Appendices section, reflecting 2012 and 2013 pro forma balance sheets with the account descriptions and balances on the same page. The sum of the Distribution Plant, General Plant, Other Capital Assets and Accumulated Amortization is $37,742,555, the same as Exhibit 2 Tab 2 Schedule 1 page 11.

b) Please revise the applicable schedules and appendices, such as Fixed Asset schedules, rate base calculation, depreciation schedules and amount recorded in PP&E deferral Account 1575, Revenue Requirement Workform etc., as appropriate.

IHDSL Response:

There is no revision to the applicable schedules and appendices.

Table 1:
Differences in balances between the 2011 ending balance on the financial statements and 2011 ending balance in Appendix 2-B

Reference	Exhibit 1, Tab 3, Schedule 1, Appendix E, 2011 Financial Statements, Note 5, 6	Exhibit 2, Tab 2, Schedule 1, Page 8	
	2011 Financial Statements	**Appendix 2-B, 2011 CGAAP Ending Balance**	**Difference**
Net Book Value	24,330,475	24,219,855	110,620

Table 2:
Differences in 2013 IFRS net book value between Appendix 2-B and pro-forma balance sheet.

	Exhibit 2, Tab 2, Schedule 1, Page 11	Updated Evidence: 2013 Balance Sheet	
	Appendix 2-B	**Pro-forma***	**Difference**
2013 IFRS Ending Net book Value	37,742,555	37,709,343	33,212

*This is the sum of Distribution Plant, General Plant, Other Capital Assets and Accumulated Amortization

2.0-OEB Staff-27

Ref: Exhibit 2, Tab 2, Schedule 1, Pages 9, 10 and Exhibit 2, Tab 2, Schedule 4, p 3, 4

The following differences were noted in the additions for Account 1908 Buildings and Furniture.

	2012	**2013**
2012 CGAAP, 2012 MIFRS, 2013 MIFRS Fixed Asset Continuity Schedule 2012 CGAAP Depreciation Schedule	2,025,000	5,127,500
2012 MIFRS and 2013 MIFRS Depreciation Schedule	25,000	7,127,500
Difference	**2,000,000**	**- 2,000,000**

a) **Please explain and reconcile the difference in additions in the schedules listed in the table above.**

IHDSL Response:

Please refer to 2.0-OEB Staff IR 9e).

b) Please revise the applicable schedules and appendices, such as Fixed Asset schedules, rate base calculation, depreciation schedules and amount recorded in PP&E deferral Account 1575, Revenue Requirement Workform etc., as appropriate.

IHDSL Response:

Please refer to the Summary of Changes overview.

2.0-OEB Staff-28 - PP&E Deferral Account

Ref: Filing Requirements For Electricity Transmission and Distribution Applications, EB-2006-0170, June 28, 2012, Pages 53-54
Appendix 2-EB - IFRS-CGAAP Transitional PP&E Amounts, 2013 Adopters of IFRS for Financial Reporting Purposes
Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, page 15
Updated evidence filed Oct. 22, 2012, Exhibit 1, Tab 6, Schedule 5, Page 4
Exhibit 2, Tab 2, Schedule 4, Page 4
Revenue Requirement Workform

The Filing Requirements For Electricity Transmission and Distribution Applications, EB-2006-0170, June 28, 2012, states:

> **Account 1575 – IFRS-CGAAP Transitional PP&E Amounts**
> **The applicant must propose a disposition period to "clear" the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.**

Appendix 2-EA or 2-EB states:
Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

The Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, states:
The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years).

a) **The Board may consider a five-year disposition period to "clear" the PP&E deferral account. Please update and file with the Board Appendix 2-EB, Appendix 2-CH (Depreciation and Amortization Expense), Revenue Requirement Work Form, and any other applicable evidence to reflect a five-year disposition period for the clearance of the PP&E deferral account. Please outline the Applicant's approach and its reasons if the Applicant disagrees with a five-year disposition period.**

IHDSL Response:

IHDSL is filing updated evidence based on further review of the FAQ issued July 2012 by the board. IHDSL had submitted Appendix 2-EB within the COS filing. IHDSL has submitted an updated Appendix B to reflect the accounting policy change of useful lives as of January 1, 2012. With this IR submission Appendix B replaces Appendix 2-EB submitted on September 13, 2012.

The updated Appendix B reflects a 4 year and a 5 year disposition period as requested. IHDSL is filing an updated schedule Appendix 2-CH (below) and RRWF (Appendix C) to reflect the considered PP&E 5 year disposition by the Board. IHDSL will follow the Board's recommended disposition period.

Appendix B and Appendix C are located in the Exhibit 2 Appendices – Ex2 Appendix B IR Ref OEB Staff-28 and Ex2 Appendix C IR Ref OEB Staff-28.

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	278,500	3.00	33.33%	$ 174,811	$ 174,811	$ 0
1612	Land Rights (Formally known as Account 1906)	-	-	0.00%	$ -	$ -	$ -
1805	Land	-	-	0.00%	$ -	$ -	$ -
1806	Land rights	-	-	0.00%	$ 14,575	$ 14,575	$ 0
1808	Buildings	-	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	-	25.00	4.00%	$ 3,312	$ 3,312	$ 0
1815	Transformer Station Equipment >50 kV	-	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	194,422	40.00	2.50%	$ 93,751	$ 93,752	-$ 1
1825	Storage Battery Equipment	-	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	918,153	45.00	2.22%	$ 210,237	$ 210,238	-$ 1
1835	Overhead Conductors & Devices	1,123,543	60.00	1.67%	$ 167,753	$ 167,753	-$ 0
1840	Underground Conduit	38,205	40.00	2.50%	$ 49,687	$ 49,686	$ 1
1845	Underground Conductors & Devices	157,573	40.00	2.50%	$ 323,747	$ 323,746	$ 1
1850	Line Transformers	649,500	40.00	2.50%	$ 221,577	$ 221,577	-$ 0
1855	Services (Overhead & Underground)	216,912	50.00	2.00%	$ 83,994	$ 83,994	-$ 0
1860	Meters	-	25.00	4.00%	$ 11,490	$ 11,490	$ 0
1860	Meters (Smart Meters)	116,170	15.00	6.67%	$ 152,968	$ 152,968	$ 0
1875	Street Lighting	-	-	0.00%	$ -	$ -	$ -
1905	Land	-	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	7,127,500	50.00	2.00%	$ 100,391	$ 100,391	-$ 0
1910	Leasehold Improvements	-	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	35,000	10.00	10.00%	$ 15,561	$ 15,561	$ 0
1915	Office Furniture & Equipment (5 years)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	128,000	5.00	20.00%	$ 75,182	$ 75,182	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	110,000	5.00	20.00%	$ 170,800	$ 170,800	$ 0
1935	Stores Equipment	4,200	10.00	10.00%	$ 2,364	$ 2,364	-$ 0
1940	Tools, Shop & Garage Equipment	20,000	10.00	10.00%	$ 34,462	$ 34,462	$ 0
1945	Measurement & Testing Equipment	19,000	10.00	10.00%	$ 4,006	$ 4,006	-$ 0
1950	Power Operated Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	-	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	-	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	-	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	266,697	15.00	6.67%	$ 118,418	$ 118,418	$ 0
1985	Miscellaneous Fixed Assets	-	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	- 382,523	35.00	2.86%	-$ 246,332	-$ 246,332	$ 0
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$11,020,852			$ 1,782,754	$ 1,782,754	-$ 0
	Depreciation expense adjustment resulting from amortization of Account 1575				- 127,973		
	Rolling Stock				- 170,800		
	Total Depreciation expense to be included in the test year revenue requirement				**1,483,981**		

2.0-OEB Staff-29 – Depreciation

Ref: Revenue Requirement Workform; Exhibit 2, Tab 2, Schedule 1, Page 11
Updated evidence filed Oct. 22, 2012, Exhibit 1, Tab 6, Schedule 5, Page 4Exhibit 2, Tab 2, Schedule 4, Page 4

The following were noted with regards to depreciation:

a) **The amount of depreciation included in the Revenue Requirement Workform is $1,451,988. The depreciation per the 2013 MIFRS Fixed Asset Continuity Schedule is $1,611,954. The depreciation per the 2013 Depreciation schedule is $1,142,890. Please explain and reconcile the difference in depreciation.**

IHDSL Response:

*The amount of depreciation included in the Revenue Requirement Workform for 2013 is the 2013 depreciation expense less ¼ of the PP&E adjustment ($639,864 * 25% = $159,996), less Rolling Stock depreciation expense ($170,800). Exhibit 2, Tab 2, Schedule 4, page 4 reflects the 2013 depreciation expense less the total amount of the PP&E adjustment.*

The following updated schedule reconciles to the Revenue Requirement Workform for 2013 in the amount of $1,451,988.

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	278,500	3.00	33.33%	$ 174,811	$ 174,811	$ 0
1612	Land Rights (Formally known as Account 1906)	-	-	0.00%	$ -	$ -	$ -
1805	Land	-	-	0.00%	$ -	$ -	$ -
1806	Land rights	-	-	0.00%	$ 14,575	$ 14,575	$ 0
1808	Buildings	-	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	-	25.00	4.00%	$ 3,312	$ 3,312	$ 0
1815	Transformer Station Equipment >50 kV	-	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	194,422	40.00	2.50%	$ 93,751	$ 93,752	-$ 1
1825	Storage Battery Equipment	-	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	918,153	45.00	2.22%	$ 210,237	$ 210,238	-$ 1
1835	Overhead Conductors & Devices	1,123,543	60.00	1.67%	$ 167,753	$ 167,753	-$ 0
1840	Underground Conduit	38,205	40.00	2.50%	$ 49,687	$ 49,686	$ 1
1845	Underground Conductors & Devices	157,573	40.00	2.50%	$ 323,747	$ 323,746	$ 1
1850	Line Transformers	649,500	40.00	2.50%	$ 221,577	$ 221,577	-$ 0
1855	Services (Overhead & Underground)	216,912	50.00	2.00%	$ 83,994	$ 83,994	-$ 0
1860	Meters	-	25.00	4.00%	$ 11,490	$ 11,490	$ 0
1860	Meters (Smart Meters)	116,170	15.00	6.67%	$ 152,968	$ 152,968	$ 0
1875	Street Lighting	-	-	0.00%	$ -	$ -	$ -
1905	Land	-	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	7,127,500	50.00	2.00%	$ 100,391	$ 100,391	-$ 0
1910	Leasehold Improvements	-	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	35,000	10.00	10.00%	$ 15,561	$ 15,561	$ 0
1915	Office Furniture & Equipment (5 years)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	128,000	5.00	20.00%	$ 75,182	$ 75,182	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	110,000	5.00	20.00%	$ 170,800	$ 170,800	$ 0
1935	Stores Equipment	4,200	10.00	10.00%	$ 2,364	$ 2,364	-$ 0
1940	Tools, Shop & Garage Equipment	20,000	10.00	10.00%	$ 34,462	$ 34,462	$ 0
1945	Measurement & Testing Equipment	19,000	10.00	10.00%	$ 4,006	$ 4,006	-$ 0
1950	Power Operated Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	-	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	-	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	-	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	-	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	266,697	15.00	6.67%	$ 118,418	$ 118,418	$ 0
1985	Miscellaneous Fixed Assets	-	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	- 382,523	35.00	2.86%	-$ 246,332	-$ 246,332	$ 0
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$11,020,852			$ 1,782,754	$ 1,782,754	-$ 0
	Depreciation expense adjustment resulting from amortization of Account 1575				- 159,966		
					- 170,800		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,451,988**		

b) **Per Appendix 2-EB, the disposition period was 4 years. Annual amortization is ($159,966). However, the adjustment to depreciation included in the Depreciation schedule is ($639,864), the total depreciation for the 4 year period. In relation to Board Staff IR 2.0-Staff-28, please revise Depreciation schedule to reflect an annual amortization adjustment based on a 5 year period.**

IHDSL Response

IHDSL has updated Appendix 2-EB to reflect an annual amortization adjustment based on a 5 year period.

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	6,032,445				
Depreciation	-2,179,090				
Closing net PP&E	29,913,418				
PP&E Values assuming Accounting Changes under CGAAP in 2012					
Opening net PP&E	26,060,063				
Additions	6,032,445				
Depreciation	-1,539,226				
Closing net PP&E	30,553,282				
Difference in Closing net PP&E, "Previous" CGAAP vs "Changed" CGAAP	-639,864				
Account 1576 - PP&E Changes Under CGAAP					
Opening balance	-	- 639,864	- 479,898	- 319,932	- 159,966
Amounts added in the year	- 639,864				
Sub-total	- 639,864	- 639,864	- 479,898	- 319,932	- 159,966
Amount of amortization, included in depreciation expense - Note 1		159,966	159,966	159,966	159,966
Closing balance in deferral account	- 639,864	- 479,898	- 319,932	- 159,966	-
Effect on Revenue Requirement					
Annual disposition amount		- 159,966	- 127,973		
Disposition Period - Years (note 2)		4	5		

2-SEC-2

[Ex.2/2/1/p.8-9]

Please reconcile the 2011 closing balance amount of $52,158,528 with the 2012 opening balance of $54,353,342.

IHDSL Response:

The difference between the 2011 closing balance amount of $52,158,528 and the 2012 opening balance of $54,353,342 is the addition of the is the smart meter true up of $2,162,281 and computer software of $32,533.

2-SEC-3

[Ex.2/2/1/p.9-10]

Please provide updated 2012 Fixed Asset Continuity Schedules (CGAAP and MIFRS).

IHDSL Response:

Updated 2012 Fixed Asset Continuity schedules for CGAAP and MIFRS are not required, based on the response on 2-SEC-2 above.

2-SEC-4

[Ex.2/2/2/1/Table 2.6]

Please update Table 2.6 to include 2012 year-end actuals.

IHDSL Response:

IHDSL cannot provide 2012 year end actuals at the time of this IR submission. IHDSL has provided an updated Table 2.6 based on YTD October actuals. The majority of IHDSL capital projects are not closed until the 3rd and 4th quarters and processing through the financial system. The elapsed timeframe for processing may take 60-120 days.

2.0 Energy Probe #10

Ref: Exhibit 2, Tab 2, Schedule 1, Tables 2.5 & 2.6 & Exhibit 2, Tab 1, Schedule 1

a) **The additions to gross plant shown for 2012 in Tables 2.5 and 2.6 are identical. Please explain why there is no adjustment based on the conversion from CGAAP to MIFRS. Is IHDSL indicating that there is no change in the level of capitalization for it between CGAAP and MIFRS?**

   IHDSL Response

   As reflected in Appendix 2-D Overhead Expense, there was no change in the level of capitalization for IHDSL in adopting MIFRS.

b) Is the $465,000 in additions shown in account 1805 for the new administration offices? If yes, please explain the difference between this figure and the $650,000 noted as the purchase price on page 3 of Exhibit 2, Tab 1, Schedule 1. If no, please explain where the $650,000 for the land for the new administration offices has been included in the 2012 and 2013 continuity schedules.

IHDSL Response

The $465,000 in additions shown in account 1805 is not for the new administration office. The addition is for the purchase of land for a future required Transformer Station.

The $650,000 for the purchase of the new administration offices was included in account 1908 on the 2012 continuity schedule.

c) Is all of the $2,025,000 shown as an addition in account 1908 related to the new building?

IHDSL Response

$2,000,000 in account 1908 is related to the new building.

d) Where are the costs associated with the demolition of the old town hall shown?

IHDSL Response

The demolition of the old town hall is reflected in account 1908 and is a component of the $2,000,000.

e) Please update both continuity schedules for 2012 (Table 2.5 and the first Table 2.6) to reflect actual data for 2012. If actual data is not available for all of 2012, please update for the most recent year-to-date actual data available, along with the forecast of capital expenditures that will be put into service by the end of 2012.

IHDSL Response

Please refer to Summary of Changes Overview Appendices.

f) Please explain why IHDSL does not show any work in progress for capital expenditures that are not completed and not put into service by year end.

IHDSL Response

IHSDL inadvertently did not report the WIP balances for 2011, 2012 and 2013. The reported WIP values are as follows, 2011 $110,615, 2012 1,075,000 and 2013 $4,000,000. IHDSL has *revised the 2012 and 2013 Appendix 2-B_FA_Continuity schedules (refer to Summary of Changes Overview Appendices) to reflect the work in progress amounts.*

g) Please show where in the gross assets, the stranded meters have been removed in 2012.

IHDSL Response:
The stranded meters were reclassified from the asset account of 1860 to the approved smart meter regulatory account 1555 in 2009 and 2010.

2.0 Energy Probe #11

Ref: Exhibit 2, Tab 2, Schedule 1, Second Table 2.6

a) The second Table 2.6 shown indicates it is based on MIFRS. Please confirm that this is correct.

IHDSL Response:

Table 2.6 is MIFRS based.

b) Please explain where the stranded meters have been removed from the gross assets and accumulated depreciation in the 2013 continuity schedule. Did IHDSL remove the stranded meters from the PP&E in 2009 and 2010?

IHDSL Response:

Please refer to Energy Probe IR-8.

c) Please explain the significant reduction in Contributions and Grants shown in 2013 relative to 2012 and past years.

IHDSL Response:

The decrease is due to the completion of an urbanization project initiated by the Town of Innisfil and completed by IHDSL finalized in 2012, as this was the largest project to date with respect to contributions. The forecast was adjusted appropriately to reflect customer initiated connections only for 2013.

d) Please provide a schedule that shows for 2009 through 2012 actual (or estimated actual for 2012) and the forecast for 2013 the breakdown of the contributions and grants into the account line items that they are associated with. Please also show the gross capital additions for each of those accounts that have an associated contribution and grant associated with it.

IHDSL Response:

Please see the following table reflecting the Contributions and Grants for 2009-2013 by OEB account.

Annual Contributions & Grants by OEB Account					
OEB Account	**2009**	**2010**	**2011**	**2012**	**2013**
1830 - Poles, Towers & Fixtures	46,760	108,933	13,839	468,628	29,270
1835 - Overhead Conductors & Devices	48,171	79,014	12,209	314,190	23,313
1840 - Underground Conduit	15,485	2,150	136,065	278,173	4,108
1845 - Underground Conductors & Devices	368,587	1,382,463	124,276	289,962	40,762
1850 - Line Transformers	51,181	56,819	16,893	58,795	73,378
1855/6 - Services (Overhead & Underground)	11,861	14,755	9,253	24,413	126,682
1860 - Meters	2,670	1,774	- 325	2,178	-120
Total by Year	**544,715**	**1,645,908**	**312,210**	**1,436,339**	**297,393**

e) Please confirm that the $5,127,500 shown as an addition to account 1980 is all related to the new administration building. If this cannot be confirmed, please quantify the amount associated with the new administration building and any other expenditures.

IHDSL Response:

IHDSL confirms that the $5,092,500 of the $5,127,500 is related to the new administration building.

f) Has IHDSL included any incremental capital expenditures in 2012 or 2013 associated with new office furniture and equipment for the new facilities? If yes, please quantify.

IHDSL Response:

To date IHDSL has not incurred any incremental capital expenditures in 2012 or 2013 associated for furniture/equipment for the new operations/facilities headquarters.

2.0 Energy Probe #12

Ref: Exhibit 2, Tab 2, Schedule 4

a) Please explain why the Additions shown in the tables on page 2 and 3 in account 1908 are $2,025,000 under CGAAP and only $25,000 under MIFRS.

IHDSL Response:

Please refer to IR OEB Staff-9.

b) Please confirm that the $2,000,000 difference noted above has been included as an addition for depreciation purposes in the 2013 schedule shown on page 3.

IHDSL Response:

Please refer to IR OEB Staff-9.

c) Please explain why there is no column shown to adjust the depreciation expense in 2013 as there was in 2012 for assets that are fully depreciated within the year.

IHDSL Response:

IHDSL has no assets that are fully depreciated under the MIFRS reporting.

2.0-OEB Staff-11 – TS Land

Ref: Exhibit 2/Tab3/Schedule1, p. 17

IHDSL noted that $465,000 capital expenditures for the purchase of land under the 13M3 tower line for a future Transformer Station.

a) Please confirm that this land purchase is in addition to the 2147 Innisfil Beach Rd. property.

IHDSL Response:

The 13M3 transformer station property is in addition to 2147 Innisfil Beach Road.

b) What is the expected in service date for this transformer station?

IHDSL Response:

A transformer station is expected in 2022. It is possible that a distribution station may be required on that site within 5 years to meet growth needs within the City of Barrie.

c) Is this land currently in use for any other purpose, or is this property vacant.

IHDSL Response:

The land is currently vacant. IHDSL is currently investigating opportunities for utilization of the TS land, example distributed generation, storage facilities.

d) Please provide further explanation why this property should be considered used and useful.

IHDSL Response:

By virtue of the long range regional plan, a transformer station requirement was identified. The property purchased was the last vacant land available that was suitably zoned next to the existing Hydro ROW at a very favourable price. IHDSL submits that by not addressing long range planning needs, the corporation would be viewed as not being prudent. Since addressing long range planning is prudent, long range capital investments should be considered the same.

2.0-OEB Staff-12 - 2012 Capital Projects – Smart Meter true-up

Ref: Exhibit 2/Tab 3/Schedule 1, p. 17 and Exhibit 2/Tab 2/Schedule 1, p. 10

IHDSL has included $93,156 under the General Plant category and $74,400 under Distribution Plant.

a) **Please confirm that the addition in account 1860 – Smart Meters of $74,240 shown in the E2/T2/S1 p. 10 was approved as part of EB-2011-0435 Smart Meter Application. If not, please explain.**

IHDSL Response:

The 2012 addition in account 1860 – Smart Meters was not approved as part of EB-2011-0435. IHDSL is forecasting in 2012 meter additions of $74,240 for deployment of new services and inventory purchases.

b) **Please explain the inclusion $93,156 and confirm that this amount was approved in IHDSL Smart Meter application. If not, please explain.**

IHDSL Response:

Exhibit 2 Tab 3 Schedule 1 page 17, $93,156 was inadvertently included in the schedule. The 2012 asset continuity schedule Exhibit 2 Tab 2 Schedule 1 page 10 does not include the $93,156 within the accounts 1920 and 1925 asset additions.

2.0-OEB Staff-14 – 27kV Extension 20th SR, BBPt to 13th Line

Ref: Exhibit 2/Tab 3/Schedule 1, p. 19 (p.20)

IHDSL shows a capital expenditure of $724,294 for a 27kV Extension 20th SR, BBTt to 13th Line.

a) **Please provide further information on the need and prudence for this project.**

IHDSL Response:

This line is required for redundancy tie and back up for the new BBPt 27.6 kV station which will be installed in 2014. This piece of line will provide power for the initial connection required for the BBPt development. The expansion of our infrastructure will support our customers in the new Friday Harbour development. (This expansion will continue into 2014 with the installation of the DS to better support the load in this development), as described in E2/T3/S1/ page 19.

b) **Please provide an estimated timeline and in-service date for the development of the 27.6kV Station in Big Bay Point.**

IHDSL Response:

We expect to begin the RFP process for services in Q2 of 2013 with an expected in-service date by the end of 2014.

2.0-OEB Staff-15 – Utility Relocates

Ref: Exhibit 2/Tab 3/Schedule 1, p. 19 (p.21)

IHDSL shows a capital expenditure of 68,074 for utility relocates.

a) Please provide a table showing the actual relocates each year for the last four years.

IHDSL Response:

IHDSL has provided the following table of relocates.

IHDSL CAPITAL EXPENDITURES
FOR UTILITY RELOCATES

Year	Gross Total Spend
2009	$2,132,359.27
2010	$4,254,757.60
2011	$277,241.25
2012	$763,722.18
4 YEAR TOTAL	$7,428,080.30
4 YEAR AVERAGE	$1,857,020.08

2.0-OEB Staff-16 – Base

Ref: Exhibit 2/Tab 3/Schedule 1, p. 17 and Exhibit 2/Tab 3/Schedule 1, p. 19 (p.21)

IHDSL included $583,370 for the 2012 bridge year, which is an approx. 43% increase over the 2011 rate year and $615,376 for the 2013 test year, which is an approx. 50% increase over the 2011 rate year.

a) **Please provide a more detailed explanation and list the type of expenses that are included in this category.**

IHDSL Response:

The following list provides the type of expenditures included in the base capital.

As outlined in E2/T3/S1, page 17 and 19 the Base budget included:

1. *The installation, replacement, and relocation of capital infrastructure that is not part of identified capital projects through the year. Examples such as vehicular accidents, storm damage replacement and issues identified by Hydro staff in the day to day operations go to this section of the capital budget. In 2012:*
    a. *We incurred over $32k for storm restoration work (as seen in our SAIFI and SAIDI data),*
    b. *$63k to relocate a line and correct trespassing over private property caused by legacy construction done many years ago without proper easements.*
    c. *We incurred a cost of $19k to change a DS transformer at our Stroud DS due to a leaking bushing.*

   d. *Costs pertaining to pole replacements due to accidents cost us $9k.*

2. *All overhead and underground servicing for customer request like new installs, upgrades, relocates and replacements impact the base budget and also receive contributions towards such works as outlined in the DSC.*

3. *Payments made out to Developers as part of the Economic Evaluation payout impacts the base budget.*
   a. *In 2012, we made a $293k payment to close the Economic Evaluation for one of our subdivision Developers.*

b) **Provide the actual spending in the 2011 and 2012 rate years.**

IHDSL Response:

In 2011 total costs were $410,360, net of contributions.
In 2012 forecast costs are $583,370, net of contributions.

c) **Please provide an explanation for the increases in the 2012 bridge and the 2013 test year.**

IHDSL Response:

For much of 2011 our area was still recovering from the recession and witnessed minimal economic expansion. However, beginning in 2012 we started to see an up-tick in economic activity with a positive growth forecast, which resulted in a need for greater investment from our base capital budget. The increase from 2012 to 2013 budget, however, was much less (5.5%).

2.0 Energy Probe #13

Ref: Exhibit 2, Tab 3, Schedule 1 & Exhibit 2, Tab 2, Schedule 1

a) Please reconcile the figure of $6,188,461 shown in the 2012 capital projects table on page 16 of Exhibit 2, Tab 3, Schedule 1 with the figure of $6,083,921 shown in Tables 2.5 and 2.6 of Exhibit 2, Tab 2, Schedule 1.

IHDSL Response:

The 2012 Capital Projects Table reflected on Exhibit 2, Tab 3, Schedule 1, page 16 has been reconciled. IHDSL inadvertently linked an older version of the Capital Project table.

2012 Capital Projects - revised EP IR #13a

Projects	Category	2012
2012 Distribution Plant		
DO-005 - 2012 Pole Replacement Program	Infrastructure Replacement	389,270
DO-006 - Infrastructure Replacements	Infrastructure Replacement	166,850
DO-007- Reclosurer automation	Reliabilty	33,186
DO-009 - 27.6kv Mechanized SCADA Load Interpt	Reliability	157,808
DO-010 - 44kv Mechanized SCADA Load Interpt	Reliability	144,906
DO-012 - UG padmount TX replacements	Infrastructure Replacement	67,600
DO-013-Substandard tmasformer rehabs	Infrastructure Replacement	172,110
DO-015-County relocates IBR & 20th SDRD	Customer Demand	191,876
DO-016-County relocated 7th Line & 20th SDRD	Customer Demand	197,173
DO-017-County relocates IBR & 10th SDRD	Customer Demand	379,402
DO-018-Urbanization carry forward	Customer Demand	24,000
DO-019-Urbanization 1, pole relocation finish	Customer Demand	154,850
DO-021-Cookstown water main relocates	Customer Demand	20,020
DO-022-TS Land	Customer Demand	465,000
DB-001- Retail meters	Meters	74,000
Base	Customer Demand	583,370
Sub-Total		**3,221,421**
2012 General Plant		
GO-010 New Building	Facility	2,000,000
GB-001 Hardware &Software	Hardware & Software	193,000
GO-012 Eng topobase & IFRS enhancements	Hardware & Software	164,150
GO - 011 Scada program conversion	Hardware & Software	200,000
DO-009 27.6kv Scada controlled intercept	Reliability	68,700
Miscellaneous	Miscellaneous	236,650
Sub-Total		2,862,500
2012 Grand Total		**6,083,921**

2012 Project Costs by Category

Category	Cost
Infrastructure Replacement	795,830
Reliability	404,600
Capacity	0
Security	0
Meter	74,000
Customer Demand	2,015,691
Substation	0
Facilities	2,000,000
Hardware and Software	557,150
Transportation	0
Regulatory	0
Communication	0
Tools & Equipment	0
Miscelllaneous General Plant	236,650
2009 Grand Total	**6,083,921**

2012 excluding Facility

Category	Cost
Infrastructure Replacement	795,830
Reliability	404,600
Capacity	-
Security	-
Meter	178,540
Customer Demand	2,015,691
Substation	-
Facilities	
Hardware and Software	557,150
Transportation	-
Regulatory	-
Communication	-
Tools & Equipment	-
Miscelllaneous General Plant	236,650
2009 Grand Total	**4,188,461**

b) Please update the table on page 16 to reflect actual data for 2012. If actual data for all of 2012 is not yet available, please provide data for 2012 on the basis of actual expenditures in 2012 along with a forecast for the remainder of the year.

IHDSL Response:

IHDSL has updated the 2013 Capital Projects on page 16 and included in the revised table below. Please note that the 2012 actual costs are to November 2012 only.

Status of IHDSL 2012 Capital Projects as of November

Projects	Category	2012 Bridge Forecast	2012 Forecasted Contribution (pro-rated to Nov)	Gross Actual Spend (Nov)	YTD 11-12 Actuals	2012 Actual vs Bridge	Status as of Nov 2012	Completed as of Dec 2012
2012 Distribution Plant		Net of Contribution		Net of Contribution				
DO-005 - 2012 Pole Replacement Program	Infrastructure Replacement	389,270		316,220	316,220	-73,050	WIP	Closed
DO-006 - Infrastructure Replacements	Infrastructure Replacement	166,850		161,359	161,359	-5,491	WIP	Closed
DO-007- Reclosurer automation	Reliabilty	33,186		33,233	33,233	47	In Service	Closed
DO-009 - 27.6kv Mechanized SCADA Load Interpt	Reliability	157,808		124,836	124,836	-32,972	WIP	Closed
DO-010 - 44kv Mechanized SCADA Load Interpt	Reliability	144,906		151,441	151,441	6,535	WIP	Closed
DO-012 - UG padmount TX replacements	Infrastructure Replacement	67,600		17,578	17,578	-50,022	WIP	Closed
DO-013-Substandard trnasformer rehabs	Infrastructure Replacement	172,110		27,489	27,489	-144,621	WIP	Closed
DO-015-County relocates IBR & 20th SDRD	Customer Demand	191,876	0	0	0	-191,876	Deferred to 2014	Deferred to 2014
DO-016-County relocated 7th Line & 20th SDRD	Customer Demand	197,173	-68,671	297,101	228,431	31,258	In Service	Closed
DO-017-County relocates IBR & 10th SDRD	Customer Demand	379,402	-138,150	440,731	302,581	-76,821	In Service	Closed
DO-018-Urbanization carry forward	Customer Demand	24,000	-17,917	106,449	88,533	64,533	WIP	Closed
DO-019-Urbanization 1 Pole Relocate Finish	Customer Demand	154,850	0	0	0	-154,850	Deferred to 2014	Deferred to 2014
DO-021-Cookstown water main relocates	Customer Demand	20,020	0	0	0	-20,020	Cancelled	Cancelled
DO-022-TS Land	Customer Demand	465,000		465,000	465,000	0	In Service	Closed
DB-001- Retail meters	Meters	74,000		37,669	37,669	-36,331	WIP	Closed
Base	Customer Demand	583,370	-253,299	868,103	614,804	31,434	WIP	Closed
Sub-Total		**3,221,421**	**-478,036**	**3,047,210**	**2,569,174**	**-652,247**		
2012 General Plant								
GO-010 New Building	Facility	2,000,000		662,562	662,562	-1,337,438	WIP	Closed
GB-001 Hardware &Software	Hardware & Software	193,000		91,207	91,207	-101,793	$87,500 moved to 2014 associated with new building	$87,500 moved to 2014 associated with new building
GO-012 Eng topobase & IFRS enhancements	Hardware & Software	164,150		44,615	44,615	-119,535	WIP	Closed
GO - 011 Scada program conversion	Hardware & Software	200,000		200,000	200,000	0	WIP	Closed
DO-009 27.6kv Scada controlled intercept	Reliability	68,700		53,248	53,248	-15,452	WIP	Closed
					0	0		
Miscellaneous	Miscellaneous	236,650		64,853	64,853	-171,797		
Sub-Total		2,862,500	-	1,116,485	1,116,485	- 1,746,015		
2012 Grand Total		**6,083,921**	**-478,036**	**4,163,695**	**3,685,659**	**-2,398,262**		

LEGEND

WIP - Not in Service at this time
In Service - Outside work completed
Closed - Outside work completed, invoices processed and forwarded to Finance
Completed - processed throught the Financial system

2-SEC-5

[Ex.2/3/1/p.18]

Please provide an update on the status of all 2012 capital projects.

IHDSL Response:

Please refer to 2.0 Energy Probe #13 b).

2-SEC-6

[Ex.2/3/1/p.18]

a) **With respect to the capital projects contained in this application:**
Are there any formal business cases or detailed analysis done to support the capital expenditures outlined in this application? If so, please provide.

IHDSL Response:

IHDSL undertakes the following process when determining the analysis required supporting the capital expenditures in this Cost of Service application.

To develop the capital plan, IHDSL is fully engaged with internal and external parties to obtain and support capital expenditures.

Following is a list of the parties IHDSL is engaged with:

- *Administrative Development Advisory Committee (ADAC) – working group facilitated through the municipality that discusses ongoing projects and development within the Town of Innisfil.*
- *Industry working groups.*
- *Third party engineering firms engaged by developers and utilities.*
- *Asset testing and analysis.*
- *Direct involvement with Town, County and Ministry of Transportation engineering staff.*
- *Involvement from the Board of Directors (Town of Innisfil Mayor and CAO).*
- *Shoulder LDC's (Powerstream etc.).*

Once the information is obtained the following considerations are undertaken:

- ***Project Overview**: describes the project required to be created to address certain needs or requests. The project may be driven by infrastructure replacement, technology, or customer demand.*
- ***Project Estimate and Assumptions**: preliminary assumptions for the project are proposed. An estimate is formulated based on these assumptions and project overview.*

- ***Organizational Impact**: an assessment of the financial, technological and regulatory impacts, as well as how it will modify or affect the organization.*
- ***Infrastructure/Technology Migration**: high-level overview of how the new infrastructure /technology will be installed or replaced and how legacy infrastructure and technology will be migrated.*
- ***Project Description**: describes the approach to construct and install or replace the project scope. This includes what the project will consist of, a general description of how it will be executed, and the purpose of it.*
- ***Goals and Objectives**: goals and objectives are identified which support the project.*
- ***Project Constraints**: barriers to the project scope are identified and strategic direction taken to mitigate such constraints.*
- ***Approvals**: final approval of capital expenditures is scrutinized by the Board of Directors before budget approval.*

For a complete overview of the approval process, please refer to IR SEC-6 b) below.

b) What was provided to the Board of Directors and Senior Management Team regarding all proposed or completed capital expenditures contained in this application? Please provide those documents.

IHDSL Response:

As referenced in IHDSL's application update for EB-2012-0139 submitted on October 24, 2012, IHDSL modified Exhibit 1 Tab 5 Schedule 1, with a statement as to when the forecast was prepared and approved by IHDSL's Board of Directors.

Please see excerpt below:

IHDSL 5 YEAR BUSINESS PLAN

IHDSL has attached its 5 Year Business Plan, which provides the foundation for IHDSL's Cost of Service application, EB-2011-0139.
The forecast for the 5 Year Business Plan was prepared in May 2012 following the budget process as outlined below. IHDSL's 5 Year Business Plan was approved by IHDSL's Board of Directors on August 24, 2012 under Resolution NO. 12-91.
A copy of the August 24, 2012 Board Meeting minutes and approved resolutions have also been enclosed.

Overview of IHDSL's Budget Process
The annual and 5 year budget plan is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be measured and evaluated.

Responsibilities

- It is the responsibility of the Finance department to coordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its operating budget, capital budget, and rolling forecasts.
- The President is responsible for presenting and recommending the budget to the Board of Directors for approval.
- It is the responsibility of the Board of Directors, on behalf of the shareholders, to approve the budget.

The budget is an important planning tool for IHDSL. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year. The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. The Budget Plans address both capital and operating requirements.

Budget Review Process

IHDSL's budget review process is as follows:

- Each department budget is reviewed and approved by the corresponding Director and submitted to the Finance department.
- The Finance department consolidates all departmental work plan budgets to produce budget reports by functional areas to be reviewed by the Executive Team members.
- The Executive Team members will then have an opportunity to make recommendations to the consolidated budgets.
- A final budget package is produced for final review and approval by the Executive Team.

The Actual-to-Budget Review Process

Once the budget is final, each department reviews and tracks progress against the budget on a monthly basis. Further, quarterly reviews and forecasts of actual and/or expected results against the budget are performed during the budget year. This review process involves the following activities:

- All Directors/Managers review the year-to-date ("YTD") operating results for their area(s) of responsibility on a monthly basis.
- Significant variances in capital and operating expenditures based on YTD results are reviewed along with work plans in order to identify any changes that may have an impact on the forecast of actual expenditures.
- Any significant and/or material expenditures/savings that will affect the current year's operating results are incorporated into the actual-to-budget forecast. All expenditures

in excess of the budget and all savings are reported. An initial draft of the forecast is prepared based on the information provided and a review of significant variances/changes is conducted with each Manager/Director to create the forecast.

- The Executive Team reviews the forecast and provides feedback, comments and adjustments before the forecast is finalized.
- The President approves the final forecast for presentation to the Board of Directors. Receive approval from the Board of Directors

2.0-OEB Staff-13

Ref: Exhibit 2/Tab 3/Schedule 1, p. 16

a) Please provide a table similar to the table on page 16 and list up-to-date capital expenditures for the 2012 bridge year including all capital contributions and provide the 2011 capital expenditures for the corresponding time period.

IHDSL Response:

Please refer to IR 2.0 Energy Probe #13.

IHDSL's capital project process extends beyond the physical service date, thus there is dependency to the year-end closing. The table referenced reflects year-to-date November actuals. From the actual in-service date of a project to the fully complete status of a capital project, the lapsed time frame can range from 90 to 120 days.

2.0 Energy Probe #14

Ref: Exhibit 2, Tab 3, Schedule 3

a) For each indicator in which the SQI shown in Table 3.10 is lower than the OEB Minimum Standard, please explain why IHDSL did not meet the minimum standards.

IHDSL Response:

IHDSL has undertaken that has identified the root cause of not meeting the OEB Minimum for Appointments Met is cable locates. The following is high level summary of the findings. In the enclosed updated IHDSL Scorecard in the Exhibit 2 Appendices – Ex2 Appendix 4 IR REF Energy Probe–14 the improvement for cable locates has been positively trending for August – December 2012. IHDSL fully anticipates that the OEB Standard will be met for 2013.

Appointments Met - Underground Cable Locates:
IHDSL conducted a process review within the organization in the summer to evaluate our current processes to identify opportunities for improving our locate turnaround.

Based on our review we implemented several changes that resulted in reduced turnaround times for the second half of the year.

Some of the process improvement steps include:

- *creating a greater awareness among locators to work proactively to meet customer obligations, including planning workload in advance to prepare for unexpected peaks in locate requests, and balancing workload;*
- *hiring an external contractor to catch up on backlog of locates in August 2012;*
- *manually excluding all overhead locates and cancelled appointments;*
- *streamlining internal and external communication pertaining to locate requests to enable better work management;*
- *reviewing periodic performance to provide feedback to locators and discuss ongoing strategy to cope with peak workloads;*
- *providing additional training to locators to further improve work performance/efficiency; and*
- *mobilizing internal staff to assist when needed.*

b) Please provide an updated Scorecard that includes the most recent monthly data currently available for 2012.

IHDSL Response:

IHDSL Scorecard for 2012 is attached in the Exhibit 2 Appendices section of this document – Ex2 Appendix 4 IR Ref Energy Probe-14.

2-SEC-7

[Ex.2/3/3/p.6]

Please provide the most up-to-date IHDSL Scorecard available.

IHDSL Scorecard for 2012 is attached in the Exhibit 2 Appendices section of this document Ex2 Appendix 4 IR Ref Energy Probe-14.

12.0-VECC

Reference: Exhibit 1, Appendix 4 – Reliability Management Plan / Exhibit 2, Tab 3, Schedule 3, pg. 1.

a) Please explain why there has been an increase in outages due to equipment failure as indicated by the chart on page 4 of the Plan.

IHDSL Response:

Please refer to 2.0 Energy Probe #11c).

b) Why has IHDSL set its SAIDI and SAIFI 2012 targets (excluding loss of supply) at the highest levels experienced over the previous 4 years?

IHDSL Response:

IHDSL inadvertently incorporated the SAIDI and SAIFI 2012 targets for "including loss of supply".

c) What are the targets for 2013?

IHDSL Response:

Our expectation is that with the capital workload planned for 2013 our SAIFI and SAIDI will improve by 3% from the previous year.

13.0-VECC

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

a) In 2011 why was IHDSL unable to meet the Board service standards for Underground locates and Appointments Scheduled and Met?

IHDSL Response:

Underground cable locates are a component of the Appointment Met OEB Standard, so to clarify the only standard not met was the Appointments Met Standard. Energy Probe IR # 14 provides the analysis and actions undertaken by IHDSL to improve this standard.

Please refer to the Exhibit 2 Appendices - Ex2 Appendix 4 IR Ref Energy Probe-14 - IHDSL 2012 Scorecard.

b) What are results for these categories for 2012?

IHDSL Response:

The 2012 annual performance for Appointments Met was 64%.

Please refer to the Exhibit 2 Appendices - Ex2 Appendix 4 IR Ref Energy Probe-14 - IHDSL 2012 Scorecard.

2.0 Energy Probe #15

Ref: Exhibit 2, Tab 5, Schedule 1

a) Please update the cost of power calculations for 2013 to reflect the OEB's Regulated Price Plan Price Report dated October 17, 2012.

IHDSL Response:

IHDSL has updated the Cost of Power calculations for 2013 to reflect the OEB's Regulated Price Plan Report dated October 17, 2012. The RRWF has been updated to reflect this and will be provided as an appendix to these responses.

	April 2012 Rate		COP	October 2012 Rate	COP New Rate	Difference
RPP	$0.08069	$	13,798,424	$0.07932	$13,564,146.74	-$234,277.37
Non-RPP	$0.07877	$	6,084,035	$0.08001	$6,179,810.59	$95,775.09
Total		$	19,882,460		$19,743,957.32	-$138,502.28

b) Please show the derivation of the SME cost of $73,097. Have these costs been approved by the Board?

IHDSL Response:

The derivation of the SME costs was based on the number customers at a rate of $0.8060. The costs have not been approved by the Board.

2-SEC-8

[Ex.2/5/4/p.1]

Please explain why the Applicant is seeking a 4 year disposition period of the PP&E Deferral Account.

IHDSL Response:

Please see Staff IR 2.0-OEB Staff-28a) for updated evidence. IHDSL was seeking a 4 year disposition period of the PP&E Deferral Account to be consistent with the 4 year normal rate cycle.

2.0-OEB Staff-17 – Feeder Capacities to Connect Generation

Ref: Exhibit 2/Appendix C – Green Energy Plan, p. 10-12

The reference states the following: "We have a design threshold to limit connected DG power to 50% of our calculated average minimum load of each feeder, which is determined to be 15% of the average maximum load on the respective feeder."

The Table on page 8 provides the connected or pending Distributed Generators (DG) on each feeder and the remaining capacities. The Table on page 9 shows the available DG capacity.

a) **Please indicate the source and provide the rationale for limiting the DG to 50% of the calculated average minimum load of each feeder.**

IHDSL Response:

The decision to limit DG to 50% of the feeders minimum load was based on HONI recommendations as published in their document "Distributed generation technical interconnection requirement, interconnections at voltages 50kV and below".

The source for the "Available DG capacity" was the HONI's capacity evaluation tool that was developed to help Feed-In Tariff (including micro FIT) project applicants determine whether there is sufficient capacity to connect their proposed renewable generation installation to a Hydro One-operated station or feeder closest to, or in the vicinity of, their proposed project location.

The link for this tool is:
http://www.hydroone.com/Generators/Pages/StationCapacityCalculator.aspx.

Does the above-noted limit apply to the load and DG on the portion of the feeder that is within the IHDSL system or does it consider the entire feeder including the Hydro One portion? Please explain.

IHDSL Response:

This load calculation is based on the total load and DG on the entire feeder, including the HONI portion as applicable.

b) **Please provide a Table similar to that on page 8 but with the Connected or Pending DG capacity broken down into Connected DG and Pending DG.**

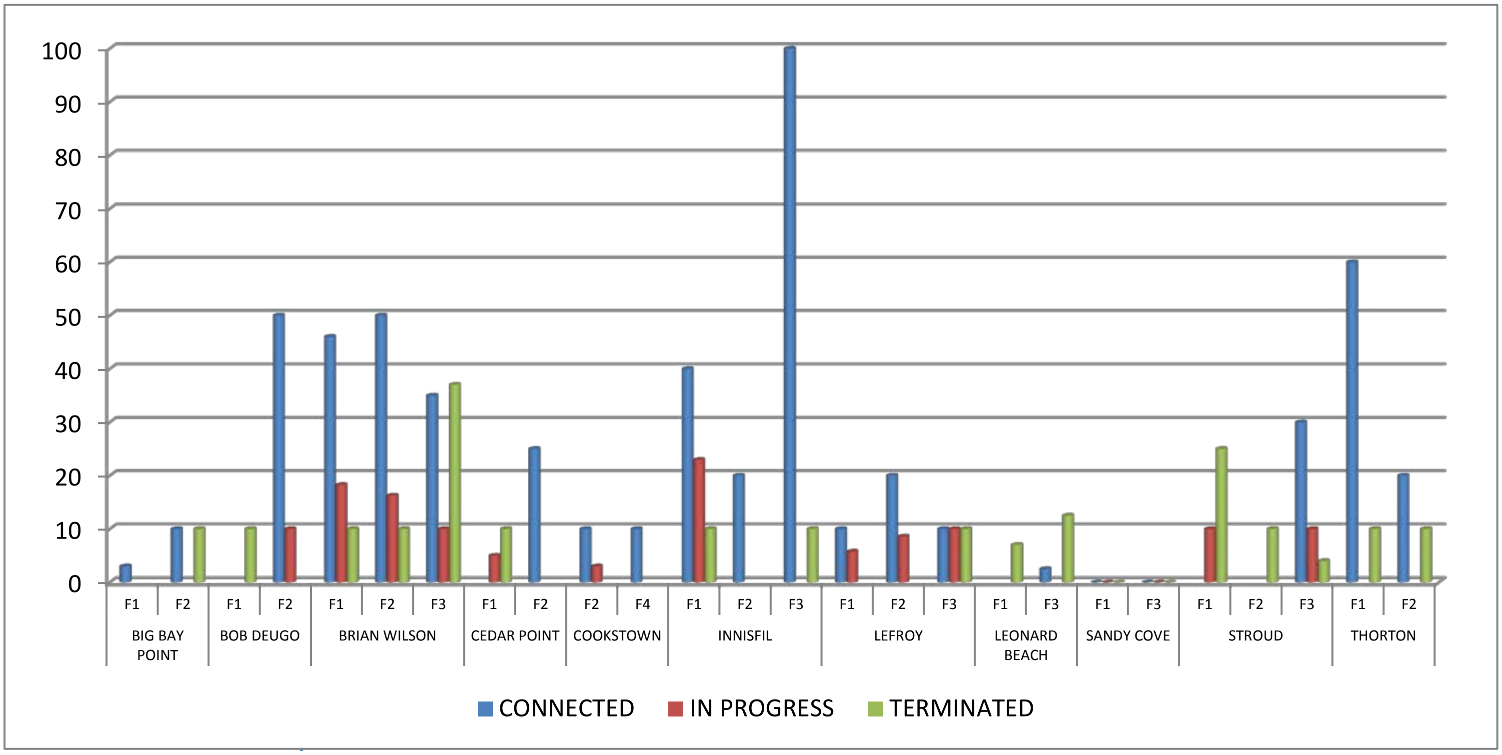
IHDSL Response:

IHDSL Micro-FIT Status Table
(as of 29-Jan-2013)

Distribution Station	Feeder	CONNECTED	IN PROGRESS	TERMINATED	Grand Total
BIG BAY POINT	F1	3	0	0	3
	F2	10	0	10	20
BIG BAY POINT Total		13	0	10	23
BOB DEUGO	F1	0	0	10	10
	F2	50	10	0	60
BOB DEUGO Total		50	10	10	70
BRIAN WILSON	F1	46	18.25	10	74.25
	F2	50	16.25	10	76.25
	F3	35	10	37	82
BRIAN WILSON Total		131	44.5	57	232.5
CEDAR POINT	F1	0	5	10	15
	F2	25	0	0	25
CEDAR POINT Total		25	5	10	40
COOKSTOWN	F2	10	3	0	13
	F4	10	0	0	10
COOKSTOWN Total		20	3	0	23
INNISFIL	F1	40	22.95	10	72.95
	F2	20	0	0	20
	F3	100	0	10	110
INNISFIL Total		160	22.95	20	202.95
LEFROY	F1	10	5.76	0	15.76
	F2	20	8.6	0	28.6
	F3	10	10	10	30
LEFROY Total		40	24.36	10	74.36
LEONARD BEACH	F1	0	0	7	7
	F3	2.5	0	12.5	15
LEONARD BEACH Total		2.5	0	19.5	22
SANDY COVE	F1	0	0	0	0
	F3	0	0	0	0
SANDY COVE Total		0	0	0	0
STROUD	F1	0	10	25	35
	F2	0	0	10	10
	F3	30	10	4	44
STROUD Total		30	20	39	89
THORTON	F1	60	0	10	70

	F2	20	0	10	30
THORTON Total		80		20	100
Grand Total		551.5	129.81	195.5	876.81

IHDSL Micro-FIT Status Chart
(as of 29-Jan-2013)



The table referred to in this question is a living document; i.e. it is updated on an on-going basis as and when new micro-FiT connection applications are processed. Hence, upon receipt of each application this sheet is checked before capacity confirmation is made. The values presented in this table take into account DG's connected to both IHDSL and HONI.

d) **How does IHDSL plan to address the one feeder where the Connected or Pending DG exceeds the Max DG Capacity and potentially the feeders that are nearing capacity for DG connection?**

IHDSL Response:

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.*

e) **Are the Available DG Capacity values shown on the Table on page 9 based on preliminary assessments by IHDSL and Hydro One or do these need to be confirmed before new DG is connected? Please explain.**

IHDSL Response:

Each DG connection request is confirmed (both internally and with HONI) before permission to proceed is granted.

f) **Do the Available DG Capacity values shown on the Table on page 9 represent values for the IHDSL portion of the feeders or are they totals for the feeders including the Hydro One portions. Please explain.**

IHDSL Response:

The Available Capacity includes DG connected on the HONI portion as well, as IHDSL is an embedded LDC.

