2016 YEARBOOK OF ELECTRICITY DISTRIBUTORS

PUBLISHED ON AUGUST 17, 2017

ONTARIO ENERGY BOARD | COMMISSION DE L'ÉNERGIE DE L'ONTARIO

Background on Statistical Yearbook of Electricity Distributors

The Ontario Energy Board (OEB) is the regulator of Ontario's natural gas and electricity sectors. In the electricity sector, the OEB sets transmission and distribution rates, and approves the Independent Electricity System Operator's (IESO) budgets and fees. The OEB also sets the rate for the Standard Supply Service for distribution utilities that supply electricity (commodity) directly to consumers.

The OEB provides this Yearbook of Electricity Distributors to publish the financial and operational information collected from electricity distributors. It is compiled from data submitted by the distributors through the Reporting and Record-Keeping Requirements.* This Yearbook is also available electronically on the OEB's website.

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*The following distributors have not filed RRR information: Attawapiskat Power Corporation, Fort Albany Power Corporation and Kashechewan Power Corporation.

NOTES

Financial Statement Disclosures

1. The Balance Sheet and Income Statement presented in the Yearbook are derived from trial balances reported under the regulatory accounting framework of the OEB. These statements may differ from the distributors' audited financial statements.

2. Year-over-year comparisons and trending may be affected due to changes in accounting and financial statement reporting.

3. Debit balances reported in credit fields were reclassified to assets; and credit balances in debit fields were reclassified to liabilities.

4. Deferred tax assets and liabilities may have been classified by utilities as regulatory assets or liabilities in their filings with the OEB. Wherever possible, this has been classified in the yearbook as other non-current assets or deferred tax liabilities depending on the sign.

5. Intangible assets and related accumulated amortization have been included in property, plant & equipment and accumulated depreciation and amortization respectively.

6. Inter-company receivables and payables are presented on a net basis in the balance sheet.

Statistical Information

7. The total customer figure is the sum of residential, GS<50, GS>50, large user and sub transmission rate classes. Changes in customer counts could be caused by rate reclassifications of customers implemented by some distributors.

8. Starting in 2015, the number of customers and metered consumption for the sub transmission rate class do not include embedded distributors.

Key Metrics Overview of Ontario Electricity Distributors' Sector

Industry Metrics Snapshot

Financial Item / Metric	2012	2013	2014	2015	2016
Power & Distribution Revenues ($) [i]	14,379,010,579	15,483,829,651	16,480,111,559	17,267,350,271	18,893,982,995
Distribution Revenues ($) [i]	3,143,453,132	3,216,192,710	3,343,550,357	3,295,921,115	3,432,927,549
Total Net Income ($)	581,313,354	624,618,574	554,774,402	671,820,220	721,519,155
Return on Shareholders' Equity (%) [ii]	9.25%	9.46%	7.88%	9.03%	9.31%
Total OM&A Expenses ($)	1,513,210,665	1,606,257,437	1,692,707,777	1,610,695,415	1,619,995,861
Net Property, Plant and Equipment ($)	14,273,013,590	15,229,923,980	16,119,680,854	17,888,654,036	19,194,493,564
Gross Capital Additions for Year ($)	1,864,090,893	1,891,729,188	1,922,688,740	2,230,339,205	2,159,876,482
Depreciation Expense ($)	783,141,384	788,353,877	796,555,442	863,846,599	925,455,321
Total Electricity Delivered (kWh) [iii]	132,774,222,852	132,417,731,276	132,168,695,217	130,749,665,017	130,194,306,824
Residential Consumption (kWh)	40,403,354,966	39,588,477,479	40,094,998,739	40,861,218,090	39,196,063,132
Total Number of Customers	4,893,782	4,944,488	4,988,859	5,054,739	5,106,528
Number of Residential Customers	4,406,331	4,460,593	4,502,650	4,564,835	4,612,551
Average Power and Distribution Revenues / Customer ($/customer)	2,938	3,132	3,303	3,416	3,700
Average Distribution Revenues / Customer ($/customer)	642	650	670	652	672
Net Income / Customer ($/customer)	119	126	111	133	141
Average OM&A Expenses / Customer ($/customer)	309	325	339	319	317

[i] The 2016 account classification has changed from previous Yearbook presentation. Please refer to the Glossary for the grouping of accounts. For consistency, the previous 4 years figures have also been updated to align with the current account classification.

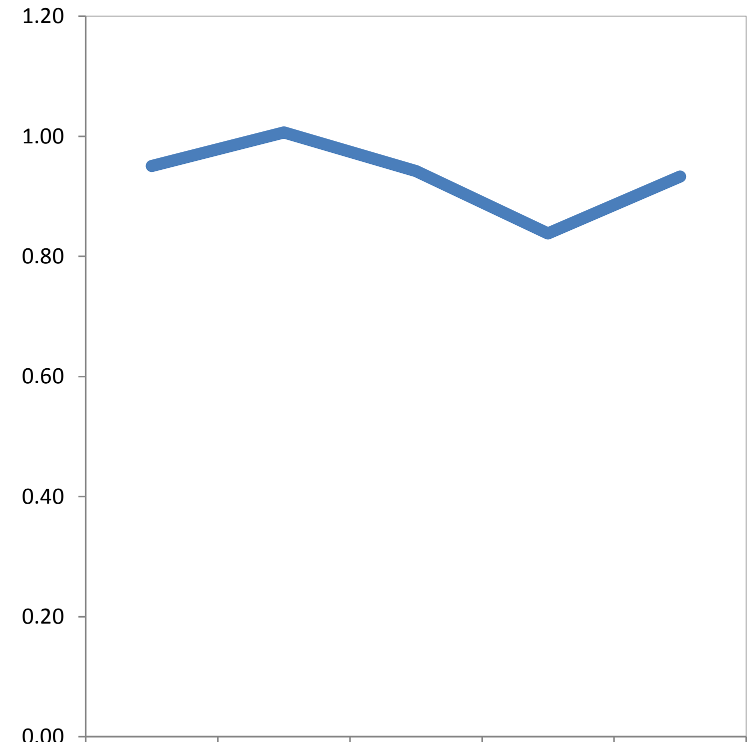
[ii] Return on Equity ratio is calculated as the sum of electricity distributors' net income divided by total shareholders' equity.

[iii] This metric represents the total kWh of electricity delivered to all customers in the distributor's licensed service area and to any embedded distributors. Past figures have been updated to reflect distributor data revisions.

Key Metrics Overview of Ontario Electricity Distributors' Sector

Balance Sheet – Consolidated	As of December 31, 2016
Cash & cash equivalents	$ 291,764,414
Receivables	3,215,501,819
Inventory	97,748,679
Inter-company receivables	55,903,897
Other current assets	112,512,369
Current assets	3,773,431,178
Property plant & equipment	26,607,122,705
Accumulated depreciation & amortization	(7,412,629,141)
	19,194,493,564
Regulatory assets	951,284,944
Inter-company investments	13,390,613
Other non-current assets	829,617,964
Total Assets	**$ 24,762,218,264**
Accounts payable & accrued charges	2,408,466,910
Other current liabilities	231,802,285
Inter-company payables	604,623,939
Loans, notes payable, current portion long term debt	799,021,177
Current liabilities	4,043,914,311
Long-term debt	5,543,919,259
Inter-company long-term debt & advances	3,630,773,155
Regulatory liabilities	858,092,719
Other deferred amounts & customer deposits	916,217,350
Employee future benefits	1,457,272,435
Deferred taxes	564,176,330
Total Liabilities	17,014,365,559
Shareholders' Equity	7,747,852,704
Total Liabilities & Equity	**$ 24,762,218,264**

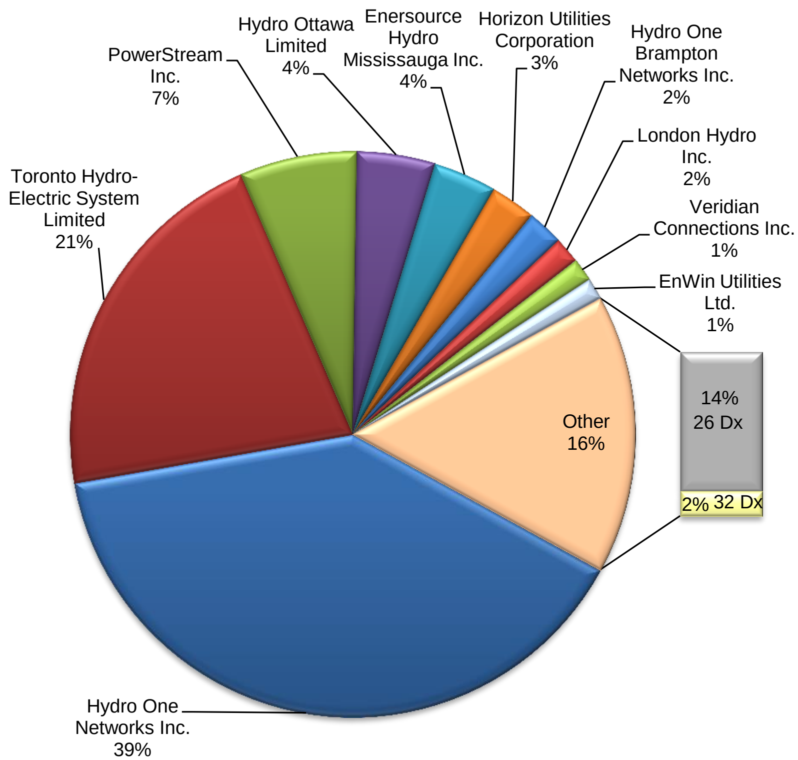
Current Ratio
(Current Assets / Current Liabilites)



	2012	2013	2014	2015	2016
Current Ratio	0.95	1.01	0.94	0.84	0.93

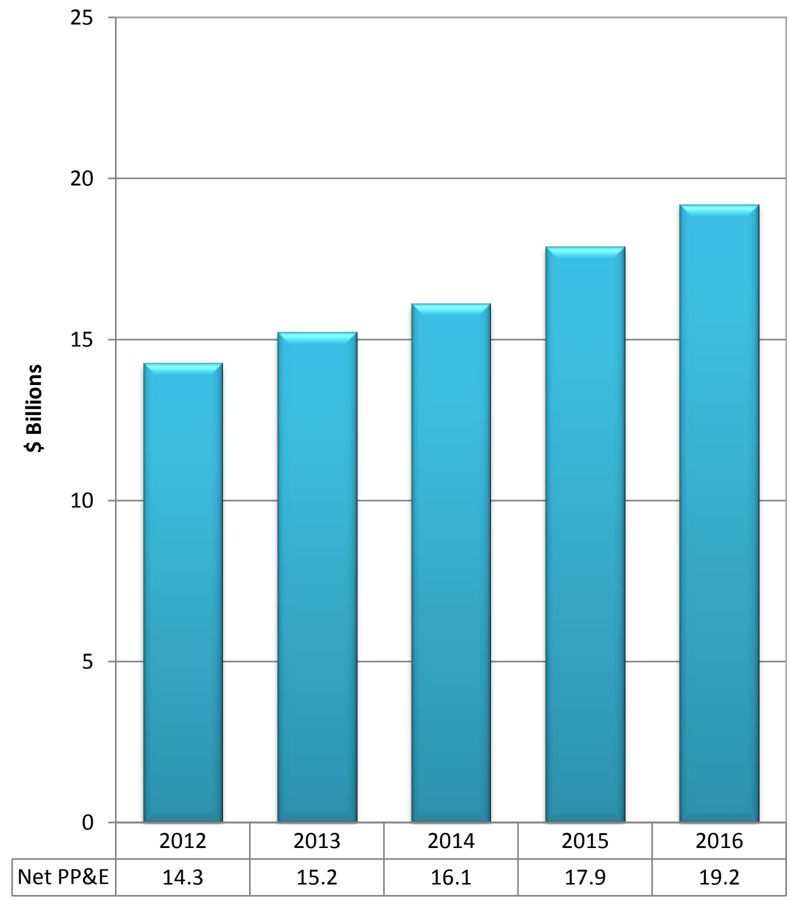
See Notes 1, 2, 3, 4, 6 on page 2

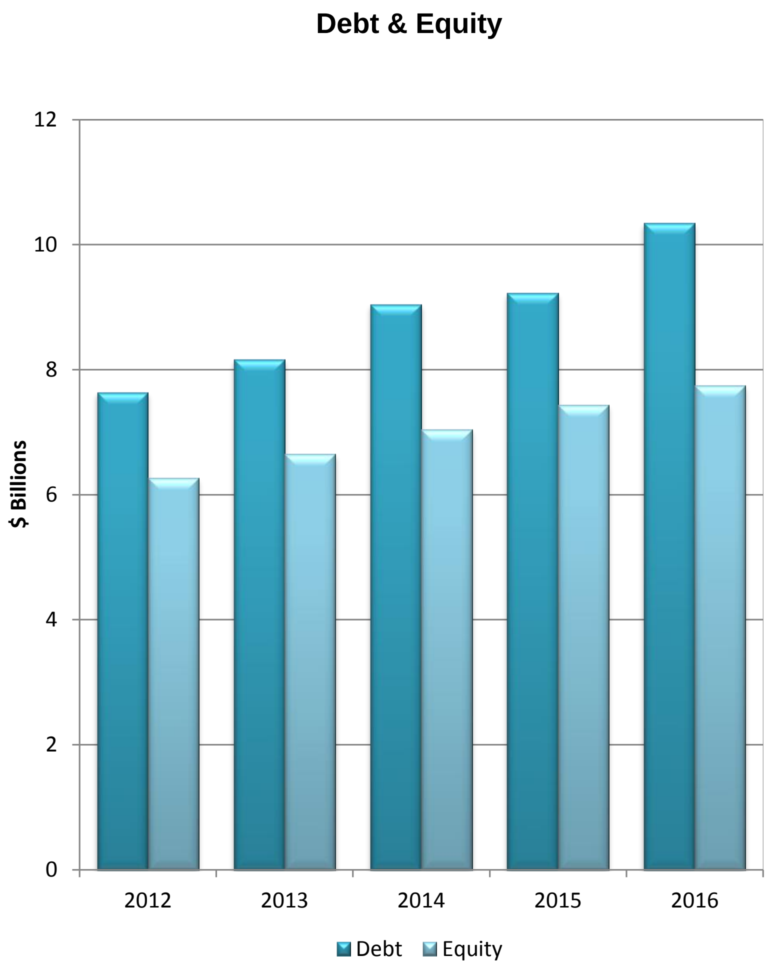
Net Property Plant & Equipment by Distributor



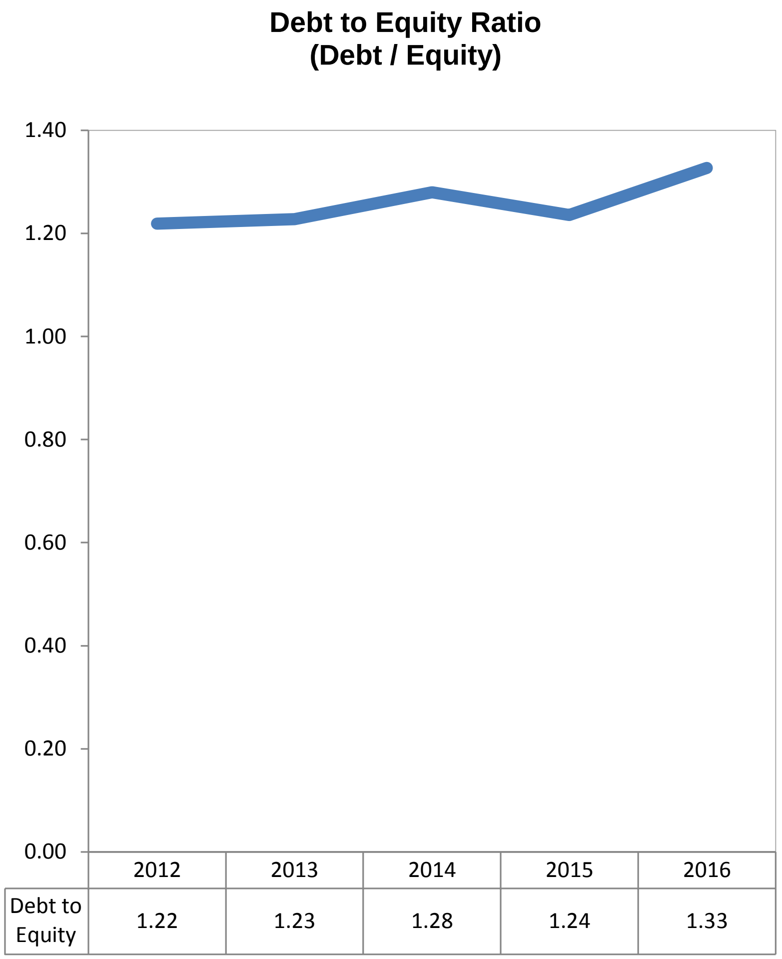
Note: 10 distributors have net property, plant & equipment (PP&E) greater than $225 million. The Other category consists of distributors that have PP&E values:
Between $50 million to $225 million   Less than $50 million

Net Property Plant & Equipment



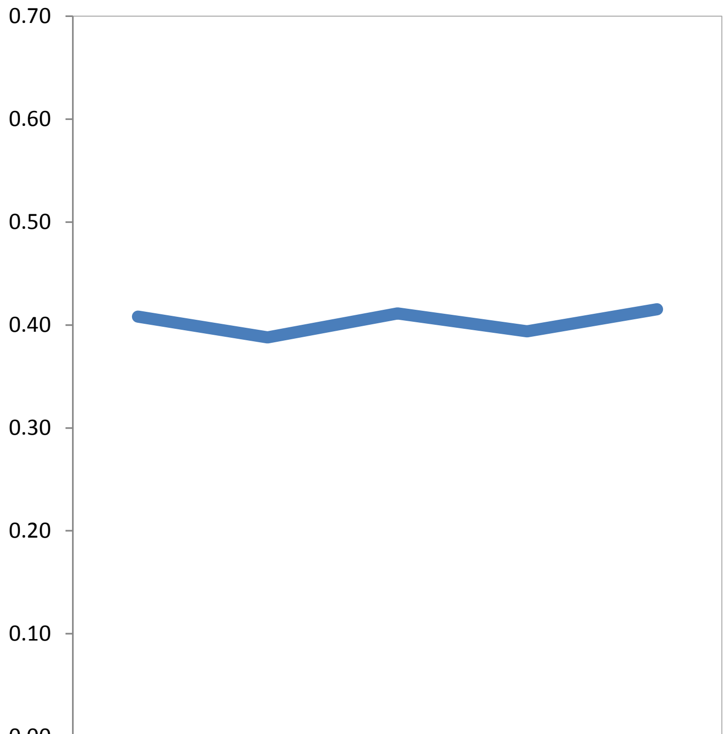


See Notes 1 and 2 on page 2



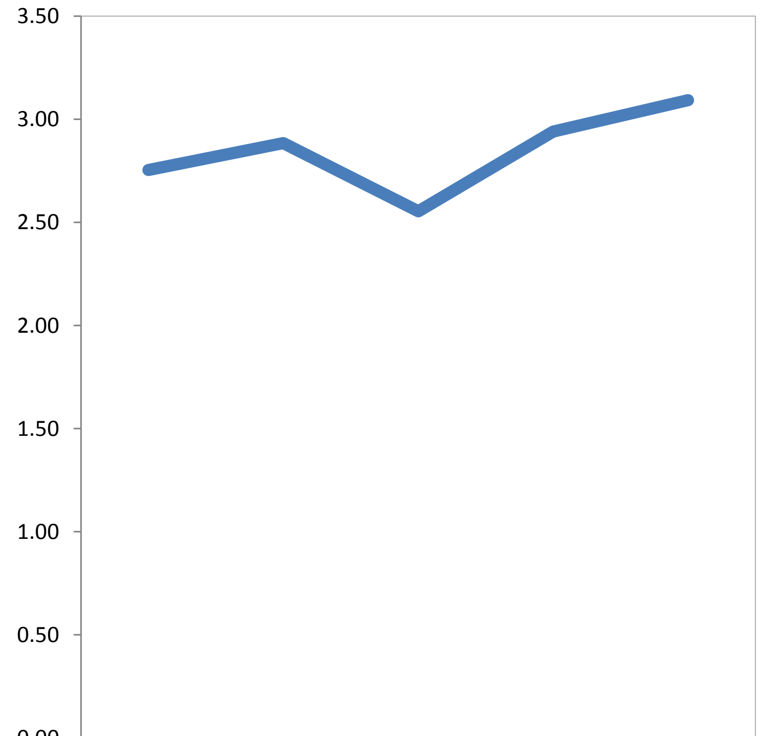
See Notes 1 and 2 on page 2

**Debt Ratio
(Debt / Total Assets)**



	2012	2013	2014	2015	2016
Debt Ratio	0.41	0.39	0.41	0.39	0.42

**Interest Coverage
(EBIT / Interest Charges)**

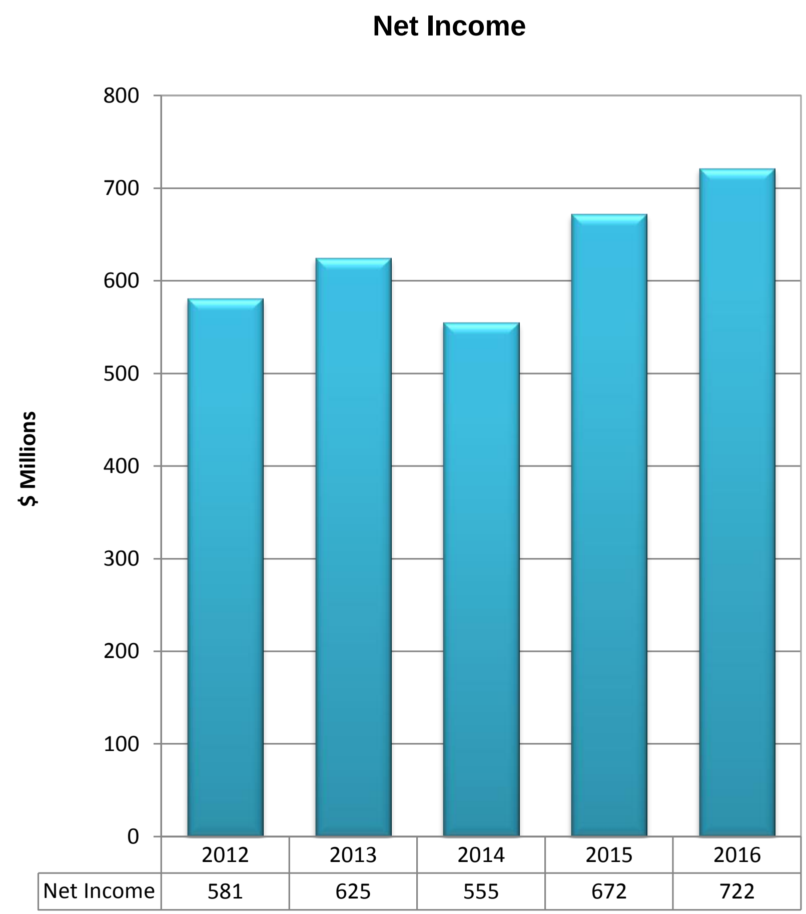


	2012	2013	2014	2015	2016
Interest Coverage	2.75	2.89	2.55	2.94	3.09

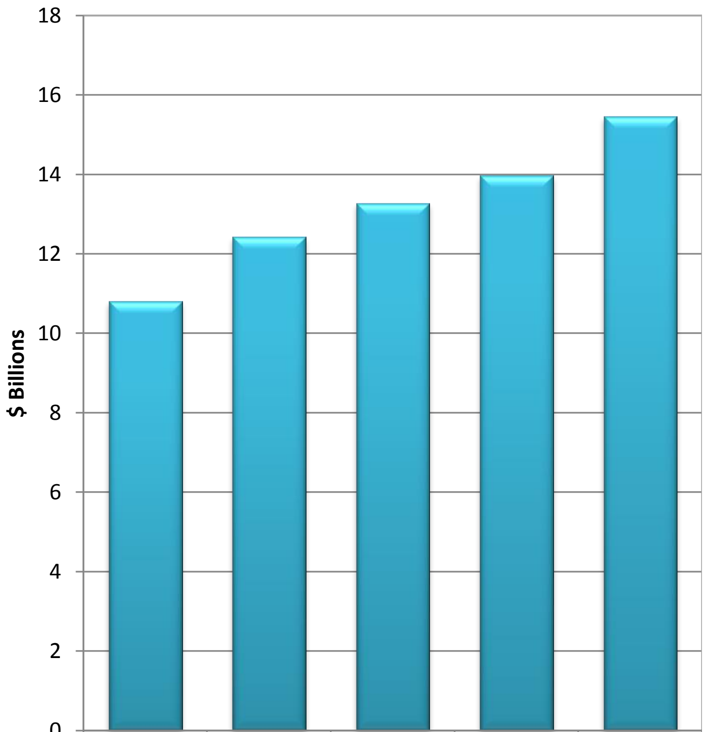
See Notes 1 and 2 on page 2

Key Metrics Overview of Ontario Electricity Distributors' Sector

Income Statement – Consolidated		Year ended December 31, 2016
Revenue		
Power & Distribution Revenue	$	18,893,982,995
Cost of Power & Related Costs		15,461,055,446
Distribution Revenue		3,432,927,549
Other Income		346,840,217
Expenses		
Operating		345,691,477
Maintenance		435,521,655
Administration		838,782,729
Depreciation and Amortization		925,455,321
Financing		399,168,105
		2,944,619,287
Net Income Before Taxes		835,148,479
PILS and Income Taxes		
Current		75,717,597
Deferred		37,911,727
		113,629,324
Net Income	**$**	**721,519,155**
Other Comprehensive Income		2,644,284
Comprehensive Income	**$**	**724,163,439**