2.0-OEB Staff-18 – Challenges Related to IHDSL's Distribution System

Ref: Exhibit 2/Appendix C – Green Energy Plan, p. 13

Page 10 of the reference states that "It is very likely that our aging infrastructure would need to be upgraded to accommodate the anticipated DG connection applications…….In the interim as we continue to expand our in-house technical capabilities……. it is imperative that we have the opportunity to employ an additional technician starting in 2013 to adequately support these efforts."

a) **For the five distribution feeders that have already reached maximum capacity or are nearing their maximum capacity for DG connectivity, please indicate the capacity and timing of the pending DG.**

IHDSL Response:

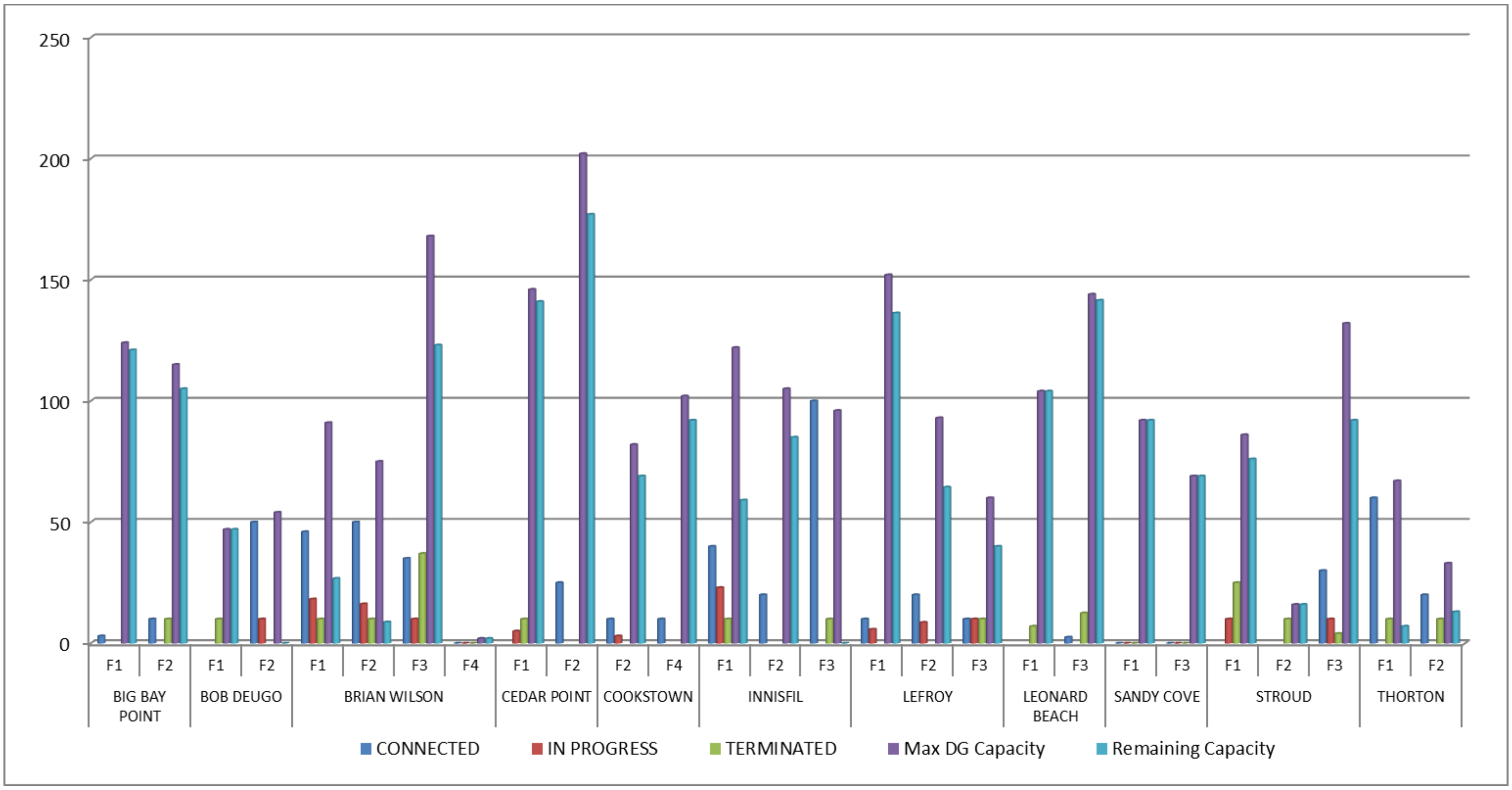
IHDSL has provided the following table to reflect the microFit applications by feeder and the phase in which the application resides. Applications that are in the "In Progress" stage will be connected within the next 90 days. IHDS now has 6 feeders that have minimal remaining capacity.

IHDSL Micro-FIT Status Table
(as of 29-Jan-2013)

Distribution Station	Feeder	CONNECTED	IN PROGRESS	TERMINATED	Max DG Capacity	Remaining Capacity
BIG BAY POINT	F1	3	0	0	124	121
BIG BAY POINT	F2	10	0	10	115	105
BOB DEUGO	F1	0	0	10	47	47
BOB DEUGO	F2	50	10	0	54	0
BRIAN WILSON	F1	46	18.25	10	91	27
BRIAN WILSON	F2	50	16.25	10	75	9
BRIAN WILSON	F3	35	10	37	168	123
BRIAN WILSON	F4	0	0	0	2	2
CEDAR POINT	F1	0	5	10	146	141
CEDAR POINT	F2	25	0	0	202	177
COOKSTOWN	F2	10	3	0	82	69
COOKSTOWN	F4	10	0	0	102	92
INNISFIL	F1	40	22.95	10	122	59
INNISFIL	F2	20	0	0	105	85
INNISFIL	F3	100	0	10	96	0
LEFROY	F1	10	5.76	0	152	136
LEFROY	F2	20	8.6	0	93	64
LEFROY	F3	10	10	10	60	40
LEONARD BEACH	F1	0	0	7	104	104
LEONARD BEACH	F3	2.5	0	12.5	144	142
SANDY COVE	F1	0	0	0	92	92
SANDY COVE	F3	0	0	0	69	69
STROUD	F1	0	10	25	86	76
STROUD	F2	0	0	10	16	16
STROUD	F3	30	10	4	132	92
THORNTON	F1	60	0	10	67	7
THORNTON	F2	20	0	10	33	13

IHDSL Micro-FIT Status Chart

(as of 29-Jan-2013)



b) **For the five feeders in (a), please indicate the expected infrastructure upgrades that will likely be required to accommodate the expected new DG.**

IHDSL Response:

The five feeders with nearing capacity refers only to micro-FiT projects, as indicated on table 5 on page 9; whereas the data on page 13 includes small FiT projects as well.

c) **Are there infrastructure upgrades anticipated for the other feeders as well in order to accommodate the expected new DG? Please explain.**

IHDSL Response:

Infrastructure upgrades will be designed and completed to meet the specific requirements of each DG projects as and when they come in.

d) **Is the proposed additional technician position to start in 2013 a permanent position or temporary? If temporary, please indicate the timeframe that the position will be required.**
IHDSL Response:

If approved the proposed technician will be integrated into a permanent position with our next COS application.

e) **What is the annual cost of the proposed additional technician position?**

IHDSL Response:

As identified on table 9, IHDSL forecasts the annual burdened rate to be approximately $75k for 2013 with a 3% (forecasted) increase each year thereafter.

f) **Does IHDSL expect that the additional technician is required solely to carry out work associated with implementation of IHDSL's Green Energy Act Plan? If not please indicate the portion of time to be spent on the Green Energy Plan and the portion for other work.**

IHDSL Response:

Yes, the technician will be carrying out work outlined in our GEA. The majority of the scope of work outlined for the new technician pertains to infrastructure upkeep (including capital) and less than 10 percent is focussed on DG work. The remainder pertains to the scope of the GEA related to the "Smart Grid". A detailed scope of work is documented in Appendix E page 10 of IHDSL's submitted evidence.

2.0-OEB Staff-19 – Identification of Expenditures

Ref: Exhibit 2/Appendix C – Green Energy Plan, p. 14-16

Table 8 and Table 9 on page 12 of the reference provide IHDSL's proposed expenditures in 2012/2013 – 2017 for Substation & Distribution System Upgrade (Table 8) and Investment in Personnel and Enterprise Architecture (Table 9).

a) **Please confirm whether the contents of Table 8 and 9 in the reference pertain to requirements under IHDSL's Green Energy Act Plan. If not all part of the Green Energy Act Plan, please indicate the portions that are and those that are not. Please explain.**

IHDSL Response:

Please refer to IR OEB Staff 22c).

b) **Please explain why the costs highlighted in green are in addition to IHDSL's forecast Capital and OM&A budgets and why the others are included in the budgets.**

IHDSL Response:

The green highlights identify the costs strictly associated with the GEA Rate Adder. IHDSL attempted to provide segregation between the SCADA forecasted capital costs and those requested for the proposed GEA Rate Adder.

c) **Please explain if and how the values shown in Tables 8 and 9 relate to the GEA Incremental Revenue Requirement Calculation shown in Appendix F, page 1.**

IHDSL Response:

The following table summarizes the costs by year to generate the Incremental Revenue Requirement Calculation shown in Appendix F, page 1.

Breakdown of Costs for GEA Funding Adder

Project Description	Equipment	Capital OM&A	Component Useful Life	2013	2014	2015	2016	2017
ASR - Automated Sectionlization & Restoration	Reclososers/Switches/Fiber/Radio	Capital	45	200,000	200,000	200,000	200,000	200,000
	Programming/Installation/Commissioning	Capital	45	50,000	50,000	50,000	50,000	50,000
Support Technician	Smart Grid/Green Energy Projects	OM&A		75,000	77,250	79,600	82,000	84,460
SCADA System Phase II	Software	Capital	10	200,000	-	-	-	-
SCADA	Hardware	Capital	10	50,000	-	-	-	-
WAN/Automation (SCADA)	Hardware	Capital	10	180,000				
	Software	Capital	10	20,000				
	Total			**775,000**	**327,250**	**329,600**	**332,000**	**334,460**

2.0-OEB Staff-20 – Smart Grid Development

Ref: Exhibit 2/Appendix C – Green Energy Plan, p. 19

In the reference, it is stated that IHDSL "worked on the AMI project which included installation of approximately 15,000 meters; upgraded SCADA system; and is planning to replace its old SCADA system".

a) **Please provide a Table showing the timing and expenditures for the work described in the reference and summarized above. Are these costs incremental to cost recovered through the GEA funding adder? If so, how does IHDSL plan to recover these costs?**

IHDSL Response:

IHDSL is not seeking cost recovery for any AMI or Smart Meter related costs within the GEA rate adder. The costs incurred in 2012 for the SCADA system was in our capital rate base. Anticipated 2013 costs are for further enhancing our SCADA system to include additional functionality such as automation, greater visibility, etc., which will help us accomplish items *noted in the Minister's Directive and is included in the GEA adder submission, as highlighted in table 9 on page 13.*

Description	2012	2013	2014	2015	2016	2017
New SCADA System	200,000	250,000	0	0	0	0

Phase 1 (2012): Direct replacement of old (base) SCADA system
Phase 2 (2013): Adding functionality to base SCADA system

Overview
Our current SCADA system was designed and built in 1996 using generic automation software to include the monitoring and control of a select number of data points on our subtransmission and distribution infrastructure. Among the 9 DS' we currently own, we have limited visibility on all, but have the ability to control protective devices on only three (3) DS'. Upgrading our SCADA system to a scalable utility specific technology will enable us to monitor and control an unlimited number of data points within our subtransmission and distribution infrastructure.

Implementation Schedule: Spread Over Two (2) Years
We intend to complete a direct replacement of our existing SCADA system in 2012 for which we have received sufficient funding. The proposed scope includes the purchase and commission the a base SCADA system; however, the extra funding we are requesting for 2013 will cover the cost of creating a more reliable and robust system with added capabilities such as (1) built-in redundancies with dual servers; (2) customized FDIR system to enable auto switching and restoration; (3) enhanced OMS system to better track our outages and gather intelligence to perform Root Cause Analysis (RCA) on major/recurring outages, and (4) effective and timely integration of operations data with other enterprise systems to maximize our Situational Awareness and Business Intelligence. As we install and commission our new SCADA system it is our intent to configure and equip a new Control Room in our new office building which we are planning on occupying at the end of 2013.

Justification
1. *Currently we have limited or no visibility on the 27.6kV, and 8.32kV distribution line.*
2. *Limited programming capability: lacking registers for Input and Output variables, timers etc.*
3. *Outdated Windows OS compatibility (Supports WinXP or lower).*
4. *Needs separate software for overview, trending and reporting.*
5. *Cannot be integrated with other software; i.e. GIS, AMI, OMS[1], etc. Therefore it cannot be used for automation or decision making.*
6. *Limited Graphical User Interface (GUI)*
7. *System reliability issues: we have experienced several malfunctions of our SCADA system over the years and expect to considerably improve system up-time with the implementation of the new system.*

[1] GIS: Geographic Information Systems, AMI: Advanced Metering Infrastructure, OMS: Outage Management System

Selection criteria of new system

1. *Automatic collection of data from multiple applications throughout the Innisfil Hydro network (44kV, 27.6kV, & 8.32kV).*
2. *Adapting an integrated communication medium that can handle data from multiple applications located throughout our infrastructure.*
3. *Integration of application software suits (GIS, SCADA, OMS, etc.) so they share collected data.*
4. *Ability to implement Distribution Automation, Advanced Metering Infrastructure, Demand Response - without rebuilding the system from the ground up.*

System Performance Requirements

1. *Enterprise-wide System integration: Customer Service, Operations, Engineering and Management to operate as a team, all having secure, and reliable access to the same pool of real-time information.*
2. *Business intelligence/Situational Awareness: Turn the volumes of real time and historical data into useful information.*
3. *Scalable system: Grows with the company and technological requirements.*
4. *Multiple protocols: Easy to implement, flexible in communications infrastructure.*
5. *Easy to use: Detailed graphical user interface.*
6. *Security: Safe system with proven security.*
7. *Reliability: Added reliability with the implementation of a redundant SCADA server.*
8. *Product support: Able to provide technical expertise needed to effectively operate and maintain Smart Grid/Green Energy systems.*

Benefits

1. *Improved Operational Efficiency: The new SCADA system will help us to:*
    - *a. respond to outages faster,*
    - *b. isolate faulted segments of the feeder more rapidly,*
    - *c. identify fault locations quicker,*
    - *d. determine type of faults more accurately, and*
    - *e. dispatch our crews to the faulted location in a more timely manner.*
2. *The new SCADA system will serve as a foundation for the new Smart Grid technology implementation, adding a centralized location for adoption of applications such as DA, OMS, DMS, FDIR, EMS[2], etc.*
3. *This new system will contribute towards the implementation of a self-healing and self-correcting gird infrastructure to automatically anticipate and respond to system disturbances for faster restoration.*
4. *This project will also enable us to use emerging, and innovative technology in our gird.*

[2] DA: Distribution Automation, OMS: Outage Management System, DMS: Distribution Management System, FDIR: Fault Detection, Isolation & Restoration, EMS: Energy Management System.

Scope

1. *It is our intent to purchase, install, and commission a new base SCADA system from Survalent® before the end of 2012, while phasing the full implementation through the end of 2013. The base system will include new computer hardware, electric utility specific SCADA software, while the add-ons will include the option to install redundant servers for greater reliability, switch order preparation software, web server, command sequencing program module, Multispeak interface to network with our GIS system, AMI interface, OMS, and FDIR.*
2. *Internal staff training is to be phased in during the implementation process.*

2.0-OEB Staff-21 – GEA Funding Justification

Ref: Exhibit 2/Appendix E – GEA Funding Justification

Sections 1., 2., 3., 5., 6., and 8. (part), contain Tables listing year by year 2013-2017 budget expenditures for works that are said to be "funded through the 5 year capital plan". The expenditures listed in these sections are summarized in the Table below:

a) Please confirm which of these projects are part of IHDSL GEA plan and are incremental to funding requested under IHDSL's capital budget for the 2013 test year.

IHDSL Response:

Table showing whether or not cost item in included in the 5 year plan

Table 8 - **Substation & Distribution System Upgrade:**

Description		2013	2014	2015	2016	2017	**Type of Expenditure**
Recloser Automation, Replacement, & Line Recloser Maintenance (4 yr cycle)		$ 223,300[a]	$ 232,000[a]	$ 248,500[a]	$ 265,900[b]	$ 253,200[b]	GEA/Smart Grid: This project (2013-2015) enables us to provide visibility to our substations which in turn will provide SCADA capability, provide remote switching ability, and reduce restoration times.
44kV SCADA Controlled Load Interrupting Gang Switches		$160,100	$166,300	$178,200	$190,600	$203,000	GEA/Smart Grid
27.6kV SCADA Controlled Load Interrupting Gang Switches		$253,200	$263,100	$281,700	$301,500	$321,000	GEA/Smart Grid
Implementation of Automated Sectionalization and Restoration (ASR)[C]		$250,000	$250,000	$250,000	$250,000	$250,000	GEA/Smart Grid
Fault Current Indicators		$38,400	$39,900	$42,700	$45,700	$48,700	GEA/Smart Grid

a: Substation Recloser upgrade; b : Line Recloser Upgrade

Table 9 - **Investment in Personnel and Enterprise Architecture:**							
Description	2012	2013	2014	2015	2016	2017	**Type of Expenditure**
Smart Grid/Green Energy Engineer	$ 75,000	$ 100,000	$ 103,000	$ 106,100	$ 109,270	$ 112,550	GEA/Smart Grid
- Tech Support [C]	$ -	$ 75,000	$ 77,250	$ 79,600	$ 82,000	$ 84,460	GEA/Smart Grid
New SCADA System	$ 200,000	$ 250,000 [c]	$ -	$ -	$ -	$ -	GEA/Smart Grid
Software Upkeep [c]	$ 25,000	$ 10,000	$ 10,300	$ 10,600	$ 10,900	$ 11,500	GEA/Smart Grid
Radio Hardware Installation & Commissioning [c]	$ -	$ 200,000	$ -	$ -	$ -	$ -	GEA/Smart Grid

[C] Not included in the current 5 year plan

Included in 5 year plan
Included in GEA adder

2.0-OEB Staff-22 – GEA Funding Justification

Ref: Exhibit 2/Appendix E – GEA Funding Justification

Sections 4., 7., 8. (part), 9. and 10. contain Tables listing year by year 2013-2017 budget expenditures for works that are said to require funding. The expenditures listed in these sections are summarized in the Table below:

Description	($)					
	2013	2-14	2015	2016	2017	Total
1. Implementation of Automated Sectionalization and Restoration (ASR)	250,000	250,000	250,000	250,000	250,000	**1,250,000**
7. Support Technician for Smart Grid/Green Energy Projects	75,000	77,250	79,600	82,000	84,460	**398,310**
8. New SCADA System - Phase 2	250,000					**250,000**
9. Software Upkeep	10,000	10,300	10,600	10,900	11,500	**53,300**
10. Radio / WAN6 / Automation Hardware Installation &Commissioning	200,000					**200,000**
TOTAL	**785,000**	**337,550**	**340,200**	**342,900**	**345,960**	**2,151,610**

a) **Please elaborate as to why/how each of the works shown in the above Table should be considered under IHDSL's Green Energy plan.**

IHDSL Response:

These projects enable us to execute our GEA plan as outlined in E2, Appendix E.

b) **Please provide in-depth justification on a per project basis to why either these projects should be considered for GEA funding.**

IHDSL Response:

IHDSL took into consideration both short term and long term benefits to our customers, and to our province at large, in determining the type, scope and schedule of projects proposed in the COS application. We chose our strategy that we deemed to work hand-in-hand with our proposed capital plan, which also met long range objectives noted in the Minister's Directive pertaining to the establishment, implementation and promotion of the Smart Grid and Distributed Generation.

We recognize that not all of the projects identified have an immediate impact on meeting some of the policy objectives noted in the Minister's Directive, however, we expect these projects to lay a foundation of necessary infrastructure that will enhance our ability to meet most, if not all, such objectives, enable the realization of long term customer benefits which will be essential to meeting future customer expectations, and the operation and maintenance of the grid of tomorrow.

The experience gained by a member of our management team who had the privilege of participating in the O E B Smart Grid working group, further contributed to the development of projects that would enable IHDSL to continue to be at the forefront of Smart Grid implementation in the province.

The additional benefits of completing the projects listed in tables 8 and 9 of our GEA plan include support for the installation and commissioning of Distributed Generation projects. As we implement and enhance automation within our grid, we are able to improve upon the isolation of faults. This enables us to use circuit switching methods and programing to restore segments of customers until the fault is corrected. In turn, this would benefit our DG customers as those affected by outages will likely have the opportunity to be reconnected to the grid much quicker. This would benefit all IHDSL customers including all rate classes and help achieve higher efficiencies within DG installations.

These proposed GEA enhancements represent an opportunity to move forward the GEA vision in advancement of mandatory directives. In addition, IHDSL envisions this GEA opportunity to be comparable as the 13 early adaptors for the smart metering initiative.

The justification for our projects is listed below:

Recloser Automation, Replacement, & Line Recloser Maintenance (4 year cycle), 44kV SCADA Controlled Load Interrupting Gang Switches, 27.6kV SCADA Controlled Load Interrupting Gang Switches, Automated Sectionalization and Restoration (ASR), Fault Current Indicators, SCADA, and Radio system: The aforementioned projects are intended to meet the following policy objectives noted in the Minister's Directive:

These help improve the efficiency of grid operation, enhances customer value, complies with coordination and interoperability requirements, enhances safety and security, provides opportunity for economic development within Ontario, and helps improve reliability.

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.

c) Please confirm that these costs are incremental to funding requested through IHDSL capital budget. If not, please explain why not.

IHDSL Response:

IHDSL confirms that the costs requested for the GEA Rate Adder are incremental to IHDSL's capital budget.

Table showing whether or not cost item in included in the 5 year plan

Table 8 - **Substation & Distribution System Upgrade:**

Description		2013	2014	2015	2016	2017	**Type of Expenditure**
Recloser Automation, Replacement, & Line Recloser Maintenance (4 yr cycle)		$ 223,300[a]	$ 232,000[a]	$ 248,500[a]	$ 265,900[b]	$ 253,200[b]	GEA/Smart Grid: This project (2013-2015) enables us to provide visibility to our substations which in turn will provide SCADA capability, provide remote switching ability, and reduce restoration times.
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a: Substation Recloser upgrade; b : Line Recloser Upgrade

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New SCADA System	$ 200,000	$ 250,000 [c]	$ -	$ -	$ -	$ -	GEA/Smart Grid
Software Upkeep [c]	$ 25,000	$ 10,000	$ 10,300	$ 10,600	$ 10,900	$ 11,500	GEA/Smart Grid
Radio Hardware Installation & Commissioning [c]	$ -	$ 200,000	$ -	$ -	$ -	$ -	GEA/Smart Grid

[C] Not included in the current 5 year plan

Included in 5 year plan
Included in GEA adder

d) Please update IHDSL GEA Funding Adder calculation if required.

IHDSL Response:

No update is required at the time of this IR submission.

2.0-OEB Staff-23 – GEA Funding Justification

Ref: Exhibit 2/Appendix E – GEA Funding Justification, Exhibit 8/Schedule 3 pp. 1-4

IHDSL provided the following GEA Funding Adder Calculations:

GEA Incremental Revenue Requirement Calculation							
	2013		2014		2015		
Net Fixed Assets		$ 710,000		$ 260,000		$ 261,000	
OM&A	$ 75.000		$ 77.000		$ 80.000		
WCA	13.0%	$ 9,750	13.0%	$ 10,010	13.0%	$ 10,400	
Rate Base		$ 719,750		$ 270,010		$ 271,400	
Deemed ST Debt	4%	$ 28.790	4%	$ 10.800	4%	$ 10.856	
Deemed LT Debt	56%	$ 403,060	56%	$ 151,206	56%	$ 151,984	
Deemed Equity	40%	$ 287,900	40%	$ 108,004	40%	$ 108,560	
ST Interest	2.08%	$ 599	2.08%	$ 225	2.08%	$ 226	
LT Interest	5.11%	$ 20,596	5.11%	$ 7,727	5.11%	$ 7,766	
ROE	8.01%	$ 23,061	8.01%	$ 8,651	8.01%	$ 8,696	
		$ 44,256		$ 16,602		$ 16,688	
OM&A		$ 75,000		$ 77,000		$ 80,000	
Amortization		$ 25,276		$ 53,333		$ 58,889	
Grossed-up PILs		-$ 2.371		-$ 17.161		-$ 15.689	
Revenue Requirement		$ 142,163		$ 129,774		$ 139,887	
Direct Benefit							
OM&A		$ 75,000		$ 77,000		$ 80,000	
Capital		$ 67,163		$ 52,774		$ 59,887	
Direct Benefit % on capital		0.00%		55.25%		41.00%	
Direct Benefit on capital		$ -		$ 29,156		$ 24,552	
Total Direct Benefit		$ 75,000		$ 106,156		$ 104,552	
Total # of Customers (Residential, GS<=50)		15,165		15,165		15,165	
GEA Rate Adder		$ 0.4121		$ 0.5833		$ 0.5745	3 year average $ 0.5233
Provincial Rate Protection		$ 67,163		$ 23,619		$ 35,335	
Monthly Adder Amount Paid by IESO		$ 5,597		$ 1,968		$ 2,945	

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%

a) **Board staff noted that the excerpt of table 6.1 shows funding for the years 2012-14. Please confirm that the excerpt of table 6.1 should correspond to the 2013-15 timeframe in the first table.**

IHDSL Response:

IHDSL confirms that the excerpt of Table 6.1 should correspond to the 2013-2015 timeframe.

b) **Please provide an itemized list of the direct benefit calculation of $427,083 and$396,417. Please reconcile with the total direct benefit calculation of $75,000 in 2013, $106,156 in 2014 and $104,552 in 2015 shown above.**

IHDSL Response:

The worksheet enclosed in OEB Staff IR 23 c) provides the determination of the weighted average % to determine the capital direct benefit. The total direct benefit costs of $75,000 in 2013, $106,156 in 2014 and $106,156 in 2015 are the sum of capital and OM&A costs.

	2013	2014	2015
Direct Benefit			
OM&A	$ 75,000	$ 77,000	$ 80,000
Capital	$ 67,163	$ 52,774	$ 59,887
Direct Benefit % on capital	0.00%	55.25%	41.00%
Direct Benefit on capital	$ -	$ 29,156	$ 24,552
Total Direct Benefit	$ 75,000	$106,156	$ 104,552

c) **Explain how IHDSL arrived at the weighted average calculation of 55.25% and 41.00% direct benefit.**

IHDSL Response:

The enclosed worksheet shows the derivation of the weighted average calculation of the direct benefit.

Total Capital costs by project - GEA Rate Adder

Cost		2013	2014	2015
Renewable Connections Capital - Expansions		-	-	-
Renewable Connections Capital - Renewable Enabling Improvements		250,000	250,000	250,000
Feeder Automation Projects		450,000	-	-
TOTAL		**700,000**	**250,000**	**250,000**

Renewable Connections Capital - Renewable Enabling Improvements

RECLOSER		**2013**	**2014**	**2015**
Opening Capital Investment		$ -	$ 250,000	$ 500,000
Capital Investment		$ 250,000	$ 250,000	$ 250,000
Closing Capital Investment		$ 250,000	$ 500,000	$ 750,000
Opening Accumulated Amortization		$ -	$ 2,778	$ 11,111
Amortization Year One	45 Years	$ 2,778	$ 2,778	$ 2,778
Amortization Thereafter		$ -	$ 5,556	$ 11,111
Closing Accumulated Amortization		$ 2,778	$ 11,111	$ 25,000
Opening Net Fixed Assets		$ -	$ 247,222	$ 488,889
Closing Net Fixed Assets		$ 247,222	$ 488,889	$ 725,000
Average Net Fixed Assets		$ 123,611	$ 368,056	$ 606,944

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

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%

d) **On page 4 of E8/S3 IHDSL states that it proposes to recover $285,708 of this amount from its customers as a direct benefit through a fixed monthly funding adder of $0.5233 per customer. Please reconcile this statement this with the excerpt of table 6.1.**

IHDSL Response:

The excerpt of Table 6.1 only reflects the weighted average calculation of the direct benefit for capital expenditures. The $258,708 represents the 3 year total of direct benefits for capital and OM&A for the GEA projects.

2.0 Energy Probe #17

Ref: Exhibit 2, Appendix E

Please confirm that the GEA costs shown in Appendix E have not been included in the capital expenditures forecast for 2012 and 2013 that have been included in the calculation of the rate base for 2013.

IHDSL Response:

IHDSL can confirm that the GEA costs reflected in Appendix E have not been included in the capital expenditures forecast for 2012 and 2013 for the calculation of rate base.

14.0-VECC

Reference: Exhibit 2, Appendix C /Appendix F, pg. 4

a) **Why does IHDSL believe that a class uniform GEA funding adder is appropriate and best reflects class benefit and cost causality?**

IHDSL Response:

IHDSL believes that a class uniform GEA funding adder is appropriate and best reflects class benefit and cost causality as the GEA projects outlined in this application provide the foundation of necessary infrastructure to realize long term customer benefit that currently are still being developed.

b) **Please provide the source/derivation of the direct benefits for Renewable Connections – Expansions/Enabling and the Feeder Automation projects.**

IHDSL Response:

One of the benefits of implementing feeder automation is the enabling of rapid isolation of faults and subsequent circuit restoration. Should one or more DG's get dropped from the *grid due to an upstream fault, we will be able to get the DG's back on the grid almost immediately if we are able to restore parts of the circuit through automation.*

10.0-VECC

Reference: Exhibit 2, Tab 3, Schedule1, pg. 1

a) Please explain the methodology used to estimate 2013 capital contributions.

IHDSL Response:

The methodology utilized by IHDSL to determine capital contributions is directly influenced or considered by the overall project category.

Commercial & Customer Substation Projects

These projects are Installations in which IHDSL will install equipment/infrastructure to connect a new commercial or industrial customer. In this category IHDSL will undertake an economic evaluation (prepared in accordance with the OEB's prescribed valuation methodologies of the service projects that require new facilities to be built on the distribution system or those that require an increase in capacity of the distribution system.

Subdivision Development

The primary driver for this category is residential development. Work involves installing residential overhead and underground distribution systems and components and or inspecting such work performed by a developer's contractor. The economic evaluation and capital contribution processes required by the DSC and described above are applied to residential expansions. The capital budget amounts reflect those expansions costs that are not recovered through capital contributions. The work predicated for this category for 2013 is derived from a combination of historical spending and anticipated projects.

Roadway Reconstruction

*The primary drivers for these projects are requests by municipalities and road authorities for plant relocation and or modifications. These projects generally occur due to road widening, resurfacing and or realignment. The **Public Service Works on Highways Act** provides for a cost sharing arrangement whereby the road authority contributes 50% of the cost of labour and equipment for the project. IHDSL is responsible for the remaining 50% of the labour and equipment cost, and 100% of the cost of material for the project. Projects that fall into this category are requested by customers, municipalities, and road authorities throughout the year.*

b) Please provide the actual 2012 capital contributions. Include those outstanding contributions (receivables) associated with projects completed in 2012.

IHDSL Response:

Please refer to Energy Probe IR 13 a) for the updated 2012 (Nov 2012) projects and contributions.

c) Which category of projects (Infrastructure replacement, customer demand, etc.) are capital contributions most associated with?

IHDSL Response:

IHDSL's completed projects have identified that the "Customer Demand" category is predominantly associated with capital contributions.

11.0-VECC

Reference: Exhibit 2, Tab 3, Schedule 1, pg. 17

a) The evidence states that pole testing will take place and that an estimate of a 4% failure rate would result in 70 poles being replaced. Please indicate how many poles were actually replaced in 2012 and the actual spending on project DO-005.

IHDSL Response:

A total of 57 poles were replaced under the pole replacement project scope. Total spend was $341K.

b) What is the forecast spending on pole replacement for 2013?

IHDSL Response:

As referenced in in E2/T3/S1, page 18 IHDSL's forecast for pole replacement in 2013 is $391,288.

EXHIBIT 2 APPENDICES

Ex2 Appendix 1 IR Ref Energy Probe 6b - Appraisal

ANDREW, THOMPSON & ASSOCIATES LTD.

642 Welham Road, Suite 103
Barrie, ON L4N 9A1
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

Real Estate Advisors

April 25, 2012

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

Attention: Mr. George Shaparew

Re: Part of 2147 Innisfil Beach Road, Innisfil, ON

Dear Mr. Shaparew:

This letter is to be an addition to the appraisal report of "Part of 2147 Innisfil Beach Road, Innisfil" dated January 25, 2012. This letter is not considered an independent opinion in absence of that report and is to be read in conjunction with the originally prepared report.

The original report addressed the valuation of the former Innisfil Town Hall assumed to be situated on approximately 3 acres. The previous value conclusions summarized were:

- Value for a "continued use" $650,000
- Value for "redevelopment" $470,000

We have since been instructed that:

- The client requires a single estimate of value.
- The assumed site size has increased to 3.5 acres, an increase of 0.5 acres.
- An easement providing for services is to run along the front yard of the property.

It is our opinion that the "market value" of the subject property is best identified by the continued use of the subject building. The indicated value for "redevelopment" represents a secondary value in the case that a user is not available after a reasonable marketing and exposure time. It is reasonable to expect that if available on the open market, a user would arise for a continued use.

It is our opinion that the addition of 0.5 acres would not have an impact on its potential value to a continued user as it would not add any additional utility to the building, above what is provided by the originally assumed 3 acre site. It is also our opinion that the presence of a servicing easement crossing the property within the front yard will have no impact on the continued use or value of the subject property.

As of the original effective date of January 12, 2012, it is our opinion that the addition of 0.5 acres in site size and the registration of a servicing easement across the front yard will have no impact to the original estimate of value provided for a “continued use”.

Therefore we conclude that the original concluded value of **$650,000** as of January 12, 2012 best provides a single estimate of value for the subject building as if on a 3.5 acre site.

We trust the information provided meets with your approval.

Respectfully Submitted,
ANDREW, THOMPSON AND ASSOCIATES LTD.

Peter Spivey, B.Sc., AACI, P.App
T:\REPORTS 2006\Innisfil\INNISFIL HYDRO 2008 & 2010 & 2012\IBR 2147, Mkt RentLetter & full report, HYDRO 2008 & 2012\2012 Report\Letter - April 24, 2012.docx

Ex2 Appendix 2 IR Ref OEB Staff 7b - Agreement

OREA Ontario Real Estate Association

Agreement of Purchase and Sale
Commercial

Form 500
for use in the Province of Ontario

This Agreement of Purchase and Sale dated this.................................. day of ....July.......... 20 12...

BUYER, INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED ...., agrees to purchase from
(Full legal names of all Buyers)

SELLER, THE CORPORATION OF THE TOWN OF INNISFIL ...., the following
(Full legal names of all Sellers)

REAL PROPERTY:

Address 2147 Innisfil Beach Road ....

fronting on the .... side of..

in the Town of Innisfil ....

and having a frontage of ....116.2 m.......... more or less by a depth of ....123.9 m.......... more or less

and legally described as Part Lot 16, Concession 7, Except Parts 1 & 2 on Plan 51R-35025

Town of Innisfil, County of Simcoe, more particularly shown as the draft R-Plan as attached as SCHEDULE 'B'. (the "property").
(Legal description of land including easements not described elsewhere)

PURCHASE PRICE: Dollars (CDN$) 650,000.00 ....

Six Hundred and Fifty Thousand ....Dollars

DEPOSIT: Buyer submits herewith ....
(Herewith/Upon Acceptance/as otherwise described in this Agreement)

One .... Dollars (CDN$) 1.00 ....

by negotiable cheque payable to the Seller .... "Deposit Holder" to be held in trust pending completion or other termination of this Agreement and to be credited toward the Purchase Price on completion. For the purposes of this Agreement, "Upon Acceptance" shall mean that the Buyer is required to deliver the deposit to the Deposit Holder within 24 hours of the acceptance of this Agreement. The parties to this Agreement hereby acknowledge that, unless otherwise provided for in this Agreement, the Deposit Holder shall place the deposit in trust in the Deposit Holder's non-interest bearing Real Estate Trust Account and no interest shall be earned, received or paid on the deposit.

Buyer agrees to pay the balance as more particularly set out in Schedule A attached.

SCHEDULE(S) A &B .... **attached hereto form(s) part of this Agreement.**

1. **IRREVOCABILITY:** This Offer shall be irrevocable by .... until .... a.m./p.m. on
(Seller/Buyer)
the ....31st.......... day of ....July.......... 20 12..., after which time, if not accepted, this Offer shall be null and void and the deposit shall be returned to the Buyer in full without interest.

2. **COMPLETION DATE:** This Agreement shall be completed by no later than 6:00 p.m. on the ....30th.......... day of ....August.........., 20 12......... Upon completion, vacant possession of the property shall be given to the Buyer unless otherwise provided for in this Agreement.

INITIALS OF BUYER(S): **INITIALS OF SELLER(S):**

3. **NOTICES:** ~~The Seller hereby appoints the Listing Brokerage as agent for the Seller for the purpose of giving and~~ receiving notices pursuant to this Agreement. Where a Brokerage (Buyer's Brokerage) has ~~entered into~~ a representation agreement with the Buyer, the Buyer hereby appoints the Buyer's ~~Brokerage~~ as agent for the purpose of giving and receiving notices pursuant to this Agreement. **~~Where a~~ Brokerage represents both the Seller and the Buyer (multiple ~~representation), the~~ Brokerage shall not be appointed or authorized to be agent for either ~~the Buyer or the Seller for the purpose of giving and receiving notices~~.** Any notice relating hereto or provided for herein shall be in writing. In addition to any provision contained herein and in any Schedule hereto, this offer, any counter-offer, notice of acceptance thereof or any notice to be given or received pursuant to this Agreement or any Schedule hereto (any of them, "Document") shall be deemed given and received when delivered personally or hand delivered to the Address for Service provided in the Acknowledgement below, or where a facsimile number or email address is provided herein, when transmitted electronically to that facsimile number or email address, respectively, in which case, the signature(s) of the party (parties) shall be deemed to be original.

~~FAX No.:~~ .... (For delivery of Documents to Seller) ~~FAX No.:~~ .... ~~(For delivery~~ of Documents to Buyer)

~~Email Address:~~ .... (For delivery of Documents to Seller) Email Address: .... (For delivery of Documents to Buyer)

4. **CHATTELS INCLUDED:**

N/A

Unless otherwise stated in this Agreement or any Schedule hereto, Seller agrees to convey all fixtures and chattels included in the Purchase Price free from all liens, encumbrances or claims affecting the said fixtures and chattels.

5. **FIXTURES EXCLUDED:**

N/A

6. **RENTAL ITEMS:** The following equipment is rented and **not** included in the Purchase Price. The Buyer agrees to assume the rental contract(s), if assumable:

N/A

7. **HST: If the sale of the property (Real Property as described above) is subject to Harmonized Sales Tax (HST), then such tax shall be in addition to the Purchase Price.** The Seller will not collect HST if the Buyer provides to the Seller a warranty that the Buyer is registered under the Excise Tax Act ("ETA"), together with a copy of the Buyer's ETA registration, a warranty that the Buyer shall self-assess and remit the HST payable and file the prescribed form and shall indemnify the Seller in respect of any HST payable. The foregoing warranties shall not merge but shall survive the completion of the transaction. If the sale of the property is not subject to HST, Seller agrees to certify on or before closing, that the transaction is not subject to HST. Any HST on chattels, If applicable, is not included in the purchase price.

8. **TITLE SEARCH:** Buyer shall be allowed until 6:00 p.m. on the ....20th........ day of........August........, 20.12.., (Requisition Date) to examine the title to the property at his own expense and until the earlier of: (i) thirty days from the later of the Requisition Date or the date on which the conditions in this Agreement are fulfilled or otherwise waived or; (ii) five days prior to completion, to satisfy himself that there are no outstanding work orders or deficiency notices affecting the property, that its present use (.commercial..) may be lawfully continued and that the principal building may be insured against risk of fire. Seller hereby consents to the municipality or other governmental agencies releasing to Buyer details of all outstanding work orders and deficiency notices affecting the property, and Seller agrees to execute and deliver such further authorizations in this regard as Buyer may reasonably require.

INITIALS OF BUYER(S): **INITIALS OF SELLER(S):**

9. **FUTURE USE:** Seller and Buyer agree that there is no representation or warranty of any kind that the future intended use of the property by Buyer is or will be lawful except as may be specifically provided for in this Agreement.

10. **TITLE:** Provided that the title to the property is good and free from all registered restrictions, charges, liens, and encumbrances except as otherwise specifically provided in this Agreement and save and except for (a) any registered restrictions or covenants that run with the land providing that such are complied with; (b) any registered municipal agreements and registered agreements with publicly regulated utilities providing such have been complied with, or security has been posted to ensure compliance and completion, as evidenced by a letter from the relevant municipality or regulated utility; (c) any minor easements for the supply of domestic utility or telephone services to the property or adjacent properties; and (d) any easements for drainage, storm or sanitary sewers, public utility lines, telephone lines, cable television lines or other services which do not materially affect the use of the property. If within the specified times referred to in paragraph 8 any valid objection to title or to any outstanding work order or deficiency notice, or to the fact the said present use may not lawfully be continued, or that the principal building may not be insured against risk of fire is made in writing to Seller and which Seller is unable or unwilling to remove, remedy or satisfy or obtain insurance save and except against risk of fire (Title Insurance) in favour of the Buyer and any mortgagee, (with all related costs at the expense of the Seller), and which Buyer will not waive, this Agreement notwithstanding any intermediate acts or negotiations in respect of such objections, shall be at an end and all monies paid shall be returned without interest or deduction and Seller, Listing Brokerage and Co-operating Brokerage shall not be liable for any costs or damages. Save as to any valid objection so made by such day and except for any objection going to the root of the title, Buyer shall be conclusively deemed to have accepted Seller's title to the property.

11. **CLOSING ARRANGEMENTS:** Where each of the Seller and Buyer retain a lawyer to complete the Agreement of Purchase and Sale of the property, and where the transaction will be completed by electronic registration pursuant to Part III of the Land Registration Reform Act, R.S.O. 1990, Chapter L4 and the Electronic Registration Act, S.O. 1991, Chapter 44, and any amendments thereto, the Seller and Buyer acknowledge and agree that the exchange of closing funds, non-registrable documents and other items (the "Requisite Deliveries") and the release thereof to the Seller and Buyer will (a) not occur at the same time as the registration of the transfer/deed (and any other documents intended to be registered in connection with the completion of this transaction) and (b) be subject to conditions whereby the lawyer(s) receiving any of the Requisite Deliveries will be required to hold same in trust and not release same except in accordance with the terms of a document registration agreement between the said lawyers. The Seller and Buyer irrevocably instruct the said lawyers to be bound by the document registration agreement which is recommended from time to time by the Law Society of Upper Canada. Unless otherwise agreed to by the lawyers, such exchange of the Requisite Deliveries will occur in the applicable Land Titles Office or such other location agreeable to both lawyers.

12. **DOCUMENTS AND DISCHARGE:** Buyer shall not call for the production of any title deed, abstract, survey or other evidence of title to the property except such as are in the possession or control of Seller. If requested by Buyer, Seller will deliver any sketch or survey of the property within Seller's control to Buyer as soon as possible and prior to the Requisition Date. If a discharge of any Charge/Mortgage held by a corporation incorporated pursuant to the Trust And Loan Companies Act (Canada), Chartered Bank, Trust Company, Credit Union, Caisse Populaire or Insurance Company and which is not to be assumed by Buyer on completion, is not available in registrable form on completion, Buyer agrees to accept Seller's lawyer's personal undertaking to obtain, out of the closing funds, a discharge in registrable form and to register same, or cause same to be registered, on title within a reasonable period of time after completion, provided that on or before completion Seller shall provide to Buyer a mortgage statement prepared by the mortgagee setting out the balance required to obtain the discharge, and, where a real-time electronic cleared funds transfer system is not being used, a direction executed by Seller directing payment to the mortgagee of the amount required to obtain the discharge out of the balance due on completion.

13. **INSPECTION:** Buyer acknowledges having had the opportunity to inspect the property and understands that upon acceptance of this Offer there shall be a binding agreement of purchase and sale between Buyer and Seller.

14. **INSURANCE:** All buildings on the property and all other things being purchased shall be and remain until completion at the risk of Seller. Pending completion, Seller shall hold all insurance policies, if any, and the proceeds thereof in trust for the parties as their interests may appear and in the event of substantial damage, Buyer may either terminate this Agreement and have all monies paid returned without interest or deduction or else take the proceeds of any insurance and complete the purchase. No insurance shall be transferred on completion. If Seller is taking back a Charge/Mortgage, or Buyer is assuming a Charge/Mortgage, Buyer shall supply Seller with reasonable evidence of adequate insurance to protect Seller's or other mortgagee's interest on completion.

15. **PLANNING ACT:** This Agreement shall be effective to create an interest in the property only if Seller complies with the subdivision control provisions of the Planning Act by completion and Seller covenants to proceed diligently at his expense to obtain any necessary consent by completion.

INITIALS OF BUYER(S): **INITIALS OF SELLER(S):**

16. **DOCUMENT PREPARATION:** The Transfer/Deed shall, save for the Land Transfer Tax Affidavit, be prepared in registrable form at the expense of Seller, and any Charge/Mortgage to be given back by the Buyer to Seller at the expense of the Buyer. If requested by Buyer, Seller covenants that the Transfer/Deed to be delivered on completion shall contain the statements contemplated by Section 50(22) of the Planning Act, R.S.O.1990.

17. **RESIDENCY:** Buyer shall be credited towards the Purchase Price with the amount, if any, necessary for Buyer to pay to the Minister of National Revenue to satisfy Buyer's liability in respect of tax payable by Seller under the non-residency provisions of the Income Tax Act by reason of this sale. Buyer shall not claim such credit if Seller delivers on completion the prescribed certificate or a statutory declaration that Seller is not then a non-resident of Canada.

18. **ADJUSTMENTS:** Any rents, mortgage interest, realty taxes including local improvement rates and unmetered public or private utility charges and unmetered cost of fuel, as applicable, shall be apportioned and allowed to the day of completion, the day of completion itself to be apportioned to Buyer.

19. **TIME LIMITS:** Time shall in all respects be of the essence hereof provided that the time for doing or completing of any matter provided for herein may be extended or abridged by an agreement in writing signed by Seller and Buyer or by their respective lawyers who may be specifically authorized in that regard.

20. **PROPERTY ASSESSMENT:** The Buyer and Seller hereby acknowledge that the Province of Ontario has implemented current value assessment and properties may be re-assessed on an annual basis. The Buyer and Seller agree that no claim will be made against the Buyer or Seller, or any Brokerage, Broker or Salesperson, for any changes in property tax as a result of a re-assessment of the property, save and except any property taxes that accrued prior to the completion of this transaction.

21. **TENDER:** Any tender of documents or money hereunder may be made upon Seller or Buyer or their respective lawyers on the day set for completion. Money may be tendered with funds drawn on a lawyer's trust account in the form of a bank draft, certified cheque or wire transfer using the Large Value Transfer System.

22. **FAMILY LAW ACT:** Seller warrants that spousal consent is not necessary to this transaction under the provisions of the Family Law Act, R.S.O.1990 unless Seller's spouse has executed the consent hereinafter provided.

23. **UFFI:** Seller represents and warrants to Buyer that during the time Seller has owned the property, Seller has not caused any building on the property to be insulated with insulation containing ureaformaldehyde, and that to the best of Seller's knowledge no building on the property contains or has ever contained insulation that contains ureaformaldehyde. This warranty shall survive and not merge on the completion of this transaction, and if the building is part of a multiple unit building, this warranty shall only apply to that part of the building which is the subject of this transaction.

24. **LEGAL, ACCOUNTING AND ENVIRONMENTAL ADVICE:** The parties acknowledge that any information provided by the brokerage is not legal, tax or environmental advice, and that it has been recommended that the parties obtain independent professional advice prior to signing this document.

25. **CONSUMER REPORTS: The Buyer is hereby notified that a consumer report containing credit and/or personal information may be referred to in connection with this transaction.**

26. **AGREEMENT IN WRITING:** If there is conflict or discrepancy between any provision added to this Agreement (including any Schedule attached hereto) and any provision in the standard pre-set portion hereof, the added provision shall supersede the standard pre-set provision to the extent of such conflict or discrepancy. This Agreement including any Schedule attached hereto, shall constitute the entire Agreement between Buyer and Seller. There is no representation, warranty, collateral agreement or condition, which affects this Agreement other than as expressed herein. For the purposes of this Agreement, Seller means vendor and Buyer means purchaser. This Agreement shall be read with all changes of gender or number required by the context.

27. **TIME AND DATE:** Any reference to a time and date in this Agreement shall mean the time and date where the property is located.

INITIALS OF BUYER(S): VS MJ **INITIALS OF SELLER(S):**

28. **SUCCESSORS AND ASSIGNS:** The heirs, executors, administrators, successors and assigns of the undersigned are bound by the terms herein.

SIGNED, SEALED AND DELIVERED in the presence of: IN WITNESS whereof I have hereunto set my hand and seal:

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED

(Witness) (Buyer/Authorized Signing Officer) (Seal) DATE July 31/12

(Witness) (Buyer/Authorized Signing Officer) (Seal) DATE JULY 31/12

~~I, the Undersigned Seller, agree to the above Offer. I hereby irrevocably instruct my lawyer to pay directly to the brokerage(s) with whom I have agreed to pay commission, the unpaid balance of the commission together with applicable Harmonized Sales Tax (and any other taxes as may hereafter be applicable), from the proceeds of the sale prior to any payment to the undersigned on completion, as advised by the brokerage(s) to my lawyer.~~

SIGNED, SEALED AND DELIVERED in the presence of: IN WITNESS whereof I have hereunto set my hand and seal:

THE CORPORATION OF THE TOWN OF INNISFIL

(Witness) Mayor (Seller/Authorized Signing Officer) (Seal) DATE July 31/12

(Witness) J. Reydar, Clerk (Seller/Authorized Signing Officer) (Seal) DATE July 31/12

~~**SPOUSAL CONSENT:** The Undersigned Spouse of the Seller hereby consents to the disposition evidenced herein pursuant to the provisions of the Family Law Act, R.S.O.1990, and hereby agrees with the Buyer that he/she will execute all necessary or incidental documents to give full force and effect to the sale evidenced herein.~~

(Witness) (Spouse) (Seal) DATE

CONFIRMATION OF ACCEPTANCE: Notwithstanding anything contained herein to the contrary, I confirm this Agreement with all changes both typed and written was finally accepted by all parties at ....a.m./p.m. this ....day of ...., 20.......... .

(Signature of Seller or Buyer)

INFORMATION ON BROKERAGE(S)

Listing Brokerage.. Tel.No.(..............)..................