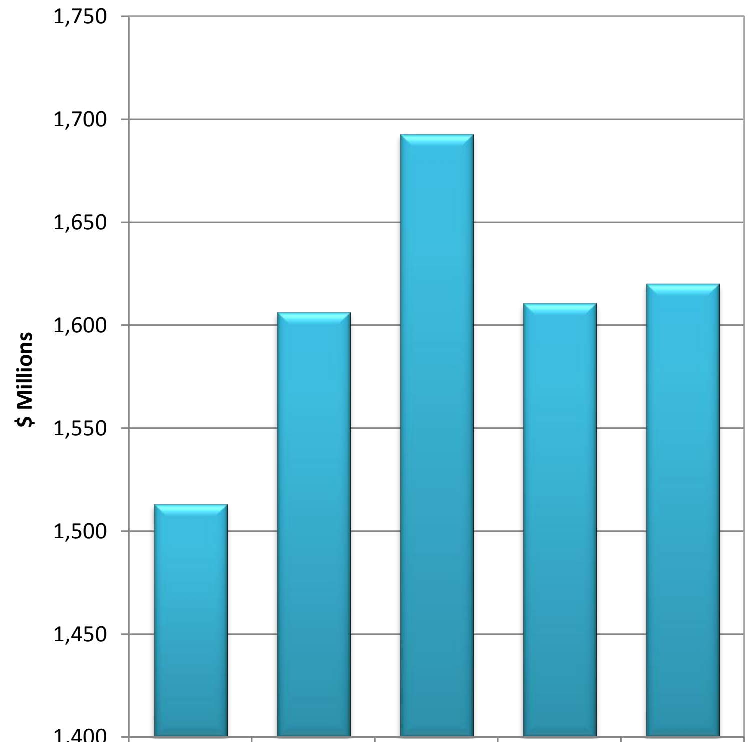


Cost of Power



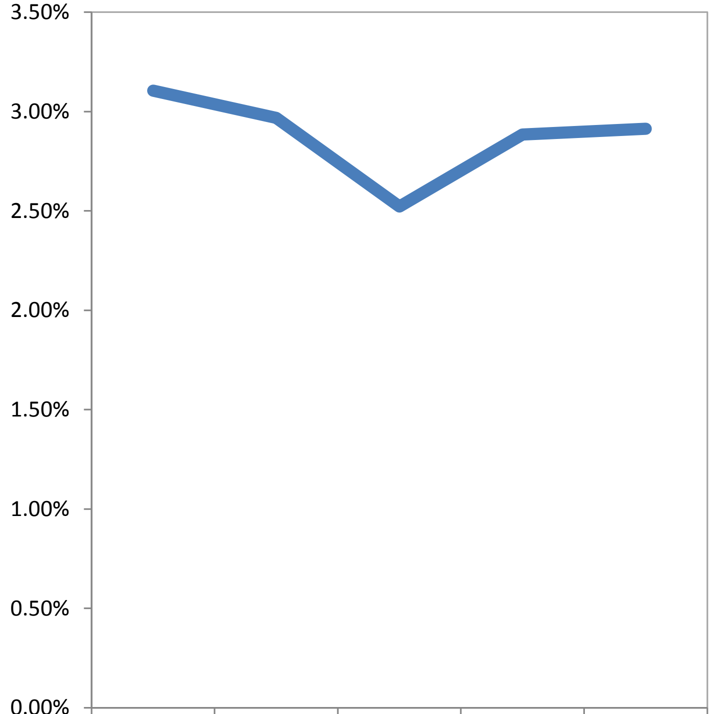
	2012	2013	2014	2015	2016
Cost of Power	10.8	12.4	13.3	14.0	15.5

Operating, Maintenance & Administrative Expenses



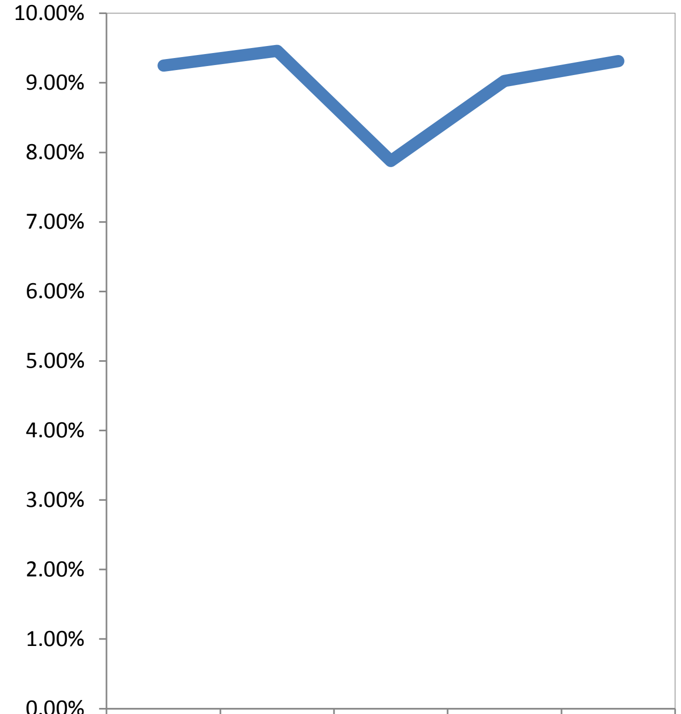
	2012	2013	2014	2015	2016
OM&A Expenses	1,513	1,606	1,693	1,611	1,620

**Financial Statement Return on Assets
(Net Income / Total Assets)**



	2012	2013	2014	2015	2016
Return on Assets	3.11%	2.97%	2.52%	2.88%	2.91%

**Financial Statement Return on Equity
(Net Income / Shareholder's Equity)**



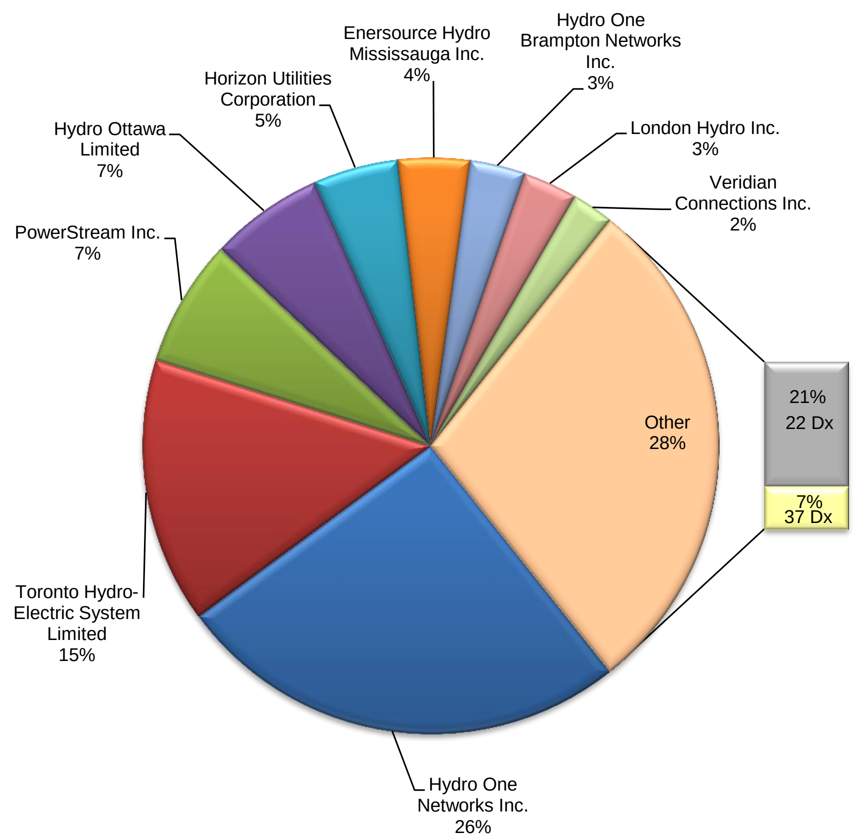
	2012	2013	2014	2015	2016
Return on Equity	9.25%	9.46%	7.88%	9.03%	9.31%

Key Metrics Overview of Ontario Electricity Distributors' Sector

General Statistics – Consolidated		Year ended December 31, 2016
Total Customers		**5,106,528**
Residential Customers		4,612,551
General Service <50kW Customers		437,396
General Service (50-4999kW) Customers		55,876
Large User (>5000kW) Customers		126
Sub Transmission		579
Total Service Area (sq km)		**992,354**
% Rural		99%
% Urban		1%
Total Circuit km of Line		**217,622**
Overhead circuit km of line		164,184
Underground circuit km of line		53,438
Total kWh Supplied		**135,092,458,977**
Total kWh Delivered (excluding losses)		130,194,306,824
Total kWh Delivered on Long-Term Load Transfer		84,433,871
Total Distribution Losses (kWh)		4,813,718,283
Gross Capital Additions for the Year ($)	**$**	**2,159,876,482**
High Voltage Capital Additions for the Year ($)	**$**	**75,638,066**

Unitized Statistics - Consolidated		
# of Customers per sq km of Service Area		5.15
# of Customers per km of Line		23.47
Distribution Revenue:		
Per Customer	$	672.26
Per Total kWh Delivered	$	0.03
Average monthly total kWh delivered per customer		2,125
Annual Cost of Power & Related Costs:		
Per Customer	$	3,028
Per Total kWh Delivered	$	0.12
OM&A per customer	$	317
Net Income per customer	$	141
Net Fixed Assets per customer	$	3,759

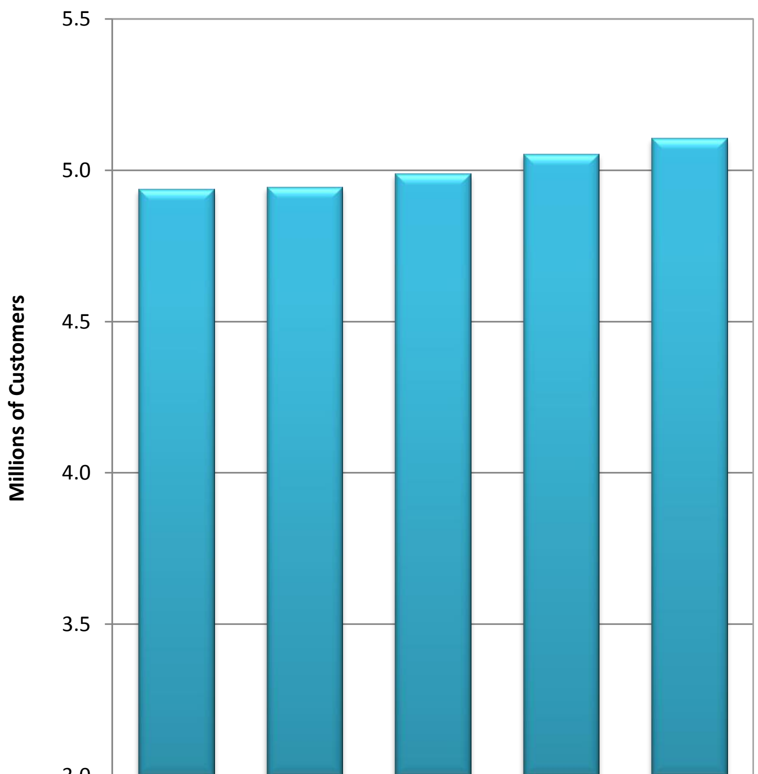
Percentage of Distribution Customers



Note: 9 distributors have greater than 100,000 customers.
The Other category consists of distributors:

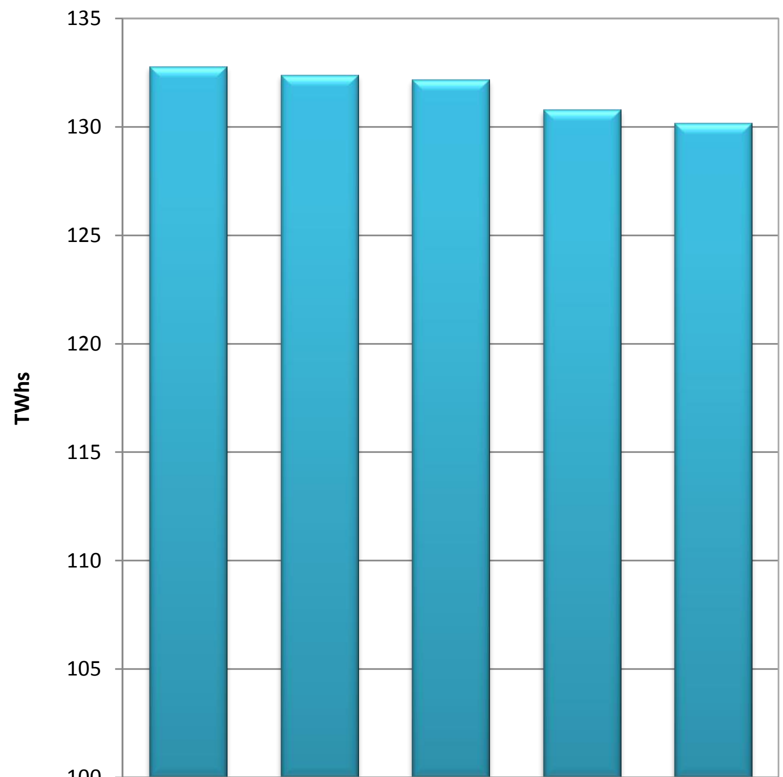
Between 25,000 to 100,000 customers   Less than 25, 000 customers

Total Number of Customers



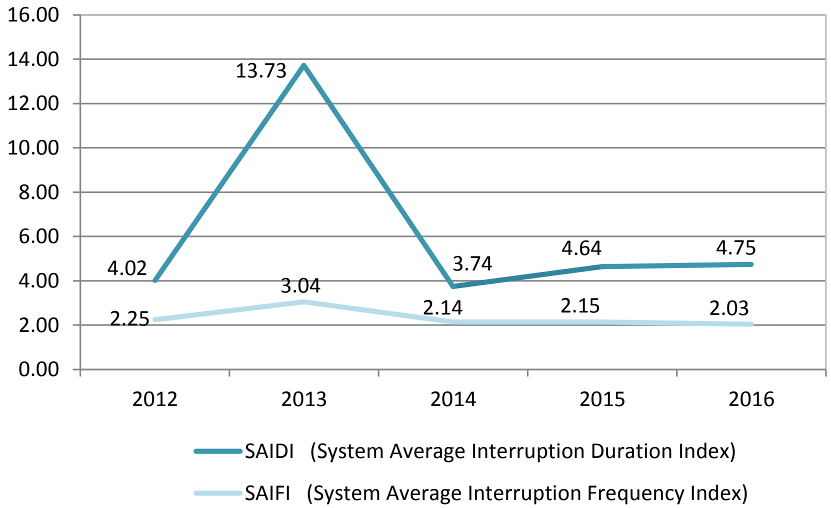
	2012	2013	2014	2015	2016
Customers	4.9	4.9	5.0	5.1	5.1

Total TWhs Delivered



	2012	2013	2014	2015	2016
TWhs Delivered	132.8	132.4	132.2	130.8	130.2

Industry System Reliability Indicators - Total Outages

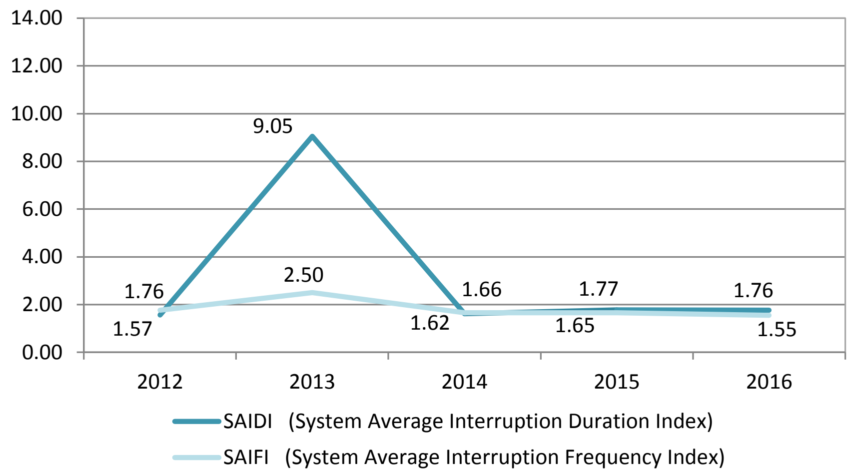


Industry Average

	2012	2013	2014	2015	2016
SAIDI	4.02	13.73	3.74	4.64	4.75
SAIFI	2.25	3.04	2.14	2.15	2.03

December 2013 was an unusual month when the province of Ontario experienced a major ice storm.

Industry System Reliability Indicators - Total Outages Excluding Hydro One Networks



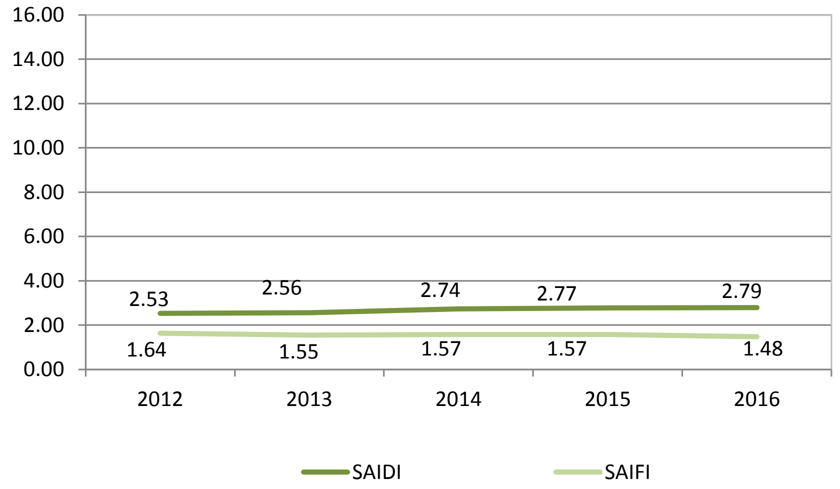
Industry Average Excluding Hydro One Networks

	2012	2013	2014	2015	2016
SAIDI	1.57	9.05	1.62	1.77	1.76
SAIFI	1.76	2.50	1.66	1.65	1.55

December 2013 was an unusual month when the province of Ontario experienced a major ice storm.

Note: Outage statistics report all outages affecting customers including those arising from within the distributor service area and those arising upstream from the distributor.