Co-op/Buyer Brokerage.. Tel.No.(..............)..................

ACKNOWLEDGEMENT

I acknowledge receipt of my signed copy of this accepted Agreement of Purchase and Sale and I authorize the Brokerage to forward a copy to my lawyer.

(Seller) DATE

(Seller) DATE

Address for Service

Tel.No.(..........)

Seller's Lawyer Keisha-Ann Shaw Hill

Address The Corporation of the Town of Innisfil

(705) 436-3740 Tel.No. (705) 436-7120 FAX No.

I acknowledge receipt of my signed copy of this accepted Agreement of Purchase and Sale and I authorize the Brokerage to forward a copy to my lawyer.

(Buyer) DATE

(Buyer) DATE

Address for Service

Tel.No.(..........)

Buyer's Lawyer HGR Graham Partners (George Cameron)

Address 190 Cundles Road East, Suite 107, Barrie, ON

(705) 737-1811 Tel.No. (705) 737-5390 FAX No.

FOR OFFICE USE ONLY

COMMISSION TRUST AGREEMENT

To: Co-operating Brokerage shown on the foregoing Agreement of Purchase and Sale:
In consideration for the Co-operating Brokerage procuring the foregoing Agreement of Purchase and Sale, I hereby declare that all moneys received or receivable by me in connection with the Transaction as contemplated in the MLS® Rules and Regulations of my Real Estate Board shall be receivable and held in trust. This agreement shall constitute a Commission Trust Agreement as defined in the MLS® Rules and shall be subject to and governed by the MLS® Rules pertaining to Commission Trust.

DATED as of the date and time of the acceptance of the foregoing Agreement of Purchase and Sale. Acknowledged by:

(Authorized to bind the Listing Brokerage) (Authorized to bind the Co-operating Brokerage)

Schedule A
Agreement of Purchase and Sale – Commercial

This Schedule is attached to and forms part of the Agreement of Purchase and Sale between:

BUYER, INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED, and

SELLER, THE CORPORATION OF THE TOWN OF INNISFIL

for the purchase and sale of 2147 Innisfil Beach Road

dated the .... day of July, 20 12.

Buyer agrees to pay the balance as follows:

1. The Buyer agrees to pay the balance of the purchase price, subject to adjustments, by bank draft or certified cheque to the Seller on the completion of this transaction.

2. This Agreement is conditional until 6:00 p.m. on August 25, 2012 (the "Condition Date") upon each of the Buyer and Seller obtaining the requisite corporate or municipal authority, as the case may be, for the purchase and sale of the subject property substantially as set forth herein (hereinafter, the "Approval Conditions"). If either the Buyer or Seller fails to satisfy the Approval Conditions by the Condition Date, then this Agreement shall be at an end, the Deposit shall be returned to the Buyer and each of the Parties shall be relieved of their respective rights, entitlements and obligations herein.

3. If, following Closing, the Buyer ("Innisfil Hydro", in this section) should receive a bona fide offer to purchase the Subject Property or part thereof which it is willing to accept ("Third Party Offer"), Innisfil Hydro shall, by notice in writing ("Notice") to the Seller (the "Town", in this section), make an offer to sell the Subject Property (the "Hydro Offer to Sell") or part thereof to the Town at the price and at the same terms and conditions as are contained in the Third Party Offer. The Town shall have a period of 30 days from the date of Notice to accept the Hydro Offer to Sell, failing which Innisfil Hydro shall be free to accept the Third Party Offer and complete the sale of the Subject Property or part thereof in accordance with the Third Party Offer.

4. Title to the Subject Property shall be transferred to the Buyer subject to the following interests:

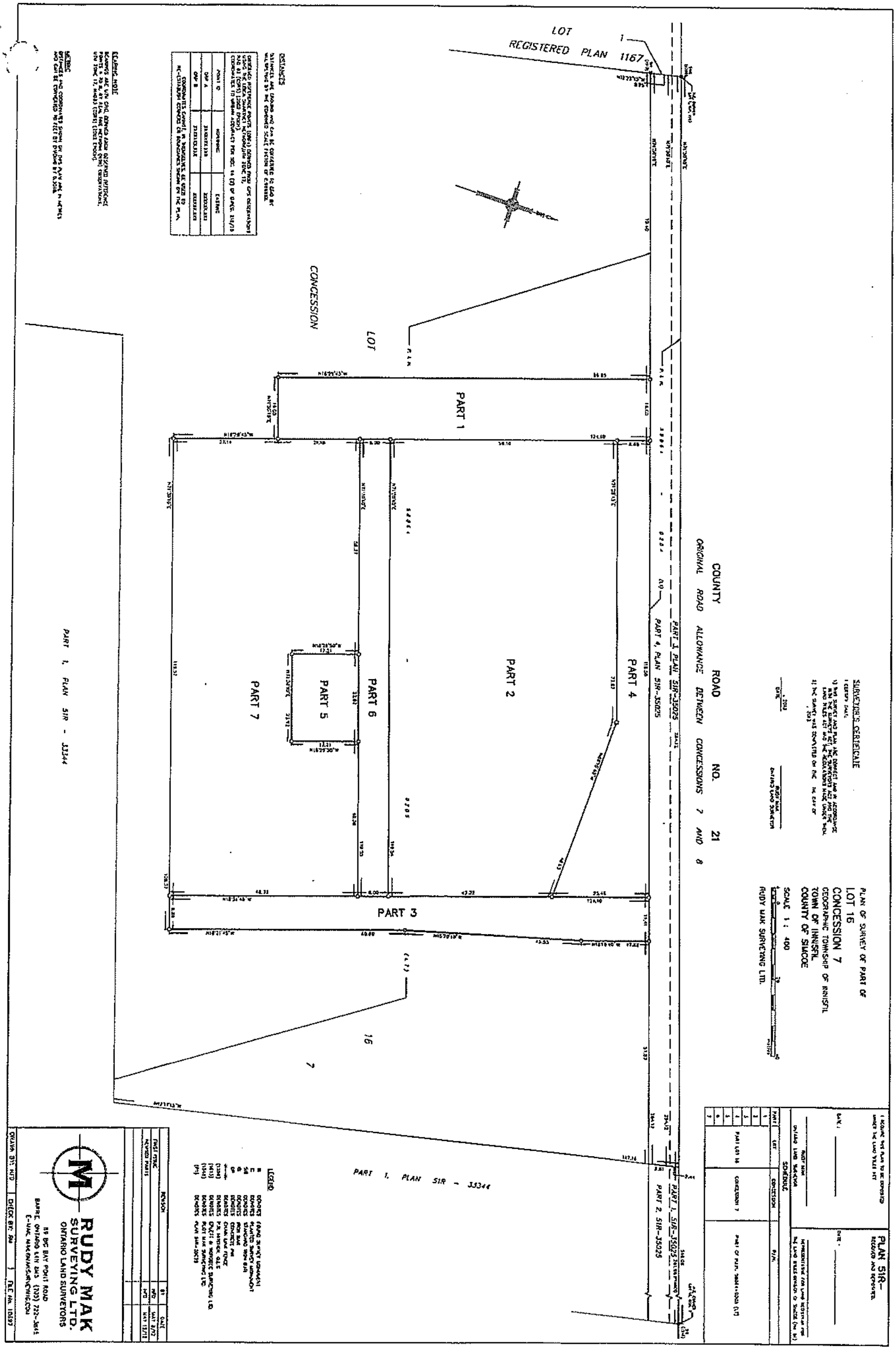
(a) together with easements for ingress and egress over Parts 1 and 3, shown on the attached sketch; and
(b) subject to easements in favour of the Town of Innisfil;
- **(i) over Part 4 for sewer and water utilities;**
- **(ii) over Part 5 for the 10kw solar facility; and**
- **(iii) over Part 6 for parking facilities.**

5. THE BUYER AND SELLER HEREBY ACKNOWLEDGE THAT CLAUSE 3 UNDER SCHEDULE 'A' SHALL REMAIN IN FULL FORCE AND EFFCET BINDING UPON THE BUYER, AND SHALL NOT BE DEEMED TO HAVE MERGED ON THE DELIVERY OF THE TRANSFER INSTRUMENT BUT SHALL SURVIVE THE CLOSING OF THE TRANSACTION.

This form must be initialed by all parties to the Agreement of Purchase and Sale.

INITIALS OF BUYER(S): **INITIALS OF SELLER(S):**

SCHEDULE "B"


LOT
REGISTERED PLAN 1167
CONCESSION
LOT
PART 1
PART 2
PART 3
PART 4
PART 5
PART 6
PART 7
COUNTY ROAD NO. 21
ORIGINAL ROAD ALLOWANCE BETWEEN CONCESSIONS 7 AND 8
PART 1, PLAN 51R-33344
16
7
PLAN OF SURVEY OF PART OF
LOT 16
CONCESSION 7
GEOGRAPHIC TOWNSHIP OF INNISFIL
TOWN OF INNISFIL
COUNTY OF SIMCOE
SCALE 1 : 400
RUDY MAK SURVEYING LTD.
RUDY MAK
SURVEYING LTD.
ONTARIO LAND SURVEYORS
SURVEYOR'S CERTIFICATE
LEGEND
PLAN 51R-

Ex2 Appendix 3 IR Ref OEB Staff-8a – Options Analysis

MCL
McKNIGHT CHARRON LAURIN INC. ARCHITECTS

McKNIGHT • CHARRON • LAURIN Inc.
ARCHITECTS

Tel: 705-722-6739
Fax: 705-726-5418
www.MCLarchitects.ca

67 High Street
Barrie, Ontario
L4N 1W5

Innisfil Hydro Option Analysis for Various Locations

15 December 2009

Site Option 1: Purchase Greenfield Site - 3249 Clifford Court (7.4 acres)

-Land cost:	$ 997,000.00
-new building: 12,000 sq. ft. x $170:	$2,040,000.00
-Operations & warehousing: 4000 sq. ft. x 120	$ 480,000.00
-Outside Storage & servicing	$ 60,000.00
-Parking: 70 x $2,500	$ 175,000.00
Sub-total:	$3,752,000.00
Less sale value for present property:	$1,000,000.00
Total:	$2,752,000.00

Site Option 2: Purchase existing 15,000 sq. ft. building - 1988 Commerce Park Drive (6 acres)

-Land cost with building:	$2,925,000.00
-renovate existing building: 15,000 x $45	$ 675,000.00
-Operations & warehousing: 4000 sq. ft. x 120	$ 480,000.00
-Outside Storage & servicing	$ 60,000.00
-Parking: existing	$ 00
Sub-total:	$4,140,000.00
Less sale value for present property:	$1,000,000.00
Total:	$3,140,000.00

Site Option 3: Existing Innisfil Hydro site with all New Building (3.3 acres)

-Land cost:	$ 00
-demolish existing 3 buildings & remove 2 portables:	$ 150,000.00
-new building: 12,000 sq. ft. x $170:	$2,040,000.00
-Operations & warehousing: 4000 sq. ft. x 120	$ 480,000.00
-Outside Storage & servicing	$ 60,000.00
-Parking: 70 x $2,500	$ 175,000.00
Total:	$2,905,000.00

michael@MCLarchitects.ca steve@MCLarchitects.ca bob@MCLarchitects.ca

Site Option 4: Existing Innisfil Hydro with 2,500 sq. ft. addition & renos (3.3 acres)

-Land cost:	$ 00
-renovate existing 3 buildings (8,500 x $50) :	$ 425,000.00
-accessibility upgrades: (ramps + 2 elevators)	$ 180,000.00
-new addition: 2,500 sq. ft. x $170:	$ 425,000.00
-Operations & warehousing: 4000 sq. ft. x 120	$ 480,000.00
-remove two portables:	$ 10,000.00
-Outside Storage & servicing	$ 60,000.00
-Parking: 70 x $2,500	$ 175,000.00
Total:	$1,755,000.00

Site Option 5: Town of Innisfil Campus (Old Town Hall) (12,000 sq. ft.)

-Land cost:	$ 00
-renovate existing buildings and add Elevator addition:	$1,835,000.00
-Operations & warehousing (south campus): 4000 sq. ft. x 120	$ 480,000.00
-Parking: existing	$ 00
-Outside Storage & servicing	$ 60,000.00
Sub-total:	$2,375,000.00
Less sale value for present property:	$1,000,000.00
Total:	$1,375,000.00

Pros & Cons:

Site Option 1: Pros: Greenfield - build to suit, will not disrupt present operations

Cons: land expense, low site may need to be raised, no sanitary or storm sewers, relatively high project cost.

Site Option 2: Pros: close to Hwy. 400, existing parking, will not disrupt present operations

Cons: large interior volumes not conducive to widow adjacencies, Log building requires special clearances at partitions for seasonal building movement, most expensive project cost

Site Option 3: Pros: close to Hwy. 400

Cons: relatively high project cost, construction will disrupt on-going operations (swing space needed), relatively small site.

Site Option 4: Pros: close to Hwy. 400, relatively low project cost, work can be phased

Cons: some disruption will occur to present operations, inefficient operational space in 3 buildings, accessibility costs high and awkward, relatively small site.

Site Option 5: Pros: part of Campus Plan (close to admin), will not disrupt present operations, least expensive option,

Cons: operations & warehousing remote from admin,

Recommendation: Site Option 5 is the recommended choice.

Michael McKnight, B. Arch. OAA

Ex2 Appendix F IR Ref OEB Staff-26

Innisfil Hydro Distribution Systems Limited
, License Number ED-2002-0520, File Number EB-2012-0139

Innisfil Hydro Distribution Systems Limited
2012 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	0
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	2,956,000
1102-Accounts Receivable - Services	(70,000)
1104-Accounts Receivable - Recoverable Work	329,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	370,000
1120-Accrued Utility Revenues	2,962,199
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(275,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	60,000
1170-Notes Receivable	0
1180-Prepayments	315,000
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**6,647,199**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	440,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**440,000**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	21,721
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,740,000
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,761,721**

Account Description	Total
1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	298,658
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	18,200
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1531-Renew. Generation Connection Capital	5,000
1532-Renewable Generation Connection OM&A	375
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	76,000
1550-LV Charges - Variance	(90,900)
1555-Smart Meters Recovery	342,850
1556-Smart Meters OM & A	0
1562-Deferred PILs	(476,200)
1563-Deferred PILs - Contra	476,200
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1576-Variance Account for PP&E Changes	(639,864)
1580-RSVA - Wholesale Market Services	(20,200)
1582-RSVA - One-Time	(20,200)
1584-RSVA - Network Charges	(20,200)
1586-RSVA - Connection Charges	(20,200)
1588-RSVA - Commodity (Power)	(40,400)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	239,636
1200-Other Assets and Deferred Charges Total	**128,755**

1450-Distribution Plant	
1805-Land	738,770
1806-Land Rights	982,703
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	86,252
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,394,009
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	10,149,911
1835-Overhead Conductors and Devices	14,357,195
1840-Underground Conduit	2,072,771
1845-Underground Conductors and Devices	12,125,856
1850-Line Transformers	9,137,896
1855-Services	4,224,541
1860-Meters	2,523,779
1865-Other Installations on Customer's Premises	0
1875-Street Lighting	0
1450-Distribution Plant Total	**60,793,683**

Account Description	Total
1500-General Plant	
1905-Land	201,049
1906-Land Rights	0
1908-Buildings and Fixtures	2,764,631
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	334,155
1920-Computer Equipment - Hardware	637,806
1925-Computer Software	645,749
1930-Transportation Equipment	1,174,196
1935-Stores Equipment	35,824
1940-Tools, Shop and Garage Equipment	514,684
1945-Measurement and Testing Equipment	41,497
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	1,775,243
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(8,798,900)
1500-General Plant Total	**(674,066)**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	75,000
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**75,000**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(29,566,335)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(29,566,335)**

Total Assets	**39,605,957**

Account Description	Total
1650-Current Liabilities	
2205-Accounts Payable	1,615,731
2208-Customer Credit Balances	200,000
2210-Current Portion of Customer Deposits	450,000
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	650,000
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	871,000
2250-Debt Retirement Charges (DRC) Payable	140,000
2252-Transmission Charges Payable	650,000
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	1,800,000
2260-Current Portion of Long Term Debt	340,243
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	70,100
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	450,000
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	120,000
2296-Future Income Taxes - Current	(22,000)
1650-Current Liabilities Total	**7,335,074**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	215,000
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	60,000
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	38,625
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**313,625**

Account Description	Total
1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	13,344,321
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	2,005,000
1800-Long-Term Debt Total	**15,349,321**

1850-Shareholders' Equity	
3005-Common Shares Issued	10,852,444
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	555,620
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	3,156,387
3046-Balance Transferred From Income	1,076,993
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	966,493
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**16,607,937**

Total Liabilities & Shareholder's Equity	**39,605,957**

Balance Sheet Total	0

Innisfil Hydro Distribution Systems Limited
2013 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	0
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	3,129,000
1102-Accounts Receivable - Services	(75,000)
1104-Accounts Receivable - Recoverable Work	333,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	380,000
1120-Accrued Utility Revenues	3,113,965
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(300,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	63,000
1170-Notes Receivable	0
1180-Prepayments	325,000
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**6,968,965**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	450,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**450,000**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	21,721
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,740,000
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,761,721**

Account Description	Total
1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	285,502
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	18,500
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1531-Renew. Generation Connection Capital	5,000
1532-Renewable Generation Connection OM&A	375
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	77,000
1550-LV Charges - Variance	(92,250)
1555-Smart Meters Recovery	0
1556-Smart Meters OM & A	0
1562-Deferred PILs	(122,050)
1563-Deferred PILs - Contra	122,050
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1576-Variance Account for PP&E Changes	(639,864)
1580-RSVA - Wholesale Market Services	(20,500)
1582-RSVA - One-Time	(20,500)
1584-RSVA - Network Charges	(20,500)
1586-RSVA - Connection Charges	(20,500)
1588-RSVA - Commodity (Power)	(41,000)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	217,990
1200-Other Assets and Deferred Charges Total	**(250,747)**

1450-Distribution Plant	
1805-Land	738,770
1806-Land Rights	982,703
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	86,252
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,588,431
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	10,963,064
1835-Overhead Conductors and Devices	15,323,238
1840-Underground Conduit	2,110,976
1845-Underground Conductors and Devices	12,230,929
1850-Line Transformers	9,776,896
1855-Services	4,441,453
1860-Meters	2,639,949
1865-Other Installations on Customer's Premises	0
1875-Street Lighting	0
1450-Distribution Plant Total	**63,882,661**

Account Description	Total
1500-General Plant	
1905-Land	201,049
1906-Land Rights	0
1908-Buildings and Fixtures	7,892,131
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	369,155
1920-Computer Equipment - Hardware	765,806
1925-Computer Software	924,249
1930-Transportation Equipment	1,284,196
1935-Stores Equipment	40,024
1940-Tools, Shop and Garage Equipment	534,684
1945-Measurement and Testing Equipment	60,497
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	2,041,940
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(9,181,423)
1500-General Plant Total	**4,932,308**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	75,000
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**75,000**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(31,072,414)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(31,072,414)**

Total Assets	**46,747,494**

Account Description	Total
1650-Current Liabilities	
2205-Accounts Payable	1,621,542
2208-Customer Credit Balances	180,000
2210-Current Portion of Customer Deposits	440,000
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	655,000
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	960,000
2250-Debt Retirement Charges (DRC) Payable	145,000
2252-Transmission Charges Payable	700,000
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	1,825,000
2260-Current Portion of Long Term Debt	346,770
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	48,900
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	475,000
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	130,000
2296-Future Income Taxes - Current	(22,000)
1650-Current Liabilities Total	**7,505,212**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	210,000
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**210,000**

Account Description	Total
1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	21,356,341
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	1,045,000
1800-Long-Term Debt Total	**22,401,341**

1850-Shareholders' Equity	
3005-Common Shares Issued	10,852,444
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	555,620
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	3,608,380
3046-Balance Transferred From Income	648,004
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	966,493
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**16,630,941**

Total Liabilities & Shareholder's Equity	**46,747,494**

Balance Sheet Total	0

Ex2 Appendix B IR Ref OEB Staff-28

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	6,032,445				
Depreciation	-2,179,090				
Closing net PP&E	29,913,418				
PP&E Values assuming Accounting Changes under CGAAP in 2012					
Opening net PP&E	26,060,063				
Additions	6,032,445				
Depreciation	-1,539,226				
Closing net PP&E	30,553,282				
Difference in Closing net PP&E, "Previous" CGAAP vs "Changed" CGAAP	-639,864				
Account 1576 - PP&E Changes Under CGAAP					
Opening balance	-	- 639,864	- 479,898	- 319,932	- 159,966
Amounts added in the year	- 639,864				
Sub-total	- 639,864	- 639,864	- 479,898	- 319,932	- 159,966
Amount of amortization, included in depreciation expense - Note 1		159,966	159,966	159,966	159,966
Closing balance in deferral account	- 639,864	- 479,898	- 319,932	- 159,966	-
Effect on Revenue Requirement					
Annual disposition amount		- 159,966	- 127,973		
Disposition Period - Years (note 2)		4	5		

Notes:

1 Amortization of the deferred balance in Account 1576 will start from the rebasing year. The amortization that will be included in the depreciation expense is the opening balance of Account 1576 / the approved disposition period.

2 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the variance account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy change of useful lives of in-service capital assets.

3 This is the impact to the net assets for the change in useful lives due the to Kinetric study. Innisfil's net assets are increasing due to longer useful lives.

Ex2 Appendix 4 IR Ref Energy Probe-14 – 2012 Scorecard

IHDSL Scorecard

Key Performance Indicators (KPI's)

INDEX

Service quality indicators and reporting requirements, including the minimum standard guidelines where applicable, are described in the Scorecard along with IHDSL's results.

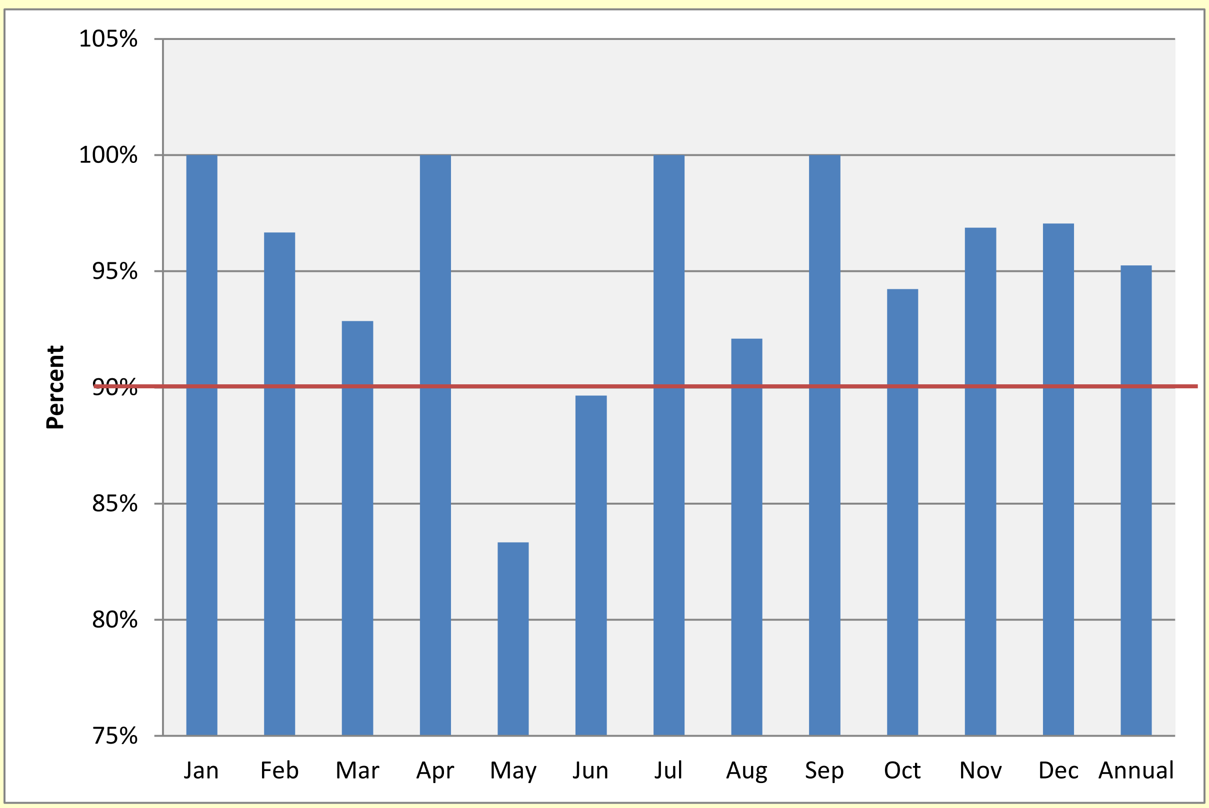
Connection of New Services

OEB Report 2.1.4.1.1

Definition:

As a minimum performance standard for the connection of new universal services, new low voltage (<750 volts) services must be connected within 5 business days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time on an annual basis. The connection of new services indicator measures the percentage of requests that are met within the required minimum.

	2007	2008	2009	2010	2011	2012
# Connections Within 5 Bus. Days	247	374	234	271	190	188
Total Connection Requests	253	395	248	279	234	187
% Requests Within 5 Bus. Days	98%	95%	94%	97%	81%	95%



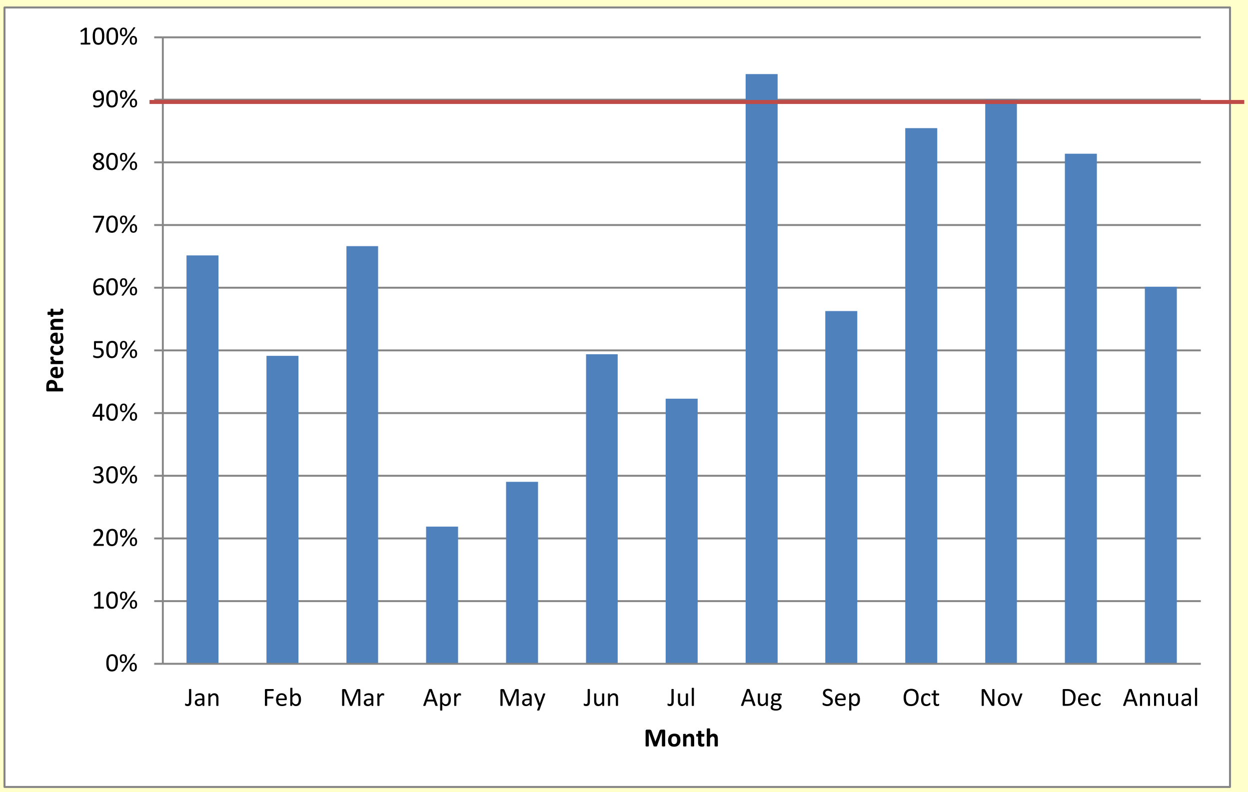
Underground Cable Locates

Major component of the OEB Appointment, Scheduling, Met and Rescheduling. The other major component is Connection of New Services.

Definition:

The current minimum standard is that underground cable locates must be completed within 5 working days of a customer's request, at least 90% of the time on an annual basis. For customers requesting a specific date, the locate must be completed within 5 working days of the requested date.

2007	2008	2009	2010	2011	2012
			61%	45%	60%



Note: After 2007, Underground Cable Locates is included in the Appointments Met metric.

Overhead locates have now been removed for all of 2012 and will continue to be removed going forward

Underground Cable Locates

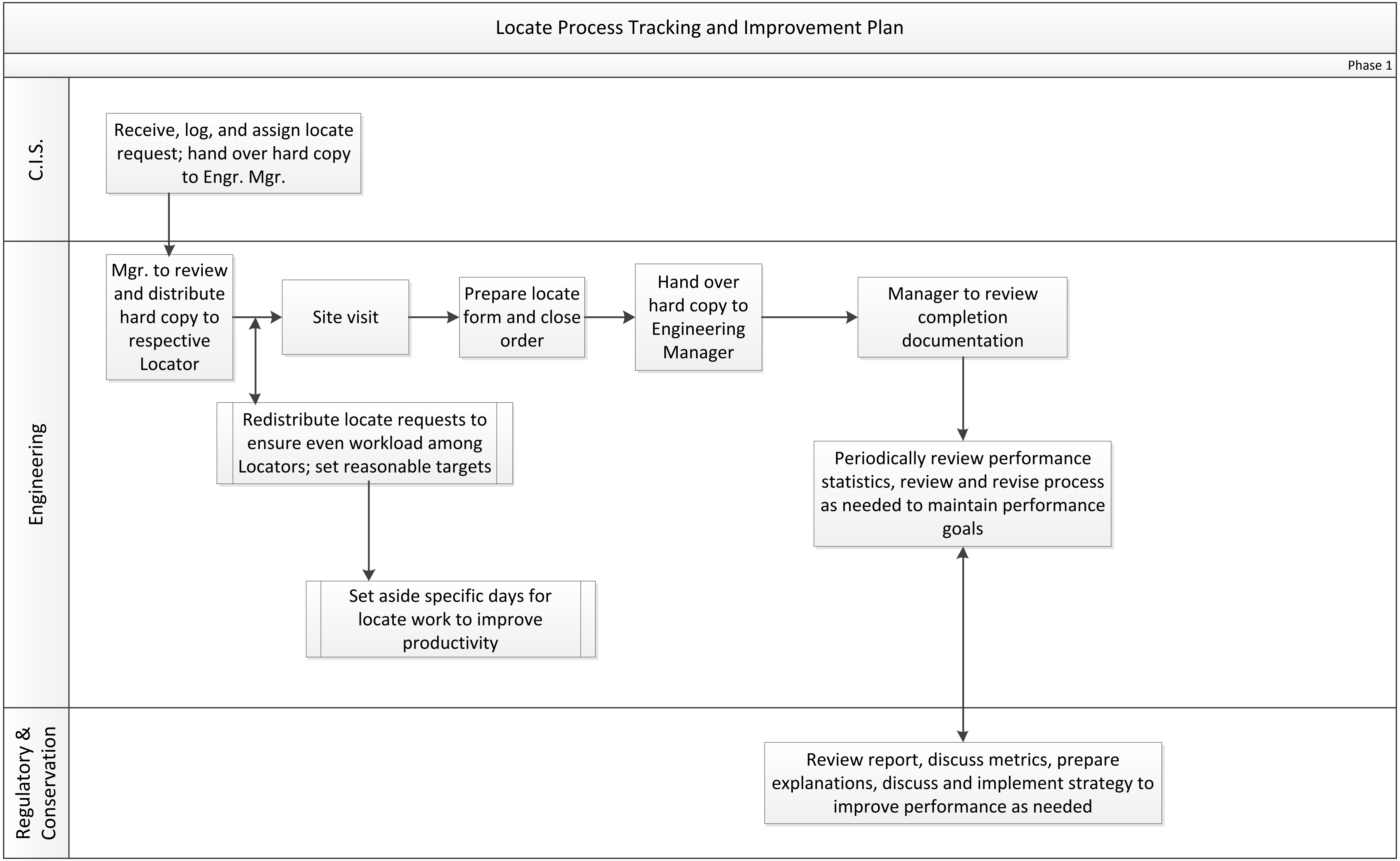
Year End Analysis

We conducted a process review within the organization in the summer to evaluate our current processes to identify opportunities for improving our locate turnaround time (our new process chart is attached).

Based on our review we implemented several changes that resulted in reduced turnaround times for the second half of the year.

Some of the process improvement steps include:

- creating a greater awareness among locators to work proactively to meet customer obligations, including planning workload in advance to prepare for unexpected peaks in locate requests, and balancing workload;
- hiring an external contractor to catch up on backlog of locates in August 2012;
- manually excluding all overhead locates and cancelled appointments;
- streamlining internal and external communication pertaining to locate requests to enable better work management;
- reviewing periodic performance to provide feedback to locators and discuss ongoing strategy to cope with peak workloads;
- providing additional training to locators to further improve work performance/efficiency; and
- mobilizing internal staff to assist when needed.



Prepared by John Aseerwatham, 15-June-2012, Rev 0

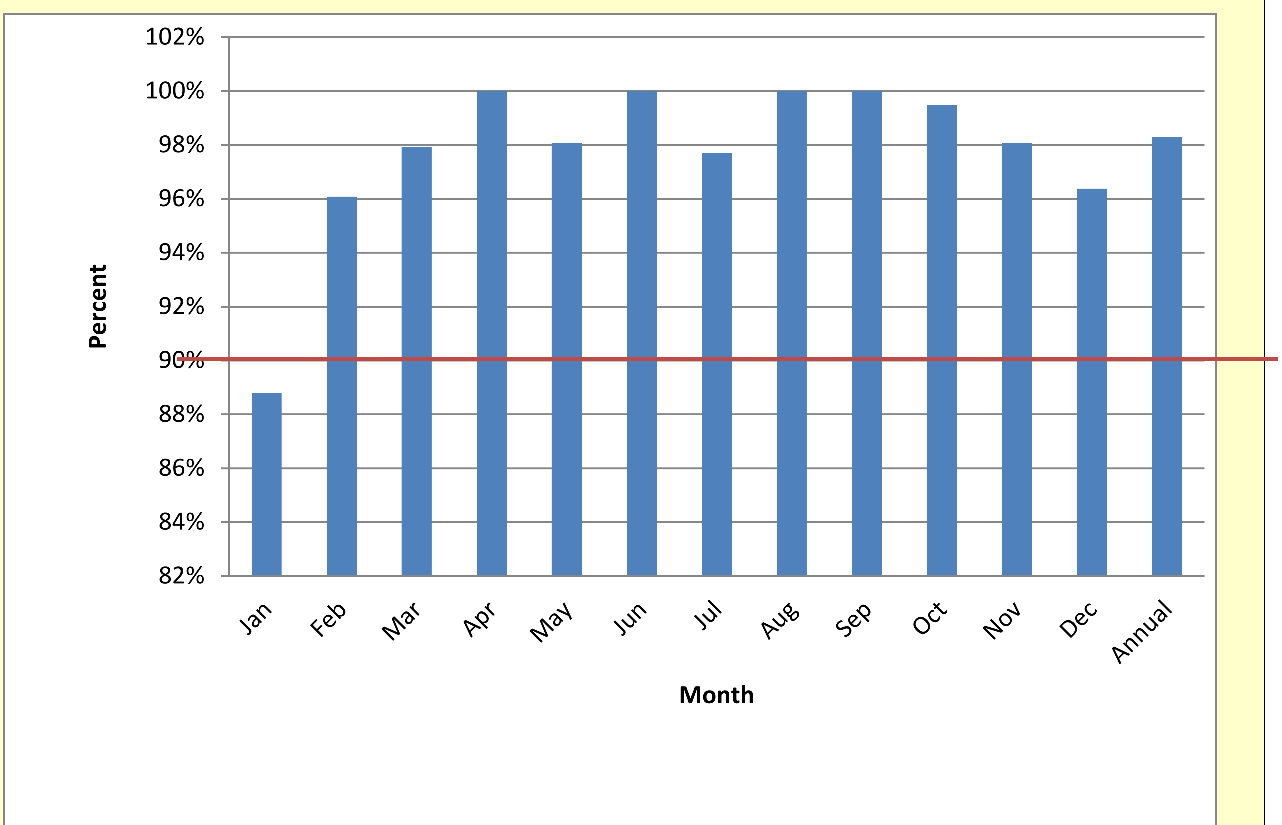
Appointments Scheduled

OEB Report 2.1.4.1.2

Definition:

The appointments indicator measures the percentage of appointments at a customer's premises or work site that are scheduled within the 5 business day window. This service quality requirement must be met at least 90% of the time on an annual basis.

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012
# Appointments scheduled/completed	95	98	142	189	254	201	212	184	212	385	202	133	2307
# Appointment requests received	107	102	145	189	259	201	217	184	212	387	206	38	2347
% Appointments scheduled/completed	89%	96%	98%	100%	98%	100%	98%	100%	100%	99%	98%	96%	98%



Appointments Met

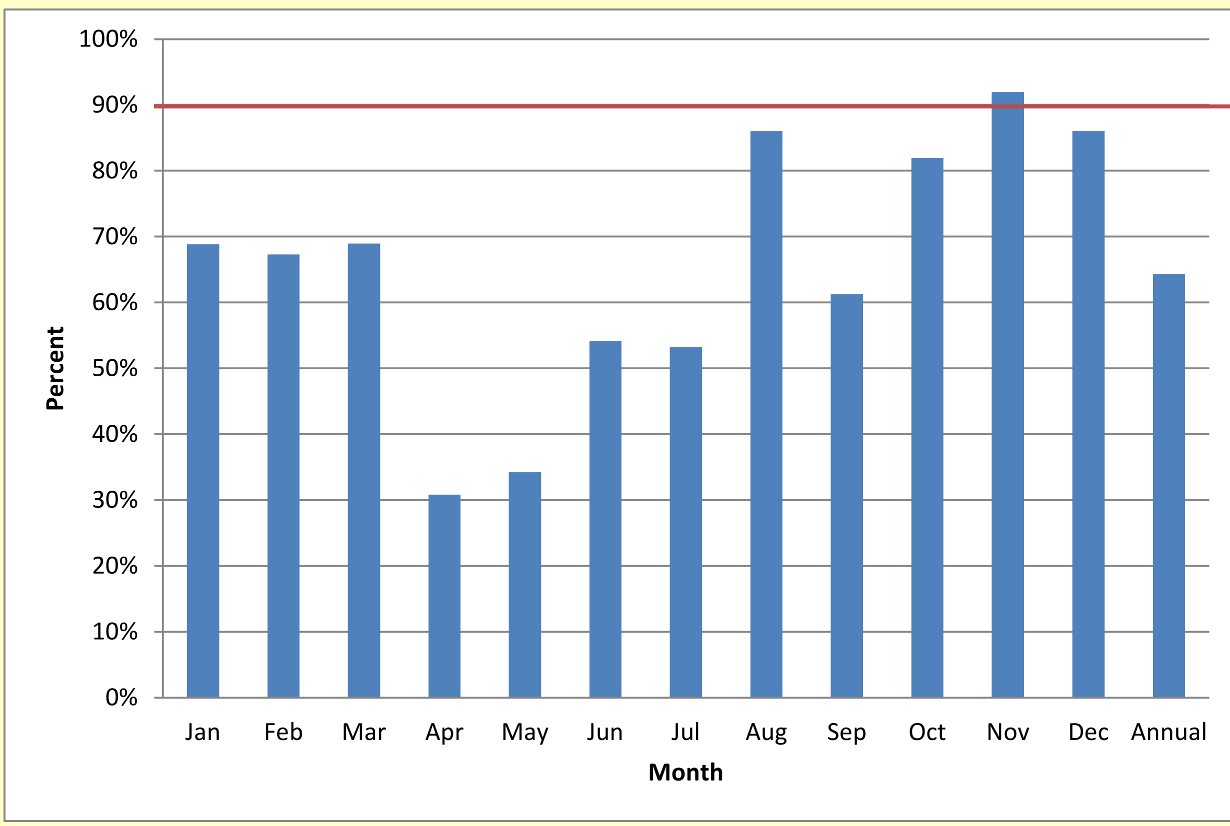
OEB Report 2.1.4.1.3

Definition:

The appointments indicator measures the percentage of appointments at a customer's premises or work site that are met at the appointed time within the minimum performance standard. As a minimum standard, the appointment must be met within a window no greater than 4 hours. The appointments must be met within this window at least 90% of the time on an annual basis; IHDSL must notify the customer if the appointed time cannot be met.

Beginning in 2012, Underground Locates and New Connections are included in Appointments Met.

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Appointments completed as scheduled	95	105	131	70	101	142	138	191	144	318	206	117	**1758**
# Appointments scheduled	138	156	190	227	302	262	259	222	235	388	224	136	**2732**
% Appointments met	**69%**	**67%**	**69%**	**31%**	**33%**	**53%**	**53%**	**86%**	**61%**	**82%**	**92%**	**86%**	**64%**



Telephone Accessibility
Calls Answered Within 30 Seconds

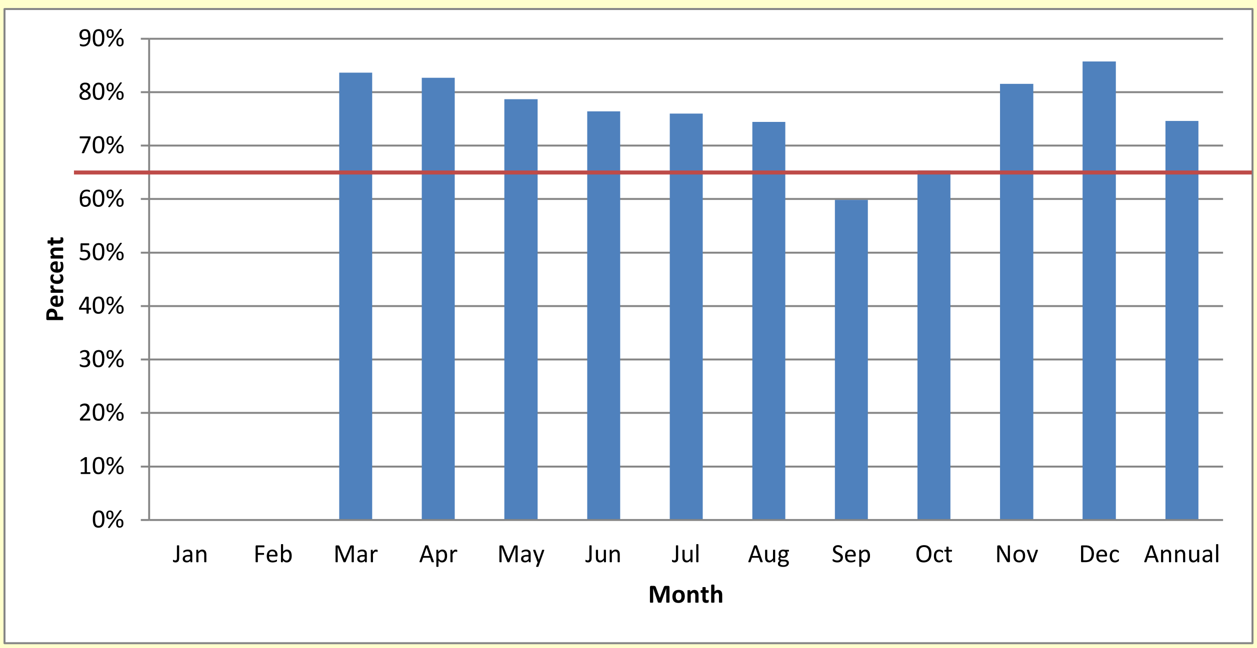
OEB Report 2.1.4.1.5

Definition:

Qualified incoming calls to IHDSL's customer care telephone number must be answered within a 30 second time period. The service quality requirement must be met at least 65% of the time on an annual basis. For qualified incoming calls that are transferred from IHDSL's Nortel phone system, the 30 seconds is counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds is counted from the first ring.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
#Calls Answered < 30sec			998	1355	1319	1274	1881	1500	1581	1691	1390	1056	14045
# Incoming Calls			1193	1639	1677	1667	2475	2015	2641	2589	1705	1232	18833
			84%	83%	79%	76%	76%	74%	60%	65%	82%	86%	75%

Note: Data available from March 9, 2012 due to installation of new system



Telephone Accessibility
Abandoned Calls

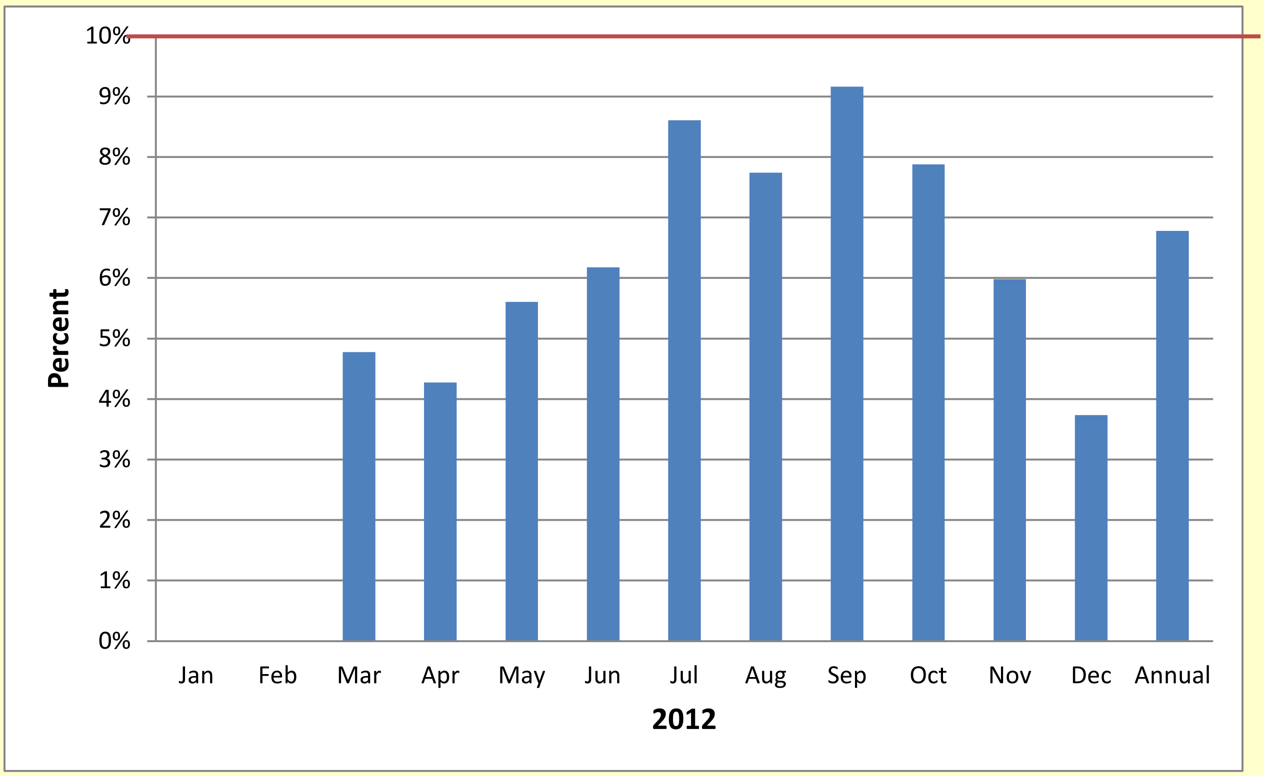
OEB Report 2.1.4.1.6

Definition:

The number of qualified calls to IHDSL's customer care telephone number that are abandoned before they are answered shall be 10 percent or <u>less</u> on an annual basis.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Abandoned			57	70	94	103	213	156	242	204	102	46	**1287**
# Incoming Calls			1193	1639	1677	1667	2475	2015	2641	2589	1705	1232	**18833**
			5%	**4%**	**6%**	**6%**	**8.6%**	**8%**	**9%**	**8%**	**6%**	**4%**	**6.8%**

Note: Data available from March 9, 2012 due to installation of new system.