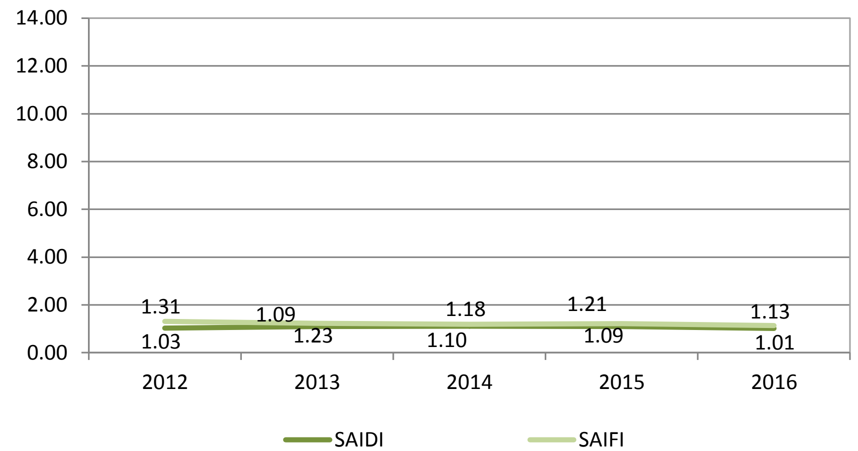
Industry System Reliability Indicators - Loss of Supply and Major Event Adjusted



Industry Average

	2012	2013	2014	2015	2016
SAIDI	2.53	2.56	2.74	2.77	2.79
SAIFI	1.64	1.55	1.57	1.57	1.48

Industry System Reliability Indicators - Loss of Supply and Major Event Excluding Hydro One Networks

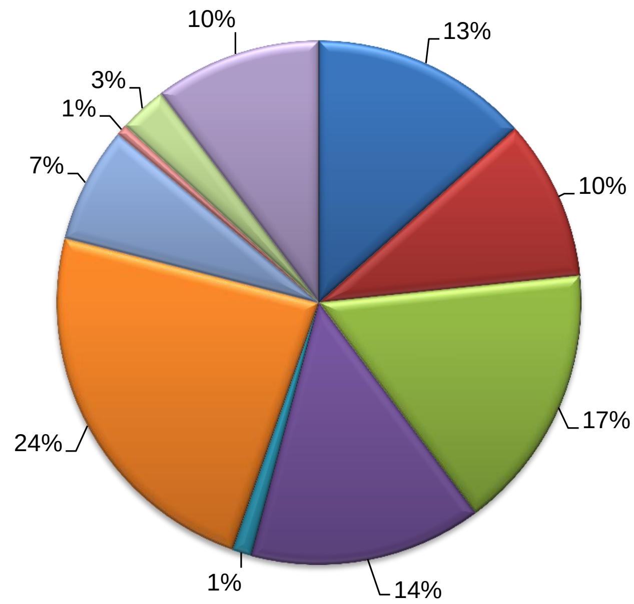


Industry Average Excluding Hydro One Networks

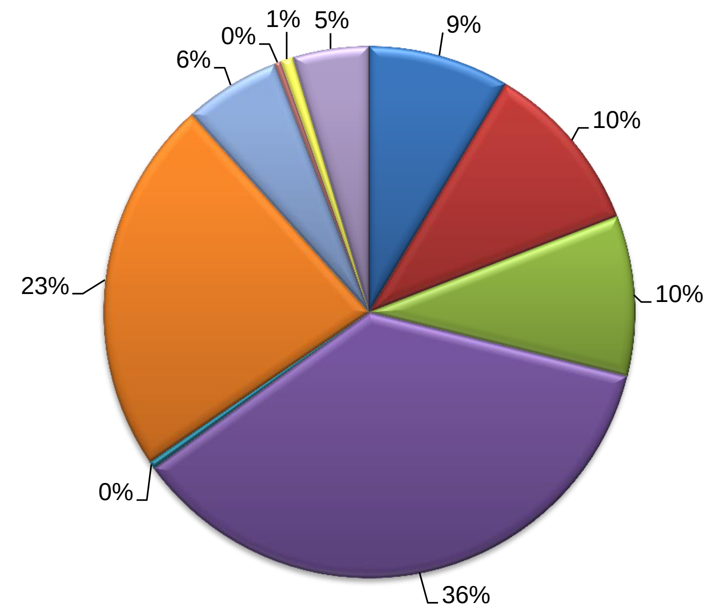
	2012	2013	2014	2015	2016
SAIDI	1.03	1.09	1.10	1.09	1.01
SAIFI	1.31	1.23	1.18	1.21	1.13

Note: Outage statistics report all outages affecting customers including those arising from within the distributor service area and those arising upstream from the distributor.

Frequency by Cause of Interruptions



Duration by Cause of Interruptions



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	1,402,852	89,548
1 - Scheduled Outage	1,036,281	15,379
2 - Loss of Supply	1,720,125	152,695
3 - Tree Contacts	1,495,227	305,321
4 - Lightning	125,282	12,368
5 - Defective Equipment	2,466,602	230,135
6 - Adverse Weather	746,682	399,331
7 - Adverse Environment	71,456	14,748
8 - Human Element	304,862	8,362
9 - Foreign Interference	1,072,311	40,969
Total	**10,441,680**	**1,268,856**

Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	2,087,322	561,682
1 - Scheduled Outage	2,570,620	34,585
2 - Loss of Supply	2,371,550	680,380
3 - Tree Contacts	8,803,985	4,339,391
4 - Lightning	107,351	14,962
5 - Defective Equipment	5,574,904	1,523,780
6 - Adverse Weather	1,428,778	1,098,076
7 - Adverse Environment	92,299	8,082
8 - Human Element	190,314	3,017
9 - Foreign Interference	1,123,687	61,393
Total	**24,350,809**	**8,325,348**

Balance Sheet As of December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Cash & cash equivalents	$ 1,024,587	$ 490,450	$ -	$ 10,649,066	$ 6,965,818	$ 1,911,616
Receivables	5,335,663	924,399	24,684,310	25,926,067	52,105,068	10,584,250
Inventory	68,784	105,867	393,481	1,783,064	2,758,601	42,174
Inter-company receivables	-	-	520,678	-	760,715	-
Other current assets	258,598	60,079	1,081,057	405,850	704,611	426,442
Current assets	6,687,632	1,580,795	26,679,525	38,764,047	63,294,813	12,964,482
Property plant & equipment	169,421,013	6,460,667	112,659,853	74,476,229	274,982,853	150,815,292
Accumulated depreciation & amortization	(66,055,422)	(3,591,975)	(55,118,857)	(9,632,017)	(152,786,423)	(58,974,645)
	103,365,591	2,868,692	57,540,996	64,844,212	122,196,430	91,840,647
Regulatory assets	4,574,544	138,099	2,377,229	2,582,879	4,631,129	3,486,564
Inter-company investments	-	-	-	-	-	-
Other non-current assets	2,981,357	120,252	-	895,048	1,236,606	4,752,351
TOTAL ASSETS	$ 117,609,124	$ 4,707,838	$ 86,597,750	$ 107,086,186	$ 191,358,977	$ 113,044,043
Accounts payable & accrued charges	$ 3,598,114	$ 786,634	$ 14,875,880	$ 14,712,214	$ 23,502,102	$ 9,691,387
Other current liabilities	116,181	29,276	355,927	489,890	771,980	211,330
Inter-company payables	2,388,550	-	3,153,048	635,208	80,492	25,966,168
Loans and notes payable, and current portion of long term debt	-	117,723	242,739	2,083,707	971,607	4,000,000
Current liabilities	6,102,845	933,633	18,627,593	17,921,019	25,326,180	39,868,885
Long-term debt	52,000,000	129,894	23,223,511	15,882,410	13,345,887	16,050,000
Inter-company long-term debt & advances	-	282,000	-	24,189,168	47,878,608	20,000,000
Regulatory liabilities	1,746,364	408,490	3,100,627	3,897,621	7,623,231	2,655,430
Other deferred amounts & customer deposits	-	128,164	1,517,277	990,362	13,530,990	-
Employee future benefits	7,011,000	-	11,736,497	1,332,175	4,777,098	7,528,499
Deferred taxes	-	120,252	-	-	-	2,489,555
Total Liabilities	66,860,210	2,002,434	58,205,506	64,212,756	112,481,994	88,592,370
Shareholders' Equity	50,748,915	2,705,403	28,392,244	42,873,430	78,876,983	24,451,673
LIABILITIES & SHAREHOLDERS' EQUITY	$ 117,609,124	$ 4,707,838	$ 86,597,750	$ 107,086,186	$ 191,358,977	$ 113,044,043

Balance Sheet As of December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Cash & cash equivalents	$ 230,306	$ 564,644	$ 940,680	$ 1,445,957	$ 2,125,113	$ 6,655,052
Receivables	5,053,028	744,745	9,348,240	871,703	7,613,357	47,930,065
Inventory	298,143	36,465	310,242	-	275,459	2,406,293
Inter-company receivables	-	503,776	200,022	-	172,439	21
Other current assets	99,589	-	513,080	-	85,589	528,341
Current assets	5,681,066	1,849,630	11,312,264	2,317,659	10,271,956	57,519,772
Property plant & equipment	25,637,117	2,837,645	23,703,768	4,728,744	23,849,611	184,354,704
Accumulated depreciation & amortization	(10,873,769)	(1,726,964)	(3,031,455)	(1,947,466)	(15,254,514)	(12,749,886)
	14,763,348	1,110,681	20,672,313	2,781,278	8,595,097	171,604,818
Regulatory assets	889,451	466,547	8,622,693	394,415	5,203,804	9,988,199
Inter-company investments	-	-	-	-	100	-
Other non-current assets	810,760	-	-	-	168,089	531,698
TOTAL ASSETS	$ 22,144,625	$ 3,426,858	$ 40,607,270	$ 5,493,353	$ 24,239,046	$ 239,644,487
Accounts payable & accrued charges	$ 3,048,006	$ 468,827	$ 8,229,164	$ 873,117	$ 4,484,104	$ 27,851,183
Other current liabilities	67,673	-	2,709	-	47,035	1,087,145
Inter-company payables	-	440,605	-	-	510,858	-
Loans and notes payable, and current portion of long term debt	118,346	-	534,270	-	-	-
Current liabilities	3,234,025	909,432	8,766,143	873,117	5,041,998	28,938,327
Long-term debt	4,136,755	-	11,447,235	-	4,600,000	85,000,000
Inter-company long-term debt & advances	5,046,753	-	-	-	-	6,684,703
Regulatory liabilities	420,125	430,341	7,018,238	161,579	3,708,062	13,871,800
Other deferred amounts & customer deposits	1,086,850	27,979	3,047,871	35,566	1,499,562	18,938,547
Employee future benefits	217,580	-	838,844	-	525,745	3,140,004
Deferred taxes	-	-	-	-	-	-
Total Liabilities	14,142,087	1,367,752	31,118,330	1,070,261	15,375,367	156,573,382
Shareholders' Equity	8,002,537	2,059,106	9,488,940	4,423,091	8,863,679	83,071,105
LIABILITIES & SHAREHOLDERS' EQUITY	$ 22,144,625	$ 3,426,858	$ 40,607,270	$ 5,493,353	$ 24,239,046	$ 239,644,487

Balance Sheet As of December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Cash & cash equivalents	$ -	$ 3,799,744	$ 15,144,551	$ -	$ 2,283,367	$ -
Receivables	178,271,607	20,099,368	56,329,710	12,663,383	2,026,332	14,682,238
Inventory	4,663,410	880,440	5,194,682	88,158	75,846	643,381
Inter-company receivables	311,707	26,096	3,766,885	141,813	-	129,503
Other current assets	9,236,951	817,442	1,817,839	528,702	53,557	182,414
Current assets	192,483,674	25,623,090	82,253,667	13,422,056	4,439,103	15,637,536
Property plant & equipment	846,642,249	93,554,234	298,190,511	40,244,413	9,620,090	79,924,145
Accumulated depreciation & amortization	(150,450,221)	(10,947,388)	(62,956,322)	(2,922,578)	(5,466,631)	(28,997,793)
	696,192,028	82,606,845	235,234,190	37,321,835	4,153,459	50,926,352
Regulatory assets	16,887,851	4,823,447	8,139,242	7,312,864	2,450,752	8,373,107
Inter-company investments	-	-	3,698,575	-	-	-
Other non-current assets	26,253,963	-	12,698,404	42,230	9,826	-
TOTAL ASSETS	$ 931,817,517	$ 113,053,383	$ 342,024,077	$ 58,098,986	$ 11,053,140	$ 74,936,995
Accounts payable & accrued charges	$ 123,651,276	$ 15,161,656	$ 36,471,565	$ 12,173,901	$ 3,236,164	$ 16,585,585
Other current liabilities	-	195,627	546,066	-	86,243	240,367
Inter-company payables	1,783,020	-	13,976,314	351,076	-	-
Loans and notes payable, and current portion of long term debt	119,047,226	-	326,359	2,700,479	-	5,471,551
Current liabilities	244,481,523	15,357,282	51,320,305	15,225,456	3,322,407	22,297,503
Long-term debt	-	-	51,000,000	19,929,303	2,322,067	16,105,746
Inter-company long-term debt & advances	334,000,000	49,523,326	-	-	1,524,511	373,943
Regulatory liabilities	26,933,126	5,636,887	22,818,892	4,199,775	349,918	6,791,864
Other deferred amounts & customer deposits	48,896,855	4,150,837	24,813,230	3,320,763	356,701	1,060,667
Employee future benefits	5,446,047	3,883,836	59,627,762	797,100	-	4,080,582
Deferred taxes	386,435	-	-	-	34,523	540,840
Total Liabilities	660,143,985	78,552,168	209,580,188	43,472,396	7,910,127	51,251,146
Shareholders' Equity	271,673,532	34,501,215	132,443,889	14,626,589	3,143,012	23,685,849
LIABILITIES & SHAREHOLDERS' EQUITY	$ 931,817,517	$ 113,053,383	$ 342,024,077	$ 58,098,986	$ 11,053,140	$ 74,936,995

Balance Sheet As of December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Cash & cash equivalents	$ -	$ 3,489,472	$ -	$ 106,714	$ 22,701,063	$ -
Receivables	15,315,662	2,268,188	27,687,216	4,215,744	40,076,840	13,452,314
Inventory	121,944	106,179	1,331,391	632,887	1,915,320	885,349
Inter-company receivables	96,889	-	296,367	15,321	1,579,716	904,847
Other current assets	385,327	78,843	1,575,990	550,204	2,676,222	675,538
Current assets	15,919,823	5,942,682	30,890,964	5,520,870	68,949,162	15,918,048
Property plant & equipment	60,467,898	12,423,013	202,850,397	33,415,639	175,379,056	72,967,843
Accumulated depreciation & amortization	(6,457,560)	(8,775,853)	(119,780,757)	(6,781,377)	(38,402,234)	(6,537,664)
	54,010,338	3,647,160	83,069,640	26,634,261	136,976,822	66,430,179
Regulatory assets	709,807	196,546	3,532,910	1,117,864	6,648,137	1,677,910
Inter-company investments	-	-	400,000	-	-	-
Other non-current assets	566,403	-	6,328,911	-	1,612,292	4,214,395
TOTAL ASSETS	$ 71,206,370	$ 9,786,388	$ 124,222,425	$ 33,272,995	$ 214,186,413	$ 88,240,532
Accounts payable & accrued charges	$ 10,133,921	$ 1,104,844	$ 17,390,132	$ 4,053,509	$ 28,121,700	$ 10,676,407
Other current liabilities	311,471	221,023	408,926	56,501	373,678	474,829
Inter-company payables	15,564,421	-	48,645,457	18,041	-	-
Loans and notes payable, and current portion of long term debt	3,193,723	-	3,196,755	5,107,339	564,990	6,351,936
Current liabilities	29,203,535	1,325,867	69,641,270	9,235,390	29,060,368	17,503,172
Long-term debt	13,640,922	-	730,405	3,690,879	95,000,000	12,299,655
Inter-company long-term debt & advances	-	-	-	5,782,746	-	16,141,969
Regulatory liabilities	969,607	445,069	3,489,247	886,064	9,821,932	1,993,074
Other deferred amounts & customer deposits	1,456,585	1,849,144	1,248,797	4,534,671	3,081,371	4,952,229
Employee future benefits	1,401,539	-	16,293,248	-	9,763,767	763,168
Deferred taxes	-	168,618	6,452,628	93,069	-	3,813,295
Total Liabilities	46,672,189	3,788,698	97,855,595	24,222,818	146,727,438	57,466,561
Shareholders' Equity	24,534,182	5,997,691	26,366,831	9,050,177	67,458,976	30,773,970
LIABILITIES & SHAREHOLDERS' EQUITY	$ 71,206,370	$ 9,786,388	$ 124,222,425	$ 33,272,995	$ 214,186,413	$ 88,240,532

Balance Sheet As of December 31		Hearst Power Distribution Company Limited		Horizon Utilities Corporation		Hydro 2000 Inc.		Hydro Hawkesbury Inc.		Hydro One Brampton Networks Inc.		Hydro One Networks Inc.
Cash & cash equivalents	$	3,235,176	$	500	$	400	$	1,074,609	$	55,214,752	$	8,628,758
Receivables		2,197,153		122,296,932		693,425		3,388,659		87,473,630		819,996,613
Inventory		82,586		9,411,535		-		95,423		1,342,165		4,144,713
Inter-company receivables		-		5,630,660		-		-		-		-
Other current assets		22,396		3,026,626		3,103		13,784		1,236,962		39,994,860
Current assets		5,537,313		140,366,253		696,927		4,572,476		145,267,509		872,764,944
Property plant & equipment		2,155,249		611,021,740		924,881		7,328,320		437,007,938		11,706,283,655
Accumulated depreciation & amortization		(700,991)		(114,613,044)		(178,322)		(599,499)		(40,288,666)		(4,173,113,617)
		1,454,258		496,408,696		746,559		6,728,821		396,719,273		7,533,170,038
Regulatory assets		355,697		5,862,997		495,954		670,069		14,831,835		374,654,503
Inter-company investments		-		-		-		-		-		-
Other non-current assets		16,000		10,988,611		4,601		87,302		10,491,035		656,683,072
TOTAL ASSETS	$	7,363,268	$	653,626,556	$	1,944,042	$	12,058,667	$	567,309,652	$	9,437,272,557
Accounts payable & accrued charges	$	2,097,836	$	103,995,260	$	620,277	$	3,649,364	$	72,306,630	$	589,925,871
Other current liabilities		34,059		1,893,733		14,377		-		1,527,126		183,889,644
Inter-company payables		454,567		32,093,469		-		-		-		75,361,013
Loans and notes payable, and current portion of long term debt		-		13,670,364		14,493		1,453,995		18,930,574		236,620,321
Current liabilities		2,586,462		151,652,826		649,147		5,103,359		92,764,330		1,085,796,849
Long-term debt		1,250,000		-		-		641,755		193,000,000		3,838,244,660
Inter-company long-term debt & advances		-		190,000,000		-		-		-		-
Regulatory liabilities		232,279		17,757,314		24,095		1,065,617		21,347,794		270,420,496
Other deferred amounts & customer deposits		117,375		36,669,251		133,914		781,361		39,048,633		79,163,998
Employee future benefits		-		29,896,900		-		-		3,751,000		905,749,366
Deferred taxes		-		-		72,100		-		4,032,932		491,790,859
Total Liabilities		4,186,116		425,976,291		879,256		7,592,093		353,944,690		6,671,166,227
Shareholders' Equity		3,177,152		227,650,265		1,064,786		4,466,574		213,364,962		2,766,106,330
LIABILITIES & SHAREHOLDERS' EQUITY	$	7,363,268	$	653,626,556	$	1,944,042	$	12,058,667	$	567,309,652	$	9,437,272,557

Balance Sheet As of December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Cash & cash equivalents	$ 6,367,249	$ -	$ 1,999,094	$ 4,504,640	$ 20,118,659	$ 457,741
Receivables	179,572,782	8,827,755	1,887,708	16,700,173	51,124,045	7,139,892
Inventory	12,765,788	466,228	208,531	2,082,191	2,524,429	305,576
Inter-company receivables	8,055,006	469,076	860,493	-	67,401	3,701,179
Other current assets	3,804,106	378,064	79,142	198,987	1,295,042	156,556
Current assets	210,564,930	10,141,123	5,034,968	23,485,991	75,129,576	11,760,944
Property plant & equipment	966,315,194	58,685,691	8,551,266	54,243,132	383,446,600	20,959,261
Accumulated depreciation & amortization	(111,802,887)	(6,358,479)	-	(5,488,066)	(160,194,693)	(2,944,562)
	854,512,307	52,327,212	8,551,266	48,755,066	223,251,907	18,014,699
Regulatory assets	4,302,813	3,558,232	416,808	11,484,490	4,487,356	2,589,794
Inter-company investments	-	-	-	-	-	-
Other non-current assets	438,721	58,823	254,066	252,751	1,500,957	-
TOTAL ASSETS	$ 1,069,818,771	$ 66,085,390	$ 14,257,108	$ 83,978,298	$ 304,369,796	$ 32,365,438
Accounts payable & accrued charges	$ 147,061,565	$ 5,454,791	$ 1,365,938	$ 15,195,338	$ 36,899,136	$ 3,985,096
Other current liabilities	3,144,608	-	25,849	-	307,144	-
Inter-company payables	4,713,426	2,802,282	62,604	-	-	5,195,882
Loans and notes payable, and current portion of long term debt	22,000,000	4,388,090	100,000	6,133,437	1,107,549	204,888
Current liabilities	176,919,599	12,645,164	1,554,391	21,328,775	38,313,828	9,385,865
Long-term debt	-	31,210,188	4,310,946	19,875,741	2,909,855	9,682,503
Inter-company long-term debt & advances	507,185,000	-	-	10,880,619	76,962,142	-
Regulatory liabilities	34,948,257	1,656,270	1,109,556	1,888,173	9,787,495	3,134,099
Other deferred amounts & customer deposits	18,463,713	428,289	233,053	1,881,915	29,846,321	221,038
Employee future benefits	12,500,900	139,779	282,300	987,730	5,034,988	383,425
Deferred taxes	-	-	-	-	-	-
Total Liabilities	750,017,469	46,079,689	7,490,246	56,842,953	162,854,629	22,806,931
Shareholders' Equity	319,801,302	20,005,701	6,766,862	27,135,345	141,515,167	9,558,506
LIABILITIES & SHAREHOLDERS' EQUITY	$ 1,069,818,771	$ 66,085,390	$ 14,257,108	$ 83,978,298	$ 304,369,796	$ 32,365,438

Balance Sheet As of December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Cash & cash equivalents	$ 2,813,363	$ 713,346	$ 70,397	$ 10,780,281	$ 9,691,630	$ 21,563,744
Receivables	9,808,211	87,016,199	4,943,438	21,960,626	29,080,879	31,925,075
Inventory	373,474	844,569	183,713	1,553,268	875,151	1,364,874
Inter-company receivables	8,290	-	-	456,229	-	5,982
Other current assets	227,805	1,898,379	132,905	387,497	3,506,622	2,609,077
Current assets	13,231,142	90,472,493	5,330,453	35,137,901	43,154,282	57,468,752
Property plant & equipment	55,712,226	476,014,147	16,922,078	157,654,749	122,177,880	268,671,235
Accumulated depreciation & amortization	(23,099,831)	(189,667,362)	(2,293,379)	(65,971,651)	(57,441,310)	(139,281,327)
	32,612,395	286,346,784	14,628,699	91,683,098	64,736,571	129,389,908
Regulatory assets	2,581,491	4,477,799	1,168,173	2,856,371	2,939,013	3,615,895
Inter-company investments	-	-	-	-	-	-
Other non-current assets	836,852	2,331,463	1,282,879	-	-	3,773,736
TOTAL ASSETS	$ 49,261,880	$ 383,628,539	$ 22,410,205	$ 129,677,370	$ 110,829,866	$ 194,248,290
Accounts payable & accrued charges	$ 6,548,157	$ 54,713,832	$ 3,625,688	$ 15,733,068	$ 15,227,450	$ 19,683,030
Other current liabilities	41,773	3,457,145	74,322	-	525,942	1,341
Inter-company payables	941,320	8,671,138	-	86,975	-	-
Loans and notes payable, and current portion of long term debt	245,617	2,304,000	1,430,724	1,656,071	21,214	11,466,355
Current liabilities	7,776,866	69,146,116	5,130,733	17,476,114	15,774,605	31,150,727
Long-term debt	17,840,912	108,826,000	3,724,029	52,632,529	29,475,892	42,975,217
Inter-company long-term debt & advances	-	-	-	-	2,553,645	25,605,090
Regulatory liabilities	1,087,474	12,395,374	572,239	3,796,904	11,887,560	12,762,766
Other deferred amounts & customer deposits	6,461,821	26,835,932	2,311,318	13,335,166	2,317,478	92,517
Employee future benefits	55,109	14,481,000	87,612	319,821	876,508	2,619,248
Deferred taxes	-	1,162,663	278,230	1,738,621	-	-
Total Liabilities	33,222,184	232,847,085	12,104,161	89,299,155	62,885,688	115,205,564
Shareholders' Equity	16,039,697	150,781,454	10,306,044	40,378,215	47,944,178	79,042,726
LIABILITIES & SHAREHOLDERS' EQUITY	$ 49,261,880	$ 383,628,539	$ 22,410,205	$ 129,677,370	$ 110,829,866	$ 194,248,290

Balance Sheet As of December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Cash & cash equivalents	$ -	$ 12,270,622	$ -	$ 13,697,515	$ 801,553	$ 364
Receivables	5,991,012	14,590,116	4,188,848	51,193,437	7,256,296	8,743,842
Inventory	361,700	511,305	215,901	3,507,224	310,154	526,786
Inter-company receivables	-	545,005	-	-	-	884,638
Other current assets	111,835	951,546	145,274	731,753	99,281	107,501
Current assets	6,464,547	28,868,595	4,550,023	69,129,928	8,467,284	10,263,131
Property plant & equipment	51,387,327	121,159,551	8,386,446	211,628,244	20,910,534	31,256,655
Accumulated depreciation & amortization	(25,387,285)	(59,875,145)	(1,809,976)	(25,858,828)	(2,572,657)	(3,201,920)
	26,000,041	61,284,406	6,576,470	185,769,416	18,337,877	28,054,735
Regulatory assets	3,770,159	964,913	797,653	10,619,307	1,647,929	2,469,938
Inter-company investments	-	-	-	-	-	-
Other non-current assets	236,940	3,758,177	29,969	12,849,475	420,000	2,890,000
TOTAL ASSETS	$ 36,471,687	$ 94,876,090	$ 11,954,115	$ 278,368,126	$ 28,873,090	$ 43,677,804
Accounts payable & accrued charges	$ 4,255,072	$ 9,882,675	$ 2,526,909	$ 41,061,087	$ 4,898,715	$ 6,980,879
Other current liabilities	6,475	921,759	-	892,761	9,804	164,490
Inter-company payables	-	478,430	7,745	-	-	252,639
Loans and notes payable, and current portion of long term debt	3,091,194	2,541,391	1,153,910	4,601,910	448,887	6,347,131
Current liabilities	7,352,741	13,824,255	3,688,564	46,555,758	5,357,406	13,745,139
Long-term debt	816,667	32,040,705	3,644,743	19,820,917	10,085,151	525,000
Inter-company long-term debt & advances	7,056,709	-	-	69,468,580	-	9,762,000
Regulatory liabilities	1,344,284	2,697,944	951,233	5,602,387	1,065,420	2,984,800
Other deferred amounts & customer deposits	3,672,764	3,183,296	235,366	40,930,527	1,739,344	2,116,185
Employee future benefits	357,440	4,005,164	60,145	11,221,000	340,021	589,336
Deferred taxes	74,948	2,868,194	-	-	420,000	-
Total Liabilities	20,675,553	58,619,558	8,580,051	193,599,170	19,007,342	29,722,460
Shareholders' Equity	15,796,135	36,256,532	3,374,065	84,768,955	9,865,748	13,955,344
LIABILITIES & SHAREHOLDERS' EQUITY	$ 36,471,687	$ 94,876,090	$ 11,954,115	$ 278,368,126	$ 28,873,090	$ 43,677,804

Balance Sheet As of December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Cash & cash equivalents	$ 9,265,323	$ 2,463,052	$ 5,334,704	$ 1,579,287	$ 3,999,922	$ 950
Receivables	28,760,922	5,987,040	18,883,075	232,364,008	16,796,051	2,678,539
Inventory	77,714	495,908	1,159,388	3,719,351	1,486,453	251,253
Inter-company receivables	-	-	-	23,795,912	-	24,080
Other current assets	622,696	401,266	99,578	4,831,974	796,077	67,427
Current assets	38,726,654	9,347,266	25,476,744	266,290,533	23,078,504	3,022,249
Property plant & equipment	189,124,006	13,639,802	131,808,037	1,537,538,805	99,638,159	6,190,813
Accumulated depreciation & amortization	(90,001,620)	(3,201,614)	(54,711,278)	(248,072,404)	(12,072,523)	(704,641)
	99,122,386	10,438,188	77,096,760	1,289,466,401	87,565,635	5,486,172
Regulatory assets	7,401,724	1,115,389	4,764,173	42,825,579	1,172,360	1,037,007
Inter-company investments	-	-	-	9,177,607	-	-
Other non-current assets	907,649	972,184	2,122,965	-	-	322,978
TOTAL ASSETS	$ 146,158,414	$ 21,873,027	$ 109,460,641	$ 1,607,760,119	$ 111,816,499	$ 9,868,405
Accounts payable & accrued charges	$ 26,353,860	$ 5,786,725	$ 11,504,812	$ 123,848,525	$ 15,144,729	$ 1,785,756
Other current liabilities	215,290	3,019	433,877	7,486,519	-	25,599
Inter-company payables	6,889,816	249,905	-	17,340,146	-	477,367
Loans and notes payable, and current portion of long term debt	-	75,028	1,517,000	203,443,536	-	30,828
Current liabilities	33,458,967	6,114,677	13,455,689	352,118,726	15,144,729	2,319,550
Long-term debt	22,642,896	5,585,838	41,591,619	347,528,299	38,624,235	10,108
Inter-company long-term debt & advances	23,064,000	-	1,510,000	182,429,859	26,534,040	2,705,168
Regulatory liabilities	5,076,098	1,737,362	4,507,635	35,414,154	3,620,890	864,879
Other deferred amounts & customer deposits	4,507,108	499,037	17,460,789	213,024,821	-	176,530
Employee future benefits	13,255,706	214,704	630,395	20,294,905	-	159,308
Deferred taxes	-	-	-	3,862,471	-	-
Total Liabilities	102,004,775	14,151,618	79,156,126	1,154,673,236	83,923,894	6,235,542
Shareholders' Equity	44,153,639	7,721,409	30,304,515	453,086,883	27,892,606	3,632,863
LIABILITIES & SHAREHOLDERS' EQUITY	$ 146,158,414	$ 21,873,027	$ 109,460,641	$ 1,607,760,119	$ 111,816,499	$ 9,868,405

Balance Sheet As of December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Cash & cash equivalents	$ 284,239	$ -	$ 2,633,999	$ 49,977	$ 343,999	$ 0
Receivables	3,774,411	2,771,667	8,214,963	27,249,336	6,208,798	541,074,385
Inventory	231,121	52,487	207,311	1,886,678	276,107	9,664,954
Inter-company receivables	-	-	-	1,090,010	-	749,564
Other current assets	183,550	237,005	300,648	1,949,185	28,644	14,489,409
Current assets	4,473,322	3,061,159	11,356,921	32,225,187	6,857,548	565,978,312
Property plant & equipment	6,923,339	9,515,618	31,374,925	212,453,931	21,841,477	4,587,769,949
Accumulated depreciation & amortization	(1,062,376)	(4,438,282)	(3,484,800)	(108,993,222)	(11,340,801)	(503,428,728)
	5,860,963	5,077,336	27,890,125	103,460,709	10,500,676	4,084,341,221
Regulatory assets	858,703	168,311	3,289,024	2,396,909	503,720	292,021,671
Inter-company investments	-	-	-	114,331	-	-
Other non-current assets	154,734	99,154	897,822	1,335,427	-	42,690,193
TOTAL ASSETS	$ 11,347,722	$ 8,405,959	$ 43,433,892	$ 139,532,563	$ 17,861,944	$ 4,985,031,396
Accounts payable & accrued charges	$ 2,290,752	$ 3,009,037	$ 7,514,651	$ 21,695,035	$ 1,581,087	$ 505,797,660
Other current liabilities	36,595	20,826	255,755	224,115	816,788	15,922,315
Inter-company payables	1,814,799	-	593,027	18,001	829,781	325,268,088
Loans and notes payable, and current portion of long term debt	181,001	268,597	16,938	842,604	149,528	85,288,819
Current liabilities	4,323,146	3,298,461	8,380,371	22,779,756	3,377,184	932,276,882
Long-term debt	449,670	1,266,383	11,214,426	19,295,592	109,219	-
Inter-company long-term debt & advances	1,163,352	-	-	26,490,500	-	1,830,595,099
Regulatory liabilities	1,029,691	472,077	3,977,474	3,578,314	1,209,694	211,937,434
Other deferred amounts & customer deposits	307,069	330,110	1,388,681	1,015,297	2,437,627	159,344,743
Employee future benefits	31,772	58,596	1,143,798	2,435,869	-	279,290,000
Deferred taxes	-	-	-	-	-	39,332,677
Total Liabilities	7,304,700	5,425,627	26,104,751	75,595,327	7,133,725	3,452,776,835
Shareholders' Equity	4,043,022	2,980,333	17,329,141	63,937,235	10,728,219	1,532,254,561
LIABILITIES & SHAREHOLDERS' EQUITY	$ 11,347,722	$ 8,405,959	$ 43,433,892	$ 139,532,563	$ 17,861,944	$ 4,985,031,396

Balance Sheet As of December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Cash & cash equivalents	$ 4,953,074	$ 1,931,169	$ 3,194	$ 1,551,660	$ -	$ 1,536,278
Receivables	66,475,406	4,231,802	45,445,488	8,338,997	3,138,069	2,580,216
Inventory	3,030,587	-	3,237,595	508,355	127,105	407,257
Inter-company receivables	-	-	-	133,578	-	-
Other current assets	1,201,897	310,421	785,745	176,226	244,804	16,859
Current assets	75,660,964	6,473,392	49,472,022	10,708,815	3,509,979	4,540,610
Property plant & equipment	287,143,341	13,973,675	356,112,684	60,377,949	10,526,620	10,432,837
Accumulated depreciation & amortization	(34,406,783)	(1,840,155)	(151,182,998)	(30,983,471)	(1,271,259)	(1,097,210)
	252,736,558	12,133,521	204,929,686	29,394,478	9,255,361	9,335,627
Regulatory assets	7,825,315	1,330,987	3,738,636	677,054	659,919	742,391
Inter-company investments	-	-	-	-	-	-
Other non-current assets	3,898,337	341,344	1,221,393	1,371,745	152,145	-
TOTAL ASSETS	$ 340,121,174	$ 20,279,243	$ 259,361,737	$ 42,152,092	$ 13,577,404	$ 14,618,628
Accounts payable & accrued charges	$ 45,155,177	$ 2,692,677	$ 39,153,002	$ 7,137,790	$ 2,522,148	$ 2,170,307
Other current liabilities	566,642	81,825	2,344,338	205,539	-	16,088
Inter-company payables	-	-	1,000,100	-	-	-
Loans and notes payable, and current portion of long term debt	968,724	-	6,257,014	-	775,445	2,705,286
Current liabilities	46,690,543	2,774,501	48,754,454	7,343,330	3,297,593	4,891,681
Long-term debt	63,940,295	-	104,679,646	-	5,037,357	2,520,658
Inter-company long-term debt & advances	74,688,000	3,593,269	-	13,499,953	-	-
Regulatory liabilities	13,116,083	2,349,902	6,240,327	2,385,877	532,762	699,598
Other deferred amounts & customer deposits	35,104,828	155,662	4,381,082	957,920	619,202	518,239
Employee future benefits	-	-	4,426,109	1,572,730	176,872	291,961
Deferred taxes	2,510,541	-	-	-	176,471	43,409
Total Liabilities	236,050,290	8,873,335	168,481,618	25,759,810	9,840,257	8,965,546
Shareholders' Equity	104,070,884	11,405,909	90,880,119	16,392,282	3,737,148	5,653,082
LIABILITIES & SHAREHOLDERS' EQUITY	$ 340,121,174	$ 20,279,243	$ 259,361,737	$ 42,152,092	$ 13,577,404	$ 14,618,628

Balance Sheet As of December 31	Westario Power Inc.	Whitby Hydro Electric Corporation	Total Industry
Cash & cash equivalents	$ 565,502	$ 735,495	$ 291,764,414
Receivables	10,447,430	23,874,970	3,215,501,819
Inventory	711,372	1,142,843	97,748,679
Inter-company receivables	-	-	55,903,897
Other current assets	1,414,397	493,189	112,512,369
Current assets	13,138,701	26,246,498	3,773,431,178
Property plant & equipment	59,243,282	183,082,470	26,607,122,705
Accumulated depreciation & amortization	(5,716,587)	(91,655,122)	(7,412,629,141)
	53,526,695	91,427,348	19,194,493,564
Regulatory assets	7,706,983	4,203,915	951,284,944
Inter-company investments	-	-	13,390,613
Other non-current assets	321,525	400,358	829,617,964
TOTAL ASSETS	$ 74,693,904	$ 122,278,119	**$ 24,762,218,264**
Accounts payable & accrued charges	$ 9,506,699	$ 15,241,422	$ 2,408,466,910
Other current liabilities	34,425	86,502	231,802,285
Inter-company payables	-	5,508,160	604,623,939
Loans and notes payable, and current portion of long term debt	2,139,968	400,000	799,021,177
Current liabilities	11,681,092	21,236,084	4,043,914,311
Long-term debt	11,754,941	3,600,000	5,543,919,259
Inter-company long-term debt & advances	5,260,461	28,337,942	3,630,773,155
Regulatory liabilities	4,522,022	4,923,251	858,092,719
Other deferred amounts & customer deposits	8,084,335	15,158,679	916,217,350
Employee future benefits	386,427	-	1,457,272,435
Deferred taxes	1,713,000	-	564,176,330
Total Liabilities	43,402,278	73,255,956	17,014,365,559
Shareholders' Equity	31,291,626	49,022,163	7,747,852,704
LIABILITIES & SHAREHOLDERS' EQUITY	$ 74,693,904	$ 122,278,119	**$ 24,762,218,264**

Income Statement For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Power and Distribution Revenue	$ 47,459,880	$ 6,225,132	$ 129,617,343	$ 138,004,212	$ 250,723,870	$ 80,932,478
Cost of Power and Related Costs	24,749,483	4,891,255	108,110,150	121,260,802	221,163,950	63,239,709
Distribution Revenue	22,710,398	1,333,877	21,507,194	16,743,411	29,559,920	17,692,769
Other Income (Loss)	(144,840)	100,132	1,697,172	1,456,002	2,126,789	2,941,279
Expenses						
Operating	1,296,572	399,043	3,833,861	1,693,710	5,152,785	1,693,096
Maintenance	5,064,915	93,416	163,255	1,807,120	4,198,648	1,902,724
Administrative	5,583,419	601,622	9,764,927	6,917,503	8,864,186	6,012,842
Depreciation and Amortization	3,326,205	189,853	4,135,676	3,153,797	5,255,671	4,271,027
Financing	2,731,677	18,118	1,490,596	1,881,989	3,131,417	2,482,618
	18,002,788	1,302,053	19,388,314	15,454,118	26,602,706	16,362,308
Net Income Before Taxes	4,562,770	131,957	3,816,051	2,745,295	5,084,004	4,271,740
PILs and Income Taxes						
Current	311,560	25,301	399,000	24,949	1,052,813	738,340
Deferred	129,343	-	-	810,230	(598,519)	63,198
	440,903	25,301	399,000	835,179	454,294	801,538
Net Income (Loss)	4,121,867	106,656	3,417,051	1,910,116	4,629,710	3,470,202
Other Comprehensive Income (Loss)	-	-	(1,888,933)	(23,693)	(156,918)	-
Comprehensive Income (Loss)	$ 4,121,867	$ 106,656	$ 1,528,118	$ 1,886,423	$ 4,472,792	$ 3,470,202

Income Statement For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Power and Distribution Revenue	$ 22,326,551	$ 4,045,082	$ 43,396,962	$ 4,663,296	$ 33,956,530	$ 238,397,073
Cost of Power and Related Costs	19,179,014	3,263,340	36,667,055	3,838,439	30,683,184	205,119,062
Distribution Revenue	3,147,537	781,741	6,729,907	824,857	3,273,346	33,278,011
Other Income (Loss)	300,146	50,523	633,061	42,122	769,728	2,027,617
Expenses						
Operating	312,568	236,332	754,396	34,209	284,289	2,934,425
Maintenance	354,386	-	1,727,736	46,223	647,045	2,671,173
Administrative	1,504,232	514,694	2,438,380	522,674	1,625,228	11,759,032
Depreciation and Amortization	548,179	52,874	845,096	124,120	343,271	6,114,161
Financing	545,061	2,425	488,790	-	100,166	4,273,947
	3,264,427	806,326	6,254,397	727,225	3,000,000	27,752,738
Net Income Before Taxes	183,256	25,939	1,108,572	139,754	1,043,074	7,552,891
PILs and Income Taxes						
Current	(15,584)	1,902	150,279	13,540	326,000	669,321
Deferred	(12,765)	-	-	-	-	(36,644)
	(28,349)	1,902	150,279	13,540	326,000	632,677
Net Income (Loss)	211,605	24,037	958,293	126,214	717,074	6,920,213
Other Comprehensive Income (Loss)	(29,157)	-	(93,928)	-	45,077	(141,565)
Comprehensive Income (Loss)	$ 182,448	$ 24,037	$ 864,365	$ 126,214	$ 762,151	$ 6,778,648

Income Statement For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Power and Distribution Revenue	$ 1,026,384,371	$ 139,232,107	$ 334,094,633	$ 70,067,200	$ 9,488,529	$ 83,704,839
Cost of Power and Related Costs	897,270,594	121,128,611	281,993,088	60,034,318	7,846,388	71,601,477
Distribution Revenue	129,113,777	18,103,497	52,101,544	10,032,882	1,642,141	12,103,362
Other Income (Loss)	8,237,370	2,014,886	4,617,409	392,736	135,426	(122,643)
Expenses						
Operating	12,376,304	1,281,676	2,445,426	91,574	293,867	1,050,289
Maintenance	12,057,111	1,747,848	2,028,985	286,802	353,215	1,439,707
Administrative	38,449,640	7,500,775	21,221,448	5,736,465	739,499	4,414,633
Depreciation and Amortization	33,305,664	3,846,009	10,501,504	1,712,622	129,660	1,493,988
Financing	18,077,874	2,846,129	2,892,954	1,553,622	165,261	946,282
	114,266,593	17,222,438	39,090,318	9,381,085	1,681,502	9,344,899
Net Income Before Taxes	23,084,555	2,895,945	17,628,635	1,044,533	96,065	2,635,820
PILs and Income Taxes						
Current	1,163,158	455,998	5,230,316	35,000	(24,151)	170,308
Deferred	134,707	-	-	-	-	-
	1,297,865	455,998	5,230,316	35,000	(24,151)	170,308
Net Income (Loss)	21,786,690	2,439,947	12,398,320	1,009,533	120,216	2,465,512
Other Comprehensive Income (Loss)	641,506	(524,826)	(2,120,549)	71,969	(1,329)	-
Comprehensive Income (Loss)	$ 22,428,196	$ 1,915,121	$ 10,277,771	$ 1,081,502	$ 118,887	$ 2,465,512

Income Statement For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Power and Distribution Revenue	$ 89,518,859	$ 11,386,325	$ 138,439,207	$ 27,214,575	$ 240,302,271	$ 78,690,636
Cost of Power and Related Costs	78,718,905	9,564,815	115,764,113	22,644,068	210,656,255	68,889,508
Distribution Revenue	10,799,954	1,821,510	22,675,094	4,570,507	29,646,016	9,801,128
Other Income (Loss)	841,505	179,180	2,895,430	825,778	2,924,244	961,318
Expenses						
Operating	904,318	514,922	5,954,274	786,475	4,843,935	1,460,237
Maintenance	1,228,752	307,191	2,162,163	661,048	1,455,021	444,659
Administrative	3,609,931	927,706	6,387,467	2,092,877	8,165,041	4,224,099
Depreciation and Amortization	2,156,996	210,483	3,685,266	1,081,719	5,645,805	1,795,856
Financing	1,739,454	3,002	4,620,875	488,310	4,623,749	1,083,977
	9,639,452	1,963,304	22,810,045	5,110,429	24,733,550	9,008,827
Net Income Before Taxes	2,002,008	37,386	2,760,479	285,856	7,836,710	1,753,619
PILs and Income Taxes						
Current	266,000	-	316,763	(20,000)	1,622,622	23,588
Deferred	-	-	(1,812,789)	(122,785)	687,155	379,943
	266,000	-	(1,496,026)	(142,785)	2,309,777	403,531
Net Income (Loss)	1,736,008	37,386	4,256,504	428,641	5,526,933	1,350,087
Other Comprehensive Income (Loss)	(22,973)	-	5,027,926	-	378,024	-
Comprehensive Income (Loss)	$ 1,713,035	$ 37,386	$ 9,284,430	$ 428,641	$ 5,904,957	$ 1,350,087