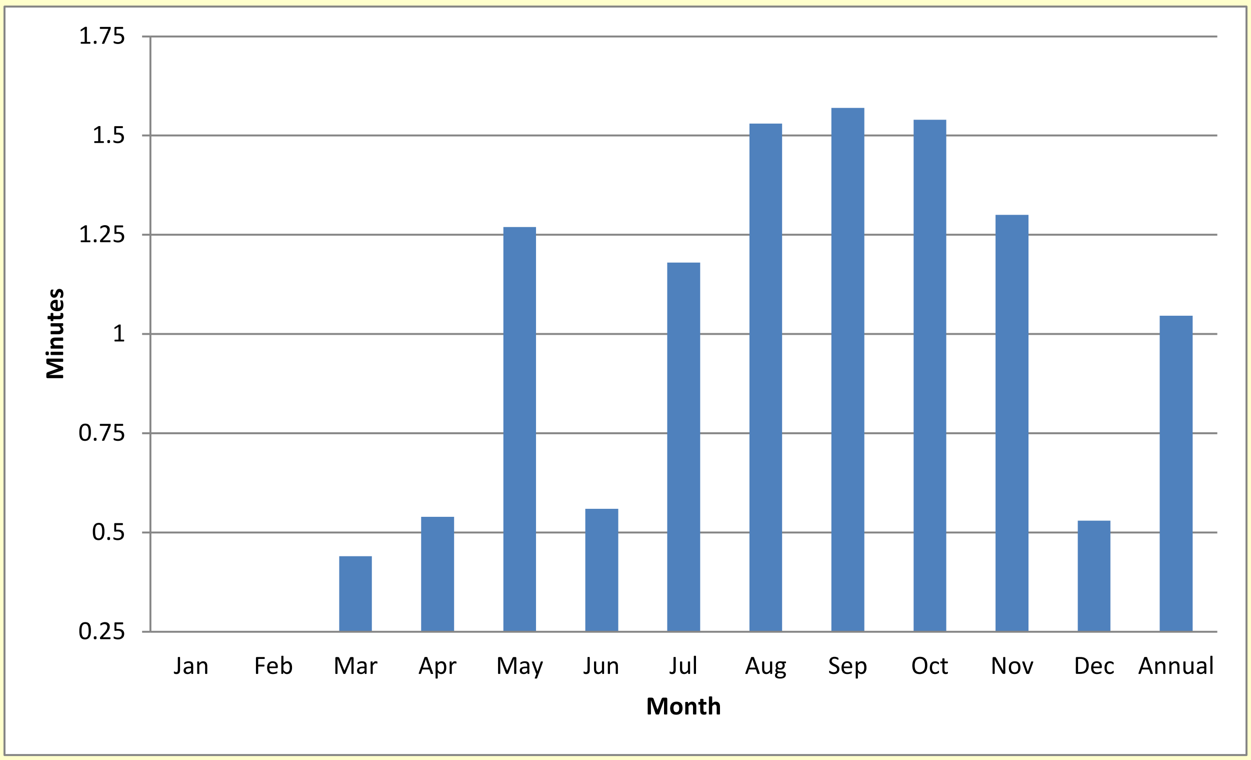


Telephone Accessibility
Average time to Abandon

This is an internal measurement which identifies a customer's tolerance to wait for a Customer Service Representative. The time reflected is tracked once a customer opts for the CSR queue.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Incoming Calls			1250	1709	1771	1770	2688	2170	2881	2792	1806	1277	**20114**
Average Time to Abandon (mns)			0.44	0.54	1.27	0.56	1.18	1.53	1.57	1.54	1.3	0.53	**1.05**

Note: Data available from March 9, 2012 due to installation of new system

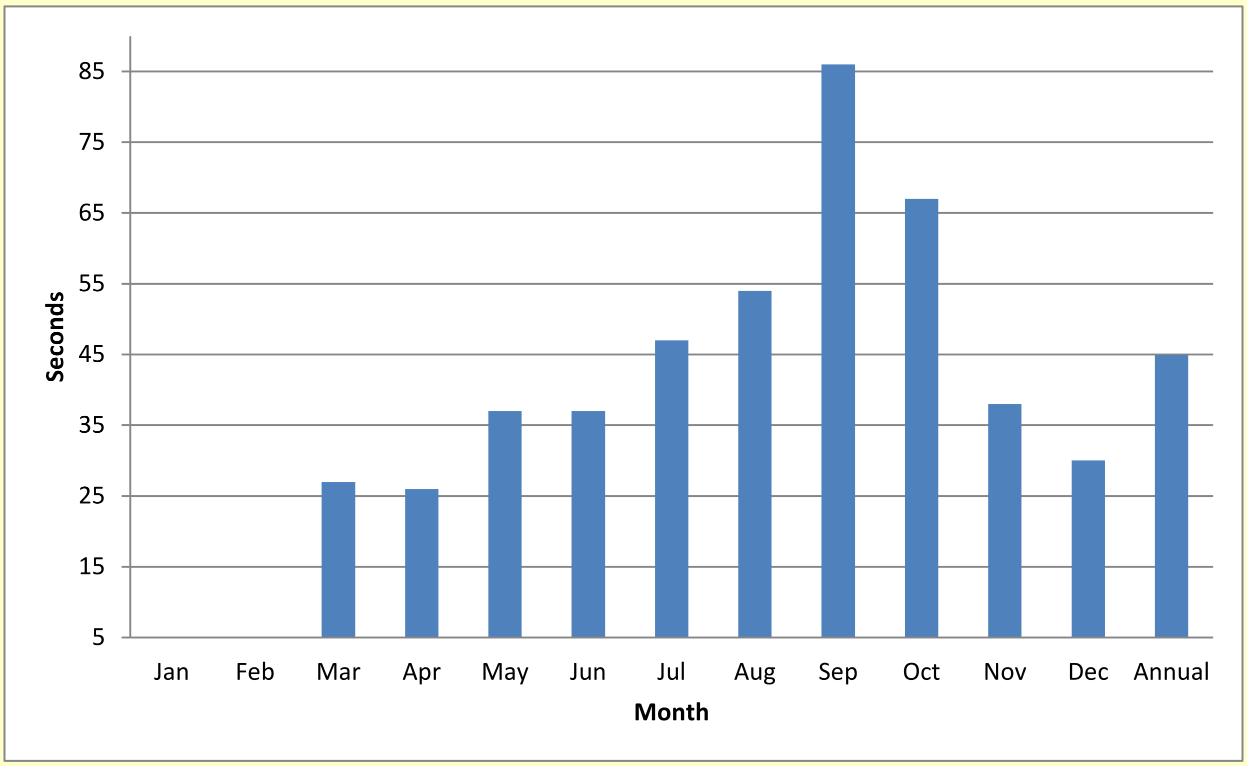


Telephone Accessibility
Average Time to Answer

This is an internal measurement, used to tack the average time taken to answer an incoming customer call.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
# Incoming Calls			1250	1709	1771	1770	2688	2170	2881	2792	1806	1277	**20114**
Average Time to Answer (seconds)			27	26	37	37	47	54	86	67	38	30	**45**

Note: Data available from March 9, 2012 due to installation of new system

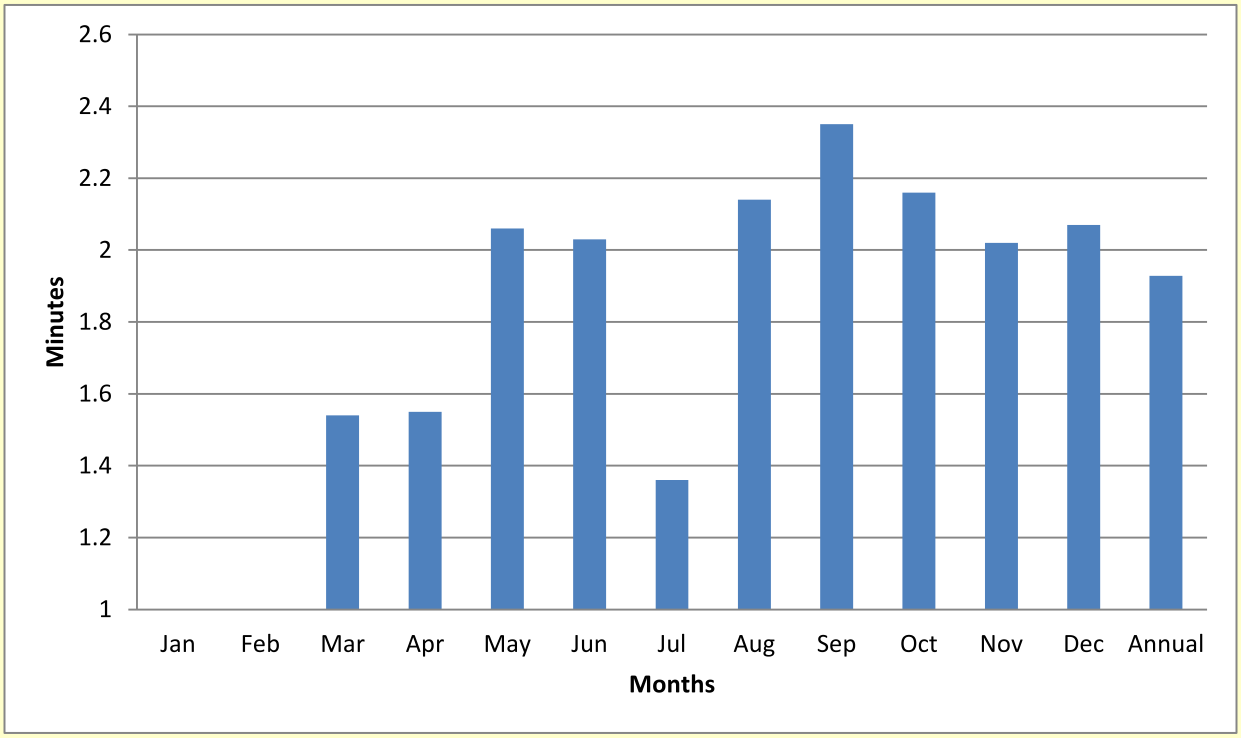


Telephone Accessibility
Average Call Length

This is an internal measurement, used to track the average length of a customer call.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Average Call Length			1.54	1.55	2.06	2.03	1.36	2.14	2.35	2.16	2.02	2.07	1.93

Note: Data available from March 9, 2012 due to installation of new system



Written Responses to Enquiries

OEB Report 2.1.4.1.7

Definition:

The minimum standard for responding to requests by a customer or an agent of the customer for written information relating to the customer's account will be within 10 working days following receipt of the request. The written response time must be met at least 80% of the time on an annual basis.

Gap: All customer requests must be logged in a central filing system.

Recommendation:

2007	2008	2009	2010	2011	2012 YTD
100%	100%	100%	100%	100%	100%

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
# of Written Responses Provided in 10 days	74	51	66	110	140	141	145	146	81	88	93	75
# of Qualified Enquiries Received	74	51	66	110	140	141	145	146	81	88	93	75
% Written Responses Provided in 10 days	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

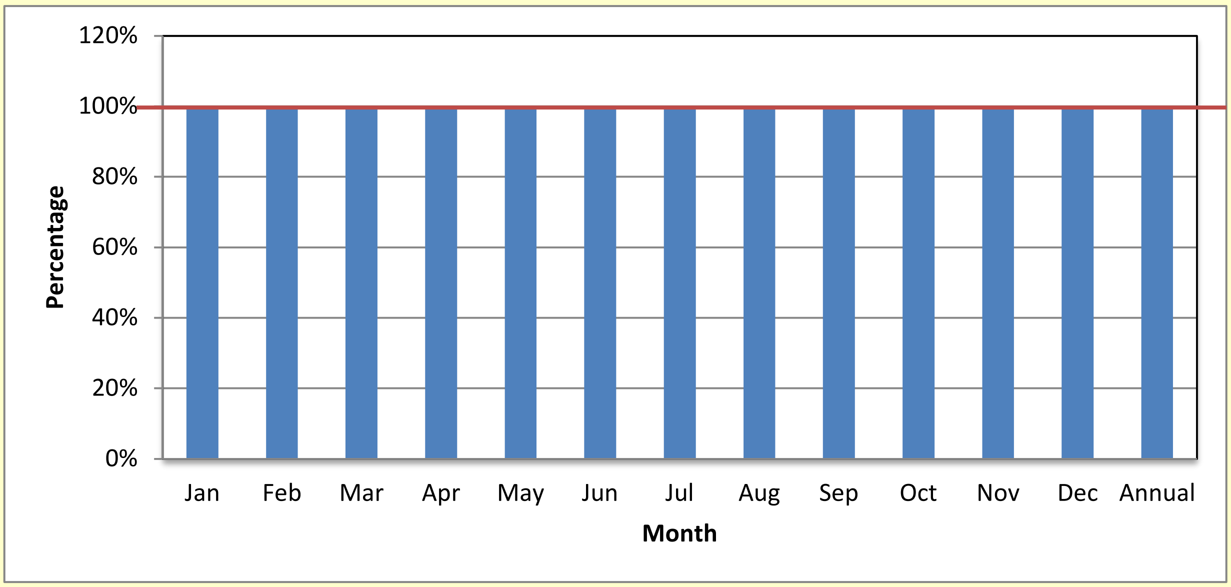
Emergency Response in Rural Areas

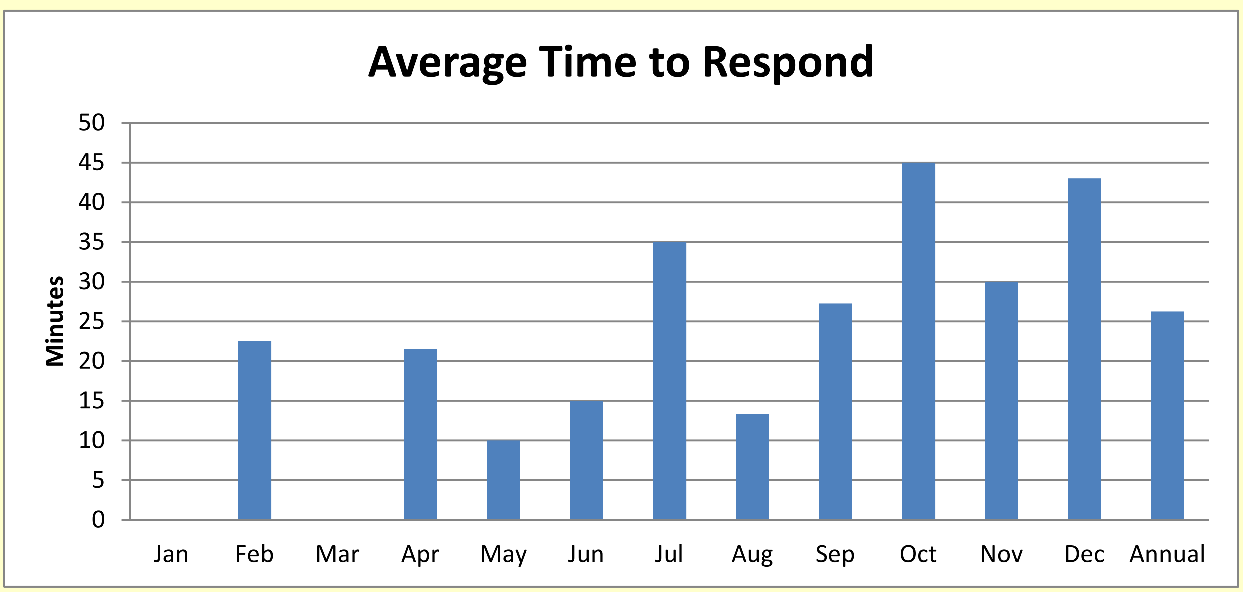
OEB Report 2.1.4.1.8

Definition:

Emergency calls must be responded to within 120 minutes in rural areas, at least 80% of the time on an annual basis.

2007	2008	2009	2010	2011	2012 YTD
100%	100%	100%	100%	100%	100%





SUMMARY OF SERVICE RELIABILITY STATISTICS

IHDSL tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index).

Reliability Indicator														Annual	
		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	2012	2011
System Average Interruption Duration Index (SAIDI)	All outages	0.03	0.77	0.81	0.06	0.00	0.06	1.03	.07	.10	.11	.05	.01	3.11	1.04
	Excluding Loss of Supply*	0.03	0.00	0.05	0.06	0.00	0.06	1.03	.07	.02	.02	.00	.01	1.36	.98
System Average Interruption Frequency Index (SAIFI)	All outages	0.06	0.22	0.31	0.04	0.00	0.06	0.50	.03	.38	.04	.03	.00	1.69	1.39
	Excluding Loss of Supply*	0.06	0.00	0.01	0.04	0.00	0.06	0.50	.03	.00	.01	.00	.00	.71	1.11
Customer Average Interruption Duration (CAIDI)	All outages	0.52	3.48	2.38	1.77	2.95	1.07	2.07	2.38	.26	3.12	1.73	2.01	1.84	0.75
	Excluding Loss of Supply*	0.52	1.52	3.35	1.77	2.95	1.07	2.07	2.38	6.04	3.83	.83	2.01	1.92	.88

Note: The following graphs are shown excluding "Loss of Supply". For the purposes of this Scorecard, we are addressing those instances where we have control only.

System Average Interruption Duration Index (SAIDI)

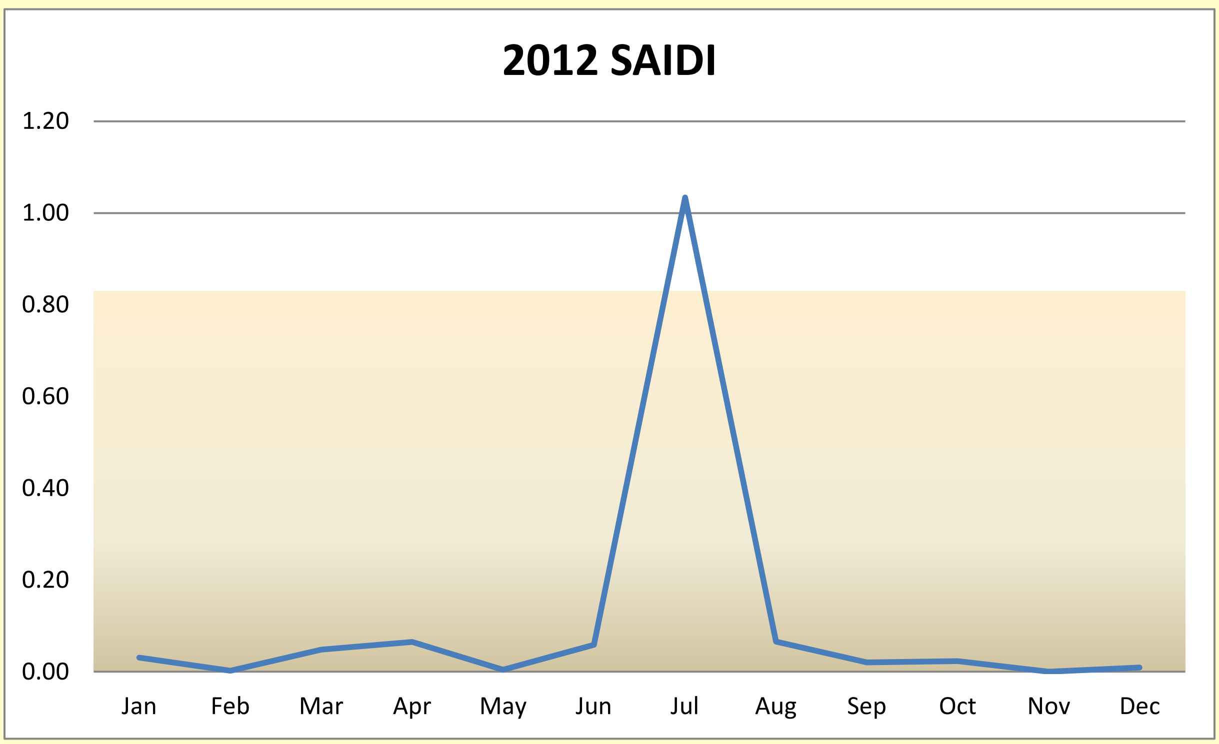
Excluding Loss of Supply

SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year, on average. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

$$\textbf{SAIDI} = \frac{\textbf{Total Customer Hours of Interruptions}}{\textbf{Total Number of Customers Served}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

The highlighted section indicates the range for the period 2009 to 2011: 0 to .83 hours. Therefore, IHDSL was above the range for July 2012 due to large volume of storms/adverse weather conditions which occurred in that month.



System Average Interruption Frequency Index (SAIFI)

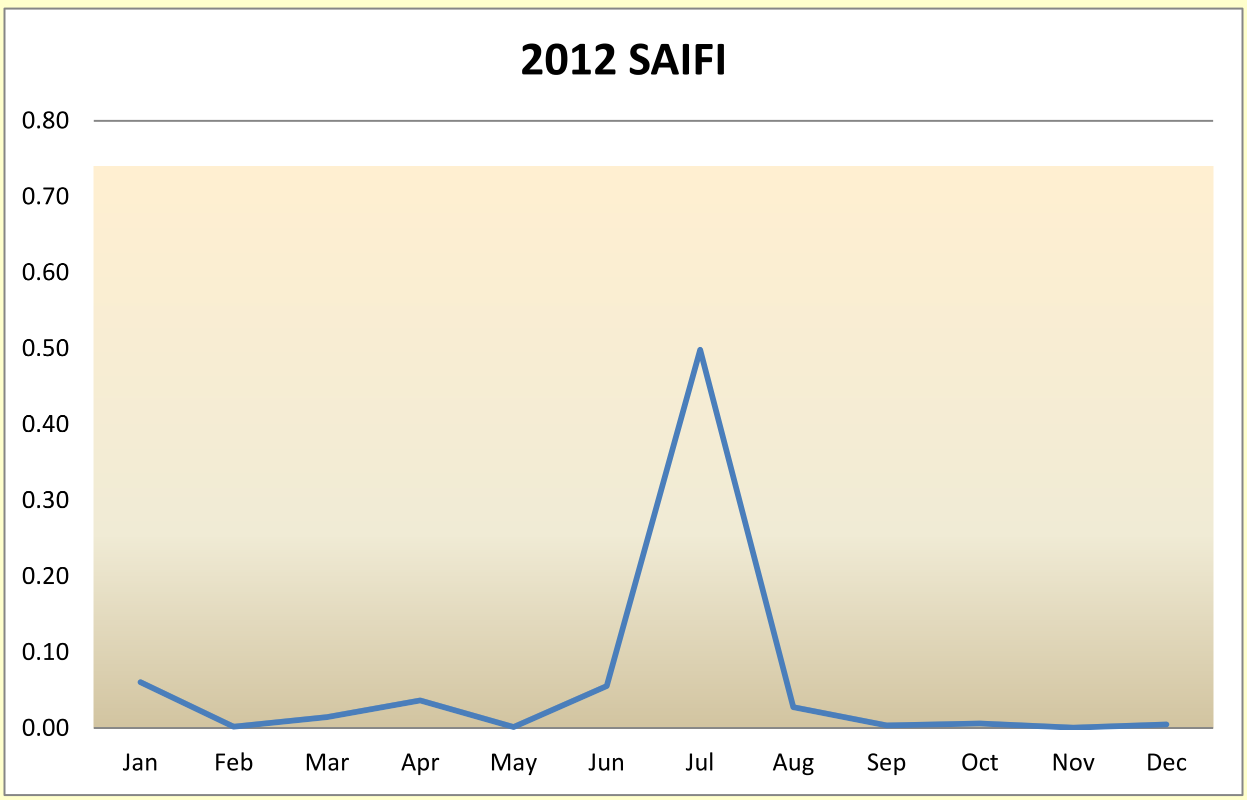
Excluding Loss of Supply

SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the number of interruptions normalized per customer served, and is expressed as follows:

$$\textbf{SAIFI} = \frac{\textbf{Total Customer Interruptions}}{\textbf{Total Number of Customers Served}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

The highlighted section indicates the range for period 2009 to 2011: 0 to .74 hours. Therefore, IHDSL has remained within the range for 2012. *Note that in July there were a large volume of storms/adverse weather conditions.*



Customer Average Interruption Duration Index (CAIDI)

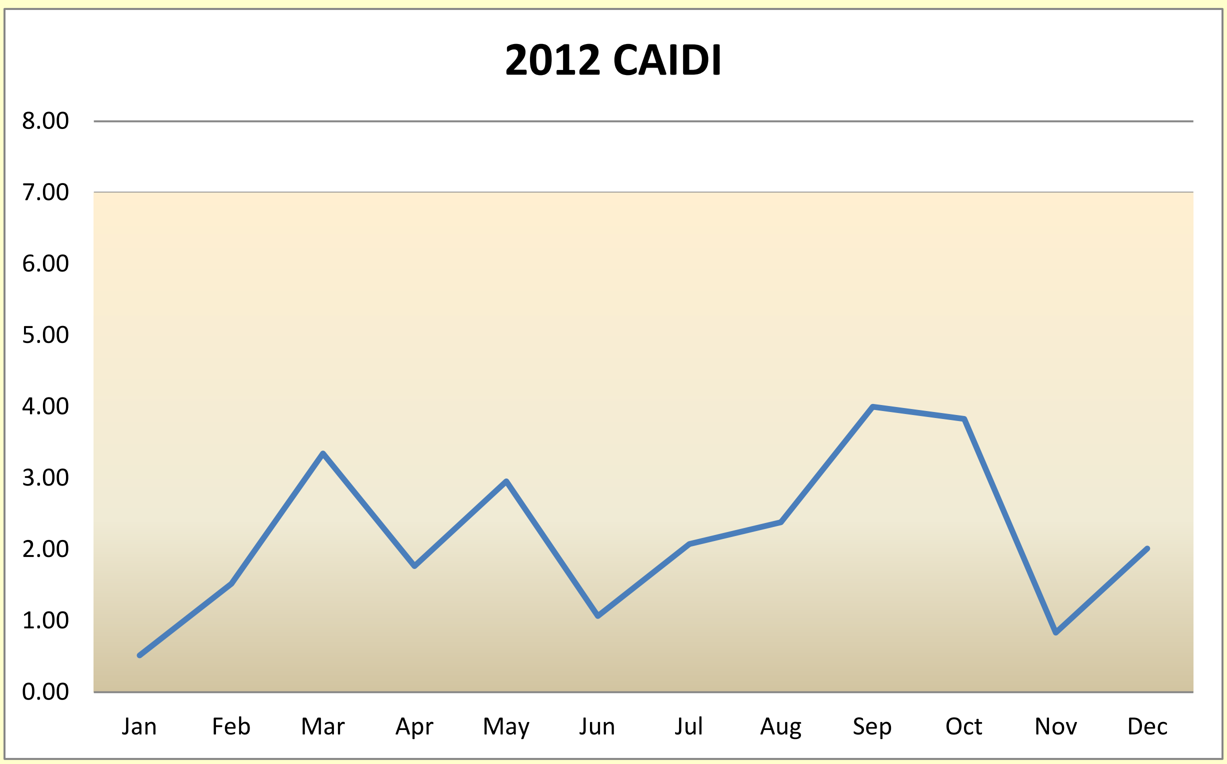
Excluding Loss of Supply

CAIDI is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the average duration of interruptions in the year, and is expressed as follows:

$$\textbf{CAIDI} = \frac{\textbf{System Average Interruption Duration Index (SAIDI)}}{\textbf{System Average Interruption Frequency Index (SAIFI)}}$$

IHDSL is required to remain, at minimum, within the range of our historical 3-year performance.

The highlighted section indicates the range for period 2009 to 2011: .47 to 7.00 hours. You will note that IHDSL has remained within the range for 2012.



2012 SAIFI, SAIDI, CAIDI Year End Analysis

July 2012 Performance:

During the month of July IHDSL service territory experienced three days of inclement weather on July 7, 23, and 31, consisting of what appeared to be micro-bursts/high winds, rains, thunder and lightning, etc. As seen in the table below over 75% of total customers who lost power in July did so during these three days; and of the total hours of down time, 56% of it occurred during these three days.

Cause	Non-storm	Storm	No of Customers Affected
Adverse Weather		5748	5748
Defective Equipment	1540		1540
Foreign Interference	2		2
Lightning	1	28	29
Scheduled Outage	272		272
Tree Contacts	4	34	38
Grand Total	1819	5810	7629
	24%	**76%**	100%

Cause	Non-storm	Storm	Total Customer Hrs.
Adverse Weather		8752	8752
Defective Equipment	6043		6043
Foreign Interference	12		12
Lightning	1	45	47
Scheduled Outage	894		894
Tree Contacts	25	48	73
Grand Total	6975	8845	15820
	44%	**56%**	**100%**

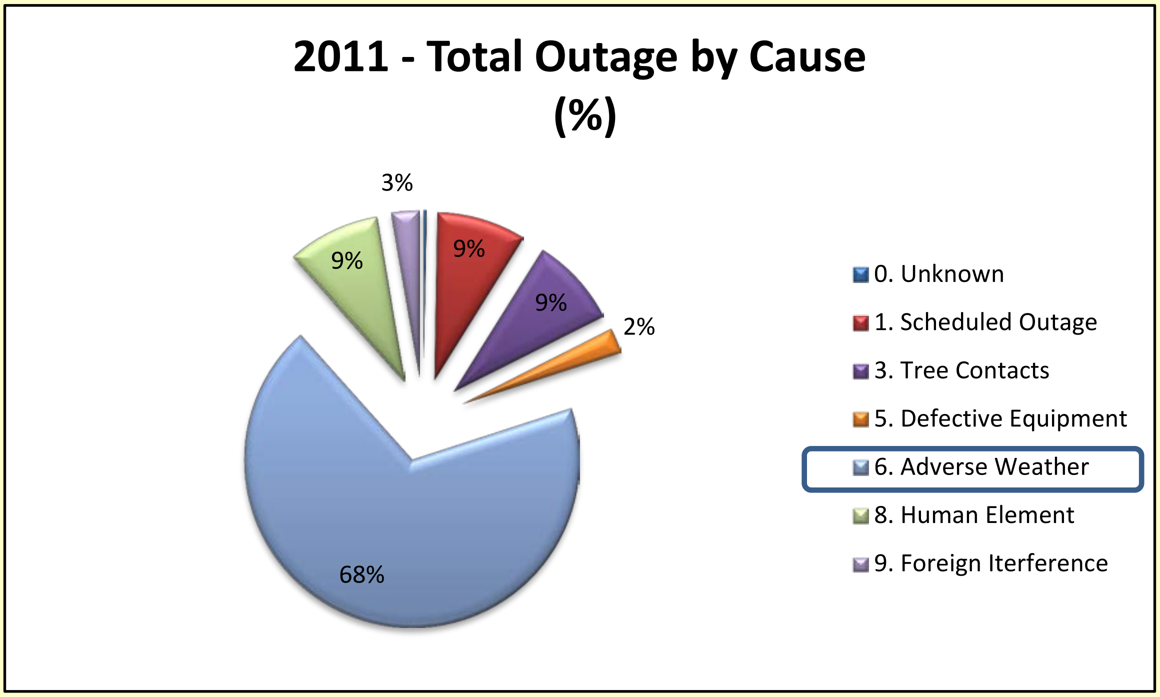
We have implemented corrective measures such as tree trimming, asset inspection/replacement of deteriorating infrastructure to help storm harden our infrastructure.

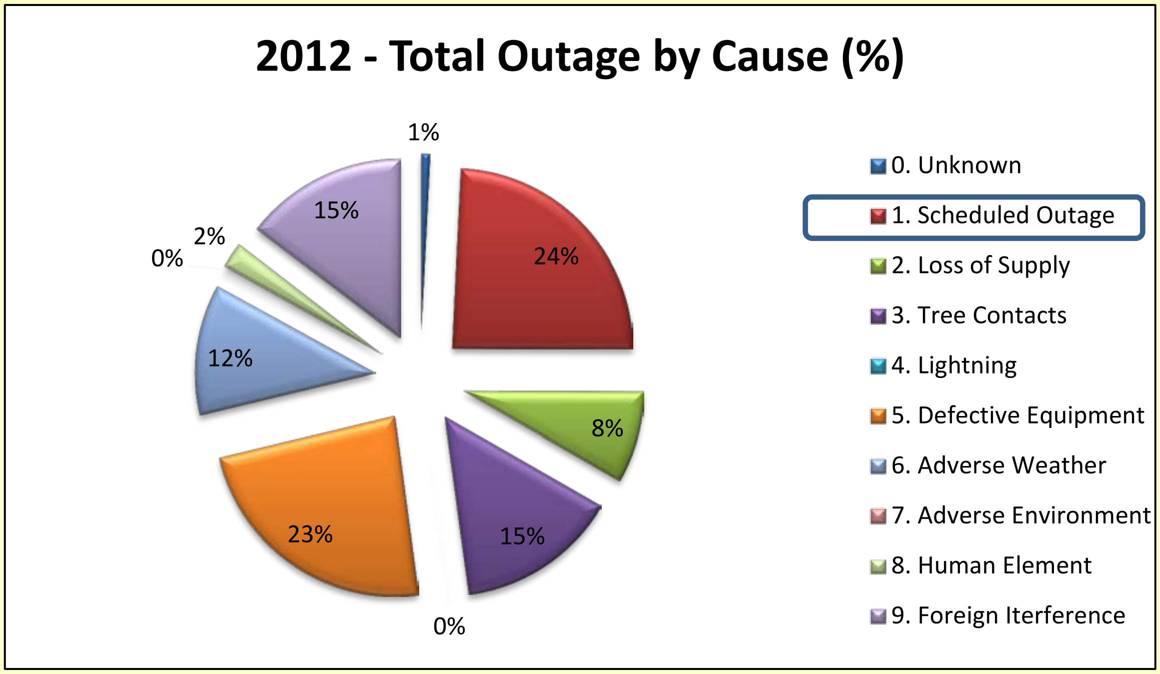
September 2012 Performance:

High CAIDI value:
During the month of September we needed to take two long scheduled outages to take down a tree that posed a danger to our crews (if they had worked on it live). These two outages together contributed to **83%** of total customer outage hours.

Service Interruption
by Cause (percentage)

The following graphs show the breakdown of causes of customer outages, excluding Loss of Supply.

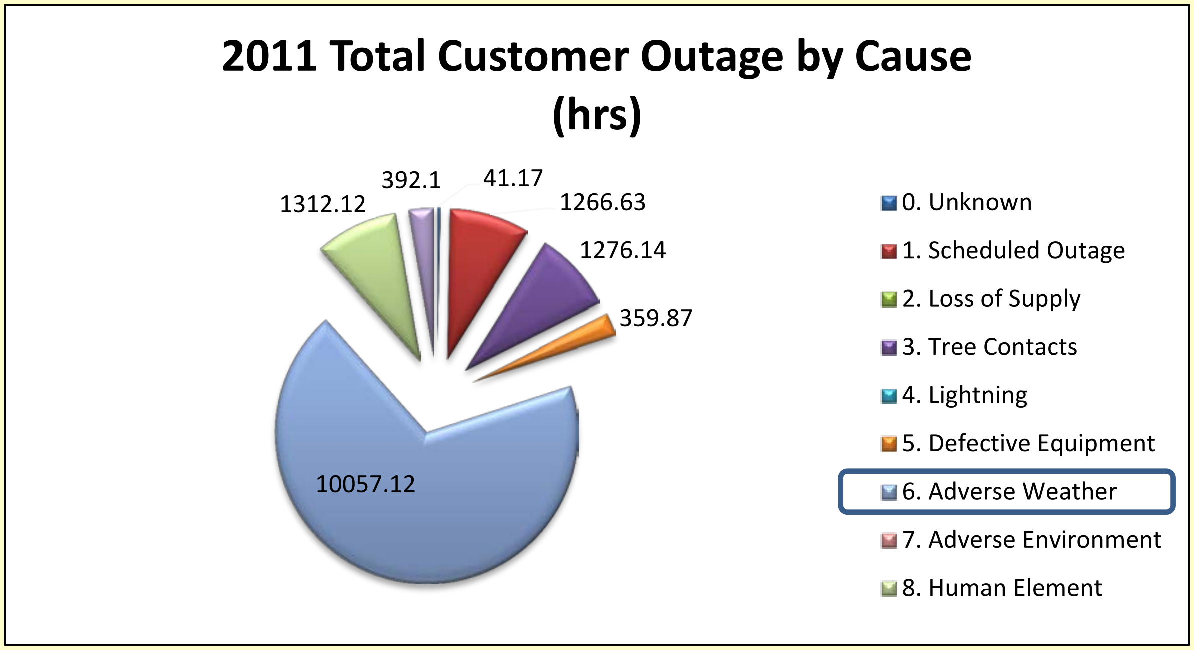


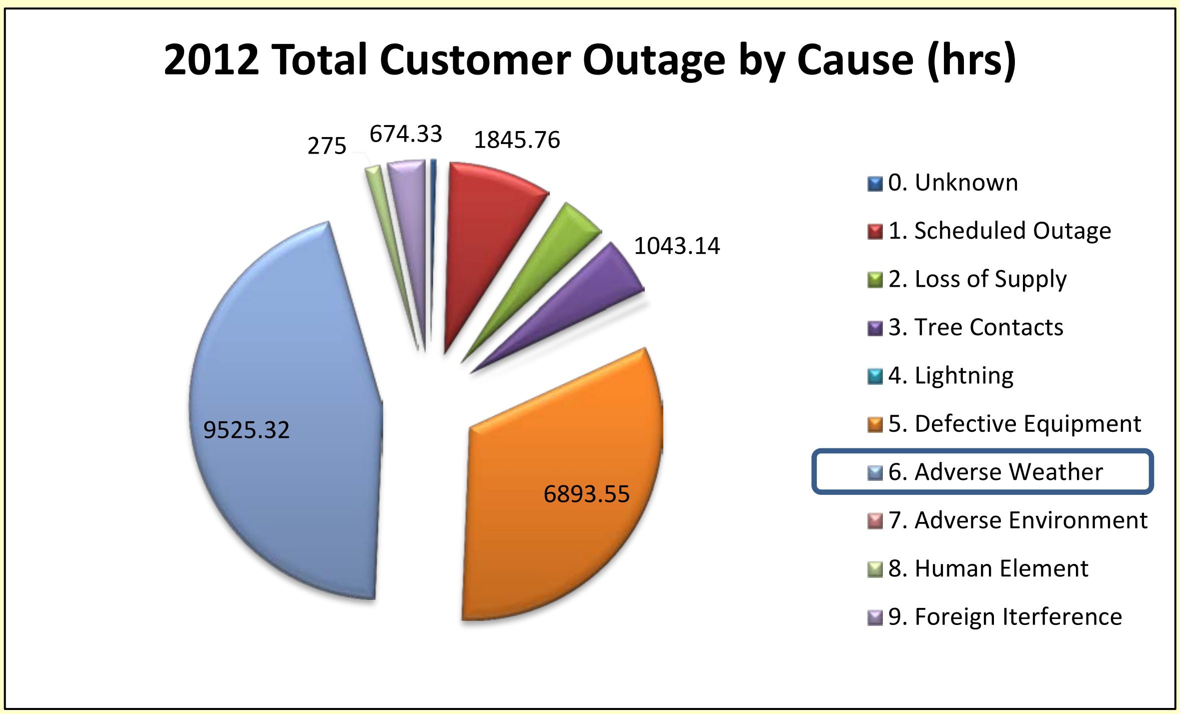


Service Interruption

by Cause (hours)

The following graphs show the breakdown of cause of customer outages, excluding Loss of Supply.

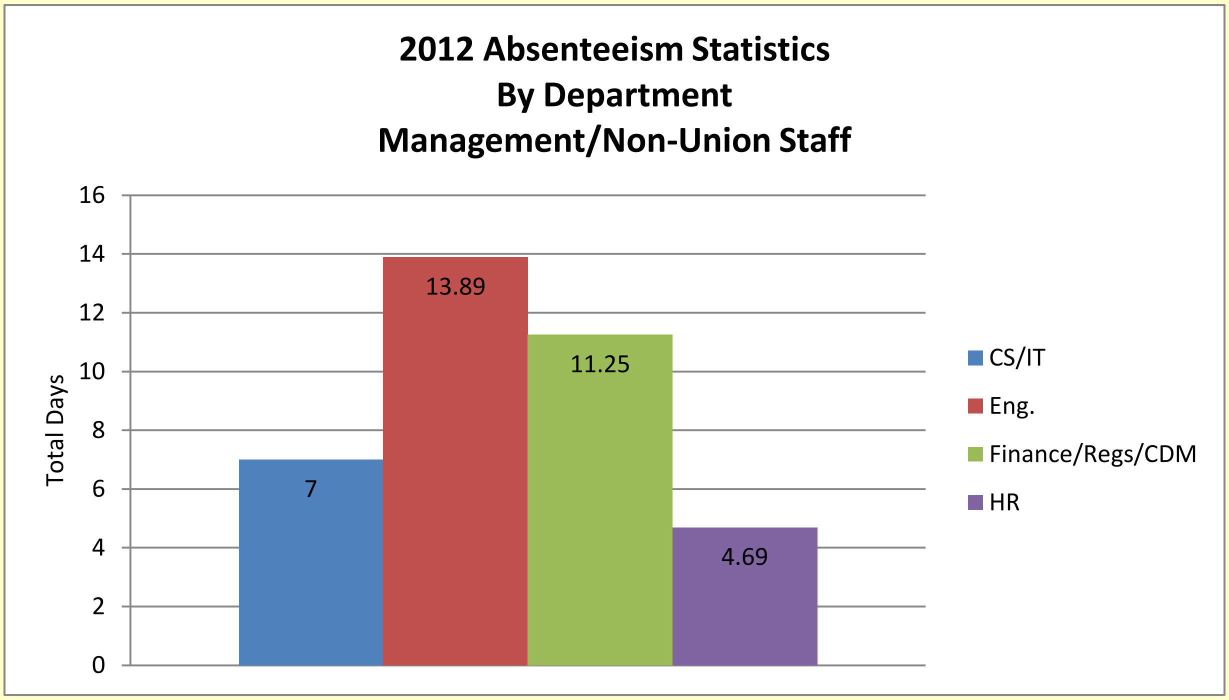


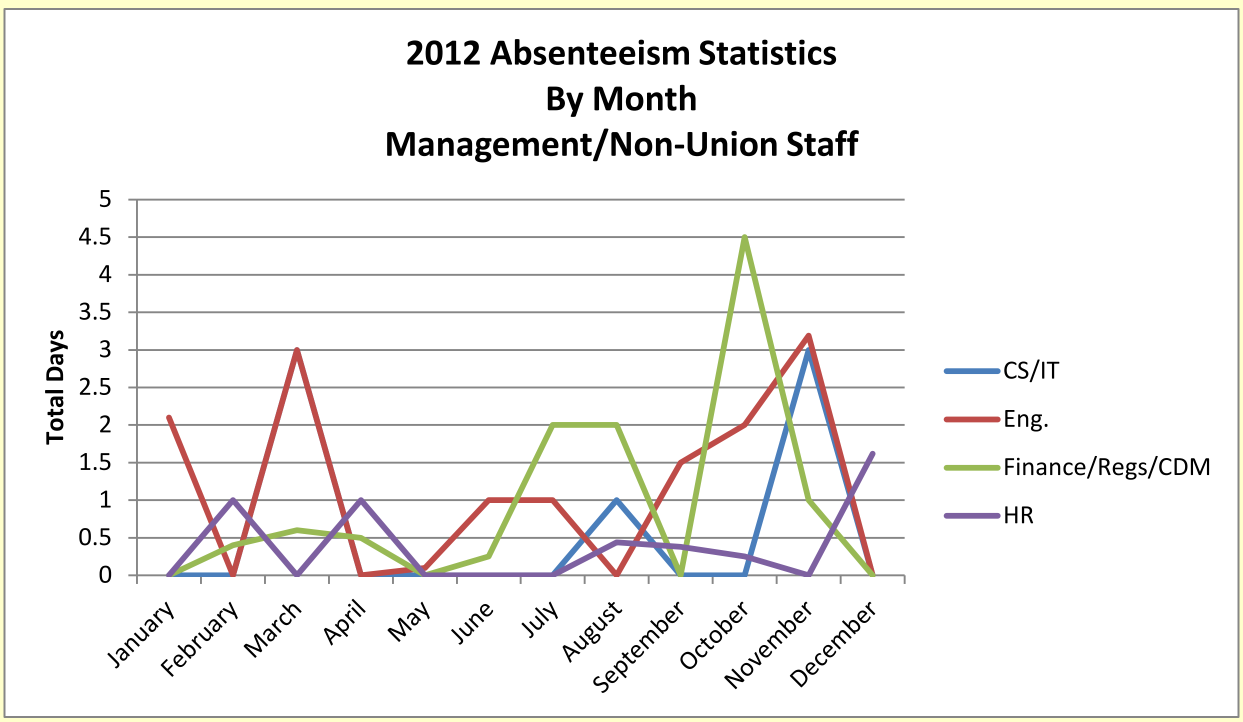


Human Resources

Absenteeism Statistics – 2012 To Date

Management/Non-Union Staff

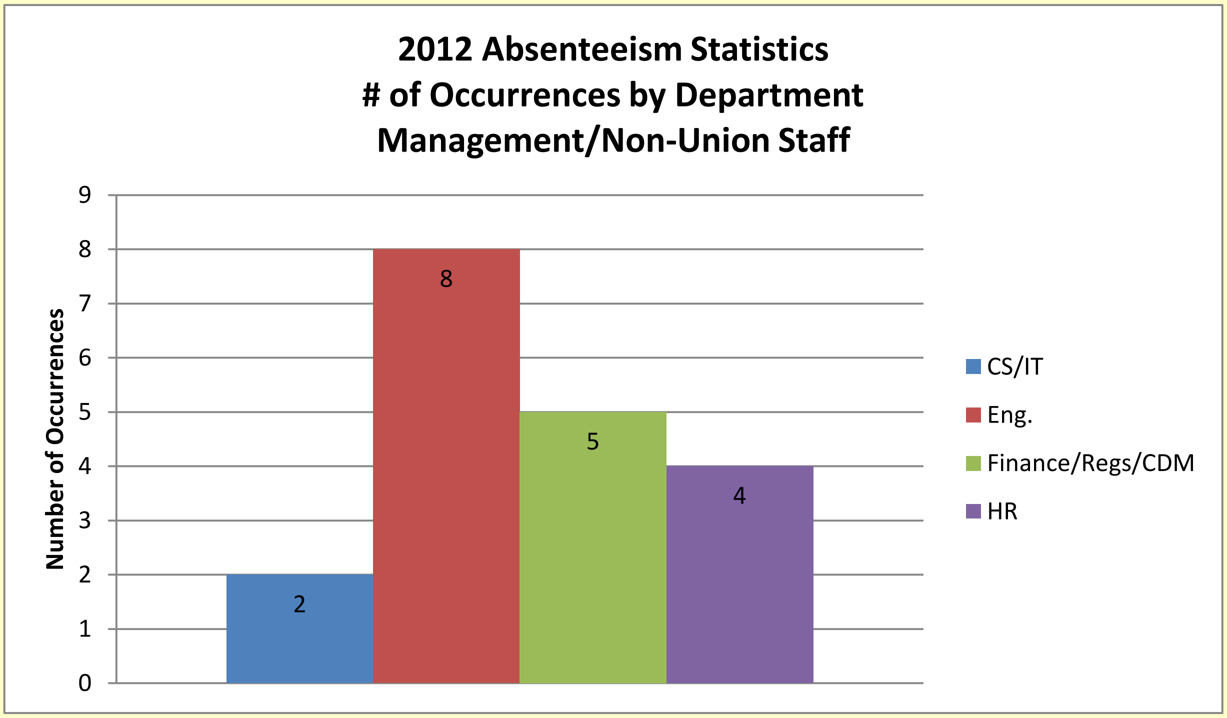


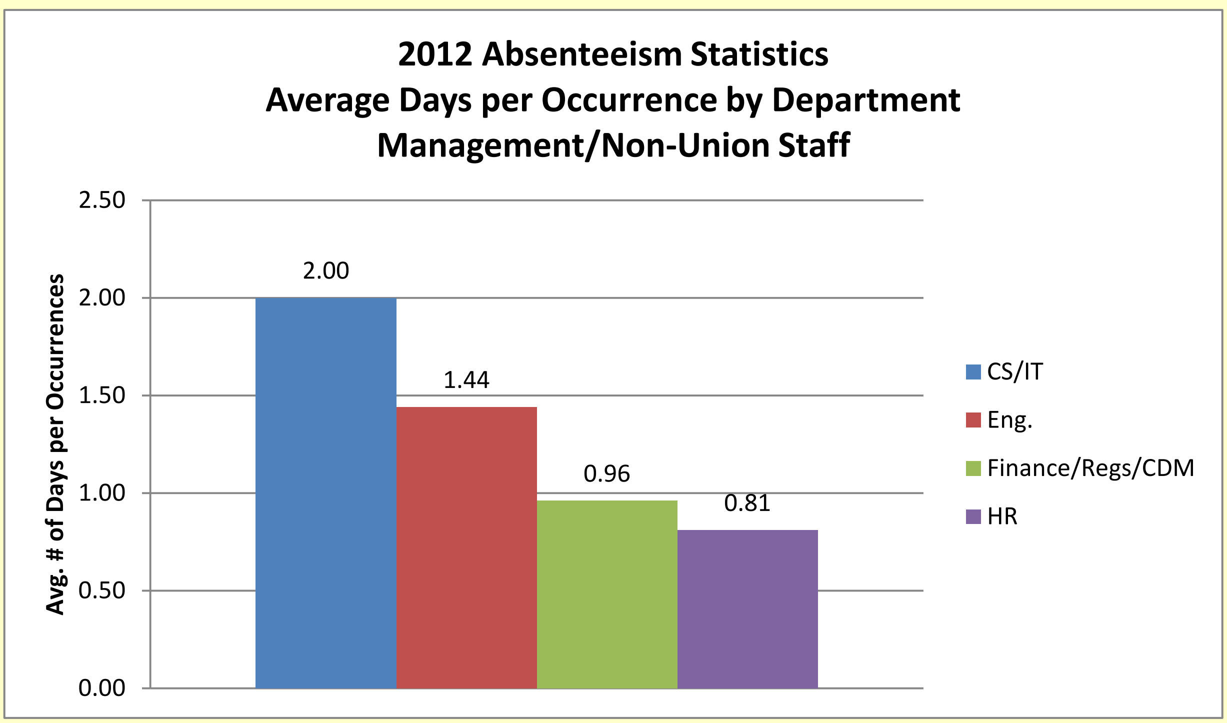


Human Resources

Absenteeism Statistics – 2012 To-Date

Management/Non-Union Staff

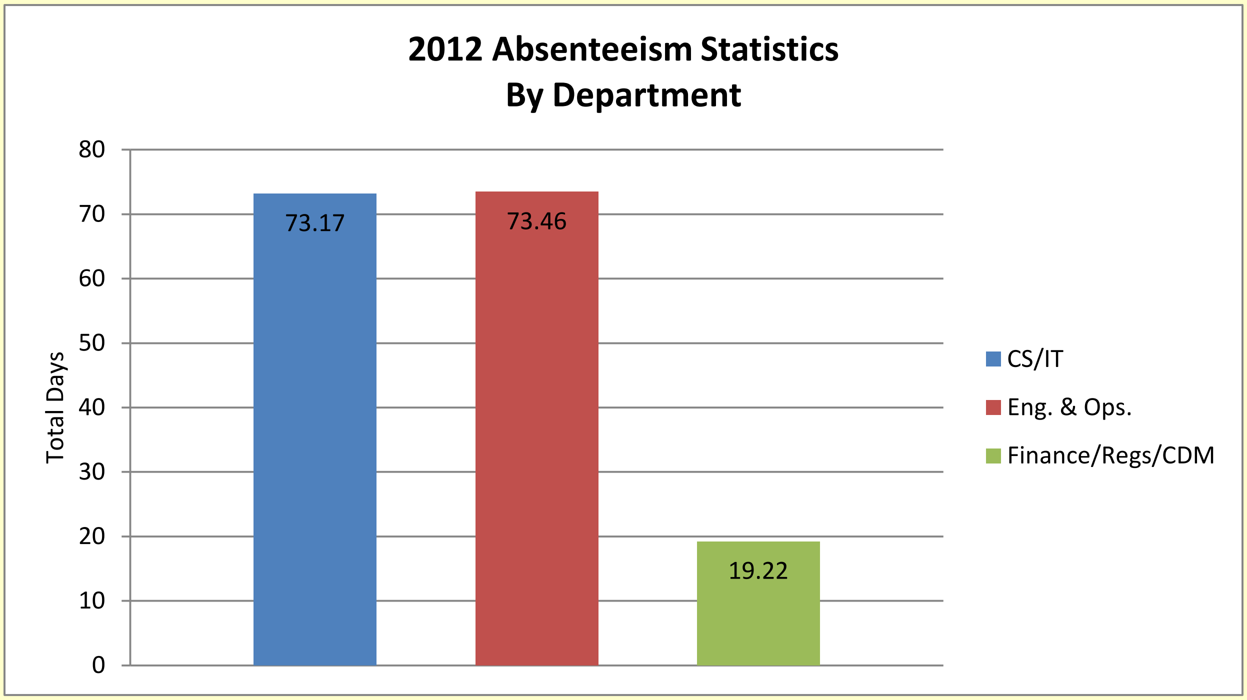


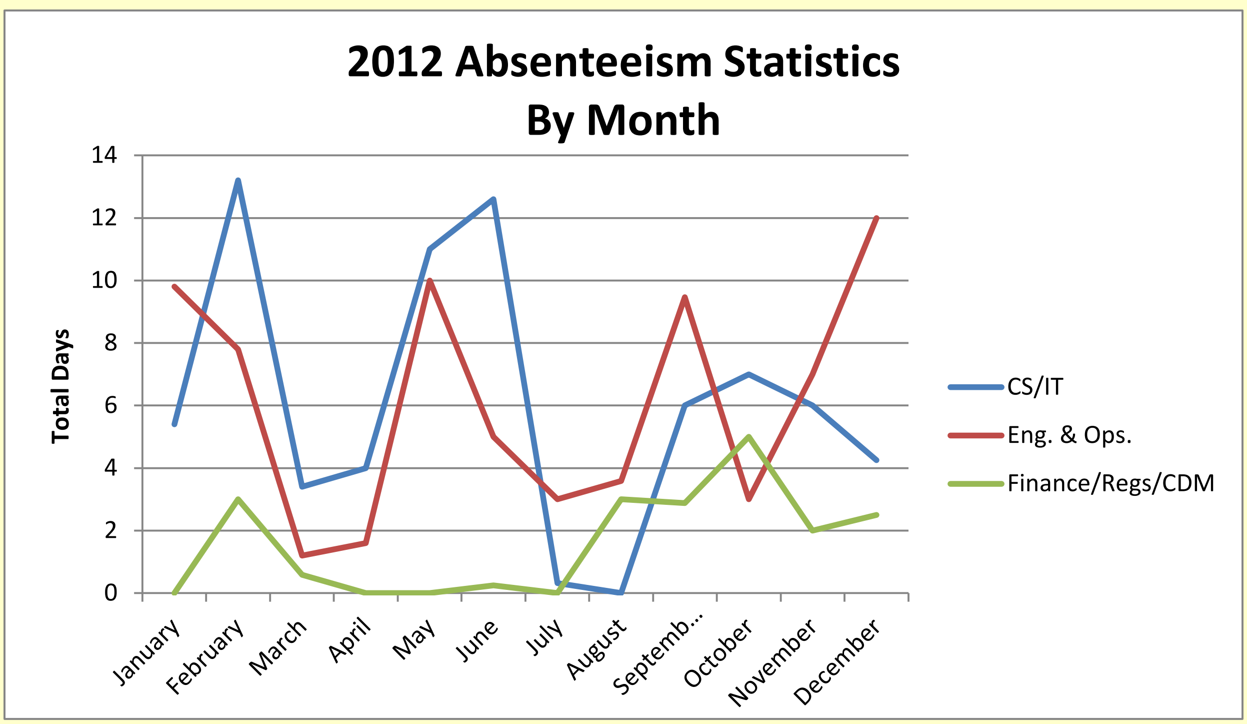


Human Resources

Absenteeism Statistics – 2012 To-Date

Unionized Staff



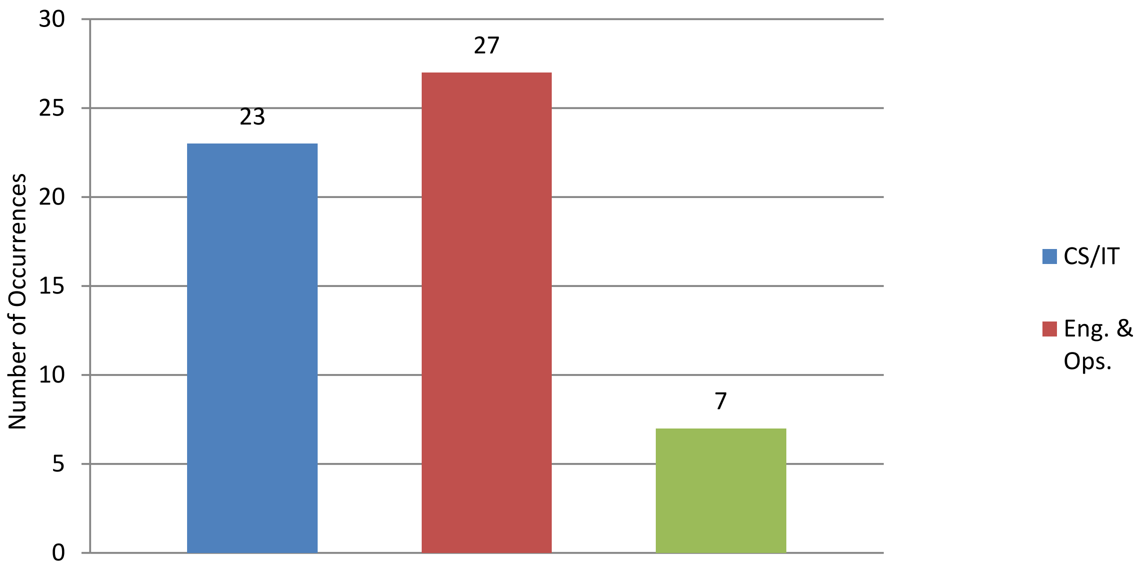


Human Resources

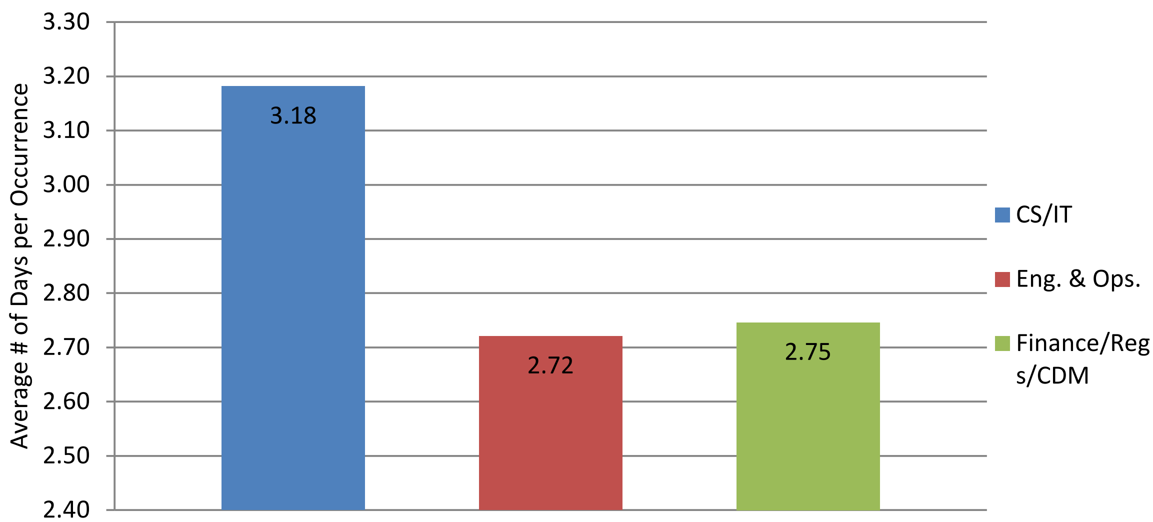
Absenteeism Statistics – 2012 To-Date

Unionized Staff

2012 Absenteeism Statistics
# of Occurrences by Department



2012 Absenteeism Statistics
Average Number of Days Per Occurrence by Department
Unionized Staff



Human Resources

Year End Analysis

In an effort to address the escalating sick leave costs, IHDSL has implemented a corporate Wellness Policy in January 2013, which contains regular reporting, acceptable thresholds and follow-up procedures.

CDM Quarterly

Unverified Progress To Targets 2012:

IHDSL Target 2011 - 2014	Q1	Q2	Q3	Q4	YTD
Demand Savings: 2.5 MW	8.6%	6.9%*			
Energy Savings: 9.2 GWH	20.1%	30.6%			

***** ***Demand savings are not cumulative***

Note: Results are not verified until September of the following year.

Q2 - 2012 OPA Results

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

Table 4: Innisfil Hydro Distribution Systems Limit

#	Initiative	Unit	Incremental Activity (new program activity occuring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Consumer Program														
1	Appliance Retirement	Appliances	12	20			1	1			308	8,663		
2	Appliance Exchange	Appliances	0	0			0	0			0	0		
3	HVAC Incentives	Equipment	24	15			6	3			14,952	7,496		
4	Conservation Instant Coupon Booklet	Coupons	0	0			0	0			0	0		
5	Bi-Annual Retailer Event	Coupons	0	1,512			0	4			0	57,788		
6	Retailer Co-op	Items	0	0			0	0			0	0		
7	Residential Demand Response	Devices	233	233			130	130			338	338		
8	Residential New Construction	Houses	0	0			0	0			0	0		
Consumer Program Total							138	139			15,597	74,285		
Business Program														
9	Retrofit	Projects	1	2			3	7			21,220	48,625		
10	Direct Install Lighting	Projects	7	4			8	5			21,069	12,039		
11	Building Commissioning	Buildings	0	0			0	0			0	0		
12	New Construction	Buildings	0	0			0	0			0	0		
13	Energy Audit	Audits	0	0			0	0			0	0		
14	Small Commercial Demand Response	Devices	5	5			3	3			12	12		
15	Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total							14	14			42,300	60,676		
Industrial Program														
16	Process & System Upgrades	Projects	0	0			0	0			0	0		
17	Monitoring & Targeting	Projects	0	0			0	0			0	0		
18	Energy Manager	Managers	0	0			0	0			0	0		
19	Retrofit	Projects	1	0			3	0			11,512	0		
20	Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total							3	0			11,512	0		
Home Assistance Program														
21	Home Assistance Program	Projects	0	0			0	0			0	0		
Home Assistance Program Total							0	0			0	0		
Pre-2011 Programs completed in 2011														
22	Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0		
23	High Performance New Construction	Projects	0	0			0	0			0	0		
24	Toronto Comprehensive	Projects	0	0			0	0			0	0		
25	Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
26	LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total							0	0			0	0		
OPA-Contracted LDC Portfolio Total							154	153			69,410	134,961		

IHDSL Summarized Operating Results
Eleven months ending November 30, 2012

Monthly	Actual with SM	Smart Meter	Actual W/O SM	Prior Yr	Budget	Actual vs % Pr	Actual vs % Budget	
Distribution Revenue	600,636	-	600,636	522,695	538,030	114.9%	111.6%	
Other Revenue	6,457	-	6,457	49,251	41,324	13.1%	15.6%	
Expenses	554,156	-	554,156	526,081	563,000	105.3%	98.4%	
Earnings from operations	52,937	-	52,937	45,865	16,354	115.4%	323.7%	
NI after tax and interest	(50,324)	-	(50,324)	(8,695)	(35,450)	578.8%	142.0%	
Distribution plant capital	114,561	-	114,561	305,386	210,329	37.5%	54.5%	
General plant capital	20,820	-	20,820	16,272	648,124	127.9%	3.2%	
Total capital expenditures	135,381	-	135,381	321,658	858,453	42.1%	15.8%	
Total DVA			1,022,833	151,815	695	673.7%	147170.2%	

Year to date	Actual with SM	Smart Meter	Actual W/O SM	Prior Yr	Budget	Actual vs % Pr	Actual vs % Budget	2012 Budget
Distribution Revenue	7,959,545	1,019,141	6,940,404	6,882,092	7,007,770	100.8%	99.0%	7,780,700
Other Revenue	227,737	(42,256)	269,993	540,818	454,476	49.9%	59.4%	495,800
Expenses	6,055,704	864,622	5,191,082	5,670,593	6,314,632	91.5%	82.2%	6,847,810
Earnings from operations	2,131,578	112,263	2,019,315	1,752,317	1,147,614	115.2%	176.0%	1,428,690
NI after tax and interest	999,158	80,268	918,890	813,574	326,230	112.9%	281.7%	486,690
Distribution plant capital	4,626,806	2,162,281	2,464,525	2,873,143	4,361,889	85.8%	56.5%	4,492,261
General plant capital	1,067,909	32,533	1,035,376	(699,491)	1,436,677	-148.0%	72.1%	3,395,300
Total capital expenditures	5,694,715	2,194,814	3,499,901	2,173,652	5,798,566	161.0%	60.4%	7,887,561
Total DVA	(1,753,330)		(1,753,330)	(441,247)	(6,950)	397.4%	25227.8%	2,281,739

Smart Trueup JE - recorded May, June and July 2012

Description	Amount	Category	Account #	Amount
Distribution Revenue-recovery	(1,019,141)	O&M	20.5065.005.000	264,543
Other revenue-Carrying chges	42,256	Billing	40.5320.005.027	69,348
			40.5320.058.000	23,808
Expenses-O&M	264,543		Total B&C	93,156
-Billing	93,156			
-G&A	113,603	G&A	70.5630.044.000	113,603
-Depreciation	393,320	**Total Expenses**		**471,302**
Total Expenses	864,622			
		Meters-Capital cost	00.1860.004.000	2,162,281
Earnings before taxes	(112,263)	Meters-Accum dep	00.2105.423.050	(362,595)
Taxes @ 28.5%	31,995	Comp Softw-Cap cost	00.1925.000.000	32,533
		Comp Softw-Accum de	00.2105.453.055	(30,725)
Earnings after taxes	**(80,268)**	**Total Capital**		**1,801,494**

EXHIBIT 3 – LOAD FORECAST AND OPERATING REVENUES

3.0-OEB Staff-30

Ref: Exhibit 3/Tab 2/Schedule 1/pages 6-7 – Load Forecasting

IHDSL documents that it has used a multivariate regression model to estimate purchased system kWh based on the following exogenous variables:

- **Constant**
- **Heating Degree Days ("HDD") as measured at Pearson International Airport**
- **Cooling Degree Days ("CDD") as measured at Pearson International Airport**
- **Number of Days in the Month;**
- **Spring/Fall Binary Flag; and**
- **Number of customers in the three main customer classes (Residential, GS < 50 kW, and GS > 50 kW).**

a) What is the basis for selecting Pearson International Airport as the source for HDD and CDD for meteorological data typical of IHDSL's service territory? Were other locations considered? If so, which ones, and why were these rejected?

IHDSL Response:

IHDSL did consider sourcing weather data related to a location closer to its service territory. IHDSL reviewed the weather data from two weather stations in the Barrie area but the information from these stations was not complete for the required 20 years (i.e. 20 years of weather data is needed to complete the 20 year trend analysis). As a result, IHDSL followed the approved 2009 COS Load Forecast Methodology using Pearson International Airport weather data.

b) What other variables were tried to account for market size or for economic activity in IHDSL's service territory? If other variables were tried, what were the results and why were they omitted from the preferred model?

IHDSL Response:

IHDSL did consider using the Ontario Real GDP Monthly % variable to reflect economic activity. The results of the regression analysis with Ontario Real GDP Monthly % variable are shown below and since the t-stat on this variable was below 2, it was omitted from the preferred model.

Statistics		
R Square	97.6%	
Adjusted R Square	97.4%	
F Test	757.5	
Variable	Coefficients	T-stat
Intercept	(17,486,644)	(8.66)
Heating Degree Days	13,944	46.77
Cooling Degree Days	27,820	16.27
Number of Days in Month	593,085	10.34
Spring Fall Flag	(1,024,064)	(8.11)
Number of Customers - 3 Main Classes	1,037.5	7.21
Ontario Real GDP Monthly %	2,614	0.18

c) Did IHDSL try any variables to account for CDM impacts in the regression period?

i. If yes, please identify the variable(s) tried, the data and data source, the results, and why such variables were omitted from the proposed model.

ii. If no CDM variables were tried, please explain why not.

IHDSL Response:

IHDSL did consider using a CDM activity variable to reflect CDM impacts in the regression period. The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values for the variable grow at constant value over the year and in total equal the annual CDM results. The source of this data was from the 2006 – 2010 OPA Final Results plus the fourth quarter 2011 CDM OPA Status Report. The results of the regression analysis with the CDM Activity variable are shown below and since the t-stat on this variable was below 2, it was omitted from the preferred model.

Statistics		
R Square	97.6%	
Adjusted R Square	97.4%	
F Test	757.5	
Variable	Coefficients	T-stat
Intercept	(17,874,324)	(5.87)
Heating Degree Days	13,942	46.71
Cooling Degree Days	27,808	16.24
Number of Days in Month	593,031	10.34
Spring Fall Flag	(1,025,419)	(8.10)
Number of Customers - 3 Main Classes	1,092.3	5.71
CDM Activity	(0.13)	(0.19)

3.0-OEB Staff-31

Ref: Exhibit 3/Tab 2/Schedule 1/page 5/Table 3-4 – Load Forecasting

In Table 3-4, IHDSL documents the average consumption per customer by class and over time.

a) For each class, what was the average annual consumption per customer based on 2012 actuals?

IHDSL Response:

The year- end load data is not available at this time to update Table 3.4.

b) What is the rationale for the decline in average annual consumption per customer for Residential customers of 3.0% for the 2012 bridge year and 2.2% for the 2013 test year?

IHDSL Response:

The rationale for the decline in average annual consumption per customer for Residential customers of 3.0% for the 2012 bridge year and 2.2% for the 2013 test year is provided in the table below:

Residential	2011	2012	2013
Average Annual Consumption - Table 3-10 and 3-12	10,893	10,829	10,766
Growth - Geomean from Table 3-11		(0.6%)	(0.6%)
Weather Adjustment as per Table 3-18		(175.7)	(266.7)
CDM Adjustment as per Table 3-18		(87.0)	(170.1)
Total Average Annual Consumption	10,893	10,567	10,329
Growth		(3.0%)	(2.2%)

c) What is the explanation for the decline in average annual consumption per street lighting connection of 9.2% in 2011, and further forecasted declines of 1.2% per annum for the 2012 bridge and 2013 test years?

IHDSL Response:

The explanation for the decline in average annual consumption per street lighting connection of 9.2% in 2011.The explanation for further forecasted declines of 1.2% per annum for the 2012 bridge and 2013 test years is outlined in the following table.

Street Lighting	2011	2012	2013
Average Annual Consumption - Table 3-10 and 3-12	534	532	529
Growth - Geomean from Table 3-11		(0.4%)	(0.4%)
CDM Adjustment as per Table 3-18		(4.3)	(8.4)
Total Average Annual Consumption	534	528	521
Growth		(1.2%)	(1.2%)

d) **What is the explanation for the decline in average annual consumption per sentinel lighting connection of 15.6% in 2011, and further forecasted declines of 5.4% for the 2012 bridge year and 5.3% for the 2013 test year?**

IHDSL Response:

The explanation for the decline in average annual consumption per sentinel lighting connection of 15.6% in 2011.The explanation for further forecasted declines of 5.4% for the 2012 bridge year and 5.3% for the 2013 test year is shown in the table below:

Sentinel Lighting	2011	2012	2013
Average Annual Consumption - Table 3-10 and 3-12	490	467	446
Growth - Geomean from Table 3-11		(4.6%)	(4.6%)
CDM Adjustment as per Table 3-18		(3.8)	(7.0)
Total Average Annual Consumption	490	464	439
Growth		(5.4%)	(5.3%)

e) **What is the explanation for the forecasted increases in average annual consumption per Unmetered Scattered Load connection of 12.4% for the 2012 bridge year and 12.3% for the 2013 test year?**

IHDSL Response:

The explanation for the forecasted increases in average annual consumption per Unmetered Scattered Load connection of 12.3% for the 2012 bridge year and 12.4% for the 2013 test year is provided in the table below:

Unmetered Scattered Load	2011	2012	2013
Average Annual Consumption - Table 3-10 and 3-12	6,041	6,842	7,749
Growth - Geomean from Table 3-11		13.3%	13.3%
CDM Adjustment as per Table 3-18		(55.0)	(122.4)
Total Average Annual Consumption	6,041	6,787	7,626
Growth		12.3%	12.4%

3.0-OEB Staff-67

Ref: Exhibit 3/Tab 2/Schedule 1/page 19 – Load Forecasting

Innisfil has provided net CDM savings in 2013 from 2011, 2012 and 2013 programs for Lost Revenue Adjustment Mechanism ("LRAM") variance account purposes. Innisfil notes that it expects to achieve 2,869,182 net kWh savings in 2013 from 2011 to 2013 CDM programs.

a) **Please update Tables 3-17 to reflect Innisfil's final, verified 2011 CDM savings as found in Innisfil's 2011 OPA Final Evaluation Results.**

IHDSL Response:

IHDSL has updated Tables 3.16 and 3.17 7 reflecting Innisfil's final verified 2011 CDM results.

Table 3-16: Schedule to Achieve 4 Year kWh CDM Target					
4 Year 2011 to 2014 kWh target					
9,200,000					
	2011	2012	2013	2014	Total
2011 Programs	6.4%	6.4%	6.4%	6.4%	25.8%
2012 Programs		12.4%	12.4%	12.4%	37.1%
2013 Programs			12.4%	12.4%	24.7%
2014 Programs				12.4%	12.4%
	6.4%	18.8%	31.2%	43.6%	100.0%
kWh					
2011 Programs	592,454	592,454	592,454	592,454	2,369,815
2012 Programs		1,138,364	1,138,364	1,138,364	3,415,093
2013 Programs			1,138,364	1,138,364	2,276,728
2014 Programs				1,138,364	1,138,364
2011 FINAL kWh	592,454	1,730,818	2,869,182	4,007,546	9,200,000

Table 3-17: 2013 Expected Savings for LRAM Variance Account							
	Residential	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Total**
kWh	**1,822,097**	**390,836**	**629,564**	**18,246**	**1,262**	**7,177**	**2,869,182**
kW where applicable			**1,811**	**53**	**3.5**		**1,868**

b) **Please update Table 3-18 consistent with the update provided in (a) above.**

IHDSL Response:

IHDSL has update Table 3-18 consistent with the update provided in a). The updated change in kWh from 555,895 to 592,454 has had no impact.

Table 3-18: Alignment of Non-normal to Weather Normal Forecast								
Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Hydro One Load Transfers	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2012 Non-Normalized Bridge	151.4	31.6	51.3	1.5	0.1	0.5	0.9	237.5
2013 Non-Normalized Test	152.8	32.8	52.8	1.5	0.1	0.6	0.9	241.5
Weather Adjustment (GWh)								
2012	(2.5)	(0.5)	(0.7)	0.0	0.0	0.0	0.0	(3.6)
2013	(3.8)	(0.8)	(1.0)	0.0	0.0	0.0	0.0	(5.6)
Hydro One Load Tranfer Adjustment (GWh)								
2012								
2013							(0.9)	(0.9)
CDM Adjustment (GWh)								
2012	(1.2)	(0.3)	(0.4)	(0.0)	(0.0)	(0.0)	0.0	(1.9)
2013	(2.4)	(0.5)	(0.8)	(0.0)	(0.0)	(0.0)	0.0	(3.8)
Weather Normalized Billed Energy Forecast (GWh)								
2012 Normalized Bridge	147.7	30.9	50.3	1.5	0.1	0.5	0.9	231.9
2013 Normalized Test	146.6	31.4	50.9	1.5	0.1	0.6	0.0	231.1

3.0-OEB Staff-32

Ref: Exhibit 3/Tab 2/Schedule 1/page 19 – Load Forecasting

c) Please provide the Mean Absolute Percentage Error over the period January 2002 to December 2011 of the residuals based on the monthly data results.

IHDSL Response:

The Mean Absolute Percentage Error over the period January 2002 to December 2011 of the residuals based on the monthly data results is 2.0%

3.0-OEB Staff-33

Ref: Exhibit 3/Tab 2/Schedule 1/page 15/Table 3-15 – Load Forecasting and CDM Adjustment

In Table 3-15, IHDSL provides the data for the adjustment of "gross" to "net" CDM impacts for the adjustment of the load forecast for 2012 and 2013 CDM impacts. This is replicated below:

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	1,644,593	1,472,589	172,004	11.7%
2007	4,964,101	2,455,329	2,508,772	102.2%
2008	5,013,598	3,143,863	1,869,735	59.5%
2009	7,236,399	4,589,194	2,647,205	57.7%
2010	6,830,132	4,029,540	2,800,593	69.5%
2011	6,668,005	3,859,190	2,808,815	72.8%
2012	6,394,406	3,742,776	2,651,631	70.8%
2013	6,307,311	3,698,822	2,608,489	70.5%
Total	45,058,546	26,991,303	18,067,243	66.9%

a) Please update Table 3-15 to reflect the final 2011 CDM results as issued by the OPA in the fall of 2012.

IHDSL Response:

The updated Table 3-15 to reflect the final 2011 CDM results as issued by the OPA in the fall of 2012 is provided below:

Table 3-15: Average Net to Gross Percentage Updated for 2011 Final Results

	OPA 2006-2011 Final CDM Results (Gross)	OPA 2006-2011 Final CDM Results (Net)	# Difference	% Difference of Net
2006	1,644,593	1,472,589	172,004	11.7%
2007	4,964,101	2,455,329	2,508,772	102.2%
2008	5,013,598	3,143,863	1,869,735	59.5%
2009	7,236,399	4,589,194	2,647,205	57.7%
2010	6,830,132	4,029,540	2,800,593	69.5%
2011	7,480,304	4,415,085	3,065,218	69.4%
2012	7,206,705	4,298,670	2,908,034	67.6%
2013	7,119,610	4,254,717	2,864,893	67.3%
Total	47,495,442	28,658,987	18,836,454	65.7%

b) IHDSL has estimated a "net-to-gross" conversion factor of 66.9%, which is based the overall difference of "net" to "gross" results over the total period from 2006 to 2011, and including the estimated persistence of 2006 to 2011 CDM programs on 2012 and 2013 demand.

i. Why should the estimated results for 2012 and 2013, which are forecasts, be taken into account in calculating the conversion factor?

IHDSL Response:

The results for 2012 and 2013 were taken into account in calculating the conversion factor since this information was provided by the OPA and it provided more data points to determine the average factor. The information for all years outlined in Table 3-17 of the application is based on data provided from the OPA 2006-2010 Final CDM Results report. It is IHDSL's understanding that the information for 2012 and 2013 are not estimates but reflect the actual results of persistence from 2006 to 2010 programs into 2012 and 2013.

ii. In the alternative, if reliance should be placed on these as being the OPA's final estimates of the persistence of CDM programs up to 2011 on 2013 consumption in IHDSL's service territory, then why should not the 2013 data, with a factor of 70.5%, be the suitable measure for the 2013 test year load forecast.

IHDSL Response:

Using the 2013 data, with a factor of 70.5%, could be a reasonable alternative to convert net values to gross. However, the average method produces a more conservative factor which, in IHDSL's view, provides a more reasonable approach in determining the conversion factor.

3.0-OEB Staff-34

Ref: Exhibit 3/Tab 2/Schedule 1/page 16/Table 3-16 – Load Forecasting and CDM Adjustment

On page 16 and in Table 3-16, IHDSL documents its methodology for estimating the manual adjustment to account for 2012 and 2013 CDM programs on the 2013 load forecast. Board staff understands IHDSL's methodology as follows:

- **Assuming that 2011 CDM programs achieved 6.4% of IHDSL's target of 9,200,000 kWh based on the OPA results, IHDSL would need to achieve a further 12.4% of the target in each of 2012, 2013, and 2014 to achieve 100% of the target on a cumulative basis over the four years.**

- **12.4% of 9,200,000 kWh equates to 1,138,364 kWh.**

- **Thus, in addition to 2011 CDM results which are reflected in the 2011 actuals and hence would influence the load forecast before the CDM adjustment, the adjustment for 2012 and 2013 CDM programs should be 1,138,364 kWh X 2 years X 1.667 net-to-gross conversion factor = 3,800,708 kWh.**

Board staff understands that the results as reported by the OPA are "annualized" (i.e. assume that all CDM programs, including the current year's program, are in effect for the full year, from January 1 to December 31). While the full year effect for persistence of prior year CDM programs would be in place for the full year, CDM programs implemented in a given year would not have the full impact in the first year, due to timing.

The measured "full year" results, as measured by the OPA, will be used for the basis of the LRAMVA amount. However, the "full year" results in the first year of a CDM program, will overstate the actual results unless the program was implemented on January 1 of that year.

In the absence of any other information, a "half-year" rule (i.e. assuming that half of the incremental impact of programs introduced in a year is actually realized in the calendar year of introduction) may be a proxy for the actual impact, ignoring all other factors (i.e. seasonality).

a) **Please provide IHDSL's understanding of the results as published by the OPA (i.e. are the full year or do they only reflect the period that a CDM program in in place in its first year).**

   IHDSL Response:

   It is IHDSL's understanding that the results as published by the OPA are annualized.

b) **If a "half-year" rule is used to account for the fact that 2013 CDM programs will not have a full year impact on 2013 actual consumption, please provide IHDSL's perspective that the adjustment for the 2012 and 2013 CDM programs on 2013 demand would be estimated as 1,138,364 kWh X 1.5 (reflecting full year impact of 2012 CDM and half-year impact of 2013 CDM on 2013) X 1.667 = 2,847,979 kWh. (Alternatively, the net-to-gross conversion factor, as discussed in the preceding interrogatory, could be used).**

   IHDSL Response:

   Assuming the "half-year" rule is used to account for 2013 CDM programs not being in place for a full year, the adjustment for the 2012 and 2013 CDM programs on 2013 demand would be estimated as 1,138,364 kWh X 1.5 (reflecting full year impact of 2012 CDM and half-year impact of 2013 CDM on 2013) X 1.669 = -2,850,531 kWh. However, IHDSL is concerned with using the "half-year" rule since it is IHDSL's understanding, putting aside the discussion on using net or gross, there should be consistent treatment on how the load forecast is adjusted and how the LRAMVA threshold is determined. Consistent with the approach used in part b) below, it is IHDSL's view the 1,138,364 should be multiplied by 2.

c) **While the above is to adjust the load forecast which is on an "actual" year basis, the LRAMVA is based on the measured OPA results reported on a full year basis. Please confirm that the LRAMVA threshold would continue to be based on the "full year" CDM**

results of 592,454 kWh (i.e. persistence of 2011 CDM) + 1,138,364 X 2 (i.e. persistence of 2012 and impact of 2013 CDM) results, for a total of 2,689,182 kWh, as documented further on page 17 of this exhibit. In the alternative, please explain IHDSL's proposal for the kWh used to derive the threshold for the LRAMVA for 2013.

IHDSL Response:

IHDSL confirms that the LRAMVA threshold would continue to be based on the "full year" CDM results of 592,454 kWh (i.e. persistence of 2011 CDM) + 1,138,364 X 2 (i.e. persistence of 2012 and impact of 2013 CDM) results, for a total of 2,689,182 kWh.

3.0-OEB Staff-35

Ref: Exhibit 3/Tab 2/Schedule 1, p.3, table 3-2 and Exhibit 1/Tab 1,
Appendix H – Asset Management Plan, Exhibit 2/Tab1/Schedule1, p. 1

In the Asset Management Plan – E1/T1, Appendix H IHDS describes the projected population growth for Innisfil, including a projection of 1,600 units as well as commercial load due to the Big Bay Point development. Please explain how this population and load growth has been reflected in IHDSL's load and customer forecast. If it has not been reflected, please explain why.

IHDSL Response:

The Big Bay Point Developer (Friday Harbour) has provided connected loading information of 10.7 MW. Appendix 2 of the Business Plan has factored in loading of 8.64MW which incorporates some diversity of load demand. The first 200 units have been predicted to be connected in 2014 with the final 400 units connected in 2019.

3.0-OEB Staff-36 – PP&E adjustment in other revenues

Ref: Exhibit 3, Tab 3, Schedule 3, Pages 1, 3 and APH FAQ July 2012, Q.18

IHDSL recorded a reduction to Other Revenue in 2012 in Account 4305 Regulatory Debit for $639,864 due to the "one-time adjustment for excess depreciation done in 2012". Per the APH FAQ July 2012 Question 18,

> **For the years following the changeover date…the recording of the offsetting entry to Account 1575 would be recorded in regulatory income statement Account 4305, Regulatory Debit or Account 4310, Regulatory Credit..**

IHDSL's changeover date is January 1, 2013. There are no "years following the changeover date" before the current cost of service MIFRS rate application.

a) **Please explain why IHDSL is not following the APH FAQ July 2012 and recorded an amount in Account 4305.**

IHDSL Response:

IHDSL changeover date for the change in useful life is January 1, 2012 as a change in accounting policy. IHDSL had submitted within the COS filing it would be moving to IFRS for financial reporting January 1, 2013. IHDSL received notification in late September 2012 that the AcSB decided to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014. IHDSL is electing to defer the mandatory IFRS changeover date to January 1, 2014.

b) **Please remove the amount of $639,864 from Account 4305 and revise the application as appropriate.**

IHDSL Response:

IHDSL will not be removing the 2012 PP&E adjustment from Account 4305 because the changeover date for capital asset useful life is January 1, 2012.

3.0-OEB Staff-37

Ref: Exhibit 3/Tab3/Schedule 3, p. 1, table 3.3.9

Please provide 2012 actual other revenues in the detail shown in table 3.3.9.

IHDSL Response:

IHDSL is providing an update, other revenue table, reflecting the 2012 actuals as at October 2012.

Table 3.3.9 Other Revenue - 2009 Board Approved to 2013 Test Year

USoA #	USoA Description	2009 Board Approved	2009 Actual	09 Board vs 09 Act	2010 Actual	09 Act vs 10 Act	2011 Actual	10 Act vs 11 Act	Bridge Year 2012	Bridge Year Ytd Act 10/12	Bridge Year 2012	11 Act vs 12 Bridge	Test Year 2013	12 Bridge vs 13 Test
	Reporting Basis	CGAAP	CGAAP		CGAAP		CGAAP		CGAAP	CGAAP	MIFRS		MIFRS	
4235	Specific Service Charges	$ 135,935	$ 142,194	$ 6,259	$ 127,673	-$ 14,521	$ 166,067	$ 38,394	$ 149,670	$ 128,528	$ 149,670	-$ 16,397	$ 154,100	$ 4,430
4225	Late Payment Charges	$ 89,542	$ 105,597	$ 16,055	$ 111,120	$ 5,523	$ 104,841	-$ 6,279	$ 110,402	$ 63,381	$ 110,402	$ 5,561	$ 113,700	$ 3,298
4082	Retail Services Revenues	$ 26,269	$ 35,349	$ 9,080	$ 42,813	$ 7,464	$ 78,272	$ 35,459	$ 54,203	$ 38,126	$ 54,203	-$ 24,069	$ 55,033	$ 830
4210	Pole Rental	$ 145,208	$ 154,992	$ 9,784	$ 161,381	$ 6,389	$ 157,442	-$ 3,939	$ 162,676	$ 128,820	$ 162,676	$ 5,234	$ 167,600	$ 4,924
4305	Regulatory Debit		$ -	$ -	$ -	$ -	$ -	$ -	-$ 639,864		-$ 639,864	-$ 639,864	$ -	$ 639,864
4325	Special Purpose Chg Reco			$ -	$ 49,901	$ 49,901		-$ 49,901				$ -		$ -
4355	Gain(Loss) on Disposal		$ 33,840	$ 33,840	$ -	-$ 33,840	-$ 126,618	-$ 126,618	-$ 51,476	-$ 32,636	-$ 51,476	$ 75,142	-$ 48,825	$ 2,651
4375	Misc Non-Utility Income	$ 169,431	$ 377,961	$ 208,530	$ 287,996	-$ 89,965	$ 279,583	-$ 8,413	$ 384,806	$ 209,136	$ 384,806	$ 105,223	$ 500,668	$ 115,862
4380	Misc Non-Utility Expense	-$ 169,431	-$ 331,366	-$ 161,935	-$ 389,430	-$ 58,064	-$ 268,700	$ 120,730	-$ 405,862	-$ 352,419	-$ 405,862	-$ 137,162	-$ 469,228	-$ 63,366
4390	Misc Non-Utility Income	$ 7,053	$ 9,629	$ 2,576	$ 52,823	$ 43,194	$ 24,952	-$ 27,871	$ 30,009	$ 5,715	$ 30,009	$ 5,057	$ 30,900	$ 891
4405	Interest Income	$ 34,300	$ 23,617	-$ 10,683	$ 36,839	$ 13,222	$ 53,328	$ 16,489	$ 14,600	-$ 13,820	$ 14,600	-$ 38,728	$ 3,000	-$ 11,600
4406	SRED Revenue		$ -	$ -	$ -	$ -	$ 153,377	$ 153,377	$ 50,000	$ 84,575	$ 50,000	-$ 103,377	$ 50,000	$ -
Specific Service Charges		$ 135,935	$ 142,194	$ 6,259	$ 127,673	-$ 14,521	$ 166,067	$ 38,394	$ 149,670	$ 128,528	$ 149,670	-$ 16,397	$ 154,100	$ 4,430
Late Payment Charges		$ 89,542	$ 105,597	$ 16,055	$ 111,120	$ 5,523	$ 104,841	-$ 6,279	$ 110,402	$ 63,381	$ 110,402	$ 5,561	$ 113,700	$ 3,298
Other Operating Revenues		$ 171,477	$ 190,341	$ 18,864	$ 204,194	$ 13,853	$ 235,714	$ 31,520	$ 216,879	$ 166,946	$ 216,879	-$ 18,835	$ 222,633	$ 5,754
Other Income or Deductions		$ 41,353	$ 113,681	$ 72,328	$ 38,129	-$ 75,552	$ 115,922	$ 77,793	-$ 617,787	-$ 99,449	-$ 617,787	-$ 733,709	$ 66,515	$ 684,302
Total		$ 438,307	$ 551,813	$ 113,506	$ 481,116	-$ 70,697	$ 622,544	$ 141,428	-$ 140,836	$ 259,406	-$ 140,836	-$ 763,380	$ 556,948	$ 697,784

3.0 Energy Probe #18

Ref: Exhibit 3, Tab 2, Schedule 1

a) **Are the customer/connection figures shown in Table 3-3 year-end figures or average numbers for the year?**

IHDSL Response:

The customer/connection figures shown in Table 3-3 are year-end numbers.

b) **If available, please update Tables 3-2, 3-3 and 3-4 to reflect actual data for 2012. If complete data is not available for 2012, please provide an update for the 2012 figures to reflect actual data for as many months as are available for 2012, along with the forecast for the remaining months of 2012.**

IHDSL Response:

The year- end load data is not available at this time to update Table 3-2, 3-3 and 3.4.

3.0 Energy Probe #19

Ref: Exhibit 3, Tab 2, Schedule 1

Did IHDSL try to incorporate any other explanatory variables, other than those shown on page 7? If no, please explain why not. If yes, please indicate what other explanatory variables were investigated and state why they were not included in the final version of the equation.

IHDSL Response:

IHDSL tried to incorporate other explanatory variables, other than those shown on page 7. The other explanatory variables investigated were a CDM Activity variable and an Ontario Real GDP Monthly % variable. Please see response to Board Staff-30 b) and c) for the reason they were not included in the final version of the equation.

3.0 Energy Probe #20

Ref: Exhibit 3, Tab 2, Schedule 1

Please update Table 3-7 to show historical data for 2012. If actual data for all of 2012 is not yet available, please provide a forecast for 2012 based on as many months of actual data as is currently available, along with a forecast for the remaining months in 2012.

IHDSL Response:

IHDSL has updated Table 3.7 to reflect 2012 actual connections.

Table 3-7: Historical Customer/Connection Data							
Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections							
2002	12,075	837	71	2,107	177	0	15,267
2003	12,299	852	72	2,196	181	0	15,600
2004	12,539	886	73	2,309	183	0	15,990
2005	12,748	907	72	2,371	189	0	16,287
2006	12,867	797	80	2,371	189	90	16,394
2007	12,991	819	71	2,489	186	89	16,645
2008	13,277	836	73	2,588	186	84	17,044
2009	13,533	855	72	2,625	193	83	17,361
2010	13,651	865	68	2,685	201	82	17,552
2011	13,779	896	67	2,728	225	81	17,776
2012	14,039	937	67	2,728	225	82	18,078

15.0-VECC

Reference: Exhibit 3, Tab 2, Schedule 1, pages 7-8

a) **Did IHDSL test any multifactor regression models that included independent variables that represented economic activity (e.g. local employment and/or GDP)? If not, why not? If yes, what were the resulting models and their related statistical results?**

IHDSL Response:

Please see response to IR OEB Staff- 30b.

16.0-VECC

Reference: Exhibit 3, Tab 2, Schedule 1, Att. A, pages 4, 10 and 15

a) **Please explain more fully what the "Hydro One Load Transfers" represent. In doing so, please address the following:**

- **Is Hydro One a customer of IHSDL and have a delivery point embedded in IHDSL?**
- **If not, what do these deliveries to Hydro One represent and why are they included in IHSDL's historic power purchases?**
- **If Hydro One is not a customer, how is IHSDL compensated for the fact its power purchases includes these "load transfer" quantities?**
- **Why are the transfers expected to be eliminated in 2013?**

IHDSL Response:

The Hydro One Load Transfer usage referenced in Exhibit 3, Tab 2 Schedule 1, pages 4, 10 and 15 is not for a delivery point embedded in IHDSL. The quantities are those provided to us by Hydro One annually from data extracted from their customer billing system for power supplied from IHDSL lines. Innisfil manually invoices Hydro One once each year, outside the settlement systems, for commodity, global adjustment, distribution, transmission and wholesale market services and rural rate assistance for the volume withdrawn via IHDSL lines for approximately 55 Hydro One customers in Essa Township. The expected timeline for these long term load transfers to be eliminated should have read 2014 rather than 2013.

b) **Have the load transfers now been eliminated (as of December 31, 2012)?**

IHDSL Response:

No, the LTLT's have not been eliminated as of December 31, 2012..

c) **Please re-estimate the regression model (pages 7-8) using purchases net of the Hydro One load as the explanatory variable and provide estimated equation along with revised versions of Tables 3-5 and 3-6.**

IHDSL Response:

In order to re-estimate the regression model (pages 7-8) using purchases net of the Hydro One load as the explanatory variable monthly Hydro One data is required. However, IHDSL does not have Hydro One data on a monthly basis for the following reason. Innisfil Hydro is reimbursed once annually for long term load transfers. We invoice Hydro One for the quantities they provide to us from data extracted from their customer billing system for power supplied from IHDSL lines. Innisfil manually invoices Hydro One, outside the settlement systems, for the commodity, global adjustment, distribution, transmission, wholesale market services and rural rate assistance for the volume of energy withdrawn by Hydro One on our west boundary for approximately 55 Hydro One customers in Essa Township. IHDSL uses our annual weighted average price and weighted average Global Adjustment for the yearly billing period. We do not have any monthly billing quantities to provide for these LTLT customers as we do not bill them monthly. As a result, a response to this question cannot be prepared.

17.0-VECC

Reference: Exhibit 3, Tab 2, Schedule 1, pages 15-16

a) **Please provide a copy of the OPA's final report regarding IHDSL's 2006-2010 CDM program results.**

IHDSL Response:

The 2006-2010 CDM results are enclosed in the Exhibit 3 Appendices – Ex3 Appendix 1 IR Ref VECC-17a.

b) **Please provide a copy of the OPA's final report regarding IHDSL's 2011 CDM program results.**

IHDSL Response:

The 2011 OPA final CDM Program results are enclosed in the Exhibit 3 Appendices – Ex3 Appendix 2 IR Ref VECC-17b.

c) **Please confirm that the difference between the gross and net CDM savings represents those savings that would have occurred even if there were no CDM programs. If not, please explain why not.**

IHDSL Response:

It is IHSDL's understanding the difference between the gross and net CDM savings represents those savings from activities of a customer that are similar to the activity of the CDM program, which includes an incentive, but would have occurred without the incentive.

d) **Please explain why the difference between the gross and net CDM impacts is not already reflected in the forecast values for 2012 and 2013 based on the regression model.**

IHDSL Response:

The regression analysis is based on actual data up to and including 2011. This means any CDM activity up to the end of 2011 has been included in the regression analysis and is reflected in the prediction formula for 2012 and 2013. However, any new 2012 or 2013 CDM activity, whether at the gross or net level, has not been reflected in the regression analysis. Such activity is new incremental activity and is over and above the activity included in the actual data supporting the regression analysis.

18.0-VECC

Reference: Exhibit 3, Tab 2, Schedule 1, page 12

a) **Please provide the 2012 year-to-date customer/connection count for each class for the most recent month available (preferably 2012 year-end) and, in the same schedule, provide the 2011 values for the equivalent month.**

IHDSL Response:

IHDSL has provided the following table reflecting connections by month, by and by class for 2011 and 2012. Please refer to Energy Probe IR 20 for updated total year end customer connections.

IHDSL Customer Connection Count

2011		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	Residential	11	6	9	5	9	11	22	18	8	20	24	19	162
	GS LT 50	1	2	4	1	2	0	2	4	3	3	0	2	24
	GS GT 50													0
	Sentinel Lights													0
	Street Lights													0
	USM													0
	microFIT	1	3	2	8	2	2	1	6	1	4	1	1	32
	Total	13	11	15	14	13	13	25	28	12	27	25	22	218
2012		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	Residential	14	25	13	5	9	26	26	35	12	44	25	26	260
	GS LT 50	3				5		2	3	11	7	9	1	41
	GS GT 50													0
	Sentinel Lights													0
	Street Lights													0
	USM						1							1
	microFIT	3	2	2			1		2		1	1		12
	Total	20	27	15	5	14	28	28	40	23	52	35	27	314

b) If the year-end 2012 values are available please provide the 2012 average annual customer/connection count for each customer class.

IHDSL Response:

Please refer to VECC IR# 3 a)

19.0-VECC

Reference: Exhibit 3, Tab 2, Schedule 1, Table 3-22

a) The 2012 and 2013 purchases shown in Table 3-22 appear to be the values prior to the adjustments for CDM programs and Hydro One load transfers. Please review and revise as required.

IHDSL Response:

The Hydro One load transfer adjustment only applies in 2013. As a result, the predicted purchases for 2013 to reflect the impact of CDM programs and Hydro One load transfers is 251.1 (GWh). The predicted purchases for 2012 to reflect the impact of CDM programs only is 252.0 (GWh).

b) If revisions are made as a result of part (a) are revisions also required to IHDSL's 2013 cost of power forecast as used for purposes of determining working capital requirements?

IHDSL Response:

No revision is required based on the response to part a) to the cost of power in determining the working capital requirements. The cost of power calculations are based on billed amounts and the impact of CDM programs and Hydro One load transfers are already reflected in the billed amounts.

3.0-OEB Staff-39 – Non-utility income/expenses

Ref: Exhibit 3/Tab 3/Schedule 3, p. 1-3 and Exhibit 1/Tab 1/Appendix H, p. 10

a) Please provide the service agreements for all non-utility services provided by IHDSL.

IHDSL Response:

IHDSL has enclosed the non-utility service agreements for all non-utility services provided by IHDSL. The agreements are enclosed in the Exhibit 3 appendices – Ex3 Appendix 3 IR Ref OEB Staff-39a.

b) Please provide a detailed cost allocation methodology underpinning charges to the Town of Innisfil, i.e. water and waste water billing.

IHDSL Response:

Please refer to OEB Staff IR # 39.

c) Please provide a breakdown of utility versus non-utility costs based on IHDSL's cost allocation methodology.

IHDSL Response:

N/A as this is a cost charge.

3.0 Energy Probe #21

Ref: Exhibit 3, Tab 3, Schedule 3

a) Please provide a version of Table 3.3.9 that excludes OPA revenue and costs (in accounts 4375 and 4380, respectively) and regulatory accounts interest (account 4405).

IHDSL Response
Please refer to VECC IR # 20 c).

b) Please provide the most recent year-to-date figures for 2012 in the same level of detail as shown in Table 3.3.9 requested in part (a) above. Please also provide the corresponding figures for the same year-to-date period in 2011.

IHDSL Response

Please refer to VECC IR # 20 d).

c) Please provide a breakdown of accounts 4375 and 4380 into revenues and expenses for water billing services and the Interco management fee. Please also provide actual data in the same level of detail for 2012, or the most recent year-to-date period available for 2012.

IHDSL Response

Please refer to VECC IR -20 for the breakdown of account 4375 and 4380. The year- end data is not available at this time to update 2012 actuals. Services for water billing services did not commence until August 2012.

20.0-VECC

Reference: Exhibit 3, Tab 3, Schedule 3

a) Please explain why the SRED revenue is $153,377 in 2011 but forecast to only be $50,000 in 2013.

IHDSL Response:

IHDSL is forecasting 2013 SRED revenue to be $50,000 due to the lower level of capital expenditures that are estimated to eligible.

b) Please explain the basis for the -$48,825 Gain/Loss on Disposal in 2013 relative to the -$126,618 actual value reported for 2011.

IHDSL Response:

IHDSL is estimating the 2013 Loss on disposal of $48,825 based on June 2012 actuals estimated for the full year.

c) Please provide a revised version of Table 3.3.9 setting out the 2012 year to date (preferably to December 31, 2012) values and the 2011 year to date value for the same period.

IHDSL Response:

IHDSL is providing a revised Table 3.3.9 reflecting the December 2012 and year to date actuals.

Table 3.3.9 Comparision 2012 Bridget to 2013 Test Year - Throughput Revenue

Operating Revenue	2011 Actual	2012 Actual	2012 Test	2013 Bridge	Variance	% Variance to 2012 Test
Distribution Revenue						
Residential	5,882,306	5,960,150	6,187,519	7,234,973	1,047,454	16.9%
GS<50kW	579,267	576,347	637,500	629,481	- 8,019	-1.3%
GS>50kW-4,999 kW	661,641	648,969	696,500	518,208	- 178,292	-25.6%
Sentinel Lights	22,990	25,356	29,300	37,807	8,507	29.0%
Street Lighrts	305,463	335,499	317,200	422,247	105,047	33.1%
Unmetered Scattered Load	41,084	39,487	43,500	19,972	- 23,528	-54.1%
Total Operating Revenues	7,492,751	7,585,806	7,911,519	8,862,688	951,169	12.0%

d) **For 2012 and 2013, please provide the entries for Accounts 4375 and 4380 associated with billing water and waste water for the Town of Innisfil.**

IHDSL Response:

The following table reflects the revenue and cost associated with billing water and waste water for the Town of Innisfil:

Account	***2012***	***2013***
Account 4375	*$103,406*	*$219,168*
Account 4380	*$127,762*	*$191,128*

e) **Does IHDSL have any MicroFit customers? If so, how many and where are the service charge revenues reported?**

IHDSL Response:

IHDSL currently has 50 connected microFIT customers. The service revenues are recorded in account 4082.

f) **Where are the SSS Admin charge revenues recorded?**

IHDSL Response:

The SSS Admin charge revenues are recorded into a sub account 4080 and are included in the 2013 Test year Other Revenue within account 4082.

EXHIBIT 3 APPENDICES

Ex2 Appendix 1 IR Ref VECC-17a

2010 Final CDM Results: Summary

LDC: Innisfil Hydro Distribution Systems Limited

This report provides an estimated allocation of 2010 OPA-funded conservation and demand management (CDM) program results for each LDC's service territory. A full, detailed report will be available in late September/early October.

The results provided in this report are in accordance with OPA practices and policies for reporting. Demand Response initiatives, for example, have been reported based on the total DR resources that were available (based on contracted nameplate capacity) rather than the actual demand reduction which occurred at the one-hour system peak in a given year.

The OPA welcomes inquiries regarding the determination of these province-wide CDM program results and/or allocation of these results to individual LDC territories. Please direct any questions to ldc.support@powerauthority.on.ca. The OPA is unable to provide any technical or regulatory advice to LDCs regarding specific treatment of these OPA-funded CDM program savings for the purposes of Lost Revenue Adjustment Mechanism or other filings by LDCs to the OEB. Such inquiries should be directed to the OEB.