Income Statement For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
Power and Distribution Revenue	$ 11,831,766	$ 723,252,912	$ 3,390,800	$ 12,377,142	$ 591,176,319	$ 4,533,337,720
Cost of Power and Related Costs	10,719,015	610,882,333	2,894,614	10,793,747	519,676,389	3,292,355,291
Distribution Revenue	1,112,750	112,370,579	496,186	1,583,395	71,499,929	1,240,982,430
Other Income (Loss)	183,105	4,759,102	54,511	213,537	5,937,846	183,196,611
Expenses						
Operating	129,461	28,957,361	28,341	68,472	7,229,708	91,631,017
Maintenance	282,006	4,597,742	14,113	168,399	4,995,779	248,120,233
Administrative	636,405	28,109,928	393,415	774,789	19,144,781	224,251,703
Depreciation and Amortization	94,346	22,282,559	52,237	194,087	18,203,923	375,051,162
Financing	80,946	7,552,136	2,848	- 4,963	11,683,953	156,107,933
	1,223,164	91,499,726	490,954	1,200,785	61,258,144	1,095,162,048
Net Income Before Taxes	72,691	25,629,954	59,743	596,148	16,179,632	329,016,993
PILs and Income Taxes						
Current	3,923	4,962,359	2,676	216,655	3,468,809	22,296,224
Deferred	8,200	1,864,968	4,093	(88,378)	(989,345)	36,171,158
	12,123	6,827,326	6,769	128,277	2,479,464	58,467,382
Net Income (Loss)	60,568	18,802,628	52,974	467,871	13,700,168	270,549,611
Other Comprehensive Income (Loss)	19,637	451,742	-	-	833,000	-
Comprehensive Income (Loss)	$ 80,206	$ 19,254,370	$ 52,974	$ 467,871	$ 14,533,168	$ 270,549,611

Income Statement For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Power and Distribution Revenue	$ 1,130,037,270	$ 42,829,831	$ 15,023,502	$ 98,658,643	$ 268,902,751	$ 35,461,729
Cost of Power and Related Costs	965,239,129	33,579,167	12,312,448	86,327,013	228,584,621	31,183,723
Distribution Revenue	164,798,141	9,250,664	2,711,054	12,331,630	40,318,129	4,278,006
Other Income (Loss)	13,171,018	1,002,798	459,729	(2,654,430)	2,619,674	638,554
Expenses						
Operating	17,491,732	1,352,091	139,803	2,074,448	4,499,779	547,312
Maintenance	10,563,440	731,242	570,654	1,540,546	4,998,354	273,923
Administrative	54,887,642	3,740,255	1,335,366	3,533,741	8,006,372	1,543,355
Depreciation and Amortization	40,097,278	2,348,783	678,946	- 1,600,252	8,710,983	1,178,282
Financing	16,936,740	1,257,050	138,999	1,298,829	4,232,098	703,505
	139,976,833	9,429,422	2,863,768	6,847,312	30,447,586	4,246,377
Net Income Before Taxes	37,992,326	824,039	307,015	2,829,888	12,490,218	670,183
PILs and Income Taxes						
Current	3,647,180	(233,375)	36,374	449,183	2,037,858	79,142
Deferred	-	438,762	-	379,824	(35,896)	88,900
	3,647,180	205,387	36,374	829,007	2,001,962	168,042
Net Income (Loss)	34,345,146	618,652	270,641	2,000,881	10,488,256	502,141
Other Comprehensive Income (Loss)	-	32,926	-	130,854	-	-
Comprehensive Income (Loss)	$ 34,345,146	$ 651,578	$ 270,641	$ 2,131,735	$ 10,488,256	$ 502,141

Income Statement For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Power and Distribution Revenue	$ 46,993,779	$ 488,163,590	$ 22,720,914	$ 130,597,737	$ 100,188,591	$ 194,053,615
Cost of Power and Related Costs	39,007,688	423,091,925	18,903,832	114,269,832	83,265,219	165,669,062
Distribution Revenue	7,986,091	65,071,665	3,817,082	16,327,905	16,923,372	28,384,553
Other Income (Loss)	759,896	6,947,357	402,489	1,877,125	(208,159)	2,580,305
Expenses						
Operating	340,160	8,748,779	846,831	2,436,465	1,497,581	4,411,325
Maintenance	1,292,351	8,326,377	207,028	1,360,880	1,497,959	2,203,115
Administrative	3,263,017	19,280,988	1,524,407	5,856,251	4,750,914	10,532,080
Depreciation and Amortization	1,349,997	17,771,936	816,330	3,301,468	3,068,914	6,462,385
Financing	345,732	3,021,405	235,901	2,517,805	1,614,464	2,576,609
	6,591,256	57,149,485	3,630,498	15,472,869	12,429,832	26,185,514
Net Income Before Taxes	2,154,731	14,869,537	589,073	2,732,161	4,285,381	4,779,345
PILs and Income Taxes						
Current	431,628	1,997,956	188,873	(135,464)	611,252	(188,872)
Deferred	132,385	405,100	(106,573)	(85,388)	569,371	(189,346)
	564,013	2,403,056	82,300	(220,852)	1,180,623	(378,218)
Net Income (Loss)	1,590,718	12,466,481	506,773	2,953,013	3,104,758	5,157,563
Other Comprehensive Income (Loss)	90,382	(293,900)	-	-	-	-
Comprehensive Income (Loss)	$ 1,681,100	$ 12,172,581	$ 506,773	$ 2,953,013	$ 3,104,758	$ 5,157,563

Income Statement For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Power and Distribution Revenue	$ 31,093,762	$ 74,373,835	$ 18,808,771	$ 233,445,735	$ 38,200,977	$ 47,745,319
Cost of Power and Related Costs	26,282,848	62,782,581	15,960,445	193,072,811	33,273,556	39,704,706
Distribution Revenue	4,810,914	11,591,254	2,848,326	40,372,924	4,927,421	8,040,613
Other Income (Loss)	355,088	406,657	367,406	2,542,944	282,581	(1,442,279)
Expenses						
Operating	654,295	775,642	622,388	7,067,862	406,298	991,247
Maintenance	476,273	1,724,297	496,255	2,181,509	501,001	1,000,317
Administrative	1,433,396	3,317,508	1,389,372	8,730,864	2,414,908	3,122,018
Depreciation and Amortization	741,925	926,479	380,214	8,984,647	651,574	- 246,829
Financing	512,011	1,246,750	177,234	6,066,505	357,892	771,100
	3,817,900	7,990,676	3,065,464	33,031,386	4,331,672	5,637,853
Net Income Before Taxes	1,348,103	4,007,235	150,268	9,884,482	878,330	960,481
PILs and Income Taxes						
Current	164,216	165,881	29,370	1,964,000	135,491	913,000
Deferred	174,891	-	(9,233)	63,995	-	(1,506,359)
	339,107	165,881	20,137	2,027,995	135,491	(593,359)
Net Income (Loss)	1,008,996	3,841,353	130,131	7,856,488	742,839	1,553,840
Other Comprehensive Income (Loss)	-	512,276	-	(1,043,615)	-	14,865
Comprehensive Income (Loss)	$ 1,008,996	$ 4,353,629	$ 130,131	$ 6,812,873	$ 742,839	$ 1,568,705

Income Statement For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Power and Distribution Revenue	$ 161,855,899	$ 29,754,637	$ 118,036,875	$ 1,301,272,967	$ 97,514,348	$ 13,723,083
Cost of Power and Related Costs	139,494,846	24,811,183	103,564,882	1,127,362,377	81,899,568	11,820,830
Distribution Revenue	22,361,053	4,943,453	14,471,994	173,910,590	15,614,780	1,902,253
Other Income (Loss)	1,853,364	329,118	2,003,201	19,409,463	2,533,523	(18,715)
Expenses						
Operating	1,646,675	630,729	2,517,181	22,891,417	3,771,353	284,869
Maintenance	1,370,654	613,081	573,281	8,547,936	2,206,518	168,606
Administrative	9,528,043	1,690,048	6,118,490	60,310,723	5,387,066	948,838
Depreciation and Amortization	4,437,246	1,503,773	3,423,805	48,291,289	4,089,742	270,394
Financing	2,206,228	561,404	1,724,559	25,547,026	3,058,063	200,841
	19,188,847	4,999,034	14,357,316	165,588,391	18,512,742	1,873,549
Net Income Before Taxes	5,025,570	273,537	2,117,878	27,731,663	(364,439)	9,990
PILs and Income Taxes						
Current	339,456	185,875	487,180	(6,441,772)	(44,000)	17,616
Deferred	-	-	20,035	-	-	32,312
	339,456	185,875	507,215	(6,441,772)	(44,000)	49,928
Net Income (Loss)	4,686,114	87,662	1,610,663	34,173,434	(320,439)	(39,938)
Other Comprehensive Income (Loss)	238,000	(25,086)	515,000	-	-	-
Comprehensive Income (Loss)	$ 4,924,114	$ 62,576	$ 2,125,663	$ 34,173,434	$ (320,439)	$ (39,938)

Income Statement For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Power and Distribution Revenue	$ 16,894,082	$ 10,491,851	$ 44,468,027	$ 136,562,589	$ 29,530,516	$ 3,885,992,334
Cost of Power and Related Costs	14,476,880	8,628,548	37,081,428	116,753,897	26,120,389	3,189,458,386
Distribution Revenue	2,417,203	1,863,303	7,386,599	19,808,692	3,410,127	696,533,948
Other Income (Loss)	284,299	136,599	687,665	961,484	291,124	50,187,583
Expenses						
Operating	247,781	574,153	818,177	3,475,223	498,266	56,904,313
Maintenance	429,760	194,875	310,048	4,909,263	178,960	63,054,927
Administrative	1,452,665	762,980	3,311,370	7,105,547	2,047,779	126,640,592
Depreciation and Amortization	364,321	217,627	1,254,621	3,385,685	327,997	225,905,945
Financing	92,121	59,881	555,120	944,669	40,557	74,528,582
	2,586,649	1,809,517	6,249,336	19,820,387	3,093,560	547,034,359
Net Income Before Taxes	114,853	190,386	1,824,927	949,790	607,691	199,687,172
PILs and Income Taxes						
Current	(1,231)	9,362	290,565	(83,881)	124,500	21,762,400
Deferred	24,022	25,696	-	371,562	-	179,979
	22,791	35,058	290,565	287,681	124,500	21,942,379
Net Income (Loss)	92,062	155,328	1,534,362	662,109	483,191	177,744,793
Other Comprehensive Income (Loss)	(1,801)	-	-	-	-	-
Comprehensive Income (Loss)	$ 90,261	$ 155,328	$ 1,534,362	$ 662,109	$ 483,191	$ 177,744,793

Income Statement For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Power and Distribution Revenue	$ 374,559,004	$ 20,866,951	$ 220,340,937	$ 57,513,491	$ 15,160,221	$ 13,603,740
Cost of Power and Related Costs	322,536,491	16,918,837	186,434,129	48,433,330	12,571,629	11,271,592
Distribution Revenue	52,022,513	3,948,115	33,906,808	9,080,161	2,588,592	2,332,148
Other Income (Loss)	3,956,208	520,968	2,333,217	768,019	132,757	195,253
Expenses						
Operating	5,905,265	97,379	5,986,134	1,461,617	442,995	136,320
Maintenance	3,722,893	732,972	1,560,653	1,815,064	218,122	297,310
Administrative	17,817,915	2,224,530	5,746,284	3,466,056	1,096,431	1,400,308
Depreciation and Amortization	11,349,987	542,441	8,271,633	1,365,712	365,478	279,897
Financing	5,046,716	147,480	4,851,251	876,389	198,269	222,487
	43,842,776	3,744,802	26,415,955	8,984,839	2,321,295	2,336,322
Net Income Before Taxes	12,135,945	724,280	9,824,070	863,341	400,054	191,079
PILs and Income Taxes						
Current	1,156,419	139,918	551,449	(42,968)	(23,610)	23,526
Deferred	(73,450)	48,296	288,927	(81,826)	-	22,970
	1,082,969	188,214	840,376	(124,794)	(23,610)	46,496
Net Income (Loss)	11,052,976	536,066	8,983,694	988,135	423,664	144,583
Other Comprehensive Income (Loss)	(76,548)	-	93,538	-	-	-
Comprehensive Income (Loss)	$ 10,976,428	$ 536,066	$ 9,077,232	$ 988,135	$ 423,664	$ 144,583

Income Statement For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation	Total Industry
Power and Distribution Revenue	$ 67,057,382	$ 137,845,091	$ 18,893,982,996
Cost of Power and Related Costs	57,528,471	115,778,176	15,461,055,446
Distribution Revenue	9,528,911	22,066,915	3,432,927,549
Other Income (Loss)	564,430	(645,181)	346,840,217
Expenses			
Operating	390,384	3,434,268	345,691,477
Maintenance	1,720,696	1,923,100	435,521,655
Administrative	3,671,831	6,503,438	838,782,729
Depreciation and Amortization	1,638,686	2,742,165	925,455,321
Financing	487,857	2,196,829	399,168,105
	7,909,454	16,799,801	2,944,619,287
Net Income Before Taxes	2,183,887	4,621,934	835,148,479
PILs and Income Taxes			
Current	102,000	983,431	75,717,597
Deferred	141,000	-	37,911,727
	243,000	983,431	113,629,324
Net Income (Loss)	1,940,887	3,638,502	721,519,155
Other Comprehensive Income (Loss)	(7,617)	-	2,644,284
Comprehensive Income (Loss)	$ 1,933,270	$ 3,638,502	$ 724,163,439

Financial Ratios For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.10	1.69	1.43	2.16	2.50	0.33
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.44	0.11	0.27	0.38	0.33	0.35
Debt to Equity Ratio (Debt/Total Equity)	1.02	0.20	0.82	0.96	0.79	1.64
Interest Coverage (EBIT/Interest Charges)	2.67	8.28	3.56	2.46	2.62	2.72
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.50%	2.27%	3.95%	1.78%	2.42%	3.07%
Financial Statement Return on Equity (Net Income/Total Equity)	8.12%	3.94%	12.04%	4.46%	5.87%	14.19%

Financial Ratios For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.76	2.03	1.29	2.65	2.04	1.99
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.42	0.00	0.29	0.00	0.19	0.38
Debt to Equity Ratio (Debt/Total Equity)	1.16	0.00	1.26	0.00	0.52	1.10
Interest Coverage (EBIT/Interest Charges)	1.34	11.69	3.27	N/A	11.41	2.77
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.96%	0.70%	2.36%	2.30%	2.96%	2.89%
Financial Statement Return on Equity (Net Income/Total Equity)	2.64%	1.17%	10.10%	2.85%	8.09%	8.33%

Financial Ratios For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.79	1.67	1.60	0.88	1.34	0.70
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.48	0.44	0.15	0.39	0.35	0.29
Debt to Equity Ratio (Debt/Total Equity)	1.66	1.44	0.39	1.55	1.22	0.93
Interest Coverage (EBIT/Interest Charges)	2.28	2.02	7.09	1.67	1.58	3.79
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.34%	2.16%	3.62%	1.74%	1.09%	3.29%
Financial Statement Return on Equity (Net Income/Total Equity)	8.02%	7.07%	9.36%	6.90%	3.82%	10.41%

Financial Ratios For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.55	4.48	0.44	0.60	2.37	0.91
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.46	0.00	0.42	0.43	0.44	0.39
Debt to Equity Ratio (Debt/Total Equity)	1.32	0.00	1.99	1.60	1.41	1.13
Interest Coverage (EBIT/Interest Charges)	2.15	13.45	1.60	1.59	2.69	2.62
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.44%	0.38%	3.43%	1.29%	2.58%	1.53%
Financial Statement Return on Equity (Net Income/Total Equity)	7.08%	0.62%	16.14%	4.74%	8.19%	4.39%

Financial Ratios For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.14	0.93	1.07	0.90	1.57	0.80
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.17	0.31	0.01	0.17	0.34	0.43
Debt to Equity Ratio (Debt/Total Equity)	0.39	0.89	0.01	0.47	0.90	1.46
Interest Coverage (EBIT/Interest Charges)	1.90	4.39	21.98	9.61	2.38	3.11
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.82%	2.88%	2.72%	3.88%	2.41%	2.87%
Financial Statement Return on Equity (Net Income/Total Equity)	1.91%	8.26%	4.98%	10.47%	6.42%	9.78%

Financial Ratios For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.19	0.80	3.24	1.10	1.96	1.25
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.49	0.54	0.31	0.44	0.27	0.31
Debt to Equity Ratio (Debt/Total Equity)	1.65	1.78	0.65	1.36	0.57	1.03
Interest Coverage (EBIT/Interest Charges)	3.24	1.66	3.21	3.18	3.95	1.95
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.21%	0.94%	1.90%	2.38%	3.45%	1.55%
Financial Statement Return on Equity (Net Income/Total Equity)	10.74%	3.09%	4.00%	7.37%	7.41%	5.25%

Financial Ratios For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.70	1.31	1.04	2.01	2.74	1.84
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.37	0.29	0.23	0.42	0.29	0.41
Debt to Equity Ratio (Debt/Total Equity)	1.13	0.74	0.50	1.33	0.67	1.01
Interest Coverage (EBIT/Interest Charges)	7.23	5.92	3.50	2.09	3.65	2.85
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.23%	3.25%	2.26%	2.28%	2.80%	2.66%
Financial Statement Return on Equity (Net Income/Total Equity)	9.92%	8.27%	4.92%	7.31%	6.48%	6.53%

Financial Ratios For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.88	2.09	1.23	1.48	1.58	0.75
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.30	0.36	0.40	0.32	0.36	0.38
Debt to Equity Ratio (Debt/Total Equity)	0.69	0.95	1.42	1.06	1.06	1.19
Interest Coverage (EBIT/Interest Charges)	3.63	4.21	1.85	2.63	3.45	2.25
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.77%	4.05%	1.09%	2.82%	2.57%	3.56%
Financial Statement Return on Equity (Net Income/Total Equity)	6.39%	10.59%	3.86%	9.27%	7.53%	11.13%

Financial Ratios For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.16	1.53	1.89	0.76	1.52	1.30
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.31	0.26	0.41	0.46	0.58	0.28
Debt to Equity Ratio (Debt/Total Equity)	1.04	0.72	1.47	1.64	2.34	0.76
Interest Coverage (EBIT/Interest Charges)	3.28	1.49	2.23	2.09	0.88	1.05
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.21%	0.40%	1.47%	2.13%	-0.29%	-0.40%
Financial Statement Return on Equity (Net Income/Total Equity)	10.61%	1.14%	5.31%	7.54%	-1.15%	-1.10%

Financial Ratios For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.03	0.93	1.36	1.41	2.03	0.61
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.16	0.18	0.26	0.33	0.01	0.45
Debt to Equity Ratio (Debt/Total Equity)	0.44	0.51	0.65	0.73	0.02	1.45
Interest Coverage (EBIT/Interest Charges)	2.25	4.18	4.29	2.01	15.98	3.68
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.81%	1.85%	3.53%	0.47%	2.71%	3.57%
Financial Statement Return on Equity (Net Income/Total Equity)	2.28%	5.21%	8.85%	1.04%	4.50%	11.60%

Financial Ratios For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.62	2.33	1.01	1.46	1.06	0.93
Leverage Ratios						
Debt Ratio (Debt/Total Assets)	0.41	0.18	0.43	0.32	0.43	0.36
Debt to Equity Ratio (Debt/Total Equity)	1.34	0.32	1.23	0.82	1.56	0.92
Interest Coverage (EBIT/Interest Charges)	3.40	5.91	3.03	1.99	3.02	1.86
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.25%	2.64%	3.46%	2.34%	3.12%	0.99%
Financial Statement Return on Equity (Net Income/Total Equity)	10.62%	4.70%	9.89%	6.03%	11.34%	2.56%

Financial Ratios For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation
Liquidity Ratios		
Current Ratio (Current Assets/Current Liabilities)	1.12	1.24
Leverage Ratios		
Debt Ratio (Debt/Total Assets)	0.26	0.26
Debt to Equity Ratio (Debt/Total Equity)	0.61	0.66
Interest Coverage (EBIT/Interest Charges)	5.48	3.10
Profitability Ratios		
Financial Statement Return on Assets (Net Income/Total Assets)	2.60%	2.98%
Financial Statement Return on Equity (Net Income/Total Equity)	6.20%	7.42%

General Statistics For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Residential	11,665	1,392	32,491	36,155	60,468	26,092
General Service < 50 kW	-	229	3,472	2,793	5,323	2,512
General Service >= 50 kW	42	18	388	457	1,033	204
Large User	-	-	4	-	-	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	11,707	1,639	36,355	39,405	66,824	28,808
Rural Service Area (sq km)	14,197	-	109	-	90	284
Urban Service Area (sq km)	3	380	96	74	98	73
Total Service Area (sq km)	14,200	380	205	74	188	357
Overhead Circuit km of Line	1,836	90	568	270	832	941
Underground Circuit km of Line	14	2	205	233	674	84
Total Circuit km of Line	1,850	92	773	503	1,506	1,025
Winter Peak (kW)	40,592	6,745	129,015	140,228	257,037	80,952
Summer Peak (kW)	29,413	6,118	164,284	187,331	360,232	101,753
Average Peak (kW)	31,617	5,703	135,332	148,938	282,697	78,930
Full-time Equivalent Number of Employees	57	7	110	57	91	84

General Statistics For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Residential	6,006	1,072	14,984	1,965	10,312	56,989
General Service < 50 kW	743	162	1,753	161	1,381	6,297
General Service >= 50 kW	49	13	127	11	101	835
Large User	-	-	-	-	-	2
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	6,798	1,247	16,864	2,137	11,794	64,123
Rural Service Area (sq km)	-	-	-	-	-	458
Urban Service Area (sq km)	11	2	45	5	22	104
Total Service Area (sq km)	11	2	45	5	22	562
Overhead Circuit km of Line	80	26	210	16	89	1,195
Underground Circuit km of Line	73	1	140	18	68	532
Total Circuit km of Line	153	27	350	34	157	1,727
Winter Peak (kW)	24,019	6,023	57,281	6,236	46,645	265,456
Summer Peak (kW)	27,793	4,979	50,903	6,446	60,936	334,471
Average Peak (kW)	23,717	4,133	48,680	5,616	47,467	274,609
Full-time Equivalent Number of Employees	15	5	20	3	18	126