All results are incremental savings in 2010 presented at the end-user level

Program	Initiative	Activity Unit	Innisfil Hydro Distribution Systems Limited					Province-Wide				
			Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)
Consumer	Cool Savings Rebate	Rebates	164	0.03	42	0.06	100	136,626	20.22	31,117	46.01	72,821
Consumer	Every Kilowatt Counts Power Savings Event	Products purchased	2,405	0.01	75	0.02	162	613,248	1.70	19,100	4.00	41,300
Consumer	Great Refrigerator Roundup	Appliances	313	0.03	182	0.05	343	67,822	5.96	39,290	11.64	73,912
Consumer	***peaksaver®***	Devices installed	64	0.04	0	0.04	0	36,507	20.44	81	22.49	89
Business	Toronto Comprehensive	Projects	0	0.00	0	0.00	0	730	17.70	114,600	37.50	281,200
Business	Electricity Retrofit Incentive Program	Projects	0	0.00	0	0.00	0	1,532	19.80	111,740	37.82	220,230
Business	High Performance New Construction*	Projects	0	0.01	33	0.02	47	288	12.91	29,433	18.44	42,048
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Devices installed	0	0.00	0	0.00	0	939	0.80	2,500	0.88	2,750
Business	Multifamily Energy Efficiency Rebates	Projects	0	0.00	12	0.00	16	970	4.55	53,700	5.95	72,900
Business	***peaksaver®***	Devices installed	4	0.00	0	0.00	0	243	0.09	2	0.17	2
Business	Power Savings Blitz	Projects	89	0.08	237	0.08	238	48,274	42.20	129,200	42.60	129,500
Business, Industrial	Demand Response 3	Facilities	0	0.28	6	0.28	6	246	251.70	4,932	251.70	4,932
Business, Industrial	Loblaw & York Region Demand Response*	Facilities	0	0.03	0	0.03	0	2	29.21	0	29.21	0
Industrial	Demand Response 2	Facilities	0	0.13	155	0.13	155	3	119.00	139,100	119.00	139,100
Total				**0.6**	**743**	**0.7**	**1,067**		**546.3**	**674,795**	**627.4**	**1,080,783**

Program	Initiative	Allocation Methodology	Notes
Consumer	Cool Savings Rebate	Actual LDC specific results	
Consumer	Every Kilowatt Counts Power Savings Event	Measure level allocation based on 2010 Residential Energy Throughput	
Consumer	Great Refrigerator Roundup	Actual LDC specific results	
Consumer	***peaksaver®***	Actual LDC specific results	
Business	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Ltd. service territory	
Business	Electricity Retrofit Incentive Program	LDC's respective proportion of province-wide reported gross demand savings.	
Business	High Performance New Construction	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	Evaluation not yet complete; Updates expected in October/November
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Program run exclusively in Hydro Ottawa service territory	
Business	Multifamily Energy Efficiency Rebates	LDC's respective proportion of province-wide reported gross demand savings.	
Business	***peaksaver®***	Actual LDC specific results	
Business	Power Savings Blitz	LDC's respective proportion of province-wide reported gross demand savings.	
Industrial	Demand Response 2	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population can lead to participant confidentiality issues if disclosed on an actual LDC share basis.
Business, Industrial	Demand Response 3	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	
Business, Industrial	Loblaw & York Region Demand Response*	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	2) Program results are based on contracted nameplate capacity at the end of the calendar year and not actual summer coincident peak demand reduction.

** Initiative is not evaluated*

Ex2 Appendix 2 IR Ref VECC-17b

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

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OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

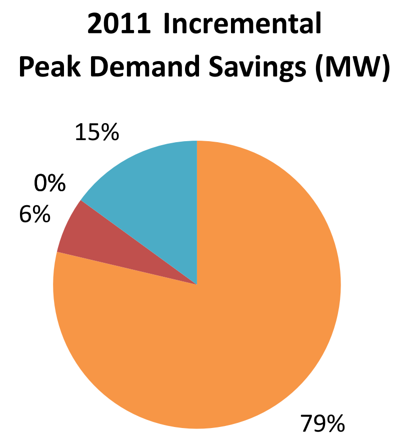
LDC: Innisfil Hydro Distribution Systems Limited

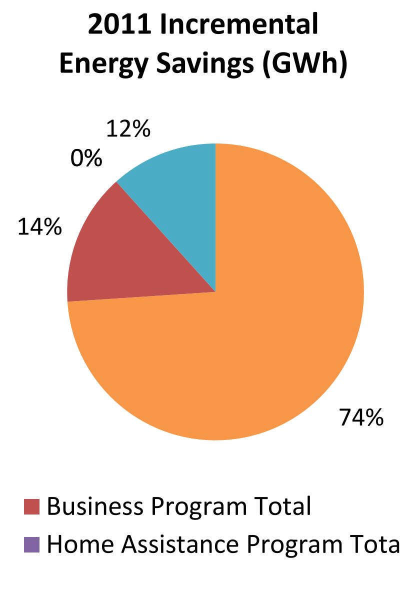
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.3	**5.3%**	**11.0%**
Net Cumulative Energy Savings (GWh)	0.6	**23.9%**	**24.0%**

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

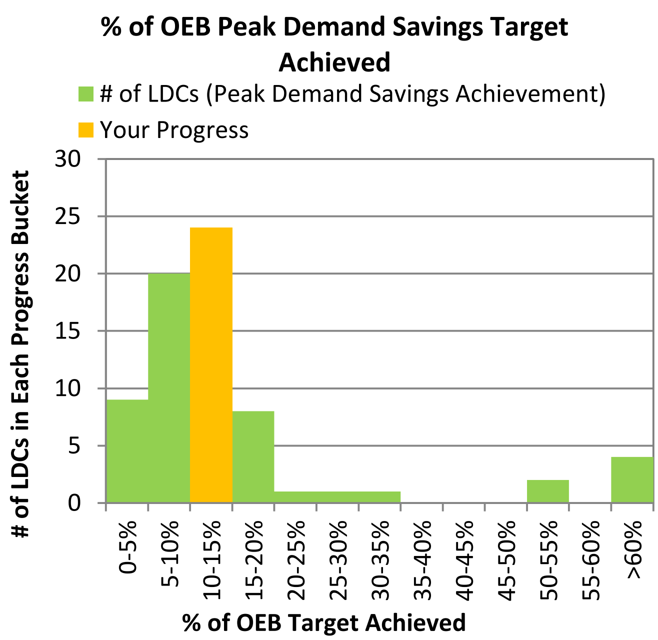
Achievement by Sector





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)



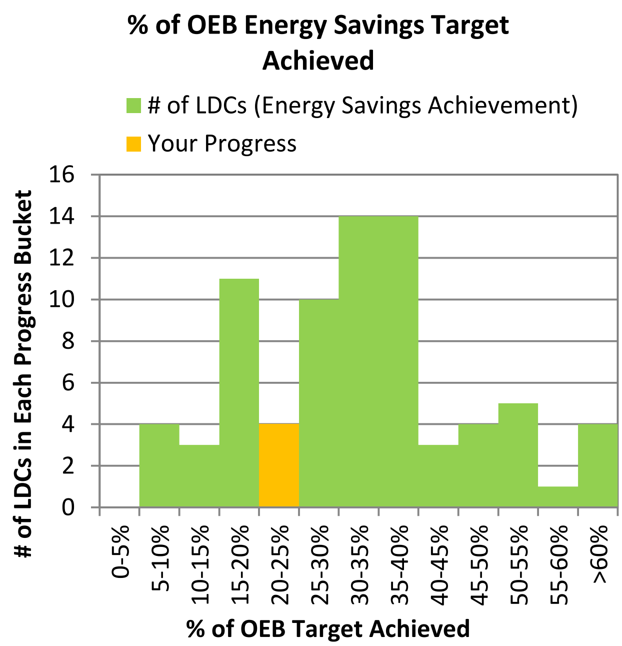


Table 1: Participation[1]

#	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			Net Savings	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	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		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	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		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	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

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

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	

#	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				

#	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.

#	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).

#	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).

#	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.

#	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		

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).

Ex2 Appendix # IR Ref OEB Staff-39a

DUPLICATE ORIGINAL

THE CORPORATION OF THE TOWN OF INNISFIL

BY-LAW NO. 023-12

A By-Law of The Corporation of the Town of Innisfil to authorize the Mayor and Clerk to execute the Water/Wastewater Billing Services Agreement with Innisfil Hydro Distribution Systems Limited.

WHEREAS municipalities have the capacity, rights, powers and privileges of a natural person for the purpose of exercising its authority under the *Municipal Act, 2001,* S.O. 2001, c. 25, pursuant to Section 9 of that Act;

AND WHEREAS Council considered Staff Report DSR-024-12 on February 1, 2012 at its Regular Meeting;

AND WHEREAS Council for the Town of Innisfil deems it appropriate to enter into the Water/Wastewater Billing Services Agreement with Innisfil Hydro Distribution Systems Limited.

NOW THEREFORE the Council of The Corporation of the Town of Innisfil enacts as follows:

1. THAT subject to all of the conditions being met, authority is hereby granted for the Mayor and Clerk to execute the Water/Wastewater Billing Services Agreement with Innisfil Hydro Distribution Systems Limited to the obligations under the Agreement, substantially in the form attached hereto as Schedule "A", which forms part of this by-law.

2. THAT this by-law shall come into force and take effect immediately upon the approval of Council.

READ A FIRST TIME AND PASSED THIS 1ST, DAY OF FEBRUARY, 2012.

Barbara Baguley, Mayor

Jason Reynar, Clerk

WATER/WASTEWATER BILLING SERVICES AGREEMENT

THIS AGREEMENT made in quadruplicate this day of , 2012.

BETWEEN:

THE CORPORATION OF THE TOWN OF INNISFIL
("Town")

OF THE FIRST PART

- and –

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED
("Contractor")

OF THE SECOND PART

WHEREAS the Council of the Corporation of the Town of Innisfil deems it appropriate to contract with Innisfil Hydro Distribution Systems Limited to provide more frequent water and wastewater billings to its customers than is being provided at the date of this agreement; and,

WHEREAS Council passed By-law No. 023-12 on February, 2012, authorizing the execution of this Agreement for a five year period;

WHEREAS the Innisfil Hydro Distribution Systems Limited Board authorized the direction contemplated in this Agreement on October 17, 2011.

NOW THEREFORE IN CONSIDERATION OF THE MUTUAL COVENANTS AND AGREEMENTS CONTAINED HEREIN AND SUBJECT TO THE TERMS AND CONDITIONS HEREINAFTER SET OUT, THE PARTIES HEREBY AGREE AS FOLLOWS:

<u>Definitions</u>

1. In this Agreement the following terms shall have the meaning ascribed to them:

   (a) "Act" refers to the *Occupational Health and Safety Act,* R.S.O. 1990, c. O.1., as amended;

   (b) "Catch-up" refers to the difference between the life to date consumption billed to the customer and the life to date consumption as registered by the water meter;

   (c) "Commercial/Industrial Customer" refers to all Non-Residential properties for which water and waste water services are provided by the Town;

   (d) "Contractor" refers to Innisfil Hydro Distribution Systems Limited;

   (e) "Customers" refers collectively to Commercial/Industrial Customers and Residential Customers;

   (f) "Deferred Payment" refers to a required payment resulting from a Catch-up amount outstanding in addition to the current billing;

(g) "Direct Read" refers to a reading taken directly from the water meter and does not include reads taken from a Remote device;

(h) "Estimate" refers to a reading attributed to an account in the absence of an actual reading;

(i) "Regulations" refers to the regulations passed under the *Occupational Health and Safety Act*, R.S.O. 1990, c.O.1., as amended;

(j) "Remote" refers to the device outside the premise that is attached by wire to the water meter and is capable of communicating the read from the water meter;

(k) "Residential Customer" refers to any customer whose water consumption is for normal household purposes such as bathing, cooking, washing, etc.;

(l) "Standards" refers to the applicable industry standards for services; and,

(m) "Town" refers to The Corporation of the Town of Innisfil.

METER READING

<u>Regular Readings</u>

2. The Contractor shall conduct all readings within the municipal boundaries of The Town of Innisfil on behalf of the Town from the Remote or from the water meter inside the serviced location receiving municipal water services.

<u>Frequency of Reads</u>

3. The Contractor shall use its best commercial efforts to read the meters or Remotes of Residential Customers not less than once every month or such other periodic basis mutually agreed to in writing between the parties of the contract.

4. The Contractor shall use its best commercial efforts to read the meters or remotes of Commercial/Industrial Customers not less than once every month or such other periodic basis mutually agreed to in writing between the parties of the contract.

<u>Non-Remote Locations – (Direct Reads)</u>

5. Notwithstanding section 3 and 4 of this Agreement, in the event the Customer does not have a Remote, the Contractor shall use its best commercial effort to enter the serviced location to take a Direct Read. If there is no response from the Customer, the Contractor shall leave a Self Read Card supplied by the Contractor for the Customer in a place where the Customer would be reasonably expected to see it, which indicates that the Customer is required to provide same to the Contractor.

<u>Capacity for the Customer to Direct Read</u>

6. The Contractor will provide for an efficient system that is convenient for the Customer to communicate the Customer's Direct Read to the Contractor.

Method of Recording

7. Except where the Customer is requested to provide a Direct Read, each Direct Read or Remote read shall be captured electronically and the reading capture device shall be capable of communicating to the person conducting the read the correct number of dials to be read for each Customer location.

Final Reads

8. In the case where the Customer at a serviced location is going to change, the Contractor shall make commercially best efforts to obtain a final meter reading for the serviced location either by Direct read or from the Remote.

Re-reads

9. (a) Upon request by a Customer, the Contractor will re-read the meter when a concern over reading accuracy is raised. In the event that there is an error in the meter reading, the Customer's original bill will be cancelled and a new bill prepared and provided to the Customer at no cost to the Town or the Customer. Alternatively, the Contractor may elect to accordingly adjust the amount owing on the next month's bill to correct the error.

(b) In the event the reading is proven to be correct, the Customer requesting the re-read will be charged a "Check Read" Fee per the Town's by-laws and policies and the Customer's bill will be due and payable as rendered. In the event that the Town's by-laws and policies do not stipulate a "Check Read" Fee to be paid by the Customer, the Contractor shall charge the Town $5.00 per "Check Read" in the first three years of this Agreement and $5.50 in the last two years.

Routes

10. The Contractor shall develop the most efficient routes for reading the meters.

Hours of Work

11. The meter reading services shall generally be provided between the hours of 8 a.m. and 5 p.m. on week days, subject to extenuating circumstances.

Training

12. The Contractor shall be responsible for training its employees, agents and subcontractors to take accurate reads from all the Town's meters and Remotes. The Contractor shall also be responsible for notifying its meter reading employees, agents and subcontractors of any dangers that it knows or ought to know are present at a specific Customer location (e.g. dog in backyard).

Notification of Irregularities

13. The Contractor shall notify the Town of all serviced locations where the meter or Remote has stopped functioning correctly.

14. The Contractor shall notify the Town of any serviced locations where it appears that water service is provided but is not metered.

15. The Contractor shall notify the Town of any premise where it appears that the water service has been illegally by-passed or if the Remote or meter is damaged or has been tampered with. The Town shall provide the Contractor with training on how to recognize such tampering and damage at the Contractor's request.

Identification

16. Each person charged with meter reading shall carry and prominently display their official identification. At no time shall the Contractor, its employees, agents or subcontractors display identification or otherwise portray themselves as employees of the Town.

BILLING

General

17. The Contractor shall calculate the water and wastewater charges based on the reads of the consumption drawn in the case of a base rate plus volume usage or fixed rates where applicable, and any ad-hoc charges, all in accordance with the latest Town billing rates and policies. The Contractor shall produce the customer invoices and distribute these invoices as part of the customer's regular hydro bill. The frequency of the water and waste water invoices shall be the same as the hydro billing or monthly, whichever is more frequent.

Estimates

18. (a) In the event the meter or Remote appears to have malfunctioned, the Contractor shall estimate the amount of consumption for the period based on the customer's historic use and apply current year's rates and billing practices.

(b) In cases where the Customer is serviced with water but has no meter, the Contractor upon discovery shall bill the customer the Town's fixed service charge and any other charges as directed by the Town's latest billing rates and policies. Under no circumstances will the Contractor bear any liability in relation to the malfunctioned Remote, the absence of a Customer meter, or for loss of revenue or consumption charges that could have been charged to the Customer but for the malfunctioned Remote and/or the absence of a meter, except in the case of the negligence of the Contractor or its employees, agents or subcontractors.

Catch-Up

19. Upon the completion of a meter work order that indicates that there is Catch-up consumption, the Contractor shall apply the Town's current year's rates and billing policies to the Catch-up amount.

Billing System Capabilities

20. The Contractor shall provide the necessary computer hardware, software and staffing resources to correctly calculate the fees for service during the billing period, apply customer payments and adjustments, and retain and maintain the Customer and water

meter database. Without limiting the generality of the foregoing, the Contractor's billing system shall be specifically capable of:

(a) accepting imperial measurement readings and converting the billed consumption to metric measurement;

(b) changing billing rate structures on a Customer-wide and Customer-group basis;

(c) accommodating a range of Customer payment options, including deferred payments;

(d) providing overdue account notification, including to landlords and tenants as required;

(e) accommodating non-cyclical billing requests (e.g. change of ownership of property with non-billing cycle moving dates);

(f) including miscellaneous ad-hoc billings related to water and wastewater services;

(g) calculating an adjusted bill or replacement bill to replace an existing bill as required;

(h) recording the type of reads by Customer (e.g. Direct Read by Customer, i.e. self read, estimate, Remote, or Direct Read);

(i) specifying the required number of digits to be read associated with specific meter types;

(j) rejecting non-conforming reads with respect to the number of dials to be read;

(k) flagging consumption which is outside of the pre-set high/low parameters for the account;

(l) pro-rating over a rate change period;

(m) providing flat rate billing where a meter cannot be installed; and

(n) monthly and annual (i.e. January 1 to December 31 inclusive) usage for each meter expressed in cubic meters.

21. The Contractor will provide the Town with database access for Customer contact and meter information, which complies with security and privacy of personal information requirements.

Customer Invoice Content

22. The invoices produced by the Contractor shall be in conformity with the Ontario Energy Board requirements, and shall have a prominent, dedicated section for the water and wastewater portion of the bill. The typeface used in this section will conform to the typeface used in the hydro portion of the invoice, although the Contractor shall endeavour to comply with the Town's accessibility policies. No other non-Town charges shall appear in this section.

23. After the initial changes required to include the following information into the hydro bill, further significant revisions to the Town's portion of the invoice, where such changes materially impact the ongoing operational costs of producing the invoice, those additional costs shall be at the Town's expense. The initial changes required to incorporate the water and wastewater invoice information shall include the following information:

On the joint part of the bill:

(a) Customer name, address and account number;
(b) serviced address;
(c) account classification;
(d) date meter read;
(e) date of previous meter reading;
(f) number of days of consumption that the billing period covers;
(g) penalties and late payment charges;
(h) payments received during the billing period;
(i) opening account balance;
(j) total amount due;
(k) equal payment plan amount due (year to date charges, payments, balance);
(l) date due;
(m) amount payable;
(n) phone numbers for customer billing enquiries, meter maintenance service calls, and after hours meter leaking calls only; and
(o) remittance stub indicating complete customer profile, amount owing and date on which gross and net amounts are payable.

On the Town only part of the bill:

(p) conversion indicator when converting imperial to metric;
(q) previous period reading;
(r) current period reading and indication if it is an estimate;
(s) consumption for the equivalent period or average per day for the equivalent period of the previous year consumption charge for water;
(t) wastewater charges;
(u) service charges for both water and wastewater (shown separately);
(v) applicable wastewater flow discounts;
(w) monthly maximum billable flows by classification (i.e. Commercial/Industrial or Residential);
(x) special charges and fees;
(y) Catch-up amount due;
(z) billing adjustments; and,
(aa) ongoing long term special line items (i.e. Fire Protection).

<u>Equal Billing/PAP Options Allowed</u>

24. The Contractor shall offer the Customer an equal payment and/or Pre-Authorized Payment options if those options are also available for the hydro portion of the bill and provided that the account is adjusted to actual compensation at least once a year as it relates to the equal payment option.

Customer Communications

25. The Customer's invoice shall have a text communication area as a shared section within the common portion of the bill. The Contractor shall implement this communication for water, wastewater, electricity or other communication purposes as deemed appropriate by the Contractor and agreed to by the Town for water and wastewater related information.

26. In addition to the Customer communication area of the invoice, the Town may request the inclusion of inserts in accordance with the specifications provided by the Contractor and at a cost to be negotiated between the parties.

Databases and Information Flow

27. The Contractor shall maintain a database with data initially provided by the Town for each Customer, meter, service and the parties shall, after execution of this agreement, agree in writing to an Addendum setting out the data items and formats provided or required and the data and formats in which the information for the database(s) will be stored.

Meter/Service Work

28. The Contractor shall communicate in writing (by electronic means) all meter work requests to the Town.

29. The Town shall communicate in writing (by electronic means) all completed work order requests to the Contractor.

Notification of Billing Adjustments

30. The Contractor shall take the following steps with Catch-up billing within ten (10) working days after the month's end in which that situation arises:

(a) apply the Catch-up consumption to the current bill in accordance with this Agreement and the Contractor shall note the Catch-up consumption and the time of the billing adjustment in the Customer's file; and,

(b) when requested, explain to the Customer the reasons for the Catch-up.

CUSTOMER SERVICES

General

31. The Contractor shall provide Customer services in the same fashion as hydro services, as well as through a customer service counter and via telephone, mail, fax and email responses. The Contractor shall provide appropriate responses in a courteous and timely fashion. Without limiting the generality of the foregoing, the following Contractor shall:

(a) explain charges on a Customer's account;

(b) inform the Customer of the Town's rates and billing and collection practices;

(c) log a service request for broken meters and Remotes and forward it to the Town for appropriate response and/or action by the Town; and

(d) provide customer account updates (change of banking information or ownership, seasonal disconnects/reconnects, etc.).

32. The Contractor shall not be required to defend, justify or provide an opinion to a Customer on the fairness or suitability of the Town's water and wastewater policies, rates or water quality.

33. The Contractor's record-keeping system shall have the capability to log, categorize and archive Customer inquiries and such information shall be provided to the Town at its request.

Customer Service Hours of Operation

34. The Contractor shall provide Customer services during the Contractor's regular hours of business.

CUSTOMER PAYMENTS

Cash Collections

35. The Contractor shall allow Customer payments at the same locations as electricity customers.

36. The Contractor's billing system and cash collection processes shall be adapted to incorporate the capability to facilitate the following:

(a) multiple payment options;

(b) NSF cheques;

(c) post dated cheques;

(d) damaged cheques and those that cannot be processed;

(e) audit trails and internal controls over accuracy and completeness;

(f) duplicate payments;

(g) partial payments;

(h) overpayments;

(i) stale dated cheques; and

(j) deferred payments.

Overdue Accounts

37. An overdue interest charge as prescribed by the Contractor shall be imposed on all water and wastewater accounts not paid in full by the due date specified on the customer invoice. Any revenue therefrom shall be collected by the Contractor and paid to the Town.

38. The Contractor shall be responsible for making every reasonable effort to collect past due accounts, including but not limited to, the imposition of overdue interest and notification to the Customer of past due amounts through email, written and/or telephone contact. Overdue interest rates charged to Customers shall be the same as those charged by the Contractor for electricity customers (currently one and half percent (1.5%) per month as of the date of signing).

<u>Town Assistance</u>

39. The Contractor may elect to request the Town's assistance in collecting past due water and wastewater accounts in arrears for more than sixty (60) days. Upon the request of the Contractor, the Town shall contact the Customer and determine the appropriate action which may include the termination of service, a repayment plan or such other action that the Town may deem to be appropriate. The Town will promptly notify the Contractor of the resolution of the arrears situation resulting from the Town's contact with the Customer.

<u>Transfer of Accounts to the Town</u>

40. The Contractor shall transfer to the Town all Customer accounts that have been in arrears for ninety (90) days within ten (10) working days after the month's end in which the accounts are ninety (90) days in arrears.

41. Where the Contractor receives a payment, including post-dated cheques, from the Customer after the account has been transferred to the Town, the Contractor shall notify the Town within ten (10) working days after the month's end in which the receipt occurred.

<u>Collection Agencies Restricted</u>

42. The Contractor shall not transfer any arrears of accounts to an independent collection agency unless authorized in writing to do so by the Town. If so authorized, all associated costs of the debt collection process, including agency and legal fees, shall be at the Town's expense.

FLOW OF MONIES TO THE TOWN

<u>Calculation</u>

43. The Contractor shall apply payments received from Customers first to owing electricity charges and then to the water and wastewater owing amounts. The Contractor shall forward to the Town, or other entity as directed by the Town, the total amount received from Customers in respect of water and wastewater charges, less the total fees or other amounts charged by the Contractor for its services pursuant to Schedule "A" attached hereto, plus the amount of any account transferred to the Town during such month, not more than thirty (30) days after the month's end in which the collection of amount occurred.

44. Payment shall be made through an electronic transfer of monies directly into the bank account specified by the Town.

45. Under no circumstances will the Contractor withhold payment or contra other non-water or non-wastewater related items from the monthly remittance required.

Billing Days

46. Where the Contractor does not forward the Town its expected payments in accordance with this Agreement, an overdue interest charge for the number of days delayed at an annual charge equal to the Toronto Dominion Canada Trust prime rate plus two percent (2%) shall be assessed against the total amount delayed.

Reporting

47. Each payment remittance to the Town's Finance Department shall include the following information:

(a) number of Customers billed and total volume of water billed (expressed in cubic metres);

(b) amount billed; and,

(c) supporting documentation for final accounts transferred to the Town, clearly indicating account name, service address, forwarding address, owner's name(s) and address if tenanted and details of amounts transferred.

Statements

48. A monthly summary of the Contractor's fees and other charges for services rendered under this Agreement is to be submitted to:

The Town of Innisfil
2101 Innisfil Beach Road
Innisfil, ON L9S 1A1

Attention: Director of Finance

49. Any questions regarding statements are to be directed to the Town's Director of Finance or the Contractor's CFO/Treasurer, respectively.

CHANGES TO THE SERVICES

Quarterly Contact Administrative Meetings

50. The Town or the Contractor may request from the other party a quarterly review of the performance of the services by each party and each party's obligations and to review any potential changes to the services.

Responsibility of the Town for Meter and Remote Maintenance

51. The Town shall provide the Contractor with two existing meter reading devices. On-going maintenance of the meter reading devices will be the responsibility of the Contractor. A work station with the necessary and applicable software loaded shall be provided by the Contractor.

52. The parties acknowledge that the Town is the owner of the meters and Remotes at serviced locations and is responsible for their maintenance and to keep them in good working order.

53. Upon receipt of a notice of a defective meter or Remote from the Contractor, the Town shall make best commercial efforts to undertake to contact the Customer within five (5) working days to arrange for an appointment to inspect, test and repair the meter and/or Remote.

54. The Town shall make best commercial efforts to inspect and repair the meter or Remote of a Customer within twenty (20) working days following notification by the Contractor. The Contractor shall bear no responsibility for the collection of any unbilled water and wastewater consumption of that Customer during the inspection, repair, maintenance or replacement time period.

55. Upon completion of the inspection, repair, maintenance or replacement of the meter or Remote, the Town shall notify the Contractor of the results of the work within five (5) working days or completion and convey the appropriate information necessary to correct and update the Customer's account and the meter or Remote information, such as readings, serial numbers, make and model of new equipment installed, and the old equipment removed.

<u>Supervision</u>

56. The Contractor shall provide skilful and efficient supervision of the services it provides to the Customer and the Town.

<u>Staff and Methods</u>

57. The Contractor shall ensure that its employees, agents and subcontractors comply with the applicable legislation, regulations and Town by-laws and policies. The Town will forward all applicable by-laws and policies to the Contractor on a timely basis.

58. Any of the Contractor's employees, agents or subcontractor's responsible for meter or Remote reading who are deemed by the Town, acting reasonably, to be unacceptable because of incompetence, improper conduct, security risk or disregard for the safety of themselves or others shall be removed from the place at which the services are being performed and replaced forthwith.

TERMS AND TERMINATION

<u>Term of Agreement</u>

59. The term of the Agreement shall be for a period of five (5) years, commencing August 1, 2012.

<u>Subsequent Agreements</u>

60. The parties agree to enter into negotiations twelve (12) months prior to the end of the term of this Agreement to facilitate the transfer of the billing services back to the Town or to negotiate a new agreement for the services.

Termination

61. Either party may at any time and for any reason by notice in writing suspend or terminate the services or any portion thereof on three hundred and sixty-five (365) days' written notice. Upon termination, the Contractor shall provide all data files pertaining to services rendered pursuant to this Agreement to the Town and shall return any and all Remotes and other equipment provided by the Town to the Contractor.

62. Upon receipt of such notice by the Town, the Contractor shall perform the services reasonably necessary, as determined by the Town, to complete the billings to the end of the notice period and close out the services referred to in this Agreement. The Contractor shall only be entitled to invoice for the Contractor's services performed up until the expiry of the three hundred and sixty-five (365) day notice period at the rate in place at the time of receipt of the invoice.

63. Both parties reserve the right at its exclusive option to terminate this Agreement without further liability of any kind upon sixty (90) days written notice:

    i. for failure by the other party to perform its obligations under the Agreement in a timely fashion or as required by this Agreement; and,
    ii. for breach of a condition of the Agreement by the other party.

Ownership and Transfer of Customer and Maintenance History Data

64. In the event this Agreement is terminated or comes to an end, the parties agree that the Contractor will deliver to the Town the water and wastewater Customer data and history and serviced location meter data and history in electronic format.

INDEMNIFICATION

General

65. For the arising out of the performance of the Contractor's services under this Agreement, including without limitation any negligent act or omission by any director, employee or agent of the Contractor in providing the Services,

66. Each party covenants and agrees to indemnify and save harmless the other party, its elected officials, directors, officers, employees and agents from any liability, action, claim, loss, injury, damage, payment, cost, fine, fine surcharge, recovery or expense, including substantial indemnity legal fees, recovered against itself, its councillors, officers, employees or agents, arising out of the performance or failure to perform by the other party under the obligations of this Agreement, including without limitation any negligent act or omission by any director, employee or agent. The parties agree that they shall provide the other party with prompt notice of any matter giving rise to this indemnification.

67. The Contractor shall defend a claim or suit arising from this Agreement against (a) both the Town and the Contractor; or, (b) the Town individually. If the Town, at its discretion, is unsatisfied with the defence provided by the Contractor, the Town may engage or retain its own counsel, the fees for which will be paid by the Contractor.

Damage Claims

68. The Contractor shall continuously protect the Town's and Customers' property and any adjacent property from damage, injury or loss arising in connection with this Agreement. It shall make restitution at its own expense for any damage, injury or loss to the Town's or Customers' property or adjacent property. The Contractor shall not be responsible for any such damage, injury or loss which the Town has agreed in writing to insure or which may be directly caused by the Town, its agents or employees.

Force Majeure

69. (a) Neither party shall be responsible for any delay or failure to perform its obligations under this Agreement where such delay or failure is due to fire, flood, explosion, war, embargo, governmental action, labour disruption, Act of Public Authority, Act of God, or to any other cause beyond its control, except labour disruption.

(b) In the event Force Majeur occurs, the party who is delayed or fails to perform shall give prompt notice to the other party and shall take all reasonable steps to eliminate the cause.

(c) Should the Force Majeure event last for longer than thirty (30) days, the Town may terminate this Agreement by notice to the Contractor without further liability, expense or cost of any kind.

INSURANCE

General Liability

70. The Contractor shall effect prior to the commencement of the services, and shall maintain and keep in force during the carrying out of the Contractor's services under this Agreement, commercial general liability insurance, naming the Town as an additional insured, protecting both the Contractor and the Town against claims for contractual liability, personal injury, bodily injury, death, property damage, or other third party or public liability claims arising from any accident or occurrence in respect of such services performed by the Contractor, in an amount not less than FIVE MILLION DOLLARS ($5,000,000.00) in respect of any one accident or occurrence.

Automobile Liability

71. The Contractor shall effect prior to commencement of the services, and shall maintain and keep in force during the carrying out of the services, automobile liability insurance. Such policy shall protect the Contractor against all liability arising out of the use of owned and non-owned automobiles. The limits of the liability under this insurance policy shall be in an amount not less than ONE MILLION DOLLARS ($1,000,000.00) per occurrence.

Terms and Policies

72. The Contractor shall effect, and shall keep in force during the carrying out of its services, naming jointly the Contractor and the Town, any other form of insurance as

the Town may from time to time require, in which case the fees set out in Schedule "A" attached hereto may be adjusted accordingly to allow for the costs of the additional premiums for such insurance.

73. In the event that the Town requests that the amount of coverage be increased under any policy of insurance required to be effected under this section, the Contractor shall endeavour forthwith to obtain such increased coverage and the Town shall pay for any additional cost thereof with written notice.

74. Any policies required to be effected by the Contractor shall, where available, contain a cross-liability clause.

75. Subject to paragraphs 74 and 75 in this Agreement, the Contractor shall pay all premiums and costs of all insurance required to be effected by the Contractor under any provision of this Agreement, and shall, prior to commencing its services, furnish to the Town a certificate of insurance and from time to time keep on file with the Town any renewal Agreement and other documents sufficient to show and establish accurately at all times the current status of policies in force, and in particular shall submit to the Town not later than fifteen (15) days before the expiration of every current policy evidence of the renewal of the policy or the issuance of a replacement policy and of the payment of all premiums due for the renewal or replacement, and shall promptly notify the Town of any cancellation or intended cancellation by any insurer of any policy or any circumstances known to the Contractor materially affecting its coverage. The Contractor should advise the Town of any insurance carrier change but does not require prior approval to change carriers.

76. If the Contractor defaults on any of its obligations under this Agreement regarding insurance, the Town may, but is not obliged to, place any insurance at the cost and expense of the Contractor, or pay any arrears of premium, and any expense incurred by the Town, including deductible payments, shall be reimbursed to it by the Contractor on demand without prejudice to any other rights and remedies of the Town under this Agreement.

SUCCESSORS AND ASSIGNS

Previous Agreements

77. This agreement supersedes all previous agreements, arrangements, or understandings between the parties whether written or oral in connection with, or incidental to, the services.

Inspection and Access

78. The Town shall have the right to periodically examine the Contractor's records and equipment to ensure the completeness and accuracy of the Customer's payments processed. The Town shall provide the Contractor with at least seventy-two (72) hours notice of its intent to examine the Contractor's records and equipment.

Relationship of the Parties

79. (a) The Contractor expressly acknowledge that it is an independent contractor and no agency, partnership or employer-employee relationship is intended or created by this Agreement.

(b) The Contractor shall be solely responsible for all matters relating to statutory deduction of all taxes, employment insurance and Canada Pension and all licenses and permits which may be or become required to perform its services.

(c) The Contractor shall be solely responsible for all matters relating to leave, remuneration, Workers' Compensation, insurance premiums, discipline, and the health and safety of its employees, agents and subcontractors..

Workplace Safety and Insurance Act

80. The Contractor shall furnish evidence of compliance with all requirements of the *Workplace Safety and Insurance Act, 1997*, S.O. 1997, c. 16, as amended, and its regulations passed thereunder. Such evidence shall include a certificate of good standing issued prior to commencement of the services under this Agreement.

Taxes

81. Unless otherwise stated, the Town shall pay all applicable provincial and federal government sales taxes, known at the commencement of this Agreement, with respect to the services carried out by the Contractor for the Town under this Agreement. The Contractor will charge the Customer, where applicable, and remit the necessary taxes related to any of the services the Contractor provides directly to the Customer.

By-Laws, Codes and Regulations

82. Unless otherwise specified, the Contractor shall obtain and pay for all necessary permits, licenses, certificates and inspections required for the execution of the services.

83. Where codes or regulations conflict, the more stringent shall govern.

84. The Contractor shall maintain a copy of the Contractor's own internal code, policy or standard relating to the services, and agrees to produce such copy at the request of the Town.

Warranty

85. Each party represents and warrants to the other party that all of its written representations and warranties made in this Agreement shall be true and correct in all material respects as at the time of the execution of this Agreement.

Dispute Resolution

86. (a) In the event of a dispute arising between the Town and the Contractor as to their respective rights and obligations under this agreement, both parties agree to use

their best efforts to resolve the dispute by mutual agreement for a period of not less than fourteen (14) days.

(b) In the event the parties fail to resolve the dispute by mutual agreement after fourteen (14) days, either party may give written notice to the other party requesting the matter be submitted to a dispute resolution committee made up of a maximum of three mutually agreeable members drawn from either party or externally selected. This informal dispute resolution committee will convene a meeting and attempt to resolve the matter within fourteen (14) days of written notice of the other party agreeing to the request to submit the matter to the dispute resolution committee.

(c) In the event the request to submit the matter to the dispute resolution committee is rejected or left unanswered, or the dispute resolution committee is unsuccessful in resolving the dispute, the , either party may give written notice to the other party declaring the attempted dispute resolution by mutual agreement to be a failure.

(d) In the event notice of failure to resolve the dispute by mutual agreement is given, the dispute shall be submitted to binding arbitration by a single arbitrator mutually agreed to by the parties with the costs of the arbitration being borne equally by the parties.

Notice

87. Any notice required to be given under this Agreement may be given personally or by prepaid first class mail (in which case receipt shall be deemed to have occurred five (5) clear days after the mailing thereof) or via facsimile (in which case receipt shall be deemed to have occurred one day after transmission). Notice to the parties shall be delivered at the following address or fax numbers:

Town: The Town of Innisfil
2101 Innisfil Beach Road
Innisfil, ON L9S 1A1

Fax: 705-436-7120

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

Fax: 705-431-5901

In the case of the Town, the Notice shall be directed to the attention of the Director of Finance. In the case of the Contractor, the Notices shall be addressed to the Vice-President of Corporate Services.

Confidentiality

88. The Contractor and the Town shall not at any time before, during or after the completion of the services, divulge any confidential information, or copies, notes and records reflecting such information, communicated to or acquired by the Contractor or the Town in the course of carrying out the services provided that such information is

Customer related or identified as confidential at the time of disclosure, except as required by relevant legislation or a court of competent jurisdiction. No such information shall be used by the Contractor or the Town before, during or after the completion of the services on any other project without the prior written consent of the other party or Customer, as applicable. The Contractor acknowledges that the *Municipal Freedom of Information and Protection of Privacy Act* applies to records in the control of the Town, pursuant to that Act.

Tax Changes

89. Where a change in Canadian Federal or Provincial taxes occurs after the Contract execution date, the Town will increase or decrease its payments owing to the Contractor to account for the exact amount of tax change involved.

90. Claims for compensation for additional tax cost shall be submitted by the Contractor to the Town within sixty (60) days of the introduction of the change.

91. The *Retail Sales Act,* R.S.O. 1990, c, R.31, as amended, shall apply to this Agreement.

92. Where goods and services are supplied under this Agreement by the Contractor, the unit prices in Schedule "A" involving goods and service shall not include the Harmonized Sales Tax (HST), which will be billed in addition to the charges listed, where applicable. The Contractor shall provide the Town with its HST Registration Number.

Further Assistance

93. The Contractor and the Town agree that each of them shall and will, upon reasonable request of the other, make, do, execute, or cause to be made, done or executed, all such further and other lawful acts, deeds, things, devices and assurances whatsoever necessary to give effect to this Agreement.

Severability

94. In the event that any of the terms, conditions or provisions contained in this Agreement shall be determined invalid, unlawful or unenforceable to any extent, such terms, conditions, or provisions shall be severed from the remaining terms, conditions and provisions, which shall continue to be valid to the fullest extent permitted by law.

Waiver

95. The failure by either party to insist in one or more instances upon the performance by the other party of any term or terms of this Agreement shall not be construed as a waiver of future performance of any such term or terms and the obligation of the other party with respect to such a future performance shall continue in full force and effect.

Governing Law and Interpretation

96. The Agreement and the services shall be governed by the laws of the Province of Ontario, including regulations and codes issued by the Ontario Energy Board.

97. Words used in the Agreement importing the singular number or the one gender only, include more persons, parties or things of the same kind than one, and females as well as males and the converse.

98. This Agreement constitutes the entire agreement between the parties and can only be changed by mutual agreement in writing signed by the parties.

99. The Contractor shall not subcontract or assign its obligation or rights under this Agreement without the written consent of the Town, which will not be unreasonably withheld.

100. This Agreement shall inure to the benefit of and be binding upon the parties and their respective successors and permitted assigns.

IN WITNESS WHEREOF the Corporate parties have hereunto caused their Corporate Seals to be affixed and attested by their proper officers and the individual parties have hereunto set their hands and seals, at the times and places indicated:

SIGNED AND SEALED	THE TOWN OF INNISFIL
This 6 day of	Per:
February	Barbara Baguley, Mayor
2012, at Innisfil	Per:
Province of Ontario	Jason Reynar, Clerk

SIGNED AND SEALED	INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMTIED
This 23 day of	Per:
FEBRUARY	John Skorobohacz, Chairman
2012, at Innisfil	Per:
Province of Ontario	George Shaparew, President

SCHEDULE "A"

Innisfil Hydro Distribution Systems Limited
Water Billing Contract – Pricing Schedule

	Year 1	Year 2	Year 3	Year 4	Year 5
Monthly (Water and Water with Wastewater)	$ 1.90	$ 1.90	$ 1.90	$2.00	$2.00
Wastewater Only	$1.50	$1.50	$1.50	$1.60	$1.60
Account Set-Up	$5.00	$5.00	$5.00	$5.50	$5.50

Notes:

- Prices quoted are on a per bill basis.
- Prices do not include tax (i.e. applicable taxes are extra).

EXHIBIT 4 – OPERATING COSTS

4.0-OEB Staff-40 – FTE's

Ref: Exhibit 4/Tab 1/Schedule 1, pp. 5-9 and Exhibit 1/Tab 1/Appendix H, p. 10

Please reconcile the Human Resources Five Year Plan in Appendix H, p. 10-11 with the Justification/Drivers provided for the 4.5 FTE's in Exhibit 4/Tab1/Schedule 1, pages 5-9.

IHDSL Response:

The hire of the Smart Grid Engineer was accelerated into 2012 in order to accommodate the retirement of the contract engineer. The funding for the position was through realized savings and capitalization of labour.

4.0-OEB Staff-41 – FTEs

Ref: Exhibit 4/Tab1/Schedule 1, p. 2

IHDSL stated that one of the cost drivers for a 17.9% increase in OM&A in the 2013 test year over the 2012 bridge year is the requirement of 4.5 FTE's in 2013.

a) Please state if any of these positions were filled in 2012. If so, please provide the date of hire.

IHDSL Response:

IHDSL can confirm that the identified 4.5 FTE's were not filled in 2012.

b) Please provide the expected hiring date for the remaining positions.

IHDSL Response:

The expected hiring of the positions is anticipated to be June of 2013.

4.0-OEB Staff-42 – Procurement and Inventory Officer

Ref: Exhibit 4/Tab 1/Schedule 1, p. 7 and Exhibit 1/Tab 1/Appendix H, p. 10

On page 10 of E1/T1/Appendix H, IHDSL noted that the position of Purchaser/Stockkeeper "is required for back-up to the one incumbent and for custodianship of the new building".

a) Please provide further explanation as to the above statement.

IHDSL Response:

Expansion of job duties over the past few years has exponentially increased the job scope of the Purchasing/stockkeeper. Examples of, ESA regulation 22/04 pertaining to materials and specifications, additional employees which has increased misc. laborious duties, higher capital expenditures requiring specialized material sourcing and procurement, IFRS implementation creating procedural changes, adding complexity and time, and of recent a larger administrative and operational facility in the works for 2013.

Throughout the course of the evolving role of the Purchasing/stockkeeper, persistent slipping of deadlines in all three categories, purchasing, inventory control, and laboring are occurring. Overtime has been offered generously; however, to date only a small amount has been taken advantage of.

The main function of this job is to mirror the job responsibilities of the Purchasing and Stockkeeping/labouring duties. This role will assume the same purchasing functions up to and including ESA material regulations, RFP's, RFQ's, service contracts, etc., as well as facilitating IFRS administrative duties pertaining to inventory Componentization/Disposals. It will be accountable for computer system Inventory control while contributing to the hands on issuing and receiving of materials and building maintenance the stockkeeper currently does. Redundancy in the absence of the Purchasing/stockkeeper is a direct benefit. Current student assistance in the stores area would no longer be required.

Below is a listing of Strengths, Weaknesses and Opportunities that should be noted in the Purchasing/Stockkeeper addition justification. The strengths represent how the existing Purchasing/Stockkeeper could benefit the addition. Areas of weakness are identified problems already taking place that will worsen as time progresses without this addition. Thirdly, opportunities to be gained by this additional Purchasing/Stockkeeper in the Stores area which would obviously address the weakness now encountered and provide some forward momentum to better refine the Stores department.

Areas of strength from using the current Purchasing/Stockkeeping employee

- *Leveraging current Purchasing/Stockkeeping Knowledge and experience*
- *Utilization of the current Purchasing/Stockkeeper who has demonstrated training techniques of the position (student role over)*
- *Highly competent and skilled at the purchasing and inventory role including physical inventory and data entry systems*
- *The current Purchasing/Stockkeeping role is adaptive to change and often innovative in a team contributed environment*
- *The current Purchasing/Stockkeeping role provides a positive win-win attitude*

Areas of weakness within Purchasing/Stockkeeper job functions-existing and without second Purchasing/Stockkeeper

- *Concurrent slipping of deadlines*
- *Back log of incomplete work from expanded job scope due to imposed regulations (IFRS, ESA, etc.)*
- *Acquiring back up during illness or holidays*
- *Re-allocation of alternate (back up) staff duties creating back log for them to facilitate Purchasing/Stockkeeping absence*
- *Multi department purchasing and PO generating creating confusion*
- *Little continuity for receiving's both physical and data entry*
- *Delayed remediation of building maintenance and Joint Health and Safety recommendations of existing and future facilities*
- *Limited holidays to ensure constant streaming of ordering, stocking and issuing to operations for job continuity*
- *Less involvement in progressive initiatives to assist development and expansion of current and future challenges (IFRS, ESA, etc.)*
- *Alternate back up must have at minimum training such as Forklift Certification and Transportation of Hazardous and Dangerous Goods*

Areas of opportunity for the hire of a second Purchasing/Stockkeeper

- *Centralized purchasing and receiving*
- *Higher control and administration of Request for proposals (RFP) and Request for Quotation (RFQ)*
- *Increased accuracy of material issue and returns including componentization and Disposals*
- *Full support back up ensuring high level of accuracy and control over the corporations assets and inventory*
- *Timely building maintenance which will be on the increase with the facility in 2013*
- *Fully trained with Forklift Certification and Transportation of hazardous and Dangerous Goods*

Shared responsibility and reliance on two individuals creating a better work/life balance for the sole employee.

b) Please provide a time allocation for the various responsibilities, in particular as it relates to the custodianship for the new building.

IHDSL Response:

In 2013 the entire time of the stores/custodian position will be dedicated to assisting with stores, as there is a large backlog of work that needs to be completed. As the backlog is *eliminated by the end of 2013/early 2014, the person can then dedicate more time to the custodial responsibilities of the new building.*

c) **Please explain why this position needs to be filled in 2013 given that the new office building will not be in service until the end of December 2013.**

IHDSL Response:

The position description as noted in the attachment points to the necessity for the additional body within the stores/purchasing area, allowing time in 2013 to accomplish catching up of the backlog within the store in 2013 and early 2014, which will then free up time in 2014 to work on custodial tasks in the new building.

4.0-OEB Staff-45 – Regulatory Costs

Ref: Exhibit 4/Tab 1/Schedule 1, p. 11

On page 11, table 4.5IHDSL shows that in the $115,000 of total regulatory costs it has included $16,000 for expert witness costs for regulatory matters. Please provide further detail as to the nature of these costs and the serviced received.

IHDSL Response:

IHDSL forecasted $16,000 for costs associated with the settlement process for this COS application. The cost was included in this category as IHDSL felt that the cost was over and above the forecasted consultant costs for COS preparation. If IHDSL has inadvertently input the cost in the incorrect category, this can be corrected.

4.0-OEB Staff-49 – 5120 Maintenance of Poles, Towers and Fixtures

Ref: Exhibit 4/Tab 1/Schedule 2, p. 2, table 4.7, Exhibit 4/Tab 2/Schedule 3, p. 6 and Exhibit 1/Tab 1/Appendix H, p. 46-49 – Asset Management Plan

IHDSL is showing the following maintenance expense for Poles, Towers and Fixtures:

2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
$32,833	$2,423	$1,671	$5,550	$19,340

a) **Please provide the 2009 Board-approved amount for maintenance in this category.**

IHDSL Response:

The 2009 Board approved amount for account for 5120 was $44,680.

b) Please confirm the amounts shown above are actual spending on poles, towers and fixtures maintenance.

IHDSL Response:

IHDSL confirms that the amounts reflected above are actual spending for account 5120 for poles, towers and fixtures.

c) On page 48 of the Asset Management Plan, and E4/T2/S3, p. 6 IHDSL stated that a maintenance program has not been budgeted before in the past, however with an Annual Pole Maintenance Program, IHDSL 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 has been included in account 5120 in the 2013 budget.

i. Please reconcile the amounts shown in E4/T1/S2, table 4.7 and the amounts provided in the Asset Management Plan and E4/T2/S3 page 6.

IHDSL Response:

The $19,340 reflected in E4/T1/S2 Table 4.7 is comprised of $13,440 for the specific scope of the Pole Maintenance program as referenced in E4/T2/S3 and $5,900 forecasted for unscheduled pole maintenance.

ii. Please elaborate on the conditions of poles if IHDSL had applied a consistent maintenance program since its last rebasing application.

IHDSL Response:

If we had applied a consistent maintenance program we would have been able to promptly correct the deficiencies noted by the pole inspectors. Instead, we replaced what needed to be replaced on an emergency basis only. We recognize this is not a satisfactory way under the DSC requirements. The costs noted herein are to implement a more formalized process for correcting of deficiencies noted by pole inspectors.

iii. Please provide an explanation as to why this maintenance was not provided.

IHDSL Response:

As reference in IR 49 cii) IHDSL only undertook replacements on an emergency basis.

4.0-OEB Staff-50 – 5125 Maintenance of Overhead Conductors and Devices

Ref: Exhibit 4/Tab 1/Schedule 2, p. 2, table 4.7

IHDSL is showing an increase of 111.5% in the 2013 test year over 2011 Actuals in account 5125. Please explain.

IHDSL Response:

The reason for the increase is attributed to the addition of our Smart Grid Engineer for 2012 in 2013. We also added maintenance projects in the Asset Management Plan that were not practiced in the past (see E1, Appendix H, page 15: see section labelled "Fault Indicators", and page 10: see section 3.5 labelled "Switches").