General Statistics For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Residential	182,224	36,478	79,048	16,671	2,861	27,131
General Service < 50 kW	18,025	3,907	7,590	1,806	393	1,944
General Service >= 50 kW	4,470	446	1,254	159	29	252
Large User	9	2	9	1	-	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	204,728	40,833	87,901	18,637	3,283	29,327
Rural Service Area (sq km)	-	-	-	1,830	76	38
Urban Service Area (sq km)	292	96	120	57	26	66
Total Service Area (sq km)	292	96	120	1,887	102	104
Overhead Circuit km of Line	1,804	681	668	239	129	186
Underground Circuit km of Line	3,416	272	448	106	11	263
Total Circuit km of Line	5,220	953	1,116	345	140	449
Winter Peak (kW)	1,078,313	141,000	365,600	76,022	12,316	73,781
Summer Peak (kW)	1,455,239	195,283	486,400	84,530	8,815	119,448
Average Peak (kW)	1,178,199	143,950	390,250	73,512	9,402	85,849
Full-time Equivalent Number of Employees	350	76	197	45	7	44

General Statistics For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Residential	18,534	3,269	42,800	10,285	49,793	20,057
General Service < 50 kW	2,072	430	4,047	773	4,033	1,844
General Service >= 50 kW	218	47	515	111	583	211
Large User	1	-	-	-	5	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	20,825	3,746	47,362	11,169	54,414	22,112
Rural Service Area (sq km)	-	-	120	50	-	255
Urban Service Area (sq km)	45	32	290	19	93	26
Total Service Area (sq km)	45	32	410	69	93	281
Overhead Circuit km of Line	165	69	751	167	420	912
Underground Circuit km of Line	95	11	250	79	712	701
Total Circuit km of Line	260	80	1,001	246	1,132	1,613
Winter Peak (kW)	93,467	15,953	171,316	29,525	253,633	82,154
Summer Peak (kW)	107,476	12,674	140,955	43,090	292,465	107,531
Average Peak (kW)	70,008	12,105	142,551	35,106	257,566	87,446
Full-time Equivalent Number of Employees	39	12	66	17	124	54

General Statistics For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
Residential	2,257	223,311	1,163	4,834	146,977	1,186,723
General Service < 50 kW	402	18,774	152	610	9,989	111,671
General Service >= 50 kW	45	2,017	12	87	1,658	8,571
Large User	-	12	-	-	6	-
Sub Transmission Customers	-	-	-	-	-	579
Total Customers	2,704	244,114	1,327	5,531	158,630	1,307,544
Rural Service Area (sq km)	-	88	-	-	-	961,888
Urban Service Area (sq km)	93	342	9	8	269	886
Total Service Area (sq km)	93	430	9	8	269	962,774
Overhead Circuit km of Line	57	1,520	18	57	814	113,218
Underground Circuit km of Line	11	2,001	3	12	2,553	9,148
Total Circuit km of Line	68	3,521	21	69	3,367	122,366
Winter Peak (kW)	16,159	794,972	5,590	30,783	598,763	5,379,822
Summer Peak (kW)	12,377	1,033,474	3,730	29,664	836,218	5,641,078
Average Peak (kW)	13,350	840,330	3,922	26,507	664,299	5,106,196
Full-time Equivalent Number of Employees	7	335	3	7	249	4,355

General Statistics For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Residential	299,909	15,344	4,753	24,258	85,248	9,001
General Service < 50 kW	24,689	1,022	751	2,956	7,875	1,085
General Service >= 50 kW	3,271	77	59	324	934	128
Large User	11	-	-	3	1	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	327,880	16,443	5,563	27,541	94,058	10,214
Rural Service Area (sq km)	662	217	-	-	284	-
Urban Service Area (sq km)	454	75	24	36	125	28
Total Service Area (sq km)	1,116	292	24	36	409	28
Overhead Circuit km of Line	2,721	660	88	226	1,017	142
Underground Circuit km of Line	2,887	183	10	110	931	50
Total Circuit km of Line	5,608	843	98	336	1,948	192
Winter Peak (kW)	1,193,901	49,363	19,063	122,976	293,555	41,183
Summer Peak (kW)	1,391,443	52,172	16,770	117,441	360,767	43,462
Average Peak (kW)	1,178,361	45,584	15,530	110,546	293,626	38,733
Full-time Equivalent Number of Employees	628	39	12	-	187	17

General Statistics For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Residential	11,119	141,323	6,347	33,867	31,945	48,400
General Service < 50 kW	2,138	12,556	775	2,629	3,147	4,457
General Service >= 50 kW	149	1,616	109	319	373	760
Large User	-	1	-	3	-	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	13,406	155,496	7,231	36,818	35,465	53,617
Rural Service Area (sq km)	144	260	-	315	3	759
Urban Service Area (sq km)	19	163	20	56	71	68
Total Service Area (sq km)	163	423	20	371	74	827
Overhead Circuit km of Line	271	1,372	86	582	362	1,455
Underground Circuit km of Line	86	1,492	48	469	493	549
Total Circuit km of Line	357	2,864	134	1,051	855	2,004
Winter Peak (kW)	48,039	511,359	31,451	137,320	106,324	182,176
Summer Peak (kW)	46,425	683,790	35,419	178,292	143,582	261,493
Average Peak (kW)	41,016	526,861	30,849	143,581	76,133	198,105
Full-time Equivalent Number of Employees	21	322	17	59	44	123

General Statistics For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Residential	7,772	21,152	5,208	62,501	10,730	12,028
General Service < 50 kW	1,333	2,658	739	5,371	1,129	1,382
General Service >= 50 kW	129	260	60	938	141	160
Large User	-	-	-	-	-	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	9,234	24,070	6,007	68,810	12,000	13,570
Rural Service Area (sq km)	119	279	-	34	-	-
Urban Service Area (sq km)	14	51	28	109	17	27
Total Service Area (sq km)	133	330	28	143	17	27
Overhead Circuit km of Line	235	495	367	494	78	173
Underground Circuit km of Line	98	78	3	1,389	138	66
Total Circuit km of Line	333	573	370	1,883	216	239
Winter Peak (kW)	34,820	93,764	23,251	251,532	41,661	52,742
Summer Peak (kW)	45,910	81,789	19,720	373,874	47,804	54,485
Average Peak (kW)	34,552	79,288	20,020	285,934	41,338	49,437
Full-time Equivalent Number of Employees	15	45	4	111	19	33

General Statistics For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Residential	52,273	9,550	32,763	325,741	29,708	3,780
General Service < 50 kW	4,006	1,294	3,446	32,397	3,419	435
General Service >= 50 kW	531	150	363	6,365	360	60
Large User	1	-	2	2	-	-
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	56,811	10,994	36,574	364,505	33,487	4,275
Rural Service Area (sq km)	78	-	-	304	284	-
Urban Service Area (sq km)	71	35	68	503	58	13
Total Service Area (sq km)	149	35	68	807	342	13
Overhead Circuit km of Line	520	152	383	2,504	621	72
Underground Circuit km of Line	450	26	181	5,240	122	8
Total Circuit km of Line	970	178	564	7,744	743	80
Winter Peak (kW)	195,540	37,047	123,922	1,309,070	125,305	12,960
Summer Peak (kW)	221,781	35,163	145,205	1,874,833	90,384	15,052
Average Peak (kW)	190,039	30,177	122,186	1,473,208	100,106	12,652
Full-time Equivalent Number of Employees	75	26	34	567	-	11

General Statistics For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Residential	5,071	2,348	15,389	45,602	6,346	679,897
General Service < 50 kW	740	394	1,722	4,679	656	71,207
General Service >= 50 kW	64	48	135	488	93	10,770
Large User	-	-	-	-	-	46
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	5,875	2,790	17,246	50,769	7,095	761,920
Rural Service Area (sq km)	7	530	-	208	2	-
Urban Service Area (sq km)	11	6	33	179	22	630
Total Service Area (sq km)	18	536	33	387	24	630
Overhead Circuit km of Line	95	256	139	933	78	15,561
Underground Circuit km of Line	12	19	103	255	56	13,044
Total Circuit km of Line	107	275	242	1,188	134	28,605
Winter Peak (kW)	19,707	17,931	45,181	168,356	31,096	3,777,078
Summer Peak (kW)	24,788	9,528	58,935	136,523	39,302	4,591,559
Average Peak (kW)	18,314	12,582	46,949	119,250	32,014	3,961,102
Full-time Equivalent Number of Employees	15	9	29	133	20	1,477

General Statistics For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Residential	109,483	12,504	49,767	20,907	3,232	3,305
General Service < 50 kW	8,991	806	5,730	1,783	467	474
General Service >= 50 kW	1,056	36	732	163	40	49
Large User	3	-	1	-	-	1
Sub Transmission Customers	-	-	-	-	-	-
Total Customers	119,533	13,346	56,230	22,853	3,739	3,829
Rural Service Area (sq km)	386	8	607	-	-	-
Urban Service Area (sq km)	253	53	65	81	14	8
Total Service Area (sq km)	639	61	672	81	14	8
Overhead Circuit km of Line	1,448	163	1,068	338	69	47
Underground Circuit km of Line	1,123	126	551	142	10	14
Total Circuit km of Line	2,571	289	1,619	480	79	61
Winter Peak (kW)	405,512	26,028	232,140	60,106	16,484	24,830
Summer Peak (kW)	494,731	28,947	291,414	77,480	16,466	26,961
Average Peak (kW)	412,835	23,599	240,346	61,537	15,877	24,449
Full-time Equivalent Number of Employees	221	18	136	39	13	9

General Statistics For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation
Residential	20,385	39,588
General Service < 50 kW	2,550	2,220
General Service >= 50 kW	233	370
Large User	-	-
Sub Transmission Customers	-	-
Total Customers	23,168	42,178
Rural Service Area (sq km)	-	64
Urban Service Area (sq km)	64	84
Total Service Area (sq km)	64	148
Overhead Circuit km of Line	378	507
Underground Circuit km of Line	152	588
Total Circuit km of Line	530	1,095
Winter Peak (kW)	69,686	140,154
Summer Peak (kW)	71,203	189,957
Average Peak (kW)	67,889	148,607
Full-time Equivalent Number of Employees	30	2

Unitized Statistics & Other For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
# of Customers per square km of Service Area	0.82	4.31	177.34	532.50	355.45	80.69
# of Customers per km of Line	6.33	17.82	47.03	78.34	44.37	28.11
Total kWh Delivered (excluding losses)	197,489,288	35,534,463	1,012,669,476	973,387,274	1,640,636,003	465,705,113
Total kWh Delivered on Long-Term Load Transfer	-	2,646	267,852	-	1,117,759	140,373
Total Distribution Losses (kWh)	15,625,556	2,412,068	32,192,793	27,297,555	58,110,071	26,890,231
Total kWh Supplied	213,114,845	37,949,177	1,045,130,121	1,000,684,829	1,699,863,833	492,735,717
Average Monthly kWh Delivered per Customer	1,405.78	1,806.71	2,321.25	2,058.51	2,045.97	1,347.15
Average Peak (kW) per Customer	2.70	3.48	3.72	3.78	4.23	2.74
Distribution Revenue:						
Per Customer Annually	$ 1,939.90	$ 813.84	$ 591.59	$ 424.91	$ 442.35	$ 614.16
Per Total kWh Delivered	$ 0.11	$ 0.04	$ 0.02	$ 0.02	$ 0.02	$ 0.04
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,114.08	$ 2,984.29	$ 2,973.74	$ 3,077.29	$ 3,309.65	$ 2,195.21
Per Total kWh Delivered	$ 0.13	$ 0.14	$ 0.11	$ 0.12	$ 0.13	$ 0.14
OM&A per Customer	$ 1,020.32	$ 667.53	$ 378.55	$ 264.39	$ 272.59	$ 333.54
Net Income (Loss) Per Customer	$ 352.09	$ 65.07	$ 93.99	$ 48.47	$ 69.28	$ 120.46
Net Fixed Assets per Customer	$ 8,829.38	$ 1,750.27	$ 1,582.75	$ 1,645.58	$ 1,828.63	$ 3,188.03
Gross Capital Additions for the Year	$ 8,580,000	$ 359,099	$ 7,898,911	$ 4,630,910	$ 11,716,382	$ 10,470,000
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
# of Customers per square km of Service Area	631.20	623.50	374.76	427.40	536.09	114.10
# of Customers per km of Line	44.43	46.19	48.18	62.85	75.12	37.13
Total kWh Delivered (excluding losses)	141,189,275	23,488,152	299,772,716	28,472,872	238,667,221	1,711,419,562
Total kWh Delivered on Long-Term Load Transfer	21,397	1,086,687	94,980	-	-	1,065,459
Total Distribution Losses (kWh)	7,025,873	1,562,885	18,964,673	1,300,600	6,302,909	51,910,392
Total kWh Supplied	148,236,546	26,137,724	318,832,369	29,773,472	244,970,130	1,764,395,413
Average Monthly kWh Delivered per Customer	1,730.77	1,569.64	1,481.32	1,110.31	1,686.36	2,224.14
Average Peak (kW) per Customer	3.49	3.31	2.89	2.63	4.02	4.28
Distribution Revenue:						
Per Customer Annually	$ 463.01	$ 626.90	$ 399.07	$ 385.99	$ 277.54	$ 518.97
Per Total kWh Delivered	$ 0.02	$ 0.03	$ 0.02	$ 0.03	$ 0.01	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,821.27	$ 2,616.95	$ 2,174.28	$ 1,796.18	$ 2,601.59	$ 3,198.84
Per Total kWh Delivered	$ 0.14	$ 0.14	$ 0.12	$ 0.13	$ 0.13	$ 0.12
OM&A per Customer	$ 319.39	$ 602.27	$ 291.78	$ 282.22	$ 216.77	$ 270.80
Net Income (Loss) Per Customer	$ 31.13	$ 19.28	$ 56.82	$ 59.06	$ 60.80	$ 107.92
Net Fixed Assets per Customer	$ 2,171.72	$ 890.68	$ 1,225.82	$ 1,301.49	$ 728.77	$ 2,676.18
Gross Capital Additions for the Year	$ 2,181,292	$ 36,284	$ 3,765,684	$ 465,096	$ 898,957	$ 16,043,120
High Voltage Capital Additions for the Year	$ -	$ -	$ 34,352	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
# of Customers per square km of Service Area	701.12	425.34	732.51	9.88	32.19	281.99
# of Customers per km of Line	39.22	42.85	78.76	54.02	23.45	65.32
Total kWh Delivered (excluding losses)	7,327,645,870	902,437,369	2,459,339,303	478,271,195	56,279,165	541,893,378
Total kWh Delivered on Long-Term Load Transfer	610,905	1,246,524	-	1,557,488	178,345	282,953
Total Distribution Losses (kWh)	241,137,147	40,345,292	71,357,159	16,873,820	2,599,927	20,861,685
Total kWh Supplied	7,569,393,922	944,029,185	2,530,696,462	496,702,503	59,057,437	563,038,016
Average Monthly kWh Delivered per Customer	2,982.68	1,841.72	2,331.54	2,138.54	1,428.55	1,539.80
Average Peak (kW) per Customer	5.75	3.53	4.44	3.94	2.86	2.93
Distribution Revenue:						
Per Customer Annually	$ 630.66	$ 443.35	$ 592.73	$ 538.33	$ 500.20	$ 412.70
Per Total kWh Delivered	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 4,382.74	$ 2,966.44	$ 3,208.08	$ 3,221.24	$ 2,390.01	$ 2,441.49
Per Total kWh Delivered	$ 0.12	$ 0.13	$ 0.11	$ 0.13	$ 0.14	$ 0.13
OM&A per Customer	$ 307.15	$ 257.89	$ 292.33	$ 328.10	$ 422.35	$ 235.44
Net Income (Loss) Per Customer	$ 106.42	$ 59.75	$ 141.05	$ 54.17	$ 36.62	$ 84.07
Net Fixed Assets per Customer	$ 3,400.57	$ 2,023.04	$ 2,676.13	$ 2,002.57	$ 1,265.14	$ 1,736.50
Gross Capital Additions for the Year	$ 70,314,010	$ 9,393,902	$ 18,697,650	$ 4,385,303	$ 426,403	$ 4,879,788
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
# of Customers per square km of Service Area	462.78	116.34	115.52	161.87	585.10	78.75
# of Customers per km of Line	80.10	46.83	47.31	45.40	48.07	13.71
Total kWh Delivered (excluding losses)	607,564,604	71,733,463	856,964,913	181,130,157	1,675,002,146	503,249,244
Total kWh Delivered on Long-Term Load Transfer	320,057	-	401,814	48,723	-	1,971,565
Total Distribution Losses (kWh)	16,483,762	4,143,961	47,286,772	8,716,874	44,587,186	22,328,883
Total kWh Supplied	624,368,423	75,877,424	904,653,499	189,895,754	1,719,589,332	527,549,692
Average Monthly kWh Delivered per Customer	2,431.23	1,595.78	1,507.83	1,351.44	2,565.21	1,896.59
Average Peak (kW) per Customer	3.36	3.23	3.01	3.14	4.73	3.95
Distribution Revenue:						
Per Customer Annually	$ 518.61	$ 486.25	$ 478.76	$ 409.21	$ 544.82	$ 443.25
Per Total kWh Delivered	$ 0.02	$ 0.03	$ 0.03	$ 0.03	$ 0.02	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 3,780.02	$ 2,553.34	$ 2,444.24	$ 2,027.40	$ 3,871.36	$ 3,115.48
Per Total kWh Delivered	$ 0.13	$ 0.13	$ 0.14	$ 0.13	$ 0.13	$ 0.14
OM&A per Customer	$ 275.77	$ 467.12	$ 306.24	$ 316.98	$ 265.81	$ 277.18
Net Income (Loss) Per Customer	$ 83.36	$ 9.98	$ 89.87	$ 38.38	$ 101.57	$ 61.06
Net Fixed Assets per Customer	$ 2,593.53	$ 973.61	$ 1,753.93	$ 2,384.66	$ 2,517.31	$ 3,004.26
Gross Capital Additions for the Year	$ 2,438,323	$ 392,772	$ 8,626,092	$ 1,398,920	$ 17,025,784	$ 8,312,782
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ -	$ 1,746,188	$ -

Unitized Statistics & Other For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
# of Customers per square km of Service Area	29.08	567.71	147.44	691.38	589.70	1.36
# of Customers per km of Line	39.76	69.33	63.19	80.16	47.11	10.69
Total kWh Delivered (excluding losses)	79,434,627	5,408,063,947	22,905,862	141,525,042	4,030,218,511	34,454,804,122
Total kWh Delivered on Long-Term Load Transfer	58,410	3,207,415	115,613	-	791,416	42,545,126
Total Distribution Losses (kWh)	2,806,846	135,175,726	646,252	2,243,196	117,524,555	1,624,913,208
Total kWh Supplied	82,299,883	5,546,447,088	23,667,728	143,768,238	4,148,534,483	36,122,262,456
Average Monthly kWh Delivered per Customer	2,448.06	1,846.15	1,438.45	2,132.30	2,117.20	2,195.90
Average Peak (kW) per Customer	4.94	3.44	2.96	4.79	4.19	3.91
Distribution Revenue:						
Per Customer Annually	$ 411.52	$ 460.32	$ 373.92	$ 286.28	$ 450.73	$ 949.09
Per Total kWh Delivered	$ 0.01	$ 0.02	$ 0.02	$ 0.01	$ 0.02	$ 0.04
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 3,964.13	$ 2,502.45	$ 2,181.32	$ 1,951.50	$ 3,276.03	$ 2,517.97
Per Total kWh Delivered	$ 0.13	$ 0.11	$ 0.13	$ 0.08	$ 0.13	$ 0.10
OM&A per Customer	$ 387.53	$ 252.61	$ 328.46	$ 182.91	$ 197.76	$ 431.35
Net Income (Loss) Per Customer	$ 22.40	$ 77.02	$ 39.92	$ 84.59	$ 86.37	$ 206.91
Net Fixed Assets per Customer	$ 537.82	$ 2,033.51	$ 562.59	$ 1,216.57	$ 2,500.91	$ 5,761.31
Gross Capital Additions for the Year	$ 147,424	$ 51,929,703	$ 26,335	$ 1,513,998	$ 31,677,539	$ 718,921,643
High Voltage Capital Additions for the Year	$ -	$ -	$ 15,250	$ 1,267,249	$ -	$ 15,519,097

Unitized Statistics & Other For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
# of Customers per square km of Service Area	293.80	56.31	231.79	771.46	229.97	371.42
# of Customers per km of Line	58.47	19.51	56.77	81.97	48.28	53.20
Total kWh Delivered (excluding losses)	7,410,417,453	242,184,899	96,413,265	694,989,181	1,785,354,632	237,451,511
Total kWh Delivered on Long-Term Load Transfer	3,482,288	957,045	-	-	1,461,421	301,132
Total Distribution Losses (kWh)	225,210,763	12,864,696	4,346,919	34,010,760	52,915,942	7,384,052
Total kWh Supplied	7,639,110,504	256,006,640	100,760,184	728,999,941	1,839,731,995	245,136,695
Average Monthly kWh Delivered per Customer	1,883.42	1,227.40	1,444.26	2,102.89	1,581.79	1,937.30
Average Peak (kW) per Customer	3.59	2.77	2.79	4.01	3.12	3.79
Distribution Revenue:						
Per Customer Annually	$ 502.62	$ 562.59	$ 487.34	$ 447.76	$ 428.65	$ 418.84
Per Total kWh Delivered	$ 0.02	$ 0.04	$ 0.03	$ 0.02	$ 0.02	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,943.88	$ 2,042.16	$ 2,213.27	$ 3,134.49	$ 2,430.25	$ 3,053.04
Per Total kWh Delivered	$ 0.13	$ 0.14	$ 0.13	$ 0.12	$ 0.13	$ 0.13
OM&A per Customer	$ 252.97	$ 354.17	$ 367.76	$ 259.57	$ 186.10	$ 231.50
Net Income (Loss) Per Customer	$ 104.75	$ 37.62	$ 48.65	$ 72.65	$ 111.51	$ 49.16
Net Fixed Assets per Customer	$ 2,606.17	$ 3,182.34	$ 1,537.17	$ 1,770.27	$ 2,373.56	$ 1,763.73
Gross Capital Additions for the Year	$ 103,176,348	$ 6,882,669	$ 640,560	$ 5,834,543	$ 24,286,420	$ 3,079,543
High Voltage Capital Additions for the Year	$ 410,684	$ -	$ -	$ -	$ 190,239	$ 2,397