4.0-OEB Staff-53 – 6205 Donations/Sub-account LEAP

Ref: Exhibit 4/Tab 2/Schedule 2, p. 3, table 4.10 and Exhibit 4/Tab 1/ Schedule 1, p. 12

On page 12 of E4/T1/S1 IHDSL states that it has included LEAP funding in the amount of $11,304. Table 4.10 does not show any entry for LEAP under account 6205. Please explain.

IHDSL Response:

IHDSL has inadvertently included the LEAP funding in account 5410. This will be corrected by IHDSL with the closing of the 2012 financial records.

4.0-OEB Staff-54 – 6205 Donations/Sub-account LEAP

Ref: Exhibit 4/Tab 2/Schedule 2, p. 3, table 4.10 & Exhibit 4/Tab 1/Sch 1, p. 12

On page 12 of E4/T1/S1 IHDSL states that it has not included any charitable donations. Table 4.10 shows an entry of $1,000 under account 6205, Donations. Please explain.

IHDSL Response:

IHDSL inadvertently stated the paragraph incorrectly. IHDSL has included charitable donations of $1000.00 for the test year.

4.0 Energy Probe #22

Ref: Exhibit 4, Tab 1, Schedule 1

a) **Please provide the most recent year-to-date expenses available for 2012 in the same level of detail as shown in Table 4.1. Please also provide the corresponding figures for the same year-to-date period in 2011.**

IHDSL Response:

Table 4.1 Summary of OMA&A Expenses - Updated Nov YTD

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2012 Nov YTD	2013 Test
Operations	778,575	694,259	870,153	947,441	1,159,195	1,226,090	1,423,862
Maintenance	657,080	544,762	436,208	528,873	601,800	355,529	713,650
Billing & Collections	1,010,600	970,447	922,744	925,296	955,500	931,026	1,106,020
Community Relations	11,700	10,826	9,114	17,892	18,400	16,468	23,900
Aministrative General Expense	1,439,785	1,476,117	1,620,369	1,776,253	1,899,865	2,011,919	2,197,640
Total OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,541,032**	**5,465,072**
Total Recoverable OM&A	**3,897,740**	**3,696,411**	**3,858,588**	**4,195,755**	**4,634,760**	**4,540,032**	**5,465,072**
Year Over Year Variance $		**- 201,329**	**162,177**	**337,167**	**439,005**	**- 94,728**	**830,312**
Year Over Year Variance %		**-5%**	**4%**	**9%**	**10%**	**-2%**	**18%**

b) What is the impact on the OM&A costs if the 2013 inflation rate of 3% (page 12) is reduced to 2%?

IHDSL Response:

4-SEC-10

[Ex.4/1/1/p.6]

Please substantiate the position that if a Customer Service Collection Specialist is not added the impact will be, "customer dissatisfaction and risk of non-required collection notices of disconnection".

IHDSL Response:

IHDSL have found that since the implementation of the 2010 and 2011 Code amendments pertaining to Customer Service Rules, that the added complexities and new procedures required, over and above the day to day procedures of conventional "collections" functions, require dedicated expertise. This is to ensure that all collection aids and deferments available to residential customers, and in particular low-income residential customers, are applied prior to a service order being issued for a truck roll to deliver notice of pending disconnection and subsequent disconnect of service (as/if required). This requires a more in-depth knowledge of the rules that apply to residential and low-income residential customers and constant follow up that they are adhered to and applied consistently. It also requires that programming changes and inputs are monitored for accuracy to ensure proper tracking for eligibility for subsequent collection aids and deferments and for proper reporting.

4-SEC-11

[Ex.4/1/1/p.8]

With respect to the proposed new IFRS/Financial Analyst position:

a) Does the current Finance Department not have IFRS knowledge and necessary skills?

IHDSL Response:

The current Finance Department has received IFRS training to develop the required knowledge and skill set.

b) How did the Applicant transition with CGAAP to IFRS without this new position?

IHDSL Response:

IHDSL has elected to further defer the IFRS transition to January 1, 2014. IHDSL has utilized contractors to assist with the development, testing and implementation of the identifiable capital records for IFRS purposes. IHDSL has developed new fixed asset processes in order to componentize by major capital expenditure and provide subsequent identification of capital assets in order to reflect disposition. This is a substantial workflow and volume increase within capital expenditures of recording, verification, reporting and ultimate disposition.

21.0-VECC

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

a) Please confirm that OM&A expenses for 2013 are the same under CGAAP and MIFRS.

IHDSL Response:

IHDSL confirms that the OM&A expenses for 2013 are the same under CGAAP and MIFRS.

27.0-VECC

Reference: Exhibit 4, Tab 1

a) Please provide the amount of ESA membership for the years 2009 through 2013.

IHDSL Response:

The following table identifies the ESA membership fees from 2009-2013.

Year	Amount	HST	Total
2009	$7,131.34	$ 356.57	$7,487.91
2010	$7,319.14	$ 365.96	$7,685.10
2011	$7,616.72	$ 990.17	$8,606.89
2012	$7,761.39	$1,008.98	$8770.37
2013	$7,834.97	$1018.55	$8,853.52

b) Does IHDSL purchase insurance through MEARIE? If yes, please explain what coverage is purchased, the amount of premiums and the steps the Utility has taken to ensure it is getting competitive insurance value.

IHDSL Response:

IHDSL does purchase insurance through MEARIE. IHDSL purchases comprehensive liability insurance $36,020 (incl.rst), fleet vehicle insurance $15,712 and property insurance $37,046, 2013 premiums for a total of $88,778. In 2011, the CHEC Association undertook a project with the goal of finding an alternative insurance provider and thus reducing insurance costs for CHEC LDC's. The first investigation produced no positive results prior to our having to resign with MEARIE for another three years. The project has now been tabled until early 2015.

4.0-OEB Staff-43 – Maintenance cost for Office building

Ref: Exhibit 4/Tab 2/Schedule 2 pp. 1-3

Please detail which maintenance cost relate to the old office building and which cost relate to the new building. Please state which, if any costs have been offset to account for the move to the new headquarters in December of 2013.

IHDSL Response:

The maintenance costs relate to IHDSL's existing facility as occupancy was planned for the 2013 year end.

4.0-OEB Staff-44 - Pensions and OPEBs

Ref: Exhibit 4/Tab2/Schedule 4, pp. 1-2

a) Please provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last Board-approved rebasing application, Historical, Bridge and Test Years.

IHDSL Response:

INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED
EMPLOYEE HEALTH BENEFIT PROGRAM

	2009				2010				2011				2012			
Benefit	**Volume**	**Number Insured**	**Rate**	**Monthly Premium**	**Volume**	**Number Insured**	**Rate**	**Monthly Premium**	**Volume**	**Number Insured**	**Rate**	**Monthly Premium**	**Volume**	**Number Insured**	**Rate**	**Monthly Premium**
Life *	2,804,000	22	0.293	$821.57	3,039,500	24	0.316	$960.48	3,361,000	26	0.307	$1,031.83	3,886,000	30	0.297	$1,154.14
AD&D *	2,804,000	22	0.049	$137.40	3,039,500	24	0.050	$151.98	3,361,000	26	0.049	$164.69	3,886,000	30	0.048	$186.53
Extended	Single	2	67.10	$134.34	Single	3	58.77	$176.31	Single	3	59.77	$179.31	Single	3	54.99	$164.97
Health	Family	20	255.94	$5,118.80	Family	21	223.15	$4,686.15	Family	23	225.65	$5,189.95	Family	27	207.60	$5,605.20
Dental	Single	2	45.94	$91.88	Single	3	54.92	$164.76	Single	3	54.92	$164.76	Single	3	50.52	$151.56
	Family	20	144.94	$2,898.80	Family	21	173.33	$3,639.93	Family	23	173.33	$3,986.59	Family	23	159.46	$4,305.42
LTD *	73,231	22	2.42	$1,724.81	75,940	23 **	2.71	$2,057.97	87,038	26	2.561	$2,229.04	100,548	30	2.47	$2,483.54
Total Monthly Premium				**$10,927.60**				**$11,837.58**				**$12,946.17**				**$14,051.36**
Average Age (yrs)	47.54				45.40				44.53				43.69			
Average Tenure (yrs)	9.46				8.41				8.43				7.95			

** pooled benefit*

*** difference due to employee reaching maximum age*

In most cases, during the period noted above, IHDSL received reduced benefit rates as a result of negotiations with the benefit provider, as well as due to a steady decrease in the average age.
In 2010, IHDSL saw an increase in pooled benefits due to the average age increasing up to 2009. There was also an increase in the dental rates due to an increase in paid claims in 2009.

4.0-OEB Staff-46 – Operating Expenses

Ref: Exhibit 4/Tab 2/Schedule 2, p. 1, table 4.6 – 4.10

Please provide the actual operating expenses for the 2012 test year in the same detail as found in table 4.6

IHDSL Response:

IHDSL has updated the operating expenses to Nov 2012.

Table 4:6 – Operation Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations								
5005	Operation Supervision and Engineering	$ 94,914	$ 128,729	$ 142,878	$ 142,878	$ 188,345	$ 159,935	$ 199,285
5010	Load Dispatching	$ 8,118	$ 6,141	$ 10,772	$ 10,772	$ 10,700	$ 20,284	$ 11,050
5012	Station Buildings and Fixtures Expense	$ 43,110	$ 48,791	$ 40,852	$ 40,852	$ 45,000	$ 41,310	$ 47,400
5014	Transformer Station Equipment - Operation Labour							
5015	Transformer Station Equipment - Operation Supplies and Expenses							
5016	Distribution Station Equipment - Operation Labour	$ 6,999	$ 6,943	$ 6,632	$ 6,632	$ 6,900	$ 6,158	$ 7,100
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 1,026	$ 1,755	$ 2,685	$ 2,685	$ 2,800	$ 1,643	$ 2,900
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 69,027	$ 74,500	$ 96,661	$ 96,661	$ 107,000	$ 77,223	$ 109,100
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 36,414	$ 34,688	$ 21,151	$ 21,151	$ 24,100	$ 10,945	$ 25,050
5030	Overhead Sub-transmission Feeders - Operation	$ 1,501	$ 2,739	$ 3,457	$ 3,457	$ 3,700	$ 3,476	$ 3,850
5035	Overhead Distribution Transformers - Operation	$ 36	$ 308	$ 1,260	$ 1,260	$ 900	$ 1,530	$ 1,000
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 23,923	$ 24,103	$ 40,890	$ 40,890	$ 35,000	$ 45,460	$ 36,100
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 2,814	$ 10,394	$ 19,559	$ 19,559	$ 21,400	$ 11,096	$ 23,650
5050	Underground Sub-transmission Feeders - Operation							
5055	Underground Distribution Transformers - Operation							
5060	Street Lighting and Signal System Expense							
5065	Meter Expense	$ 55,781	$ 77,690	$ 77,675	$ 77,675	$ 206,500	$ 393,205	$ 339,849
5070	Customer Premises - Operation Labour	$ 43,380	$ 43,122	$ 42,062	$ 42,062	$ 47,000	$ 30,350	$ 48,400
5075	Customer Premises - Operation Materials and Expenses	$ 3,842	$ 7,544	$ 13,553	$ 13,553	$ 14,250	$ 7,962	$ 14,800
5085	Miscellaneous Distribution Expenses	$ 300,796	$ 394,603	$ 420,151	$ 420,151	$ 438,100	$ 415,513	$ 546,628
5090	Underground Distribution Lines and Feeders - Rental Paid							
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 2,578	$ 8,103	$ 7,203	$ 7,203	$ 7,500		$ 7,700
5096	Other Rent							
Total - Operations		$ 694,259	$ 870,153	$ 947,441	$ 947,441	$ 1,159,195	$ 1,226,090	$ 1,423,862

4.0-OEB Staff-47 – 5065 Meter Expense

Ref: Exhibit 4/Tab 2/Schedule 2, p. 1, table 4.6

IHDSL is showing an increase in meter expenses of 65% in 2013 over 2012 and 338% in 2013 over 2011 actual. Please provide further explanation for this increase given the completion of IHDSL's smart meter initiative.

IHDSL Response:

The 2013 increase over 2012 is comprised of the expense of a second meter technician and vehicle expense for same and the reverification of five wholesale revenue meters (there were no seal expiries in 2012) and the first test sampling of smart meter reverifications. The 2013 increase over 2011 actual is comprised of the annual expenses related to the operation of our AMI network, including operation of the Sensus Regional Network Interface (RNI) which is a shared facility, broadband communications, test facilities (shared) for testing firmware upgrades and meter communication upgrades prior to promoting them to production, operational data store, a second meter technician and vehicle expense for same, the re-verification of five wholesale meters (there was only one seal expiry in 2011) and the first test sampling of smart meter re-verifications. The following costs have been reflected,

- *Meter Technician $106,00*
- *Annual SMI costs $118,00*

4.0-OEB Staff-48 – 5085 Miscellaneous Distribution Expenses

Ref: Exhibit 4/Tab 2/Schedule 2, p. 1, table 4.6

IHDSL is showing a 30% increase in Miscellaneous Distribution Expenses in the 2013 test year over 2011 Actual. Please provide a breakdown of these expenses and explain the increase in more detail.

IHDSL Response:

The increase in account 5085 is directly attributed to the payroll costs for the requested Procurement and Inventory Officer of $88,400 and $10,200 increase in subcontractor expense.

4.0-OEB Staff-51 – Office Supplies and Expenses

Ref: Exhibit 4/Tab 2/Schedule 2, p. 3

IHDSL is showing a 23% increase in the 2013 test year over 2011 Actuals in account 5620 Office Supplies and Expenses. Please provide an explanation for this increase.

IHDSL Response:

The 2013 increase over 2011 actual is comprised of an increase in building maintenance costs (old buildings and portables requiring additional maintenance to maintain safe and clean work environments), two years postal rate increases, additional telephone expense (additional phone lines and phone system functionality added during 2011), increase in utility costs and marginal increase in the cost of computer supplies.

4.0-OEB Staff-52 – 5630 Outside Services Employed

Ref: Exhibit 4/Tab 2/Schedule 2, p. 3, table 4.10

IHDSL is showing a 46% increase in account 5630 Outside Services. Please provide an explanation for this increase.

IHDSL Response:

The increase in account 5630 is directly attributable to the annual expense costs for the SMI/MDMR IT administration services (audits, SLA, sync) for $46,000.

4.0 Energy Probe #23

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please provide the most recent year-to-date actual expenses for 2012 and the corresponding figures for the same period in 2011 for each of the accounts shown in Tables 4.6 through 4.10.

IHDSL Response:

IHDSL has updated the following tables:

Table 4.6: Detailed Account by Account Operation Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations								
5005	Operation Supervision and Engineering	$ 94,914	$ 128,729	$ 142,878	$ 142,878	$ 188,345	$ 159,935	$ 199,285
5010	Load Dispatching	$ 8,118	$ 6,141	$ 10,772	$ 10,772	$ 10,700	$ 20,284	$ 11,050
5012	Station Buildings and Fixtures Expense	$ 43,110	$ 48,791	$ 40,852	$ 40,852	$ 45,000	$ 41,310	$ 47,400
5014	Transformer Station Equipment - Operation Labour							
5015	Transformer Station Equipment - Operation Supplies and Expenses							
5016	Distribution Station Equipment - Operation Labour	$ 6,999	$ 6,943	$ 6,632	$ 6,632	$ 6,900	$ 6,158	$ 7,100
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 1,026	$ 1,755	$ 2,685	$ 2,685	$ 2,800	$ 1,643	$ 2,900
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 69,027	$ 74,500	$ 96,661	$ 96,661	$ 107,000	$ 77,223	$ 109,100
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 36,414	$ 34,688	$ 21,151	$ 21,151	$ 24,100	$ 10,945	$ 25,050
5030	Overhead Sub-transmission Feeders - Operation	$ 1,501	$ 2,739	$ 3,457	$ 3,457	$ 3,700	$ 3,476	$ 3,850
5035	Overhead Distribution Transformers - Operation	$ 36	$ 308	$ 1,260	$ 1,260	$ 900	$ 1,530	$ 1,000
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 23,923	$ 24,103	$ 40,890	$ 40,890	$ 35,000	$ 45,460	$ 36,100
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 2,814	$ 10,394	$ 19,559	$ 19,559	$ 21,400	$ 11,096	$ 23,650
5050	Underground Sub-transmission Feeders - Operation							
5055	Underground Distribution Transformers - Operation							
5060	Street Lighting and Signal System Expense							
5065	Meter Expense	$ 55,781	$ 77,690	$ 77,675	$ 77,675	$ 206,500	$ 393,205	$ 339,849
5070	Customer Premises - Operation Labour	$ 43,380	$ 43,122	$ 42,062	$ 42,062	$ 47,000	$ 30,350	$ 48,400
5075	Customer Premises - Operation Materials and Expenses	$ 3,842	$ 7,544	$ 13,553	$ 13,553	$ 14,250	$ 7,962	$ 14,800
5085	Miscellaneous Distribution Expenses	$ 300,796	$ 394,603	$ 420,151	$ 420,151	$ 438,100	$ 415,513	$ 546,628
5090	Underground Distribution Lines and Feeders - Rental Paid							
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 2,578	$ 8,103	$ 7,203	$ 7,203	$ 7,500		$ 7,700
5096	Other Rent							
Total - Operations		$ 694,259	$ 870,153	$ 947,441	$ 947,441	$ 1,159,195	$ 1,226,090	$ 1,423,862

Table 4.7: Detailed Account by Account Maintenance Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Maintenance								
5105	Maintenance Supervision and Engineering	$ 16,047	$ 17,770	$ 16,605	$ 16,605	$ 18,900	$ 11,263	$ 19,550
5110	Maintenance of Buildings and Fixtures - Distribution Stations							
5112	Maintenance of Transformer Station Equipment							
5114	Maintenance of Distribution Station Equipment	$ 42,337	$ 53,377	$ 37,758	$ 37,758	$ 54,600	$ 47,394	$ 56,230
5120	Maintenance of Poles, Towers and Fixtures	$ 32,833	$ 2,423	$ 1,671	$ 1,671	$ 5,550	$ 6,402	$ 19,340
5125	Maintenance of Overhead Conductors and Devices	$ 55,600	$ 60,636	$ 47,742	$ 47,742	$ 72,950	$ 37,608	$ 101,000
5130	Maintenance of Overhead Services	$ 66,730	$ 52,512	$ 67,089	$ 67,089	$ 60,750	$ 51,875	$ 62,650
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 177,192	$ 127,532	$ 184,235	$ 184,235	$ 215,100	$ 105,476	$ 222,650
5145	Maintenance of Underground Conduit							
5150	Maintenance of Underground Conductors and Devices	$ 3,716	$ 1,996	$ 2,587	$ 2,587	$ 4,750	$ 2,379	$ 5,050
5155	Maintenance of Underground Services	$ 81,414	$ 69,956	$ 80,843	$ 80,843	$ 96,850	$ 49,288	$ 99,850
5160	Maintenance of Line Transformers	$ 35,542	$ 17,149	$ 58,987	$ 58,987	$ 31,650	$ 16,645	$ 82,530
5165	Maintenance of Street Lighting and Signal Systems							
5170	Sentinel Lights - Labour							
5172	Sentinel Lights - Materials and Expenses							
5175	Maintenance of Meters	$ 33,351	$ 32,857	$ 31,356	$ 31,356	$ 40,700	$ 25,796	$ 44,800
5178	Customer Installations Expenses - Leased Property							
5195	Maintenance of Other Installations on Customer Premises						$ 1,403	
Total - Maintenance		$ 544,762	$ 436,208	$ 528,873	$ 528,873	$ 601,800	$ 355,529	$ 713,650

Table 4.8: Detailed Account by Account Billing & Collecting Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Billing and Collecting								
5305	Supervision	$ 50,754	$ 55,307	$ 63,860	$ 63,860	$ 64,900	$ 91,516	$ 66,800
5310	Meter Reading Expense	$ 137,851	$ 125,935	$ 69,829	$ 69,829	$ 33,300	$ 21,035	$ 38,000
5315	Customer Billing	$ 352,201	$ 335,375	$ 376,323	$ 376,323	$ 384,600	$ 324,871	$ 480,600
5320	Collecting	$ 293,500	$ 268,080	$ 286,478	$ 286,478	$ 327,800	$ 394,135	$ 340,820
5325	Collecting - Cash Over and Short	$ 30	$ 138	$ 35	$ 35	$ 50	$ 36	$ 100
5330	Collection Charges							
5335	Bad Debt Expense	$ 87,724	$ 85,020	$ 67,044	$ 67,044	$ 75,000	$ 41,151	$ 100,000
5340	Miscellaneous Customer Accounts Expenses	$ 48,387	$ 52,889	$ 61,727	$ 61,727	$ 69,850	$ 58,282	$ 79,700
Total - Billing and Collecting		$ 970,447	$ 922,744	$ 925,296	$ 925,296	$ 955,500	$ 931,026	$ 1,106,020

Table 4.9: Detailed Account by Account Community Relations Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Community Relations								
5405	Supervision							
5410	Community Relations - Sundry	$ 7,572	$ 5,867	$ 15,137	$ 15,137	$ 14,400	$ 15,035	$ 19,400
5415	Energy Conservation	$ -	$ 41	$ 208	$ 208		$ 124	
5420	Community Safety Program	$ 1,704	$ 1,000	$ -	$ -	$ 1,500	$ -	$ 1,500
5425	Miscellaneous Customer Service and Informational Expenses	$ 1,550	$ 2,206	$ 2,547	$ 2,547	$ 2,500	$ 1,309	$ 3,000
5505	Supervision							
5510	Demonstrating and Selling Expense							
5515	Advertising Expenses							
5520	Miscellaneous Sales Expense							
Total - Community Relations		$ 10,826	$ 9,114	$ 17,892	$ 17,892	$ 18,400	$ 16,468	$ 23,900

Table 4.10: Detailed Account by Account General & Administrative Expenses

Account	Description	Last Rebasing Year (EB-2012-0139 Actuals)	2009 Actual	2010 Actual	2011 Actual	Bridge Year IHDSL	IHDSL YTD Nov 2012 Actuals	Test Year
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 209,979	$ 209,923	$ 218,153	$ 218,153	$ 227,875	$ 229,724	$ 233,375
5610	Management Salaries and Expenses	$ 189,103	$ 201,551	$ 214,395	$ 214,395	$ 225,025		$ 232,247
5615	General Administrative Salaries and Expenses	$ 486,302	$ 576,121	$ 673,158	$ 673,158	$ 699,800	$ 977,406	$ 849,125
5620	Office Supplies and Expenses	$ 67,522	$ 73,767	$ 86,725	$ 86,725	$ 94,000	$ 80,236	$ 107,000
5625	Administrative Expense Transferred - Credit							
5630	Outside Services Employed	$ 64,876	$ 93,488	$ 104,144	$ 104,144	$ 148,500	$ 272,853	$ 152,895
5635	Property Insurance	$ 39,448	$ 75,239	$ 57,252	$ 57,252	$ 59,470	$ 64,953	$ 61,254
5640	Injuries and Damages	$ 34,487	$ 30,319	$ 34,561	$ 34,561	$ 37,000		$ 38,110
5645	OMERS Pensions and Benefits	$ 28,828	$ 3,555	$ 3,461	$ 3,461	$ 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	$ 100,673	$ 107,000
5660	General Advertising Expenses							
5665	Miscellaneous General Expenses	$ 91,366	$ 104,035	$ 105,153	$ 105,153	$ 116,395	$ 105,605	$ 114,884
5670	Rent	$ 755	$ 319	$ 335	$ 335	$ 600		$ 750
5672	Lease Payment Charge							
5675	Maintenance of General Plant	$ 155,401	$ 198,768	$ 181,370	$ 181,370	$ 221,000	$ 170,305	$ 286,500
5680	Electrical Safety Authority Fees	$ 8,427	$ 8,627	$ 8,928	$ 8,928	$ 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
6205	Donations, Sub-account LEAP Funding			$ 32,483	$ 32,483		$ 10,164	
Total - Administrative and General Expenses		$ 1,476,961	$ 1,671,988	$ 1,776,784	$ 1,776,784	$ 1,900,865	$ 2,011,919	$ 2,198,640

b) Please explain the significant increases in meter expenses (account 5065) in both 2012 and 2013.

IHDSL Response:

Please refer to OEB Staff IR 47

c) Please explain the increase of more than $108,000 in miscellaneous distribution expenses (account 5085) between 2012 and 2013.

IHDSL Response:

Please refer to 4.0-OEB Staff-48.

d) **Please explain the increase in maintenance of overhead conductors and devices (account 5125) between 2012 and 2013.**

IHDSL Response:

*The increase is due to the addition of an annual **Distribution Switch Maintenance** and **Fault Indicator Testing**.*

Distribution Switch Maintenance

With over 600 in-line and disconnect style switches in Innisfil Hydro's distribution territory, a proactive maintenance program does not exist to ensure efficient operation and prolonged life of the overhead switches in our system. Innisfil Hydro would establish a maintenance program to inspect, operate, clean and lubricate an approximate 45 out of a total of 350 overhead distribution switches in our system per year. This program will ensure switches will be tested and will operate properly when required to do so. The annual maintenance cost of $12,900.00 has been included in the 5125 account in the 2013 budget. As referenced in Exhibit 1 Appendix H pg. 50.

Fault Indicator Testing

Innisfil Hydro has installed approximately 40 sets of radio communicated fault indicators in its 44,000 Volt subtransmission system. These fault indicators have reached an age that warrants a new maintenance program to ensure their accuracy and reliability. These fault indicators have a compulsory role in assisting emergency switching procedures during fault conditions due to storms, tree contacts, vehicular accidents and defective devices. The fault indicator will send back a signal pinpointing an area where the problem exists. Through the use of the Innisfil Hydro's SCADA system, faults can be remotely switched at any hour of the day or night. To ensure accuracy and reliability of the fault indicator, Innisfil Hydro requires an annual testing program where Line personnel would be triggering the fault indicator manually in the field while operational staff monitor the SCADA system. In past experience, fault indicator failures have occurred due to water egress, battery failure, loose connections and UV damage. This causes uncertainty in switching operations which directly affects customer reliability and statistical data (SAIFI, SAIDI). This program will improve fault indicator performance. The annual maintenance cost of $12,100.00 has been included in the 5125 account in the 2013 budget. As referenced in Exhibit 1 Appendix H pg. 54.

e) **Please explain the $50,000 increase in maintenance of line transformers (account 5160) between 2012 and 2013.**

IHDSL Response:

The increase is due to the addition of an annual Underground Transformer and Switch Gear Maintenance Program.

Elbows and terminators of the Transformers and Switchgears are visually inspected according to the Minimum Inspection Requirements in the Distribution System Code (every 3 years Urban and every 6 years rural) by the infra-red scanning program. Underground Transformers and Switch Gears have their lids opened and all connections are inspected by the infra-red scanning process. Underground Transformers and Switch Gears are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to line patrols and infra-red testing , a more in-depth maintenance program will: create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature, and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. A program of this scope has not been budgeted before in the past; however, with an Annual Underground Transformer and Switch Gear Maintenance Program, Innisfil Hydro would be able to proactively complete more thorough maintenance. The annual maintenance cost of $49,780.00 has been included in the 5161 account in the 2013 budget. As referenced in Exhibit 1 Appendix H pg. 55.

f) Please explain the $96,000 increase between 2012 and 2013 in customer billing (account 5315).

IHDSL Response:

Of the 96,000:

- *$8,000 can be attributed to change in bill stock from letter size to legal size to avoid two page bills which have resulted from printing the details of Arrears Payment Arrangements on residential accounts, TOU billing and the meter details for our GS>50 customers who have interval meters;*
- *$5000 can be attributed to the annual increase in postal rates;*
- *The balance can be attributed to the addition of one full time staff whose salary will actually be charged under the sub-section of 5320 rather than 5315 as it is for a Customer Service Collections Specialist.*

g) Please explain the increase of 33% between 2012 and 2013 for bad debt expense (account 5335).

IHDSL Response:

The increase of 33% in bad debt expense between 2012 and 2013 is due to an increase in bankruptcies that we saw between 2010 and 2011. This is supported by our actual bad debt expense for 2012 which was substantially higher than forecast at $ $108,892.97, of which $108,043.04 was on customer accounts which included a 163% increase in bankruptcies from 2011 to 2012.

4.0 Energy Probe #24

Ref: Exhibit 4, Tab 2, Schedule 4

Does the management category shown in Table 4.16 include members of the Board of Directors? If yes, please provide a version of Table 4.16 that separates the Board of Directors from management in the table.

4.0 Energy Probe #25

Ref: Exhibit 4, Tab 2, Schedule 6

a) Please confirm that IHDSL's 2009 rates were set based on the use of the half year methodology for capital additions in the current year.

IHDSL Response:

IHDSL's 2009 rates were set based on the use of the half year methodology for the capital additions in the current year.

b) Please confirm that IHDSL has used the half year methodology for all years while under IRM.

IHDSL Response:

IHDSL has used the half year methodology for all years while under IRM.

c) Please explain the reduction of $639,864 shown at the bottom of the table in Appendix 2-CH. Please also explain the difference between Appendix 2-CH and Table 2.38.

IHDSL Response:

The reduction of $639,864 is the PP&E adjustment for the change in useful life of assets for 2012. The additions difference between Appendix 2-CH and Table 2.38 is $2m spent in 2012 toward the new operations and administration building.

4-SEC-13

[Ex.4/2/3/p.3]

With respect to the Applicant's decision to internalize a group of lineman, please provide the cost-benefit analysis referred to.

IHDSL Response:

This document is included in the Exhibit 4 Appendices Section – Ex4 Appendix 1 IR Ref SEC-13.

4-SEC-15

[Ex.4/2/4/p.4]

Please explain the delay in hiring the Regulatory/CDM Manager?

IHDSL Response:

The delay in hiring was primarily due to timing in receiving approval for the 2009 COS Application and then undertaking the hiring process.

4-SEC-18

[Ex.4/2/4/p.3, Ex.1/H/p.10]

With respect to the Collective Agreement between the Applicant and its Union:

a) **Please provide a copy of the current Collective Agreement.**

   IHDSL Response:

   The current Collective Agreement is attached in the Exhibit 4 Appendices section of this document – Ex4 Appendix 2 IR Ref SEC-18a.

b) **What assumptions is the Applicant making in this application regarding any potential wage increases to be included in 2013 after the expiry of the current Collective Agreement?**

IHDSL Response:

IHDSL assumed a 3% wage increase in all calculations.

4-SEC-19
[Ex.4/2/5/p.3]

Please provide a list of Non-Affiliate Suppliers for 2012.

IHDSL Response:

IHDSL has submitted the COS filing based on filing requirements for Electricity Transmission and Distribution Applications revised on June 28, 2012 section 2.7.6. This section requires IHDSL to provide historical actuals of the Non-Affiliate Suppliers. IHDSL does not anticipate a significant change of suppliers from the 2011 list at this time.

25.0-VECC

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

a) Please provide the basis for the 3% inflation factor cost driver.

IHDSL Response:

The majority of OM&A costs are attributed to labour costs which have increased from 2009 to 2012 by 3% per year. Innisfil Hydro is a legislated participant within the Ontario Municipal Employees Retirement System Act, 2006 (OMERS). OMERS have increased direct labour related costs with the following increases: 2011 - 1%, 2012 - 1%, 2013 - .9%. The 3% inflation cost driver better reflects actual inflation pressures for this business whereby CPI is reflective on consumer driven purchases.

b) Please provide the actual Statistics Canada CPI inflator for the years 2009 through 2012.

IHDSL Response:

From the Statistics Canada website, the Consumer Price Index changes are: 2009 - .3%, 2010 - 1.8%, 2011 - 2.9%, Jun 2011 to Jun 2012 - 1.5%.

c) Please provide the actual PWU contract inflation factor for 2009 through 2014.

IHDSL Response:

For the period 2009 to 2012, the term of the current Collective Agreement, the actual PWU contract inflation factor was 3% per year.

26.0-VECC

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 4/ Tab 1, Schedule 1

a) An incremental 0.5 FTE is forecast in 2013 for a Regulatory Analyst – is this a part-time position?

IHDSL Response:

The Regulatory Analyst position is a part time position.

b) An incremental 1 FTE is forecast in 2013 for a Financial Analyst. The evidence states that this will result in reduced dependency on consultants. What are the estimated cost savings if this position is filled in 2013.

IHDSL Response:

The incremental FTE for the Financial Analyst will not produce cost savings but rather cost avoidance. IHDSL Finance department is experiencing an increased workload due to componentization of capital assets, economic evaluations, increased reporting requirements, growth within the utility and in the LDC territory. This is not expected to change in the foreseeable future. A FTE is required to avoid the need to bring in outside consultants at a substantially higher cost, therefore more economical. A FTE allows for greater efficiency as the initial training period does not have to be repeated and the knowledge can develop in house.

4.0 Energy Probe #26

Ref: Exhibit 4, Tab 3, Schedule 1

Please confirm that the Ontario Income Tax rate shown in Table 3.2 for the 2012 and 2013 years is actually 11.50%.

IHDSL Response:

The Ontario Income Tax rate shown in Table 3.2 for the 2012 and 2013 years should be 11.50%. An older version of Table 3.2 was copied in error.

4.0 Energy Probe #27

Ref: Exhibit 4, Tab 3, Schedule 2

a) **Please confirm that the CCA schedule for 2012 reflects A UCC opening balance that is consistent with the actual closing balance from the 2011 tax filing.**

IHDSL Response:

The CCA schedule for 2012 UCC opening balance is consistent with the actual closing balance from the 2011 tax filing.

b) **Please explain why IHDSL has included computer hardware in CCA class 10 rather than in class 50 in both 2012 and 2013.**

IHDSL Response:

SC UPDATE - IHDSL has inadvertently included the computer hardware in CCA class 10 rather than in class 50.

c) **Please confirm that in the 2011 tax filing, IHDSL included computer hardware additions in CCA class 50.**

IHDSL Response:

IHDSL included the computer hardware additions in CCA class 50 in the 2011 tax filing.

d) **Please provide revised CCA schedules for 2012 and 2013 where the computer hardware additions for both 2012 and 2013 are put into CCA class 50 instead of class 10.**

IHDSL Response:

Revised CCA schedules for 2012 and 2013 as follows:

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Revised Submission: Bridge Year CCA	Revised Submission: UCC End of Bridge Year	Original Submission: Bridge Year CCA	Original Submission: UCC End of Bridge Year	Variance: Bridge Year CCA	Variance: UCC End of Bridge Year
1	Distribution System - post 1987	$14,160,463			$14,160,463	$ -	$14,160,463	4%	$ 566,419	$13,594,044	$ 566,419	$13,594,044	$ -	$ -
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -	$ -	$ -	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -	$ -	$ -	$ -	$ -
8	General Office/Stores Equip	$ 733,538	$ 65,000		$ 798,538	$ 32,500	$ 766,038	20%	$ 153,208	$ 645,330	$ 153,208	$ 645,330	$ -	$ -
10	Computer Hardware/ Vehicles	$ 679,501	$ -		$ 679,501	$ -	$ 679,501	30%	$ 203,850	$ 475,651	$ 222,225	$ 579,776	-$ 18,375	-$ 104,125
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
12	Computer Software	$ 36,623	$ 282,150		$ 318,773	$ 141,075	$ 177,698	100%	$ 177,698	$ 141,075	$ 177,698	$ 141,075	$ -	$ -
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -	$ -	$ -	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -	$ -	$ -	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -	$ -	$ -	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 5,592			$ 5,592	$ -	$ 5,592	45%	$ 2,516	$ 3,076	$ 2,516	$ 3,076	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
47	Distribution System - post February 2005	$15,678,237	$5,149,271	-$310,000	$20,517,508	$ 2,419,636	$18,097,873	8%	$1,447,830	$19,069,678	$1,447,830	$19,069,678	$ -	$ -
50	Data Network Infrastructure Equipment - post Mar 2007	$ 17,532	$ 122,500		$ 140,032	$ 61,250	$ 78,782	55%	$ 43,330	$ 96,702	$ 9,643	$ 7,889	$ 33,688	$ 88,813
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -	$ -	$ -	$ -	$ -
95	CWIP	$ 110,615		-$ 35,615	$ 75,000	$ -	$ 75,000		$ -	$ 75,000	$ -	$ 75,000	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
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					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL	$ 31,422,101	$ 5,618,921	-$345,615	$36,695,407	$ 2,654,461	$34,040,947		$2,594,851	$34,100,556	$2,579,538	$34,115,869	$ 15,313	-$ 15,312

Schedule 8 CCA - Test Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Revised Submission: Bridge Year CCA	Revised Submission: UCC End of Bridge Year	Original Submission: Bridge Year CCA	Original Submission: UCC End of Bridge Year	Variance: Bridge Year CCA	Variance: UCC End of Bridge Year
1	Distribution System - post 1987	$13,594,044			$13,594,044	$ -	$13,594,044	4%	$ 543,762	$13,050,283	$ 543,762	$13,050,283	$ -	$ -
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -	$ -	$ -	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -	$ -	$ -	$ -	$ -
8	General Office/Stores Equip	$ 645,330	78,200		$ 723,530	$ 39,100	$ 684,430	20%	$ 136,886	$ 586,644	$ 136,886	$ 586,644	$ -	$ -
10	Computer Hardware/ Vehicles	$ 475,651	110,000		$ 585,651	$ 55,000	$ 530,651	30%	$ 159,195	$ 426,455	$ 209,633	$ 608,143	-$ 50,438	-$ 181,688
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
12	Computer Software	$ 141,075	278,500		$ 419,575	$ 139,250	$ 280,325	100%	$ 280,325	$ 139,250	$ 280,325	$ 139,250	$ -	$ -
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ -			$ -	$ -	$ -	8%	$ -	$ -	$ -	$ -	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -	$ -	$ -	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -	$ -	$ -	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 3,076			$ 3,076	$ -	$ 3,076	45%	$ 1,384	$ 1,692	$ 1,384	$ 1,692	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -	$ -	$ -	$ -	$ -
47	Distribution System - post February 2005	$19,069,678	8,426,152	-325,500	$27,170,330	$ 4,050,326	$23,120,004	8%	$1,849,600	$25,320,730	$1,849,600	$25,320,730	$ -	$ -
50	Data Network Infrastructure Equipment - post Mar 2007	$ 96,702	128,000		$ 224,702	$ 64,000	$ 160,702	55%	$ 88,386	$ 136,316	$ 4,339	$ 3,550	$ 84,047	$ 132,766
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -	$ -	$ -	$ -	$ -
95	CWIP	$ 75,000			$ 75,000	$ -	$ 75,000	0%	$ -	$ 75,000	$ -	$ 75,000	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
					$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL	$ 31,422,101	$ 5,618,921	-$345,615	$36,695,407	$ 2,654,461	$34,040,947		$2,594,851	$34,100,556	$3,025,929	$39,785,292	$ 33,609	-$ 48,922

4.0 Energy Probe #28

Ref: Exhibit 4, Tab 3, Schedule 2 & Exhibit 4, Tab 4, Schedule 3

a) Please explain the difference in Tables 3.3 through 3.6 in Exhibit 4, Tab 3, Schedule 2 and Tables 4.4 through 4.7 in Exhibit 4, Tab 4, Schedule 3.

IHDSL Response:

The Tables 4.4 through 4.7 in Exhibit 4, Tab 4, Schedule 3 were inadvertently included.

b) Which set of tables has been used to calculate the CCA and CEC deductions for PILs purposes in 2013?

IHDSL Response:

Tables 3.3 through 3.6 in Exhibit 4, Tab 3, Schedule 2 have been used to calculate the CCA and CEC deductions for PILs purposed in 2013.

4.0 Energy Probe #29

Ref: Exhibit 4, Tab 3, Schedule 1

a) Did IHDSL have any Apprenticeship Training Tax credits, Co-Operative Education Tax credits or Federal Job Creation tax credits in 2011? If yes, please provide details and quantify.

IHDSL Response:

IHDSL currently has a Powerline Apprentice. In 2011, IHDSL received $12,192 in Apprenticeship tax credits.

IHDSL participates in the co-operative education program with Georgian College. In 2011, IHDSL received $13,524 in Co-operative education tax credits These credits are detailed in Schedule 1 of IHDSL's 2011 corporate tax return.

b) Has IHDSL claimed any of the tax credits noted above in part (a)? If not, please explain why not. If yes, please quantify.

IHDSL Response:

Please refer to 4.0 Energy Probe #29 a) above.

c) Has IHDSL claimed any other tax credits, other than those noted in part (a) above? If yes, please quantify.

IHDSL Response:

IHDSL has not claimed any other tax credits other than those noted in part (a).

9.0-OEB Staff-64 – PILS

Ref: Income Tax/PILS Workform for 2013 Filers
Exhibit 4, Tab 4, Appendix B 2011 Federal & Ontario Tax Returns, Page 84
EB-2006-0170 - Filing Requirements For Electricity Transmission and Distribution Applications

In IHDSL's Income Tax/PILS Workform for 2013 Filers, the calculation of Taxable Income for the Test Year includes an addition and a deduction of $81,910 for reserves from financial statements. As per IHDSL's 2011 tax return, this amount relates to the reversal of settlement variance.

Pages 33 and 34 of the *Filing Requirements For Electricity Transmission and Distribution Applications*, EB-2006-0170, June 28, 2012, state the following:

> **Regulatory assets (and regulatory liabilities) should generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.**

a) **The $81,910 addition and deduction to the 2013 taxable income represents regulatory assets and regulatory liabilities. Regulatory assets and regulatory liabilities should be excluded from PILs calculations. Please update the PILs evidence and other related evidence to exclude this amount from all calculations of regulatory taxable income and all PILs calculations.**

IHDSL Response:

The $81,910 represents the 2011 net change relating to the regulatory assets and liabilities that was moved from the Income Statement to the Balance Sheet. IHDSL's actual tax return is prepared to reflect the exclusion of the regulatory assets and liabilities from the PILs calculations. The addition to the financial statement income is required to exclude the impact of the regulatory assets and liabilities due to the variance accounting reflected within the financial reporting.

b) **Please provide the Notice of Assessment for the 2011 tax year, if available.**

IHDSL Response:

Please see Appendix E, which is located in the Exhibit E Appendices section – Ex4 Appendix # IR Ref OEB Staff-64b.

22.0-VECC

Reference: Exhibit 4, Appendix 2-G

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

IHDSL Response:

24.0-VECC

Reference: Exhibit 4, Appendix 2-G / Exhibit 4, Tab 2, Schedule 3, pg. 8

a) Please explain how the forecast for 2013 Bad Debt expense was calculated.

IHDSL Response:

The expense for the 2013 bad debt was calculated by reviewing final billed accounts that had been placed with a third party collection agency and deemed 'recovery unlikely' by the agency, reviewing the actual bad debt write offs for 2009 and 2010 (for trending), by taking into consideration the increase in bankruptcies and forecasting the effect of the 2010 and 2011 code amendments that extend payment arrangements beyond historical limits. From an analysis of our 2012 residential arrears payment plans, the sampling of completed agreements is indicating that the shorter term agreements (5 months) are proving to be more successful that the longer term agreements (10 months) and that the majority of arrangements we are making are for the longer term. Additionally, yet longer term agreements are allowed for low-income residential customers and the volume of customers being deemed eligible for the applicable customer service rules is steadily increasing.

b) Provide the actual 2012 bad debt expense.

IHDSL Response:

The bad debt expense for 2012 is currently estimated at $108,892.97. The estimated value will be revised once DRC and HST components have been removed.

c) Please explain why IHDSL does not have any Collection Charges (credits).

IHDSL Response:

Collection charges are recorded in a sub-account 4235 Other Revenue. IHDSL made this change within the 2009 rate application.

d) Please explain why bad debt costs are forecast to increase when IHDSL is also proposing to hire a Customer Service Collections Specialist.

IHDSL Response:

IHDSL is forecasting that bad debt costs will increase, despite the proposed hiring of a Customer Service Collections Specialist, because the latter is to address the new Customer Service Rules that pertain to residential customers only. Since the economic downturn in 2008, we have had a marked increase in personal bankruptcies and commercial account bad debts which are not remedied by the proposed hiring. This is evidenced by our actual 2012 write-offs which were higher than forecast and included 163% increase in the number of write-offs due to bankruptcies.

EXHIBIT 4 APPENDICES

Ex4 Appendix 1 IR Ref SEC-13 – Internalizing Line Staff Analysis

Ex4 Appendix 2 IR Ref SEC-18a – Collective Agreement

Ex4 Appendix E IR Ref OEB Staff-64b – Notice of Assessment

EXHIBIT 5 – COST OF CAPITAL

5.0-OEB Staff-55 – Long-term debt

Ref: Exhibit 5/Tab 1/Schedule 2, pp. 2-5

Please confirm that IHDSL included its $8M demand loan at a rate of 5%in its calculation of the long-term debt rate. Please provide the basis for this rate and confirm the date as January 1, 2013.

IHDSL Response:

IHDSL has included the 2013 additional $8m demand loan totalling $13.8m demand load for 2013. The basis for this rate was based on the March 2012 rate with the Toronto Dominion Bank. The date for demand loan is January 1, 2013.

5.0 Energy Probe #30

Ref: Exhibit 5, Tab 1, Schedule 1

a) **What is the impact on the revenue deficiency of reducing the return on equity from 9.12% to 8.93% as set in accordance with the Cost of Capital Parameter Updates for 2013 Cost of Service Applications issued by the OEB on November 15, 2012?**

IHDSL Response:

IHDSL has adjusted the Cost of Capital parameters from 9.12% to 8.93% in accordance with the November 15, 2012 update. The impact to revenue deficiency is a decrease of $34,187, from $761,836 to $727,649.

The revised 6.1.1 Revenue Deficiency table reflects the change.

Table 6.1.1

Innisfil Hydro Distribution Systems Limited
Revenue Deficiency Determination

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**727,649**
Distribution Revenue	8,503,677	8,100,851	8,100,851
Other Operating Revenue (Net)	422,748	556,948	556,948
Total Revenue	**8,926,425**	**8,657,799**	**9,385,448**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,873,762	3,327,560	3,327,560
Operation & Maintenance	1,760,995	2,137,512	2,137,512
Depreciation & Amortization	1,422,426	1,611,954	1,611,954
Amortization PP&E Adjustment		-159,966	-159,966
Return on PP&E Adjustment		-42,167	-42,167
Property Taxes	12,000	12,500	12,500
Deemed Interest	945,411	1,119,814	1,119,814
Total Costs and Expenses	**7,014,594**	**8,007,207**	**8,007,207**
Utility Income Before Income Taxes	**1,911,831**	**650,592**	**1,378,241**
Income Taxes:			
Corporate Income Taxes	193,831	-23,537	20,489
Total Income Taxes	**193,831**	**-23,537**	**20,489**
Utility Net Income	**1,718,000**	**674,128**	**1,357,751**
Income Tax Expense Calculation:			
Accounting Income	1,911,831	650,592	1,378,241
Tax Adjustments to Accounting Income	-1,048,318	-1,039,600	-1,039,600
Taxable Income	**863,513**	**-389,008**	**338,641**
Income Tax Expense before credits	**193,831**	**-23,537**	**20,489**
Credits			**32,000**
Income Tax Expense	193,831	-23,537	20,489
Tax Rate Refecting Tax Credits	22.45%	6.05%	6.05%
Actual Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Interest Expense	945,411	1,119,814	1,119,814
Net Income	1,718,000	674,128	1,357,751
Total Actual Return on Rate Base	**2,663,411**	**1,793,943**	**2,477,566**
Actual Return on Rate Base	8.39%	4.72%	6.52%
Required Return on Rate Base:			
Rate Base	31,728,141	38,010,954	38,010,954
Return Rates:			
Return on Debt (Weighted)	4.97%	4.91%	4.91%
Return on Equity	8.01%	8.93%	8.93%
Deemed Interest Expense	945,411	1,119,814	1,119,814
Return On Equity	1,016,570	1,357,751	1,357,751
Total Return	**1,961,981**	**2,477,566**	**2,477,566**
Expected Return on Rate Base	6.18%	6.52%	6.52%
Revenue Deficiency After Tax	**-701,430**	**683,623**	**0**
Revenue Deficiency Before Tax	**-904,450**	**727,649**	**0**

b) Please confirm that the 2.087% shown on line 11 on page 2 should be 2.08%.

IHDSL Response:

IHDSL confirms that the value should be 2.08%.

5.0 Energy Probe #31

Ref: Exhibit 5, Tab 1, Schedule 1 &Exhibit 5, Tab 1, Schedule 2

a) Please reconcile the further increase in the demand load of $8.0m for the 2013 capital projects noted on page 2 of Exhibit 5, Tab 1, Schedule 1 with the demand loan shown in Table 5.1.3 in Exhibit 5, Tab 1, Schedule 2 with an issuance date of January 1, 2013 in the amount of $13,843,930.

IHDSL Response:

The demand loan referenced on January 1, 2012 was $5.5m. On March 2012 $3.8m was converted to a commercial loan. The balance of the January 2012 demand loan of $1.7m is included in the balance of the Jan 2013 demand loan of 13m.

b) Please explain how the amount of $13,843,930 for the demand loan noted above was determined.

IHDSL Response:

The amount of the demand loan was determined by the 2013 Capital requirements.

c) Please indicate how the rate of 5.0% was determined as the forecast for the $13,843,930 demand loan.

IHDSL Response:

The 5% rate for the 2013 demand loan was determined based on the commercial loan that was converted on March 2012 @4.05% and discussions with the Toronto Dominion bank for anticipated loan rates for 2013.

d) Please confirm that the loan of $3,805,466 with an issuance date of March 14, 2012 and an interest rate of 4.05% reflects an actual loan and not a forecast.

IHDSL Response:

IHDSL confirms that the commercial loan of $3,805,466 issued March 14, 2012 with an interest rate of 4.05% for 25 years is an actual loan.

e) Please explain why the debenture from the Town of Innisfil is not considered an affiliate loan?

IHDSL Response:

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.

f) Please provide a copy of the debenture from the Town of Innisfil, along with all amendments made to the debenture.

IHDSL Response:

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.

g) Please explain why IHDSL is forecasting the issuance of a demand loan on January 1, 2013 rather than a long term debt instrument?

IHDSL Response:

IHDSL has assumed that with the completion of capital projects at the end of 2013 the demand loan would be converted to long term debt in 2014.

h) Please explain why IHDSL is forecasting the issuance of a loan in 2013 from the Toronto Dominion bank rather from Infrastructure Ontario.

IHDSL Response:

IHDSL has found that the TD bank debt rates are comparable to Infrastructure Ontario debt rates.

i) What are the current rates available from Infrastructure Ontario for term loans of 5, 10, 20 and 30 years?

IHDSL Response:

The rates from the Infrastructure Ontario as of February 11, 2013are as follows:
5 years - 2.42%
10 years - 3.10%
20 years - 3.80%
30 years - 4.10 %

5.0 Energy Probe #32

Ref: Exhibit 5, Tab 1, Schedule 2

The tables for 2012 and 2013 shown on page 4 of Exhibit 5, Tab 1, Schedule 2 show a variable rate demand loan of $5,481,662 at a rate of 4.50% for 2012 and a variable rate demand loan of $13,843,930 at a rate of 5.0% for 2013.

a) Please confirm that the variable rate loan shown for 2012 is subsumed in the variable rate loan shown for 2013. If this cannot be confirmed, please explain where this $5,481,662 loan in 2012 has gone in 2013.