Unitized Statistics & Other For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
# of Customers per square km of Service Area	82.25	367.52	361.55	99.24	479.26	64.83
# of Customers per km of Line	37.55	54.29	53.96	35.03	41.48	26.75
Total kWh Delivered (excluding losses)	279,908,356	3,199,325,732	189,513,337	875,560,447	633,878,396	1,216,236,367
Total kWh Delivered on Long-Term Load Transfer	539,716	423,094	-	1,713,217	-	2,160,906
Total Distribution Losses (kWh)	14,479,989	99,138,098	6,369,937	28,473,936	30,849,709	39,434,041
Total kWh Supplied	294,928,061	3,298,886,924	195,883,274	905,747,600	664,728,105	1,257,831,314
Average Monthly kWh Delivered per Customer	1,739.94	1,714.58	2,184.04	1,981.73	1,489.45	1,890.32
Average Peak (kW) per Customer	3.06	3.39	4.27	3.90	2.15	3.69
Distribution Revenue:						
Per Customer Annually	$ 595.71	$ 418.48	$ 527.88	$ 443.48	$ 477.19	$ 529.39
Per Total kWh Delivered	$ 0.03	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,909.72	$ 2,720.92	$ 2,614.28	$ 3,103.64	$ 2,347.81	$ 3,089.86
Per Total kWh Delivered	$ 0.14	$ 0.13	$ 0.10	$ 0.13	$ 0.13	$ 0.14
OM&A per Customer	$ 365.17	$ 233.81	$ 356.56	$ 262.20	$ 218.43	$ 319.80
Net Income (Loss) Per Customer	$ 118.66	$ 80.17	$ 70.08	$ 80.21	$ 87.54	$ 96.19
Net Fixed Assets per Customer	$ 2,432.67	$ 1,841.51	$ 2,023.05	$ 2,490.17	$ 1,825.37	$ 2,413.23
Gross Capital Additions for the Year	$ 2,502,246	$ 35,609,719	$ 763,589	$ 11,320,875	$ 9,949,992	$ 15,426,432
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
# of Customers per square km of Service Area	69.43	72.94	214.54	481.19	705.88	502.59
# of Customers per km of Line	27.73	42.01	16.24	36.54	55.56	56.78
Total kWh Delivered (excluding losses)	200,239,261	488,765,497	118,642,423	1,616,484,336	245,835,972	303,694,309
Total kWh Delivered on Long-Term Load Transfer	105,904	-	-	584,121	1,090,987	-
Total Distribution Losses (kWh)	8,861,954	20,222,127	7,470,053	58,366,714	8,908,615	9,815,387
Total kWh Supplied	209,207,120	508,987,624	126,112,476	1,675,435,172	255,835,574	313,509,696
Average Monthly kWh Delivered per Customer	1,807.08	1,692.17	1,645.89	1,957.67	1,707.19	1,864.99
Average Peak (kW) per Customer	3.74	3.29	3.33	4.16	3.44	3.64
Distribution Revenue:						
Per Customer Annually	$ 521.00	$ 481.56	$ 474.17	$ 586.73	$ 410.62	$ 592.53
Per Total kWh Delivered	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,846.31	$ 2,608.33	$ 2,656.97	$ 2,805.88	$ 2,772.80	$ 2,925.92
Per Total kWh Delivered	$ 0.13	$ 0.13	$ 0.13	$ 0.12	$ 0.14	$ 0.13
OM&A per Customer	$ 277.67	$ 241.69	$ 417.52	$ 261.30	$ 276.85	$ 376.83
Net Income (Loss) Per Customer	$ 109.27	$ 159.59	$ 21.66	$ 114.18	$ 61.90	$ 114.51
Net Fixed Assets per Customer	$ 2,815.69	$ 2,546.09	$ 1,094.80	$ 2,699.74	$ 1,528.16	$ 2,067.41
Gross Capital Additions for the Year	$ 2,828,580	$ 5,570,545	$ 692,947	$ 20,301,606	$ 1,940,991	$ 5,606,188
High Voltage Capital Additions for the Year	$ 29,230	$ -	$ -	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
# of Customers per square km of Service Area	381.28	314.11	535.49	451.90	97.92	328.85
# of Customers per km of Line	58.57	61.76	64.85	47.07	45.07	53.44
Total kWh Delivered (excluding losses)	1,082,034,739	183,317,003	788,547,109	8,560,551,340	637,462,404	85,946,976
Total kWh Delivered on Long-Term Load Transfer	-	13,754	-	1,853,776	-	-
Total Distribution Losses (kWh)	40,262,979	7,413,149	38,747,872	329,133,720	32,496,057	3,877,222
Total kWh Supplied	1,122,297,718	190,743,906	827,294,981	8,891,538,836	669,958,461	89,824,198
Average Monthly kWh Delivered per Customer	1,587.18	1,389.52	1,796.69	1,957.12	1,586.34	1,675.38
Average Peak (kW) per Customer	3.35	2.74	3.34	4.04	2.99	2.96
Distribution Revenue:						
Per Customer Annually	$ 393.60	$ 449.65	$ 395.69	$ 477.11	$ 466.29	$ 444.97
Per Total kWh Delivered	$ 0.02	$ 0.03	$ 0.02	$ 0.02	$ 0.02	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,455.42	$ 2,256.79	$ 2,831.65	$ 3,092.86	$ 2,445.71	$ 2,765.11
Per Total kWh Delivered	$ 0.13	$ 0.14	$ 0.13	$ 0.13	$ 0.13	$ 0.14
OM&A per Customer	$ 220.83	$ 266.86	$ 251.79	$ 251.71	$ 339.38	$ 328.03
Net Income (Loss) Per Customer	$ 82.49	$ 7.97	$ 44.04	$ 93.75	$ (9.57)	$ (9.34)
Net Fixed Assets per Customer	$ 1,744.77	$ 949.44	$ 2,107.97	$ 3,537.58	$ 2,614.91	$ 1,283.32
Gross Capital Additions for the Year	$ 10,425,039	$ 1,201,956	$ 5,766,000	$ 127,384,901	$ 5,988,626	$ 437,215
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ 1,845,965	$ 275,737	$ -

Unitized Statistics & Other For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
# of Customers per square km of Service Area	326.39	5.21	525.15	131.19	295.63	1,209.40
# of Customers per km of Line	54.91	10.15	71.26	42.73	52.95	26.64
Total kWh Delivered (excluding losses)	101,138,049	70,815,698	280,422,538	891,818,402	195,433,356	24,871,542,388
Total kWh Delivered on Long-Term Load Transfer	572,969	388,755	161,856	360,373	158,899	4,893,827
Total Distribution Losses (kWh)	4,417,808	4,310,715	10,365,277	41,487,455	6,092,966	711,475,515
Total kWh Supplied	106,128,826	75,515,168	290,949,671	933,666,230	201,685,221	25,587,911,729
Average Monthly kWh Delivered per Customer	1,434.58	2,115.16	1,355.01	1,463.85	2,295.44	2,720.27
Average Peak (kW) per Customer	3.12	4.51	2.72	2.35	4.51	5.20
Distribution Revenue:						
Per Customer Annually	$ 411.44	$ 667.85	$ 428.31	$ 390.17	$ 480.64	$ 914.18
Per Total kWh Delivered	$ 0.02	$ 0.03	$ 0.03	$ 0.02	$ 0.02	$ 0.03
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,464.15	$ 3,092.67	$ 2,150.15	$ 2,299.71	$ 3,681.52	$ 4,186.08
Per Total kWh Delivered	$ 0.14	$ 0.12	$ 0.13	$ 0.13	$ 0.13	$ 0.13
OM&A per Customer	$ 362.59	$ 549.11	$ 257.43	$ 305.11	$ 384.07	$ 323.66
Net Income (Loss) Per Customer	$ 15.67	$ 55.67	$ 88.97	$ 13.04	$ 68.10	$ 233.29
Net Fixed Assets per Customer	$ 997.61	$ 1,819.83	$ 1,617.19	$ 2,037.87	$ 1,480.01	$ 5,360.59
Gross Capital Additions for the Year	$ 480,494	$ 330,619	$ 2,554,843	$ 12,182,464	$ 840,760	$ 617,138,762
High Voltage Capital Additions for the Year	$ -	$ -	$ -	$ -	$ -	$ 53,844,210

Unitized Statistics & Other For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
# of Customers per square km of Service Area	187.06	218.79	83.68	281.82	267.07	478.63
# of Customers per km of Line	46.49	46.18	34.73	47.61	47.33	62.77
Total kWh Delivered (excluding losses)	2,581,082,371	127,620,360	1,438,016,300	363,388,436	102,633,741	135,692,714
Total kWh Delivered on Long-Term Load Transfer	369,875	259,933	2,642,605	240,000	33,435	-
Total Distribution Losses (kWh)	107,236,778	5,860,502	53,476,871	17,192,001	6,445,259	4,367,963
Total kWh Supplied	2,688,689,024	133,740,795	1,494,135,776	380,820,437	109,112,435	140,060,677
Average Monthly kWh Delivered per Customer	1,799.42	796.87	2,131.15	1,325.09	2,287.46	2,953.18
Average Peak (kW) per Customer	3.45	1.77	4.27	2.69	4.25	6.39
Distribution Revenue:						
Per Customer Annually	$ 435.21	$ 295.83	$ 603.00	$ 397.33	$ 692.32	$ 609.07
Per Total kWh Delivered	$ 0.02	$ 0.03	$ 0.02	$ 0.02	$ 0.03	$ 0.02
Average Cost of Power & Related Costs:						
Per Customer Annually	$ 2,698.30	$ 1,267.71	$ 3,315.56	$ 2,119.34	$ 3,362.30	$ 2,943.74
Per Total kWh Delivered	$ 0.12	$ 0.13	$ 0.13	$ 0.13	$ 0.12	$ 0.08
OM&A per Customer	$ 229.61	$ 228.90	$ 236.41	$ 295.05	$ 470.06	$ 478.96
Net Income (Loss) Per Customer	$ 92.47	$ 40.17	$ 159.77	$ 43.24	$ 113.31	$ 37.76
Net Fixed Assets per Customer	$ 2,114.37	$ 909.15	$ 3,644.49	$ 1,286.24	$ 2,475.36	$ 2,438.14
Gross Capital Additions for the Year	$ 31,485,138	$ 1,473,765	$ 44,797,283	$ 3,044,430	$ 1,545,545	$ 1,228,091
High Voltage Capital Additions for the Year	$ -	$ -	$ 457,468	$ -	$ -	$ -

Unitized Statistics & Other For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation
# of Customers per square km of Service Area	362.00	284.99
# of Customers per km of Line	43.71	38.52
Total kWh Delivered (excluding losses)	423,340,221	871,712,971
Total kWh Delivered on Long-Term Load Transfer	2,530,476	-
Total Distribution Losses (kWh)	17,049,299	33,257,324
Total kWh Supplied	442,919,996	904,970,295
Average Monthly kWh Delivered per Customer	1,522.72	1,722.29
Average Peak (kW) per Customer	2.93	3.52
Distribution Revenue:		
Per Customer Annually	$ 411.30	$ 523.19
Per Total kWh Delivered	$ 0.02	$ 0.03
Average Cost of Power & Related Costs:		
Per Customer Annually	$ 2,483.10	$ 2,744.99
Per Total kWh Delivered	$ 0.14	$ 0.13
OM&A per Customer	$ 249.61	$ 281.21
Net Income (Loss) Per Customer	$ 83.77	$ 86.27
Net Fixed Assets per Customer	$ 2,310.37	$ 2,167.65
Gross Capital Additions for the Year	$ 5,740,396	$ 11,862,259
High Voltage Capital Additions for the Year	$ -	$ -

Statistics by Customer Class For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Residential Customers						
Number of Customers	11,665	1,392	32,491	36,155	60,468	26,092
Metered kWh	107,099,604	8,885,318	254,829,615	291,366,741	543,441,721	202,182,964
Distribution Revenue	$ 18,520,573	$ 712,183	$ 11,984,269	$ 9,644,695	$ 17,965,126	$ 10,502,846
Metered kWh per Customer	9,181	6,383	7,843	8,059	8,987	7,749
Distribution Revenue per Customer	$ 1,588	$ 512	$ 369	$ 267	$ 297	$ 403
General Service <50kW Customers						
Number of Customers	-	229	3,472	2,793	5,323	2,512
Metered kWh	-	4,951,711	103,858,081	99,430,250	168,159,643	69,095,397
Distribution Revenue	$ -	$ 258,788	$ 3,194,181	$ 1,582,551	$ 3,930,051	$ 2,448,265
Metered kWh per Customer	-	21,623	29,913	35,600	31,591	27,506
Distribution Revenue per Customer	-	$ 1,130	$ 920	$ 567	$ 738	$ 975
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	42	18	388	457	1,033	204
Number of Large Users	-	-	4	-	-	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	89,578,886	21,235,005	646,118,361	508,048,388	913,512,381	191,444,613
Distribution Revenue	$ 4,045,308	$ 225,843	$ 5,568,801	$ 5,008,034	$ 7,319,540	$ 4,223,543
Metered kWh per Customer	2,132,831	1,179,723	1,648,261	1,111,703	884,330	938,454
Distribution Revenue per Customer	$ 96,317	$ 12,547	$ 14,206	$ 10,958	$ 7,086	$ 20,704
Unmetered Scattered Load Connections						
Number of Connections	-	-	259	424	575	47
Metered kWh	-	-	2,221,667	1,510,794	3,115,068	1,416,419
Distribution Revenue	$ -	$ -	$ 111,582	$ 78,520	$ 111,960	$ 51,870
Metered kWh per Connection	-	-	8,578	3,563	5,418	30,137
Distribution Revenue per Connection	$ -	$ -	$ 431	$ 185	$ 195	$ 1,104

Statistics by Customer Class For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Residential Customers						
Number of Customers	6,006	1,072	14,984	1,965	10,312	56,989
Metered kWh	44,896,468	12,612,066	117,557,987	19,268,403	91,479,319	478,112,746
Distribution Revenue	$ 1,790,890	$ 493,867	$ 4,352,029	$ 630,448	$ 2,173,572	$ 16,495,528
Metered kWh per Customer	7,475	11,765	7,846	9,806	8,871	8,390
Distribution Revenue per Customer	$ 298	$ 461	$ 290	$ 321	$ 211	$ 289
General Service <50kW Customers						
Number of Customers	743	162	1,753	161	1,381	6,297
Metered kWh	23,270,826	4,617,295	45,960,686	4,547,781	28,315,731	195,299,824
Distribution Revenue	$ 664,555	$ 149,134	$ 1,083,497	$ 100,327	$ 392,925	$ 4,059,569
Metered kWh per Customer	31,320	28,502	26,218	28,247	20,504	31,015
Distribution Revenue per Customer	$ 894	$ 921	$ 618	$ 623	$ 285	$ 645
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	49	13	127	11	101	835
Number of Large Users	-	-	-	-	-	2
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	71,875,959	7,048,334	132,829,263	4,242,389	59,051,959	1,012,472,362
Distribution Revenue	$ 609,200	$ 97,684	$ 1,057,977	$ 69,667	$ 464,986	$ 11,317,022
Metered kWh per Customer	1,466,856	542,180	1,045,900	385,672	584,673	1,209,644
Distribution Revenue per Customer	$ 12,433	$ 7,514	$ 8,331	$ 6,333	$ 4,604	$ 13,521
Unmetered Scattered Load Connections						
Number of Connections	13	4	30	17	30	507
Metered kWh	562,067	2,892	398,421	93,284	257,059	2,363,434
Distribution Revenue	$ 6,407	$ 1,318	$ 4,895	$ 4,821	$ 2,810	$ 64,700
Metered kWh per Connection	43,236	723	13,281	5,487	8,569	4,662
Distribution Revenue per Connection	$ 493	$ 329	$ 163	$ 284	$ 94	$ 128

Statistics by Customer Class For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Residential Customers						
Number of Customers	182,224	36,478	79,048	16,671	2,861	27,131
Metered kWh	1,532,961,312	285,956,608	613,583,705	135,812,999	29,369,657	255,480,799
Distribution Revenue	$ 52,677,044	$ 10,654,471	$ 24,593,913	$ 5,896,553	$ 1,029,988	$ 8,394,579
Metered kWh per Customer	8,413	7,839	7,762	8,147	10,266	9,417
Distribution Revenue per Customer	$ 289	$ 292	$ 311	$ 354	$ 360	$ 309
General Service <50kW Customers						
Number of Customers	18,025	3,907	7,590	1,806	393	1,944
Metered kWh	665,390,670	112,755,324	206,455,878	47,996,002	10,089,635	67,091,686
Distribution Revenue	$ 18,121,760	$ 2,702,561	$ 6,348,450	$ 1,216,304	$ 327,422	$ 1,795,691
Metered kWh per Customer	36,915	28,860	27,201	26,576	25,673	34,512
Distribution Revenue per Customer	$ 1,005	$ 692	$ 836	$ 673	$ 833	$ 924
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	4,470	446	1,254	159	29	252
Number of Large Users	9	2	9	1	-	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	5,102,244,791	491,272,889	1,621,377,687	275,776,454	16,330,523	181,081,118
Distribution Revenue	$ 57,233,853	$ 4,465,763	$ 19,330,955	$ 2,079,008	$ 224,257	$ 1,603,629
Metered kWh per Customer	1,139,148	1,096,591	1,283,751	1,723,603	563,121	718,576
Distribution Revenue per Customer	$ 12,778	$ 9,968	$ 15,306	$ 12,994	$ 7,733	$ 6,364
Unmetered Scattered Load Connections						
Number of Connections	3,098	264	782	109	21	132
Metered kWh	11,246,375	1,254,321	2,415,557	514,359	123,304	1,551,291
Distribution Revenue	$ 512,569	$ 31,126	$ 90,363	$ 60,766	$ 5,464	$ 59,476
Metered kWh per Connection	3,630	4,751	3,089	4,719	5,872	11,752
Distribution Revenue per Connection	$ 165	$ 118	$ 116	$ 557	$ 260	$ 451

Statistics by Customer Class For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Residential Customers						
Number of Customers	18,534	3,269	42,800	10,285	49,793	20,057
Metered kWh	139,158,722	34,444,297	364,828,776	95,863,366	372,118,500	204,439,774
Distribution Revenue	$ 6,055,766	$ 1,209,303	$ 13,448,829	$ 3,197,935	$ 17,769,203	$ 6,041,377
Metered kWh per Customer	7,508	10,537	8,524	9,321	7,473	10,193
Distribution Revenue per Customer	$ 327	$ 370	$ 314	$ 311	$ 357	$ 301
General Service <50kW Customers						
Number of Customers	2,072	430	4,047	773	4,033	1,844
Metered kWh	63,059,837	13,758,092	135,269,773	18,979,203	138,048,218	51,296,823
Distribution Revenue	$ 1,806,887	$ 350,725	$ 3,816,342	$ 524,025	$ 2,658,409	$ 1,068,922
Metered kWh per Customer	30,434	31,996	33,425	24,553	34,230	27,818
Distribution Revenue per Customer	$ 872	$ 816	$ 943	$ 678	$ 659	$ 580
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	218	47	515	111	583	211
Number of Large Users	1	-	-	-	5	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	401,825,944	23,072,741	347,751,693	65,267,801	1,152,706,989	244,482,430
Distribution Revenue	$ 2,785,619	$ 219,364	$ 4,668,664	$ 614,122	$ 8,866,420	$ 2,389,596
Metered kWh per Customer	1,834,822	490,909	675,246	587,998	1,960,386	1,158,685
Distribution Revenue per Customer	$ 12,720	$ 4,667	$ 9,065	$ 5,533	$ 15,079	$ 11,325
Unmetered Scattered Load Connections						
Number of Connections	228	7	310	68	559	148
Metered kWh	665,566	62,628	1,218,851	344,840	1,915,482	924,057
Distribution Revenue	$ 28,261	$ 3,348	$ 41,060	$ 22,001	$ 885	$ 17,361
Metered kWh per Connection	2,919	8,947	3,932	5,071	3,427	6,244
Distribution Revenue per Connection	$ 124	$ 478	$ 132	$ 324	$ 2	$ 117

Statistics by Customer Class For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
Residential Customers						
Number of Customers	2,257	223,311	1,163	4,834	146,977	1,186,723
Metered kWh	22,545,902	1,647,803,823	14,332,616	48,033,529	1,311,941,173	11,401,376,627
Distribution Revenue	$ 685,660	$ 70,238,545	$ 379,350	$ 934,066	$ 41,228,816	$ 842,556,561
Metered kWh per Customer	9,989	7,379	12,324	9,937	8,926	9,607
Distribution Revenue per Customer	$ 304	$ 315	$ 326	$ 193	$ 281	$ 710
General Service <50kW Customers						
Number of Customers	402	18,774	152	610	9,989	111,671
Metered kWh	10,266,660	595,148,676	4,021,303	18,569,273	337,681,262	2,897,880,948
Distribution Revenue	$ 164,490	$ 15,807,095	$ 76,556	$ 228,261	$ 9,025,273	$ 177,189,355
Metered kWh per Customer	25,539	31,701	26,456	30,441	33,805	25,950
Distribution Revenue per Customer	$ 409	$ 842	$ 504	$ 374	$ 904	$ 1,587
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	45	2,017	12	87	1,658	8,571
Number of Large Users	-	12	-	-	6	-
Number of Sub Transmission Customers	-	-	-	-	-	579
Metered kWh	46,043,732	3,125,838,538	6,215,533	73,896,610	2,335,191,800	7,115,271,024
Distribution Revenue	$ 183,121	$ 23,823,899	$ 30,314	$ 398,853	$ 19,350,983	$ 166,298,669
Metered kWh per Customer	1,023,194	1,540,581	517,961	849,386	1,403,360	777,625
Distribution Revenue per Customer	$ 4,069	$ 11,742	$ 2,526	$ 4,585	$ 11,629	$ 18,175
Unmetered Scattered Load Connections						
Number of Connections	-	3,019	4	9	1,470	5,605
Metered kWh	-	11,571,072	18,625	293,553	5,837,113	30,026,117
Distribution Revenue	$ -	$ 459,741	$ 1,654	$ 1,750	$ 143,503	$ 3,418,812
Metered kWh per Connection	-	3,833	4,656	32,617	3,971	5,357
Distribution Revenue per Connection	$ -	$ 152	$ 413	$ 194	$ 98	$ 610