IHDSL Response:

Please refer to responses provided in IR Energy probe 31.

b) Please provide a copy of the loan agreement for the $5,481,662 shown for 2012, along with any amendments made to the loan.

IHDSL Response:

Please refer to the Exhibit 5 appendices – Ex5 Appendix A IR Ref SEC-20.

c) If the $13,843,930 demand loan has a variable rate, please explain why the Board's deemed long term debt rate would not be the ceiling applicable to the loan.

IHDSL Response:

The $13,843,930 demand loan is not a long term debt. It is estimated that a portion will be converted in 2014. Please see OEB Staff IR 55 g).

d) What are the terms upon which the demand loan can be called?

IHDSL Response:

Please see the enclosed copy of the loan agreement provided in b).

e) Please update the tables on page 4 for both 2012 and 2013 to reflect any changes necessary to reflect actual loan agreements in place as of the current time.

IHDSL Response:

Please refer to the Summary of Changes section for the revised capital expenditure updates which subsequently impact the debt requirements for 2012 and 2013.

IHDSL is submitting updated evidence for it's debt requirement for 2012 and 2013. The 2012 debt requirement is reduced by $2,366,746. The 2013 debt requirement is reduced by $5,920,732. IHDSL is submitting updated evidence for Tables 5.1.2 and 5.1.3 for 2012 and 2013 respectively.

Table 5.1.2

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Bank Loan	Toronto Dominion Bank	Third-Party	Fixed Rate	29-Oct-10	20	$ 1,960,178	4.53%	$ 88,796.06
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 2,876,000	9.75%	$ 280,410.00
3	Debentures	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 2,333,333	3.91%	$ 91,233.32
4	Commercial Loan	Toronto Dominion Bank	Third-Party	Fixed Rate	14-Mar-12	24	$ 3,909,391	4.05%	$ 158,330.34
5	Demand Loan	Toronto Dominion Bank	Third-Party	Variable Rate	1-Jan-12	Demand	$ 3,114,916	4.50%	$ 140,171.22
6									$ -
7									$ -
8									$ -
9									$ -
10									$ -
11									$ -
12									$ -
Total							$ 14,193,818	5.35%	$ 758,940.94

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Bank Loan	Toronto Dominion Bank	Third-Party	Fixed Rate	29-Oct-10	20	$ 1,887,048	4.53%	$ 85,483.27
2	Debentures	Town of Innsfil	Third-Party	Fixed Rate	1-Apr-95	20	$ 2,005,000	9.75%	$ 195,487.50
3	Debentures	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 2,166,667	3.91%	$ 84,716.68
4	Commercial Loan	Toronto Dominion Bank	Third-Party	Fixed Rate	14-Mar-12	24	$ 3,805,466	4.05%	$ 154,121.37
5	Demand	Toronto Dominion Bank	Third-Party	Variable Rate	1-Jan-12	Demand	$ 7,923,198	5.00%	$ 396,159.90
6									$ -
7									$ -
8									$ -
9									$ -
10									$ -
11									$ -
12									$ -
Total							$ 17,787,379	5.15%	$ 915,968.73

Table 5.1.3

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Note payable	Town of Innisfil	Y	December 31, 2007	2,107,444	3	1.13%	2009	23,829
Denbentures	Town of Innsfil	N	April 1, 1995	5,032,000	20	9.75%	2009	490,620
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	2,096,644	20	1.36%	2010	28,420
Denbentures	Town of Innsfil	N	April 1, 1995	4,382,000		9.75%	2010	427,245
Construction Loan	Infrastructure Ontario	N	April 15, 2010	2,500,000	Demand	1.45%	2010	36,250
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	2,029,826		4.53%	2011	91,951
Denbentures	Town of Innsfil	N	April 1, 1995	3,666,000		9.75%	2011	357,435
Debentures	Infrastructure Ontario	N	August 15, 2011	2,500,000	15	3.91%	2011	97,750
Demand Loan	Toronto Dominion Bank	N	January 1, 2011	4,000,000		2.11%	2011	84,400
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	1,960,178		4.53%	2012	88,796
Denbentures	Town of Innsfil	N	April 1, 1995	2,876,000		9.75%	2012	280,410
Debentures	Infrastructure Ontario	N	August 15, 2011	2,333,333		3.91%	2012	91,233
Commercial Loan	Toronto Dominion Bank	N	March 14, 2012	3,909,391	24	4.05%	2012	158,330
Demand Loan	Toronto Dominion Bank	N	January 1, 2012	3,114,916	Demand	4.50%	2012	140,171
Bank Loan	Toronto Dominion Bank	N	October 29, 2010	1,887,048		4.53%	2013	85,483
Denbentures	Town of Innsfil	N	April 1, 1995	2,005,000		9.75%	2013	195,488
Debentures	Infrastructure Ontario	N	August 15, 2011	2,166,667		3.91%	2013	84,717
Commercial Loan	Toronto Dominion Bank	N	March 14, 2012	3,805,466		4.05%	2013	154,121
Demand Loan	Toronto Dominion Bank	N	January 1, 2013	7,923,198	Demand	5.00%	2013	396,160
								0
								0

2009 Total Long Term Debt	7,139,444	**Total Interest Cost for 2009**	514,449
		Weighted Debt Cost Rate for 2009	7.21%
2010 Total Long Term Debt	8,978,644	**Total Interest Cost for 2010**	491,915
		Weighted Debt Cost Rate for 2010	5.48%
2011 Total Long Term Debt	12,195,826	**Total Interest Cost for 2011**	631,536
		Weighted Debt Cost Rate for 2011	5.18%
2012 Total Long Term Debt	14,193,818	**Total Interest Cost for 2012**	758,941
		Weighted Debt Cost Rate for 2012	5.35%
2013 Total Long Term Debt	17,787,379	**Total Interest Cost for 2013**	915,969
		Weighted Debt Cost Rate for 2013	5.15%

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[Ex.5/1/1/p.2]

Please provide a copy of all outstanding debt instruments.

IHDSL Response:

IHDSL has provided a copy of all outstanding debt instruments in the Exhibit 5 Appendices.

29.0-VECC

Reference: Exhibit 5, Tab 1, Schedule 2

a) Please describe what steps have been take to renegotiate the outstanding Debenture with the Town of Innisfil. Is the debt callable by either party?

IHDSL Response:

IHDSL has not attempted to renegotiate the outstanding debenture with the Town of Innisfil. Please refer to Energy Probe IR 31 a).

b) What is the remaining term of this debenture?

IHDSL Response:

The debenture with the Town of Innisfil final payment is scheduled for 2015.

c) What is IHDSL's plan for replacement of this debt?

IHDSL Response:

There is no plan to replace this debt.

EXHIBIT 5 APPENDICES

Ex5 Appendix A IR Ref SEC-20

EXHIBIT 6 – CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

6.0 Energy Probe #33

Reference: Exhibit 6, Tab 1, Schedule 1

Please reconcile the figures of $761,836 and $787,625 shown on page 1 with the figures shown in the 2013 Test Existing Rates column of Table 6.1.1 and with the gross revenue deficiency of $761,836 shown in the Revenue Requirement Workform.

IHDSL Response:

IHDSL's revenue deficiency is $761,836. The value of $787,625 includes the revenue deficiency plus the PILS value of $25,788.

EXHIBIT 6 APPENDICES

There are no appendices in this section.

EXHIBIT 7 – COST ALLOCATION

7.0-OEB Staff-56 – Weighting Factors

Ref: Exhibit 7/Schedule 1/pp. 2-3

IHDSL has provided the following utility-specific weighting factors:

Services (Account 1855)

Rate Class	Services Weighting Factor
Residential	1
General Service < 50kW	1.5
General Service ≥ 50 kW	2
Street Light	0
Sentinel Light	0
Unmetered Scattered Load	0

a) **Please provide further explanation why IHDSL has applied a 0 weighting factor service for Street Light, Sentinel Light and USL customer classes.**

IHDSL Response:

Connection costs for Street lights, Sentinel lights and Unmetered Scattered load are recoverable by IHDS as the associated assets are primarily owned by the customer, therefore no costs charged to account 1855.

7.0-OEB Staff-57 – Weighting Factors

Ref: Exhibit 7/Schedule 1/pp. 2-3

Billing and Collection (Accounts 5315 – 5340, except 5335)

Rate Class	Billing Weighting Factor
Residential	1
General Service < 50kW	.10
General Service ≥ 50 kW	.06
Street Light (per connection)	0
Sentinel Light	0.01
Unmetered Scattered Load	0

a) **Please explain the 0 billing weighting factor for the Street and USL customer classes.**

IHDSL Response:

IHDSL 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.

IHDSL results are likely different from other LDCs due to the percentage of residential customers versus the GS rate classes. In comparison to cohort LDC's, IHDSL has a residential base that averages 5.80% higher and the GS rate classes are 5.74% lower.

Cohort Compartors by Rate Class - % of Customers
2011 OEB Year Book

	IHDSL	Haldimand County	Niagara Pennisula Inc	Niagara on the Lake	Norfolk Power	Orillia
Customer Class						
Residential	93.44	88.06	89.90	83.11	88.69	88.42
General Service (<50 kW)	6.10	11.28	8.42	15.43	10.43	10.30
General Service (50-4999 kW)	0.46	0.66	1.68	1.46	0.88	1.28
Large User (>5000 kW)	0.00	0.00	0.00	0.00	0.00	0.00
Sub Transmission	0.00	0.00	0.00	0.00	0.00	0.00
Total	100.00	100.00	100.00	100.00	100.00	100.00
Total Customers	14,286	21,070	51,162	8,000	19,032	13,035

b) Please provide further explanation for the weighting factors assigned to the GS<50kW and GS>50kW customer classes.

IHDSL Response:

Please refer to OEB Staff IR 57 a).

c) Please explain why billing for Street Lights customer classes is per connection rather than per customer.

IHDSL Response:

IHDSL prepares monthly street light bills for 5 distinct customers. The calculation on the table in question uses the number of street light customers to determine the proportion of billing costs to be allocated to that class and not the number of connections.

7.0 Energy Probe #34

Ref: Exhibit 7, Schedule 1

a) Is IHDSL aware of any other distributor that has billing weighting factors for the other rate classes that are significantly below the level for the residential class as IHDSL is proposing in the table on page 3?

IHDSL Response

The weighting factors on Page 3 were developed specifically for IHDSL and no comparison was made to the weighting factors of other LDCs. The allocations made by IHDSL were made strictly on IHDSL's customer data.

b) What are the resulting revenue to cost ratios if the billing weighting factors were maintained at the default weighting factors? Please provide a table that shows the revenue to cost ratios using these default weighting factors and the weighting factors proposed by IHDSL.

IHDSL Response

	Revenue To Cost Ratios					
	Residential	GS <50 kW	GS 50 - 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Default Weighting Factors	97.68%	104.81%	154.26%	75.18%	76.75%	201.35%
IHDSL Propose Weighting Factors	93.88%	135.71%	169.40%	89.37%	90.37%	285.47%

c) Please confirm that based on the middle table on page 3, IHDSL has made the assumption that it takes the same amount of time to bill one residential customer as it does one GS < 50, one GS > 50, one street light, one USL and one sentinel light customer. Please provide the rationale for this assumption.

IHDSL Response

IHDSL can confirm that once the weight factors were reviewed with an undertaking of the associated billing tasks that the outcome of the weightings were rationale. Following is a high level listing of billing activities. With the introduction of smart metering, distributed generation and the customer service code amendments with respect to AMP (Arrear Management Plans) additional functions (activities 4,5,8,& 12) have incrementally contributed to the amount of time to bill one residential customer.

1. *Set up new accounts (including distributed generation microFIT)*
2. *Process meter changes*
3. *Processing final bills from completed move in/move outs*
4. *Cycle billings - (BQR's –billing quantify requests and BQRR – billing quantity request responses from the MDMR)*
5. *Accessing the Sensus RNI (Regional Network Interface), MDM/R GUI and the ODS (operational data store) to trouble shoot and obtain missing or incomplete data to bill*
6. *Importing daily IESO settlement files*

7. *Processing daily EBT's*
8. *Process credit statements from bi-directional meter data (distributed generation microFIT)*
9. *Process daily banking files*
10. *Create and verify weekly pre-authorized banking file*
11. *Process meter disputes*
12. *Annual reconciliation of EPP (equal payment plan)*
13. *Billing AMP (Arrear Management Plans) agreements*

7.0 Energy Probe #35

Ref: Exhibit 7, Schedule 2

a) Please explain why the figures in the Output O1 - Cost Allocation Model shown on page 2 of Exhibit 7, Schedule 2 do not match the Output O1 sheet from the Excel version of the cost allocation model that was filed.

IHDSL Response

IHDSL inadvertently included the incorrect Output O1 – Cost Allocation model shown on page 2 of Exhibit 7, Schedule 2. The correct table is provided below which matches the Output O1 sheet from the Excel version which was filed with the original submission:

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 Residential	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	$477,568	$30,913	$13,018	$31,350	$2,565	$1,534
			Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	$8,657,799	$6,822,250	$685,300	$686,589	$382,374	$34,391	$46,894
	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	$477,568	$30,913	$13,018	$31,350	$2,565	$1,534
	Total Revenue at Status Quo Rates	$9,419,635	$7,418,929	$746,841	$749,934	$415,386	$37,385	$51,160
	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	$1,455,093	$64,840	$23,705	$8,939	$1,019	$273
ad	General and Administration (ad)	$2,234,040	$1,935,752	$115,439	$86,063	$85,795	$7,726	$3,265
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	$6,829,393	$459,955	$362,232	$375,597	$33,555	$14,429
	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	$7,902,557	$550,328	$442,688	$464,773	$41,367	$17,922
		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	$4,753,481	$281,503	$208,806	$207,225	$18,676	$7,881
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$29,715,660*	*$20,123,910*	*$3,578,430*	*$5,548,617*	*$365,115*	*$29,599*	*$69,989*
	Working Capital	$3,863,036	$2,616,108	$465,196	$721,320	$47,465	$3,848	$9,099
	Total Rate Base	$38,010,956	$29,897,021	$2,745,428	$2,752,190	$2,315,825	$202,751	$97,740
		Rate Base Input equals Output						
	Equity Component of Rate Base	$15,204,382	$11,958,808	$1,098,171	$1,100,876	$926,330	$81,101	$39,096
	Net Income on Allocated Assets	$1,344,473	$589,536	$286,886	$387,702	$39,789	$3,829	$36,731
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,344,473	$589,536	$286,886	$387,702	$39,789	$3,829	$36,731
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	93.88%	135.71%	169.40%	89.37%	90.37%	285.47%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($761,836)	($1,080,307)	$134,972	$243,900	($82,398)	($6,976)	$28,972
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($483,628)	$196,513	$307,246	($49,387)	($3,982)	$33,238
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	4.93%	26.12%	35.22%	4.30%	4.72%	93.95%

b) **Please explain why the figures in the Output O1 - Cost Allocation Model shown on page 2 of Exhibit 7, Schedule 2 do not match the figures in the third table on page 3 of the same exhibit.**

IHDSL Response

Please refer to Energy Probe IR 35 a).

30.0-VECC

Reference: Exhibit 7, Tab 1, pages 2-3

a) **With respect to the demand values used in the cost allocation how did IHDSL establish the various CP and NDP allocator values (CA Model, Sheet I8) associated with the forecast 2013 energy by customer class?**

IHDSL Response:

IHDSL used the same profile (excel file) that was used by Hydro One in the Cost Allocation Informational Filing. That profile was updated to reflect the 2013 load forecast. The results of that update were used to determine the Coincident Peak and Non-Coincident Peak allocator values.

b) **With respect to the GS<50 and GS>50 weighting factors for the Services Account, please explain why "ensuring the demand data is programmed and monitored correctly" is a consideration.**

IHDSL Response:

It is a consideration to ensure accurate billing and customer information.

c) **Please confirm that there are no IHSDL assets involved in connecting Street Light, Sentinel Light or USL customers to the distribution system. If not, are the customers required to own and maintain all such assets (for example the services connecting a phone booth or billboard to the distribution system)?**

IHDSL Response:

Please refer to OEB Staff IR 56 a).

d) **The percentages set out for Account 5315 (Customer Billing) suggest that the same effort is required to bill one Residential customer as is required for one GS<50 customer or one GS>50 customer (i.e. the %'s used are proportional to the number of customers in each class). Please explain why this is the case when billing for GS>50 involves both demand and energy billing determinants.**

IHDSL Response:

Please refer to Energy Probe IR 34 c).

e) **Do the customer billings (Account 5315) weights for Street Lights, Sentinel Lights and USL account for the time/effort required to monitor and audit the unmetered connections associated with each class and, in the case of Street Light and USL, prepare consolidated bills? If yes, why are the costs roughly equal to those for Residential when calculated on a per customer basis?**

IHDSL Response:

Please refer to Energy Probe IR 34 c).

f) **Please explain why the meter reading weight for GS>50 is 0.15 relative to a value of 1.0 for Residential and GS<50 (per CA Model, Sheet I7.2).**

IHDSL Response:

Since the implementation of Smart Meters, there are added complexities, processes to ensure the communication devices and systems are performing as required to ensure the customers in the Residential and General Service <50kW classes will be billed properly. This requires additional resources. The GS 50-4,999 kW customer meters are read by a 3rd party (Oshawa Hydro) with the information uploaded into IHDSL's billing system.

9.0-OEB Staff-68

REF: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13: LRAM

REF: Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications, Last Revised on June 28, 2012, Section 2.7.10: CDM Costs

Innisfil has not included a request to dispose of its LRAMVA – Account 1568 balance as of December 31, 2011.

As stated in Section 13.4 of the Board's Guidelines for Electricity Distributor Conservation and Demand Management, April 26, 2012 (EB-2012-0003) and section 2.7.10 – CDM Costs,

LRAMVA, Pages 36-37 of the Filing Requirements, at a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications.

a) **Please provide the evidence supporting the disposition of your LRAMVA – Account 1568 balance as of December 31, 2011. Please ensure that the evidence comprises the elements listed below.**

IHDSL Response:

IHDSL has enclosed the following table reflecting the LRAMVA Account 1568 as of December 31, 2011. IHDSL did not submit in the EB-2012-0139 original submission due to timing differences of the submission and the OPA 2011 Final Results. IHDSL will be recording the $14,178.32 for the 2011 LRAM claim in account 1568.

IHDSL LRAMVA Calculation - 2011

No CDM Component

Calculation:	A		B		C = B-A		D 1		D 2			
			OPA Information:				EB-2009-0232		EB-2010-0093			
	CDM Component of Approved OEB Forecast		OPA Final Annual Report - 2011		Energy Volume to Calculate Variance		Distribution Volumetric Rate		Distribution Volumetric Rate		**Entry for 1568 LRAM Account**	
Customer Class	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	0	0	411,063	216	411,063	216	$0.0186		$0.0186		$7,645.77	
General Service <50 kW	0	0	108,624	44	108,624	44	$0.0092		$0.0850		$6,488.48	
General Service 50 - 4999 kW	0	0	36,208	15	36,208	15		$3.1351		$2.9491		$44.07
Sentinel Lighting	0	0	0	0	0	0		$27.3557		$34.4916		$0.00
Street Lighting	0	0	0	0	0	0		$28.8659		$36.9807		$0.00
Unmetered Scattered Load	0	0	0	0	0	0	$0.0392		$0.0393		$0.00	
Total	**0**	**0**	**555,895**	**275**	**555,895**	**275**					**$14,134.24**	**$44.07**
Combined 1568 Total											**$14,178.32**	

In IHDSL's 2012 IRM EB-2011-0176 Decision and Order, the Board approved a 2010 LRAM claim of $10,466.00 consisting of $10,185.48 for LRAM and $280.38 for carrying charges. IHDSL was directed to record the amount in Account 1595 for future disposition. With recording the LRAM claim in account 1595, IHDSL will not be in a position to request disposition until our next rebasing in 2017.

The timing of the 2012 decision preceded the Guidelines for Electricity Distributor Conservation and Demand Management issued on April 26, 2012. The calculation of both the 2010 and 2011 LRAM claims were undertaken without a variance for the CDM load forecast component. With the clarifications now outlined in the Conservation and Demand Management guidelines, IHDSL respectfully requests that the Board reconsider the directive to record the 2010 LRAM claim from account 1595 to account 1568. The transfer of the 2010 LRAM claim will provide consistency in tracking CDM LRAM claims.

IHDSL understands that account 1568 will be reviewed as part of the IRM process. If considered the LRAMVA amounts recorded in account 1568 would be as follows for 2010 and 2011:

LRAM Rate Rider by Class - Reflecting 2010/2011 Programs Only

Rate Class	LRAM $	CARRYING CHARGES	2009 Forecasted kWh/kW	Per Volumatric
Residential 2010 LRAM	$ 5,929.91	163.24	155528870	$ 0.0001
Residential 2011 LRAM	$ 7,645.77			
General Service LT50 kW 2010 LRAM	$ 2,854.34	78.57	31359068	$ 0.0003
General Service LT50 kW 2011 LRAM	$ 6,488.48			
General Service GT 50 kW 2010 LRAM	$ 1,401.23	38.57	116345	$ 0.0128
General Service GT 50 kW 2011 LRAM	$ 44.07			
2010 LRAM Total	$10,185.48	280.38		
2011 LRAM Total	$14,178.32			
Account 1568 Total	$24,363.80			

i. **Full LRAMVA calculations that are based on the final evaluation results for 2011 OPA-Contracted Province-Wide CDM Programs ("OPA Programs"). The LRAMVA calculations are determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;**

IHDSL Response:

IHDSL has based the LRAMVA calculations on the final 2011 OPA Program results and the calculations have been determined ***by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class****.*

ii. **Separate tables for each rate class that shows the LRAMVA amounts requested in association with the final evaluation results for 2011 OPA Programs;**

IHDSL Response:

The table in OEB Staff IR 68 a) reflects the amounts by rate class in association with the final evaluation results.

iii. **A statement that indicates the amount, if any, that Innisfil's last approved load forecast was adjusted to reflect forecasted CDM impacts in association with Innisfil's 2011-2014 CDM Targets;**

IHDSL Response:

IHDSL did not adjust the 2009 load forecast to reflect forecasted CDM impacts.

iv. Calculations showing the variance, if any, between the CDM component related to the 2011-2014 CDM Targets included in Innisfil's last approved load forecast and the final evaluation results for Innisfil's 2011 OPA Programs;

IHDSL Response:

N/A as the CDM components was not included in the 2011 forecast.

v. A statement indicating that the distributor has relied on the most recent final evaluation report from the OPA in support of its LRAMVA calculation;

IHDSL Response:

The 2011 LRAMVA calculations were undertaken utilizing the OPA 2011 Final CDM results for IHDSL which includes the final evaluation report.

vi. A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAMVA amount;

IHDSL Response:

IHDSL has utilized the most recent input assumptions from the OPA 2011 Final CDM results.

vii. Applicable LRAMVA rate riders for all affected rate classes;

IHDSL Response:

IHDSL is not seeking disposition of the LRAMVA account with EB-2013-0139. IHDSL will record 2011 LRAM value of $14,178.32 in account 1568. IHDSL is waiting for clarification IHDSL request to move the 2010 LRAM claim from account 1595 to account 1568.

viii. A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAMVA amount; and,

IHDSL Response:

Please refer to the table provided in OEB Staff IR 68 a). Carrying charges have been calculated on the 2010 LRAM claim based on Decision and Order for EB-2011-0176. Carrying charges for the 2011 claim have not been calculated.

ix. Documentation of the distributor's final evaluation results for its 2011 OPA Programs.

IHDSL Response:

IHDSL has enclosed the 2011 Final CDM Results in the Appendix 4 appendices section – Ex4 Appendix 2 IR Ref VECC-17b.

EXHIBIT 7 APPENDICES

There are no appendices in this section.

EXHIBIT 8 – RATE DESIGN

8.0-OEB Staff-58 – GEA Funding Adder

Ref: Exhibit 8/Tab 8/Schedule 3, p. 1

IHDSL proposed an average rate adder of $0.5233 per customer per month over three years. Please explain why IHDSL requested average GEA rate adder, given that the required funding adder year over year was calculated as part of the GEA Incremental Revenue Requirement Calculation.

IHDSL Response:

IHDSL has proposed an average GEA rate adder primarily for consistency and transparency to our customers. Requesting an average rate adder levels the annual increases/decreases that would be applicable for this requested adder.

Yearly GEA Rate Adder:

2013	*2014*	*2015*
0.4121	*0.5833*	*0.5745*

8.0 Energy Probe #37

Ref: Exhibit 8, Tab 5, Schedule 1

a) **If available at the time of the filing of the interrogatory responses, please update Table 8.11 to include actual 2012 data, including the SFLF calculation based on actual 2012 purchases from the IESO and Hydro One.**

IHDSL Response:

IHDSL is not in a position at this time to update Table 8.1.1 Line Loss Calculation with 2012 data.

b) **Given the unusual loss in 2008, does IHDSL believe it would be more reasonable to use a 3 year average (2009 through 2011) than the 5 year average to calculate the loss factor? If no, please explain why not.**

IHDSL Response:

8.0 Energy Probe #38

Ref: Exhibit 8, Tab 6, Schedule 1

a) **Is IHDSL proposing any rate mitigation measures for the Sentinel Light class?**

IHDSL Response:

No IHDSL is not proposing any rate mitigation for Sentinel Lights.

b) Please confirm that the impact per month of the total bill increase of 13.59% for the Sentinel Light class is an increase of about $10 per month.

IHDSL Response:

IHDSL confirms

8.0 Energy Probe #39

Ref: Exhibit 8, Tab 8, Schedule 3 & Appendix B

a) Is the GEA rate adder of $0.5233 a per customer per month charge or a per kWh charge or something else?

IHDSL Response:

THE proposed GEA rate adder of $0.5233 is reflected incorrectly for the Residential Service proposed tariff. IHDSL has corrected the impacted tariff and enclosed below.

Innisfil Hydro Distribution Systems Ltd.
Proposed TARIFF OF RATES AND CHARGES for 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.04
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	0.27
Rate Rider for Smart Meter –Stranded Meter – effective until April 30, 2015	$	0.83
Distribution Volumetric Rate	$/kWh	0.0214
Low Voltage Service Rate	$/kWh	0.0022
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0032)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	(0.0019)
Rate Rider for Global Adjustment Account Disposition (2012) - effective until April 30,2014 applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 applicable only for Non-RPP Customers	$/kWh	0.0062
GEA Rate Adder Rider– effective until April 30, 2016	$	0.5233
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

b) **Appendix B shows the residential GEA rate adder rider as $0.5233 per kWh while for the GS < 50 and GS > 50 classes it is shown as a charge of $0.5233 per month. Please reconcile.**

IHDSL Response:

The proposed GEA rate adder should be a fixed monthly charge for the Residential, GS < 50, and the GS > 50 rate classes. Appendix B has been corrected. Appendix C Bill Impacts were correct in reflecting the monthly fixed charge.

c) **Please confirm that IHDSL proposes to change the microFIT rate to $5.40 per month.**

IHDSL Response

IHDSL is will be adapting the change from the current $5.25 rate to the updated rate of $5.40 in conjunction with this rate application.

31.0-VECC

Reference: Exhibit 8, Tab 2, Schedule 1, page 1

a) **Contrary to lines 2-6, Table 8.3 does not set out the current F/V split based on the 2013 load forecast and 2012 approved rates. Please provide a corrected version of the table that reconciles to the 2013 revenues at 2012 rates as set out in Appendix 2-P, Column 7B.**

IHDSL Response:

IHDSL has enclosed the revised Table 8.3

33.0-VECC

Reference: Exhibit 8, Tab 4, Schedule 1

a) **Please update the proposed RTSR's to reflect the recently approved UTRs for 2013.**

IHDSL Response:

IHDSL has updated the proposed RTSR`s reflecting the 2013 approved UTR`s. The following table reflects the revised RTSR rates.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0061	$	0.0044
General Service Less Than 50 kW	kWh	$	0.0055	$	0.0041
General Service 50 to 4,999 kW	kW	$	2.2449	$	1.5804
General Service 50 to 4,999 kW – Interval Metered	kW	$	2.1743	$	2.3174
Unmetered Scattered Load	kWh	$	0.0055	$	0.0041
Sentinel Lighting	kW	$	1.7016	$	1.8112
Street Lighting	kW	$	1.6930	$	1.2216

EXHIBIT 8 APPENDICES

There are no appendices in this section.

EXHIBIT 9 – DEFERRAL AND VARIANCE COSTS

9.0-OEB Staff-59

Ref: Exhibit 9, Tab 2, Schedule 1, Page 6 and Exhibit 9, Tab 2, Schedule 1, Page 1

IHDSL is seeking the disposition of a debit balance of Account 1508 for $308,464 as at December 31, 2011.

a) Please indicate if any One Time Incremental IFRS Transition Costs recorded in Account 1508 have been included in the 2013 OM&A.

IHDSL Response:

There is no One Time Incremental IFRS Transition Costs recorded in Account 1508 that have been included in the 2013 OM&A.

b) If yes, please remove the costs from OM&A.

IHDSL Response:

N/A

9.0-OEB Staff-60

Ref: Exhibit 9, Tab 2, Schedule 1, Page 11
APH FAQ December 2010, Question 4
Exhibit 9, Tab 2, Schedule 2, Page 1
Exhibit 9, Tab 2, Schedule 3, Page 1

EB-2006-0170 - Filing Requirements For Electricity Transmission and Distribution Applications

IHDSL is requesting disposition of a credit balance for $43,209 for Account 1592 – Sub-account HST for the balance as at December 31, 2011.

a) As required in the EB-2006-0170 Filing Requirements, Page 52, please provide detailed schedules, similar to Table 1 and Table 2 of Question 4 of the December 2010 APH-FAQs, to indicate the period HST savings on OM&A costs and capital expenditures for the periods of:
   - **i. July 1, 2010 to December 31, 2010;**
   - **ii. January 1, 2011 to December 31, 2011; and**
   - **iii. January 1, 2012 to December 31, 2012**
   - **iv. January 1, 2013 to April 30, 2013**

IHDSL Response:

IHDSL is providing the HST savings schedules on OM&A costs and capital expenditures for the period of July 2010 to April 2013. IHDSL had inadvertently calculated the PST savings from July 1 2010 to December 31 2012. IHDSL has recalculated the PST savings from July 1 2010 to April 30 2013 resulting in a revised credit balance of $50,177 from the $43,209 credit originally submitted. Tables 1 and 2 below provide the PST savings by year for July 1 2010 to April 30 2013.

Table 1 - PST Savings on Capital Purchases

Pre-HST Purchases PST included in Asset				**Depreciation**		
	Asset	**2010**	**2011**	**2012**	**2013**	**Total**
2010 Purchase $708,411	$ 764,545	55,007	55,007	55,007	55,007	220,027
2011 Purchase $708,411	$ 764,545	-	55,007	55,007	55,007	165,020
2012 Purchase $708,411	$ 764,545	-	-	55,007	55,007	110,014
2013 Purchase $708,411	$ 764,545	-	-	-	55,007	55,007
Total Depreciation Exp (A)		55,007	110,014	165,020	220,027	550,068
Post-HST Purchases with ITC included in Asset				**Depreciation**		
	Asset	**2010**	**2011**	**2012**	**2013**	**Total**
2010 Purchase $708,411	$ 708,411	50,982	50,982	50,982	50,982	203,929
2011 Purchase $708,411	$ 708,411	-	50,982	50,982	50,982	152,946
2012 Purchase $708,411	$ 708,411	-	-	50,982	50,982	101,964
2013 Purchase $708,411	$ 708,411	-	-	-	50,982	50,982
Total Depreciation Exp (B)		50,982	101,964	152,946	203,929	509,821
Total Capital PST Savings (A-B)		**4,025**	**8,049**	**12,074**	**16,098**	**40,246**

Table 2 - Sumnmary of PST Savings from 2009 Historic Year Analysis

	7-12/2010	**2011**	**2012**	**1-4/2013**	**Total**
OM&A expenses PST savings	12,856	25,713	25,713	8,571	72,853
Captial items PST savings	2,012	8,049	12,074	5,366	27,502
Total PST savings	14,869	33,762	37,787	13,937	100,354
			50% disposition		**$ 50,177**

b) If IHDSL has not calculated HST savings from January 1, 2012 to April 30, 2013, please calculate the amount using the APH FAQ December 2010 guidelines and request to clear the amount in the current application as well

IHDSL Response:

Please see IR OEB Staff-60a).

c) **Since the calculation of the HST savings in Question 4 of the December 2010 APH-FAQs for OM&A costs and capital expenditures is based on a proxy using 2009 spending, has IHDSL experienced actual spending which were materially different for the above-noted periods in part a)? If so, please explain the basis for the differences and provide detailed schedules for the HST savings for each period.**

IHDSL Response:

IHDSL did not experience actual spending which were materially different for the above noted PST savings periods.

d) **IHDSL indicated "IHDSL requests the Board to allow account 1592 to remain open, pending Board approval to discontinue tracking costs, and until such time as IHDSL files its 2014 IRM rate application at which time IHDSL will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592 Sub-account HST".**

Page 52 of EB-2006-0170 Filing Requirements indicate that "No more amounts should be recorded in Account 1592…for the Test Year and going forward, as the impact of the HST and associated ITS on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement.

i) **Please explain why IHDSL is requesting to deviate from the Filing Requirements and have Account 1592 to remain open.**

IHDSL Response:

IHDSL is respectfully requesting to withdraw the statement to allow account 1592 to remain open past the test year. IHDSL is requesting disposition of the PST savings $50,177 calculated to April 30, 2013 for account 1592.

e) **Per Tables 9.4, and 9.5, Account 1592 was not included in the "Total Claim" column requested for disposition. Please confirm that IHDSL is requesting the disposition of a credit balance of $43,209 in this rate application and update the tables accordingly.**

IHDSL Response:

IHDSL is providing updated Tables 9.4 and 9.5 to reflect account 1592 included in the 'Total Claim' column and the revised disposition credit balance of $50,177.

Table 9.4 Summary of December 31, 2011 Audited Balances

Group 1 Accounts	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$ 46,364	$ 1,672	-$ 44,692
RSVA-Wholesale Market Service Charge	1580	-$ 291,192	-$ 5,869	-$ 297,061
RSVA-Retail Transmission Network	1584	-$ 20,724	$ 714	-$ 20,010
RSVA-Retail Transmission Connection	1586	-$ 99,359	-$ 1,689	-$ 101,048
RSVA-Power (excl Global Adjustment)	1588	-$ 248,519	-$ 5,052	-$ 253,571
RSVA-Power Global Adjustment	1588	$ 441,977	$ 16,132	$ 458,109
Recovery of Regulatory Asset Balances	1595	-$ 7,183	-$ 87,009	-$ 94,192
Group 1 Sub total		**-$ 271,364**	**-$ 81,101**	**-$ 352,465**
Group 2 Accounts				
Sub Acct Deferred IFRS Transition Costs	1508	$ 299,035	$ 9,429	$ 308,464
Retail Cost Variance Account	1518	$ 32,409	-$ 1,072	$ 31,337
Retail Cost Variance Account - STR	1548	$ 71,664	$ 13,974	$ 85,638
RSVA - One Time	1582	$ 71,180	$ 11,961	$ 83,141
Other Deferred Credits	2425	-$ 96,053	-$ 2,729	-$ 98,782
HST/OVAT Input Tax Credits (ITCs)	1592	-$ 50,177	$ -	-$ 50,177
Group 2 Sub total		**$ 328,058**	**$ 31,563**	**$ 359,621**
Group 1 & Group 2 Total		**$ 56,694**	**-$ 49,538**	**$ 7,156**

Table 9.5 Summary of 2013 DVA Dispositions Group 1 & 2 (excluding 1588 GA sub account)

Group 1 Accounts	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$ 46,364	$ 1,672	-$ 44,692
RSVA-Wholesale Market Service Charge	1580	-$ 291,192	-$ 5,869	-$ 297,061
RSVA-Retail Transmission Network	1584	-$ 20,724	$ 714	-$ 20,010
RSVA-Retail Transmission Connection	1586	-$ 99,359	-$ 1,689	-$ 101,048
RSVA-Power (excl Global Adjustment)	1588	-$ 248,519	-$ 5,052	-$ 253,571
Recovery of Regulatory Asset Balances	1595	-$ 7,183	-$ 87,009	-$ 94,192
Sub Acct Deferred IFRS Transition Costs	1508	$ 299,035	$ 9,429	$ 308,464
Retail Cost Variance Account	1518	$ 32,409	-$ 1,072	$ 31,337
Retail Cost Variance Account - STR	1548	$ 71,664	$ 13,974	$ 85,638
RSVA - One Time	1582	$ 71,180	$ 11,961	$ 83,141
Other Deferred Credits	2425	-$ 96,053	-$ 2,729	-$ 98,782
HST/OVAT Input Tax Credits (ITCs)	1592	-$ 50,177	$ -	-$ 50,177
Group 1 & Group 2 Total		**-$ 385,283**	**-$ 65,670**	**-$ 450,953**

9.0-OEB Staff-61

Ref: Exhibit 9, Tab 2, Schedule 1, Page 9

IHDSL is requesting dispositions of a debit balance for $85,638 in Account 1548 – Retail Settlement Variance Account – Service Transaction Request.

a) **Please identify the drivers for the balances in Account 1548.**

IHDSL Response:

The drivers for the balances in Account 1548 are the excess incremental cost of labour compared to the request and processing fees charged to retailers.

b) **Please provide a schedule identifying all revenues and expenses, listed by Uniform System of Account (USoA) number, that were used to calculate the variances recorded in Account 1548.**

IHDSL Response:

The following schedule identifies the revenue and expense accounts by USoA number that was used to calculate the variance recorded in Account 1548:

Revenue and Expenses used to calculate RCVA account 1548		
Category	**USoA**	**Name**
Revenue	4084.900	Service Transaction Request - Processing
Revenue	4084.901	Service Transaction Request - Request
Expense	5315.001.801	Service Transaction Request - Cust Bill Labour
Balance Sheet	1548	Service Transaction Request Variance

c) **Please confirm whether or not the applicant has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1548.**

IHDSL Response:

IHDSL has followed Article 490 Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1548.

d) Please confirm that the all costs incorporated into the variances reported in Account 1548 are incremental costs of providing retail services and not included in the revenue requirement.

IHDSL Response:

All costs incorporated into the variances reported in Account 1548 are incremental costs of providing retail services and not included in the revenue requirement.

9.0-OEB Staff-62

Ref: Exhibit 9, Tab 2, Schedule 1, Page 10

IHDSL is requesting the disposition of a debit balance for $83,141 for Account 1582 – Retail Settlement Variance Account – One-time Wholesale Market Service.

a) Please provide further details explaining the nature of the transactions recorded in this account.

IHDSL Response:

The nature of transactions recorded to Account 1582 are IESO charge types up to 2006 as provided below and one time charges received from Hydro One load transfers from 2004 to 2008.

b) Please indicate the charge type on the IESO invoice that is mapped to this account.

IHDSL Response:

The following table provides the IESO charge type mapping to account 4712 which is variance to 1582:

IESO charge types vs. APH accounts

IESO Charge Type	APH #	Description
113	4712	Classified as non-recurring wholesale market service charge per DRH Table 11.2.
120	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
163	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
164	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003
165	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
166	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
167	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
169	4712	Classified as non-recurring wholesale market service charge per OEB letter to LCDs dated Jan. 10, 2003.
410	4712	
460	4712	
700	4712	Classified as non-recurring wholesale market service charge per DRH Table 11.2.
750	4712	Classified as non-recurring wholesale market service charges per DRH Table 11.2 and per OEB letter to LCDs dated Jan. 10, 2003.
850	4712	Classified as non-recurring wholesale market service charges per DRH Table 11.2 and per OEB letter to LCDs dated Jan. 10, 2003.

9.0-OEB Staff-63

Ref: Exhibit 9, Tab 2, Schedule 1, Page 10
2013 EDDVAR Deferral and Variance Account Continuity Schedule

IHDSL is requesting the disposition of a credit balance for $98,782 in Account 2425 Other Deferred Credits.

a) Please provide further details explaining the nature of the transactions recorded in this account.

IHDSL Response:

The nature of the transactions recorded to account 2425 are per EB-2009-0130 (Appendix D located in the Exhibit 9 Appendices section – Ex9 Appendix D IR Ref OEB Staff-63) rate order directing IHDSL to record the difference in distribution rates in the Board's EB-2008-0233 Decision and EB-2009-0130. IHDSL has also included RARA #1 from Hydro One for the period of May 2010 to December 2011. IHDSL had inadvertently recorded the Hydro One RAR-2010-General to account 2405 and has subsequently recorded the credit balance to account 2425.

b) Board Staff notes that in the RRR 2.1.7 IHDSL filed with the Board, Account 2425 shows a credit balance of $37,368. In the Deferral and Variance Account Continuity Schedule in the rate application, the RRR 2.1.7 column showed a balance of $96,899 for Account 2425.

i. Please explain and reconcile the $59,531 difference between the RRR amounts on the continuity schedule and the amount reported to the Board.

IHDSL Response:

The difference between the RRR 2.1.7 and the DVA continuity schedule is the Hydro One credit balance moved from account 2405 to 2425. IHDSL reflected this change in the RRR reporting in 2012.

ii. Please revise the amount requested for disposition as appropriate.

IHDSL Response:

N/A

9.0-OEB Staff-65

Ref: Exhibit 9/Tab3/Schedule 1, pp. 1-3; EB-2011-0435 Decision and Order, May 17, 2012

In proceeding EB-2011-0435 upon completion of its Smart Meter initiative, IHDSL proposed a net book value of $334,627.68 as of December 31, 2012. This value was accepted by the Board in its Decision and Order issued on May 17, 2012.

On page 1 of E9/T3/S1, IHDSL states that as of December 31, 2012 the NBV of the stranded meters for IHDSL is $359,195. On page 3 of E9/T3/S1, table 9.11 IHDSL shows total net book value of $359,195 which is inclusive of 2013 depreciation of$14,177.

a) Please explain the increased net book value and confirm the actual total net book value as of December 31, 2012.

IHDSL Response:

Innisfil Response IR #4

Innisfil has estimated the NBV of the stranded meters as of December 31, 2012 to be as follows:

2012 Stranded Meters	*$369,828.03*
Less 2012 Depreciation	*$ 35,200.15*
2012 NBV Estimate	*$334,627.88*

b) On page 2 IHDSL notes that the pooled residual net book value of the stranded meters as of April 2012 is forecasted to be $359,195. Please confirm that this should read April 2013. Please explain why IHDSL has included 2013 depreciation expenses, given that stranded meters should be removed from gross book value and accumulated depreciation as of December 31, 2012.

IHDSL Response:

IHDSL confirms that the pooled residual NBV of the stranded meters as of April 2012 as referenced on Exhibit 9, Tab 3, Schedule 1, page 1, line 6 should state April 2013.

c) Please update the evidence as necessary.

IHDSL Response:

IHDSL continued the depreciation of the stranded meters as they are effectively included in IHDSL rates until April 30, 2013.

9.0-OEB Staff-66 – Stranded Meters

Ref: Exhibit 9/Tab 3/Schedule 1, p. 3 – Stranded Meter Allocation

IHDSL has proposed a SMRR of $0.83 per month for Residential and $3.53 GS< 50 kW customers applicable for two year. In *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 22, of Guideline G-2011-0001, the Board states:

The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.

a) Please describe the allocation methodology used by IHDSL.

IHDSL Response:

IHDSL determined the allocation methodology by utilizing the number of meters stranded by rate class.

b) Please provide a copy of Sheet I7.1 from IHDSL's 2008/9 Cost Allocation Informational Filing.

IHDSL Response:

IHDSL has provided a copy of Sheet 17.1 from the 2008/9 Cost Allocation Informational filing.

2006 COST ALLOCATION

Innisfil Hydro Distribution

EB-2005-0382 EB-2006-0247

Monday, January 15, 2007

Sheet I7.1 Meter Capital Worksheet - Second Run

Click Here For Instructions on How to Complete This Worksheet

Meter Types	Cost per Meter (Installed)	1			2			3		
		Residential			GS <50			GS>50-Regular		
		1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average
Allocation Percentage Weighted Factor				67.94%			22%			10%
Cost Relative to Residential Average Cost				1.00			5.26			23.76
Total		12670	996185	78.62549	771	318650	413.2944	81	151350	1868.519
Single Phase 200 Amp - Urban	50	9,613	480650		171	8550			0	
Single Phase 200 Amp - Rural	150	2,699	404850		207	31050			0	
Central Meter	250	307	76750		58	14500		3	750	
Network Meter (Costs to be updated)	225	17	3825		2	450			0	
Three-phase - No demand	210	21	4410		160	33600			0	
Smart Meters	300		0			0			0	
Demand without IT (usually three-phase)	500	1	500		83	41500		9	4500	
Demand with IT	2,100	12	25200		90	189000		63	132300	
Demand with IT and Interval Capability - Secondary	2,300		0			0		6	13800	
Demand with IT and Interval Capability - Primary	10,000		0			0			0	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
LDC Specific 1			0			0			0	
LDC Specific 2			0			0			0	
LDC Specific 3			0			0			0	

Meter Types	4			5			6			7			8		
	GS> 50-TOU			GS >50-Intermediate			Large Use >5MW			Street Light			Sentinel		
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average
Allocation Percentage Weighted Factor			0%			0%			0%			0%			0%
Cost Relative to Residential Average Cost			-			-			-			-			-
Total	0	0	-	0	0	-	0	0	-	0	0	-	0	0	-
Single Phase 200 Amp - Urban		0			0			0			0			0	
Single Phase 200 Amp - Rural		0			0			0			0			0	
Central Meter		0			0			0			0			0	
Network Meter (Costs to be updated)		0			0			0			0			0	
Three-phase - No demand		0			0			0			0			0	
Smart Meters		0			0			0			0			0	
Demand without IT (usually three-phase)		0			0			0			0			0	
Demand with IT		0			0			0			0			0	
Demand with IT and Interval Capability - Secondary		0			0			0			0			0	
Demand with IT and Interval Capability - Primary		0			0			0			0			0	
Demand with IT and Interval Capability -Special (WMP)		0			0			0			0			0	
LDC Specific 1		0			0			0			0			0	
LDC Specific 2		0			0			0			0			0	
LDC Specific 3		0			0			0			0			0	

Meter Types	9			10			11			12			13		
	Unmetered Scattered Load			Embedded Distributor			Back-up/Standby Power			Rate Class 1			Rate class 2		
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average
Allocation Percentage Weighted Factor			0%			0%			0%			0%			0%
Cost Relative to Residential Average Cost			-			-			-			-			-
Total	0	0	-	0	0	-	0	0	-	0	0	-	0	0	-
Single Phase 200 Amp - Urban		0			0			0			0			0	
Single Phase 200 Amp - Rural		0			0			0			0			0	
Central Meter		0			0			0			0			0	
Network Meter (Costs to be updated)		0			0			0			0			0	
Three-phase - No demand		0			0			0			0			0	
Smart Meters		0			0			0			0			0	
Demand without IT (usually three-phase)		0			0			0			0			0	
Demand with IT		0			0			0			0			0	
Demand with IT and Interval Capability - Secondary		0			0			0			0			0	
Demand with IT and Interval Capability - Primary		0			0			0			0			0	
Demand with IT and Interval Capability -Special (WMP)		0			0			0			0			0	
LDC Specific 1		0			0			0			0			0	
LDC Specific 2		0			0			0			0			0	
LDC Specific 3		0			0			0			0			0	

Meter Types	14			15			16			17			18		
	Rate class 3			Rate class 4			Rate class 5			Rate class 6			Rate class 7		
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average
Allocation Percentage Weighted Factor			0%			0%			0%			0%			0%
Cost Relative to Residential Average Cost			-			-			-			-			-
Total	0	0	-	0	0	-	0	0	-	0	0	-	0	0	-
Single Phase 200 Amp - Urban		0			0			0			0			0	
Single Phase 200 Amp - Rural		0			0			0			0			0	
Central Meter		0			0			0			0			0	
Network Meter (Costs to be updated)		0			0			0			0			0	
Three-phase - No demand		0			0			0			0			0	
Smart Meters		0			0			0			0			0	
Demand without IT (usually three-phase)		0			0			0			0			0	
Demand with IT		0			0			0			0			0	
Demand with IT and Interval Capability - Secondary		0			0			0			0			0	
Demand with IT and Interval Capability - Primary		0			0			0			0			0	
Demand with IT and Interval Capability -Special (WMP)		0			0			0			0			0	
LDC Specific 1		0			0			0			0			0	
LDC Specific 2		0			0			0			0			0	
LDC Specific 3		0			0			0			0			0	

Meter Types	19			20					
	Rate class 8			Rate class 9			TOTAL		
	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average	Number of Meters	Weighted Metering	Weighted Average
Allocation Percentage Weighted Factor			0%			0%			100%
Cost Relative to Residential Average Cost			-			-			1.38
Total	0	0	-	0	0	-	13522	1466185	108.4296
Single Phase 200 Amp - Urban		0			0		9,784	489200	
Single Phase 200 Amp - Rural		0			0		2,906	435900	
Central Meter		0			0		368	92000	
Network Meter (Costs to be updated)		0			0		19	4275	
Three-phase - No demand		0			0		181	38010	
Smart Meters		0			0		0	0	
Demand without IT (usually three-phase)		0			0		93	46500	
Demand with IT		0			0		165	346500	
Demand with IT and Interval Capability - Secondary		0			0		6	13800	
Demand with IT and Interval Capability - Primary		0			0		0	0	
Demand with IT and Interval Capability -Special (WMP)		0			0		0	0	
LDC Specific 1		0			0		0	0	
LDC Specific 2		0			0		0	0	
LDC Specific 3		0			0		0	0	

9.0 Energy Probe #40

Ref: Exhibit 9, Tab 3, Schedule 1

a) **The evidence states that the NBV of the stranded meters as of December 31, 2012 is $359,195 (page 1, line 6). Table 9.10 reflects this same figure, but appears to include accumulated depreciation through to the end of March, 2013. Please reconcile.**

IHDSL Response:

Please refer to the OEB Staff IR 65 c).

34.0-VECC

Reference: Exhibit 9, Tab 3, Schedule 1, pg. 3

a) **Please show the allocation methodology for the stranded meter rate shown in Table 9.11**

IHDSL Response:

IHDSL determined the allocation methodology by utilizing the number of meters stranded by rate class.

35.0-VECC

Reference: Exhibit 9, Tab 3, Schedule 1, pg. 1 Table 9.10 / Appendix 2-B 2010 Continuity Schedule

a) **Please reconcile the amount shown for meter disposals in account 1860 in the 2010 Continuity Schedule of $492,071 in meter disposal and an associated $192,417 in accumulated depreciation with the figures shown for the same year in Table 9.11 of $426,641 and $181,320.**

IHDSL Response:

EXHIBIT 9 APPENDICES

Ex9 Appendix D IR Ref OEB Staff-63 – Rate Order