Statistics by Customer Class For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Residential Customers						
Number of Customers	299,909	15,344	4,753	24,258	85,248	9,001
Metered kWh	2,260,335,626	150,148,943	34,713,385	181,817,508	650,672,520	72,513,063
Distribution Revenue	$ 90,945,757	$ 7,415,034	$ 1,643,711	$ 7,389,244	$ 22,168,556	$ 2,223,077
Metered kWh per Customer	7,537	9,786	7,303	7,495	7,633	8,056
Distribution Revenue per Customer	$ 303	$ 483	$ 346	$ 305	$ 260	$ 247
General Service <50kW Customers						
Number of Customers	24,689	1,022	751	2,956	7,875	1,085
Metered kWh	733,311,565	33,474,909	22,083,795	88,264,843	239,091,361	31,677,494
Distribution Revenue	$ 21,249,335	$ 778,473	$ 478,924	$ 1,954,461	$ 5,660,242	$ 584,314
Metered kWh per Customer	29,702	32,754	29,406	29,860	30,361	29,196
Distribution Revenue per Customer	$ 861	$ 762	$ 638	$ 661	$ 719	$ 539
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	3,271	77	59	324	934	128
Number of Large Users	11	-	-	3	1	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	4,353,357,101	58,067,105	39,102,762	421,854,909	855,847,546	131,522,771
Distribution Revenue	$ 50,854,279	$ 681,659	$ 547,503	$ 2,883,506	$ 11,814,486	$ 1,218,099
Metered kWh per Customer	1,326,434	754,118	662,759	1,290,076	915,345	1,027,522
Distribution Revenue per Customer	$ 15,495	$ 8,853	$ 9,280	$ 8,818	$ 12,636	$ 9,516
Unmetered Scattered Load Connections						
Number of Connections	3,424	73	33	143	884	84
Metered kWh	15,659,015	461,652	165,231	1,196,380	3,917,912	611,896
Distribution Revenue	$ 534,169	$ 19,585	$ 6,209	$ 26,612	$ 129,648	$ 37,086
Metered kWh per Connection	4,573	6,324	5,007	8,366	4,432	7,284
Distribution Revenue per Connection	$ 156	$ 268	$ 188	$ 186	$ 147	$ 442

Statistics by Customer Class For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Residential Customers						
Number of Customers	11,119	141,323	6,347	33,867	31,945	48,400
Metered kWh	104,359,023	1,090,996,379	47,860,194	309,700,786	267,952,620	438,510,555
Distribution Revenue	$ 4,703,088	$ 40,858,603	$ 2,208,904	$ 10,878,467	$ 9,988,381	$ 18,312,456
Metered kWh per Customer	9,386	7,720	7,541	9,145	8,388	9,060
Distribution Revenue per Customer	$ 423	$ 289	$ 348	$ 321	$ 313	$ 378
General Service <50kW Customers						
Number of Customers	2,138	12,556	775	2,629	3,147	4,457
Metered kWh	58,168,178	393,919,990	23,415,877	88,447,665	87,282,578	129,793,775
Distribution Revenue	$ 1,746,905	$ 9,372,618	$ 612,765	$ 2,062,522	$ 2,915,449	$ 3,791,810
Metered kWh per Customer	27,207	31,373	30,214	33,643	27,735	29,121
Distribution Revenue per Customer	$ 817	$ 746	$ 791	$ 785	$ 926	$ 851
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	149	1,616	109	319	373	760
Number of Large Users	-	1	-	3	-	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	116,625,513	1,663,524,402	117,301,496	468,350,335	275,397,097	641,153,142
Distribution Revenue	$ 1,306,489	$ 13,494,828	$ 891,093	$ 3,035,232	$ 3,522,675	$ 5,837,488
Metered kWh per Customer	782,722	1,028,772	1,076,161	1,454,504	738,330	843,623
Distribution Revenue per Customer	$ 8,768	$ 8,346	$ 8,175	$ 9,426	$ 9,444	$ 7,681
Unmetered Scattered Load Connections						
Number of Connections	51	1,513	11	177	51	343
Metered kWh	166,068	5,610,879	394,107	1,113,107	275,297	1,544,838
Distribution Revenue	$ 18,533	$ 130,195	$ 5,685	$ 38,773	$ 16,161	$ 112,853
Metered kWh per Connection	3,256	3,708	35,828	6,289	5,398	4,504
Distribution Revenue per Connection	$ 363	$ 86	$ 517	$ 219	$ 317	$ 329

Statistics by Customer Class For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Residential Customers						
Number of Customers	7,772	21,152	5,208	62,501	10,730	12,028
Metered kWh	72,859,329	188,194,721	38,772,515	589,977,048	84,770,868	104,895,361
Distribution Revenue	$ 2,597,709	$ 6,786,340	$ 1,978,828	$ 22,050,627	$ 3,200,973	$ 4,241,282
Metered kWh per Customer	9,375	8,897	7,445	9,439	7,900	8,721
Distribution Revenue per Customer	$ 334	$ 321	$ 380	$ 353	$ 298	$ 353
General Service <50kW Customers						
Number of Customers	1,333	2,658	739	5,371	1,129	1,382
Metered kWh	42,806,409	80,643,104	18,349,612	167,865,347	33,991,437	43,617,289
Distribution Revenue	$ 1,114,648	$ 2,190,672	$ 538,234	$ 5,213,440	$ 765,543	$ 1,474,918
Metered kWh per Customer	32,113	30,340	24,830	31,254	30,108	31,561
Distribution Revenue per Customer	$ 836	$ 824	$ 728	$ 971	$ 678	$ 1,067
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	129	260	60	938	141	160
Number of Large Users	-	-	-	-	-	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	83,544,376	217,685,948	60,749,110	790,077,961	124,528,148	151,514,078
Distribution Revenue	$ 835,662	$ 2,123,836	$ 318,399	$ 11,214,005	$ 888,196	$ 1,968,354
Metered kWh per Customer	647,631	837,254	1,012,485	842,301	883,178	946,963
Distribution Revenue per Customer	$ 6,478	$ 8,169	$ 5,307	$ 11,955	$ 6,299	$ 12,302
Unmetered Scattered Load Connections						
Number of Connections	16	10	23	721	97	155
Metered kWh	178,578	42,934	164,178	4,283,631	353,441	781,133
Distribution Revenue	$ 2,134	$ 1,140	$ 6,653	$ 128,014	$ 10,939	$ 26,946
Metered kWh per Connection	11,161	4,293	7,138	5,941	3,644	5,040
Distribution Revenue per Connection	$ 133	$ 114	$ 289	$ 178	$ 113	$ 174

Statistics by Customer Class For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Residential Customers						
Number of Customers	52,273	9,550	32,763	325,741	29,708	3,780
Metered kWh	477,527,824	76,635,115	278,770,514	2,770,663,828	288,746,486	28,890,618
Distribution Revenue	$ 13,910,954	$ 3,106,428	$ 8,562,034	$ 94,817,968	$ 8,618,244	$ 1,075,053
Metered kWh per Customer	9,135	8,025	8,509	8,506	9,719	7,643
Distribution Revenue per Customer	$ 266	$ 325	$ 261	$ 291	$ 290	$ 284
General Service <50kW Customers						
Number of Customers	4,006	1,294	3,446	32,397	3,419	435
Metered kWh	131,950,149	29,514,061	115,273,707	1,035,123,196	92,174,996	10,820,876
Distribution Revenue	$ 2,858,102	$ 794,802	$ 2,310,358	$ 26,744,524	$ 2,537,821	$ 335,318
Metered kWh per Customer	32,938	22,808	33,451	31,951	26,960	24,876
Distribution Revenue per Customer	$ 713	$ 614	$ 670	$ 826	$ 742	$ 771
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	531	150	363	6,365	360	60
Number of Large Users	1	-	2	2	-	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	462,053,610	75,048,053	385,902,454	4,676,013,730	249,955,178	44,950,585
Distribution Revenue	$ 4,846,763	$ 904,233	$ 2,925,668	$ 49,436,391	$ 3,820,742	$ 408,150
Metered kWh per Customer	868,522	500,320	1,057,267	734,414	694,320	749,176
Distribution Revenue per Customer	$ 9,110	$ 6,028	$ 8,016	$ 7,764	$ 10,613	$ 6,802
Unmetered Scattered Load Connections						
Number of Connections	248	76	394	2,962	22	34
Metered kWh	819,338	594,265	1,880,868	13,630,753	1,489,410	157,514
Distribution Revenue	$ 59,603	$ 3,480	$ 63,164	$ 495,833	$ 30,762	$ 19,014
Metered kWh per Connection	3,304	7,819	4,774	4,602	67,700	4,633
Distribution Revenue per Connection	$ 240	$ 46	$ 160	$ 167	$ 1,398	$ 559

Statistics by Customer Class For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Residential Customers						
Number of Customers	5,071	2,348	15,389	45,602	6,346	679,897
Metered kWh	40,480,043	32,665,847	119,226,547	315,500,353	50,190,739	5,120,156,929
Distribution Revenue	$ 1,412,658	$ 1,156,021	$ 4,778,177	$ 11,554,176	$ 2,086,550	$ 290,080,095
Metered kWh per Customer	7,983	13,912	7,748	6,919	7,909	7,531
Distribution Revenue per Customer	$ 279	$ 492	$ 310	$ 253	$ 329	$ 427
General Service <50kW Customers						
Number of Customers	740	394	1,722	4,679	656	71,207
Metered kWh	20,348,623	11,845,216	39,742,886	134,542,473	21,213,828	2,355,601,175
Distribution Revenue	$ 466,732	$ 297,450	$ 1,149,851	$ 3,454,045	$ 575,388	$ 104,447,353
Metered kWh per Customer	27,498	30,064	23,079	28,755	32,338	33,081
Distribution Revenue per Customer	$ 631	$ 755	$ 668	$ 738	$ 877	$ 1,467
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	64	48	135	488	93	10,770
Number of Large Users	-	-	-	-	-	46
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	39,456,019	26,402,621	119,273,335	431,629,177	122,177,874	17,234,879,511
Distribution Revenue	$ 419,957	$ 311,730	$ 1,239,355	$ 4,377,434	$ 759,903	$ 285,425,094
Metered kWh per Customer	616,500	550,055	883,506	884,486	1,313,741	1,593,461
Distribution Revenue per Customer	$ 6,562	$ 6,494	$ 9,180	$ 8,970	$ 8,171	$ 26,389
Unmetered Scattered Load Connections						
Number of Connections	58	-	-	433	61	12,106
Metered kWh	546,384	-	-	2,189,100	383,453	41,271,781
Distribution Revenue	$ 12,979	$ -	$ -	$ 58,833	$ 10,255	$ 3,202,346
Metered kWh per Connection	9,420	-	-	5,056	6,286	3,409
Distribution Revenue per Connection	$ 224	$ -	$ -	$ 136	$ 168	$ 265

Statistics by Customer Class For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Residential Customers						
Number of Customers	109,483	12,504	49,767	20,907	3,232	3,305
Metered kWh	972,496,268	89,621,851	404,436,334	163,109,690	24,523,575	24,532,826
Distribution Revenue	$ 34,114,331	$ 3,243,252	$ 18,163,057	$ 6,364,943	$ 1,278,073	$ 1,295,565
Metered kWh per Customer	8,883	7,167	8,127	7,802	7,588	7,423
Distribution Revenue per Customer	$ 312	$ 259	$ 365	$ 304	$ 395	$ 392
General Service <50kW Customers						
Number of Customers	8,991	806	5,730	1,783	467	474
Metered kWh	294,898,709	17,228,609	193,116,425	53,545,593	11,967,606	14,633,569
Distribution Revenue	$ 6,710,856	$ 390,939	$ 5,097,846	$ 932,977	$ 444,909	$ 347,401
Metered kWh per Customer	32,799	21,375	33,703	30,031	25,627	30,873
Distribution Revenue per Customer	$ 746	$ 485	$ 890	$ 523	$ 953	$ 733
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	1,056	36	732	163	40	49
Number of Large Users	3	-	1	-	-	1
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	1,288,229,135	19,913,562	796,568,341	143,431,671	65,390,259	96,027,813
Distribution Revenue	$ 10,556,058	$ 252,679	$ 10,442,718	$ 1,509,637	$ 676,773	$ 574,535
Metered kWh per Customer	1,216,458	553,155	1,086,724	879,949	1,634,756	1,920,556
Distribution Revenue per Customer	$ 9,968	$ 7,019	$ 14,247	$ 9,262	$ 16,919	$ 11,491
Unmetered Scattered Load Connections						
Number of Connections	831	32	543	265	2	3
Metered kWh	4,759,713	183,647	2,729,041	976,708	5,184	83,100
Distribution Revenue	$ 151,853	$ 3,263	$ 109,155	$ 45,304	$ 626	$ 8,195
Metered kWh per Connection	5,728	5,739	5,026	3,686	2,592	27,700
Distribution Revenue per Connection	$ 183	$ 102	$ 201	$ 171	$ 313	$ 2,732

Statistics by Customer Class For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation	Total Industry
Residential Customers			
Number of Customers	20,385	39,588	4,612,551
Metered kWh	179,123,216	367,928,949	39,196,063,132
Distribution Revenue	$ 6,104,574	$ 14,508,890	$ 1,988,080,063
Metered kWh per Customer	8,787	9,294	8,498
Distribution Revenue per Customer	$ 299	$ 366	$ 431
General Service <50kW Customers			
Number of Customers	2,550	2,220	437,396
Metered kWh	65,361,600	88,118,791	13,194,493,806
Distribution Revenue	$ 1,472,544	$ 2,575,720	$ 487,542,579
Metered kWh per Customer	25,632	39,693	30,166
Distribution Revenue per Customer	$ 577	$ 1,160	$ 1,115
General Service >50kW, Large User (>5000kW) and Sub Transmission			
Number of GS >50kW Customers	233	370	55,876
Number of Large Users	-	-	126
Number of Sub Transmission Customers	-	-	579
Metered kWh	178,404,939	407,832,343	63,716,850,210
Distribution Revenue	$ 1,477,528	$ 4,488,025	$ 852,863,857
Metered kWh per Customer	765,686	1,102,250	1,126,117
Distribution Revenue per Customer	$ 6,341	$ 12,130	$ 15,073
Unmetered Scattered Load Connections			
Number of Connections	56	369	44,043
Metered kWh	277,132	1,759,728	192,581,612
Distribution Revenue	$ 9,695	$ 99,913	$ 10,972,634
Metered kWh per Connection	4,949	4,769	4,373
Distribution Revenue per Connection	$ 173	$ 271	$ 249

Service Quality Requirements For the year ended December 31	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brantford Power Inc.	Burlington Hydro Inc.	Canadian Niagara Power Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	99.40	100.00	98.30	99.70	96.70	91.10
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	N/A	N/A	100.00	N/A	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	86.60	100.00	69.10	67.10	74.70	75.70
Appointments Met *(OEB Min. Standard: 90%)*	100.00	N/A	99.60	99.80	100.00	100.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	99.30	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	N/A	100.00	100.00	100.00	95.90	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	100.00	N/A	100.00	N/A	95.90	100.00
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	3.80	-	4.80	5.10	6.40	5.30
Appointments Scheduling *(OEB Min. Standard: 90%)*	98.20	100.00	99.60	100.00	100.00	100.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	N/A	N/A	100.00	100.00	N/A	N/A
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	100.00	100.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	N/A	96.43	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.85	99.98	99.96	99.89	99.97	99.81
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	6.22	7.01	1.75	0.65	1.26	5.71
SAIFI *(Average number of times power interrupted)*	3.85	1.22	2.68	1.93	0.73	4.03
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	5.46	1.01	1.38	0.60	0.98	3.47
SAIFI *(Average number of times power interrupted)*	2.57	0.22	1.38	1.49	0.60	2.29
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	5.46	1.01	1.38	0.45	0.98	3.47
SAIFI *(Average number of times power interrupted)*	2.57	0.22	1.38	1.24	0.60	2.29

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	COLLUS PowerStream Corp.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Energy+ Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	99.30	100.00	100.00	100.00	93.90	100.00
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	N/A	100.00	N/A	N/A	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	99.30	100.00	68.90	95.20	97.20	71.50
Appointments Met *(OEB Min. Standard: 90%)*	98.90	100.00	100.00	100.00	98.90	100.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	100.00	95.30	100.00	97.90	99.70
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	N/A	N/A	100.00	100.00	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	N/A	N/A	100.00	N/A	100.00
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	-	N/A	0.30	4.80	0.10	5.00
Appointments Scheduling *(OEB Min. Standard: 90%)*	99.30	100.00	100.00	100.00	96.30	97.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	N/A	N/A	N/A	100.00	N/A
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	97.50	100.00	98.10	100.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	N/A	100.00	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.99	99.99	99.96	99.74	99.97	99.98
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	3.83	16.48	5.96	25.11	0.42	1.93
SAIFI *(Average number of times power interrupted)*	1.69	2.88	2.06	5.25	0.17	2.02
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.10	1.82	5.41	0.04	0.25	1.84
SAIFI *(Average number of times power interrupted)*	0.11	0.63	1.66	0.23	0.09	1.98
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.10	1.82	1.54	0.04	0.25	0.63
SAIFI *(Average number of times power interrupted)*	0.11	0.63	0.84	0.23	0.09	1.27

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Enersource Hydro Mississauga Inc.	Entegrus Powerlines Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	99.40	98.80	100.00	99.60	100.00	90.50
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	100.00	N/A	N/A	N/A	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	83.40	68.70	70.70	98.40	76.20	73.60
Appointments Met *(OEB Min. Standard: 90%)*	99.90	97.80	100.00	100.00	100.00	90.80
Written Response to Enquiries *(OEB Min. Standard: 80%)*	99.40	99.60	100.00	100.00	98.00	96.30
Emergency Urban Response *(OEB Min. Standard: 80%)*	98.70	93.80	100.00	100.00	N/A	97.70
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	1.80	2.00	3.80	1.60	4.00	0.80
Appointments Scheduling *(OEB Min. Standard: 90%)*	97.80	100.00	100.00	99.20	97.10	98.80
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	N/A	N/A	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	99.40	100.00	100.00	100.00	100.00	97.50
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	99.17	100.00	100.00	100.00	100.00	94.74
Billing Accuracy *(OEB Min. Standard: 98%)*	99.54	99.84	99.99	99.50	99.95	99.90
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	0.81	1.00	0.97	3.96	10.43	2.54
SAIFI *(Average number of times power interrupted)*	1.13	0.68	2.12	1.13	4.62	3.20
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.77	0.51	0.64	1.88	2.13	0.63
SAIFI *(Average number of times power interrupted)*	1.02	0.41	1.47	0.47	1.89	0.50
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.77	0.51	0.64	1.46	0.55	0.63
SAIFI *(Average number of times power interrupted)*	1.02	0.41	1.47	0.24	1.10	0.50

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Halton Hills Hydro Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	99.70	100.00	99.40	98.60	99.50	100.00
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	N/A	N/A	N/A	100.00	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	87.00	97.70	66.90	70.00	86.70	94.40
Appointments Met *(OEB Min. Standard: 90%)*	100.00	98.90	100.00	100.00	99.70	100.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	100.00	99.10	100.00	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	100.00	88.90	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	N/A	N/A	100.00	N/A	100.00
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	0.80	1.50	2.70	4.20	5.00	1.40
Appointments Scheduling *(OEB Min. Standard: 90%)*	99.50	100.00	98.80	100.00	98.90	100.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	N/A	N/A	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	99.70	100.00	100.00	100.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	N/A	100.00	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.97	98.26	99.92	99.98	99.95	99.84
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	3.94	6.27	1.29	1.19	1.08	3.48
SAIFI *(Average number of times power interrupted)*	1.73	3.37	0.91	1.41	2.19	3.22
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.32	0.33	1.19	0.55	0.79	3.11
SAIFI *(Average number of times power interrupted)*	0.93	0.35	0.87	0.69	1.41	2.77
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.32	0.33	1.19	0.55	0.71	1.38
SAIFI *(Average number of times power interrupted)*	0.93	0.35	0.87	0.69	1.34	1.65

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.
<u>Service Quality Requirements</u>						
Low Voltage Connections *(OEB Min. Standard: 90%)*	100.00	99.70	100.00	100.00	99.80	98.60
High Voltage Connections *(OEB Min. Standard: 90%)*	100.00	100.00	100.00	N/A	100.00	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	87.30	82.20	99.70	100.00	82.30	74.20
Appointments Met *(OEB Min. Standard: 90%)*	100.00	99.30	98.80	95.20	99.90	99.50
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	99.50	100.00	99.60	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	93.10	100.00	100.00	100.00	N/A
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	N/A	N/A	N/A	N/A	75.30
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	N/A	1.30	N/A	-	1.50	2.70
Appointments Scheduling *(OEB Min. Standard: 90%)*	100.00	96.60	100.00	98.30	97.20	99.50
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	N/A	100.00	100.00	100.00	100.00	98.50
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	N/A	100.00	100.00	98.50
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	N/A	100.00	N/A	N/A	100.00	99.22
Billing Accuracy *(OEB Min. Standard: 98%)*	99.91	99.90	99.93	99.99	99.64	99.04
<u>System Reliability Indicators</u>						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	3.28	1.64	0.01	7.65	0.45	13.19
SAIFI *(Average number of times power interrupted)*	1.73	1.98	0.16	1.82	0.72	3.41
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.19	1.23	-	1.39	0.41	12.57
SAIFI *(Average number of times power interrupted)*	1.27	1.62	-	0.60	0.69	2.92
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.19	1.10	-	1.39	0.41	7.83
SAIFI *(Average number of times power interrupted)*	1.27	1.57	-	0.60	0.69	2.47

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Hydro Ottawa Limited	Innpower Corporation	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	100.00	94.80	100.00	100.00	92.50	98.50
High Voltage Connections *(OEB Min. Standard: 90%)*	100.00	N/A	N/A	100.00	100.00	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	83.80	80.10	99.00	66.00	78.40	91.20
Appointments Met *(OEB Min. Standard: 90%)*	99.60	95.60	99.10	97.90	97.50	99.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	99.10	100.00	100.00	99.90	87.80
Emergency Urban Response *(OEB Min. Standard: 80%)*	97.80	N/A	N/A	100.00	80.80	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	100.00	N/A	N/A	94.70	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	1.80	9.30	0.10	3.60	4.20	0.60
Appointments Scheduling *(OEB Min. Standard: 90%)*	100.00	94.90	99.60	95.60	96.40	96.20
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	100.00	100.00	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	99.40	100.00	99.70	100.00	95.70
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	100.00	100.00	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.90	97.97	99.94	99.75	100.00	99.89
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	1.21	16.30	3.53	1.88	2.70	0.67
SAIFI *(Average number of times power interrupted)*	0.95	3.57	2.43	0.97	1.81	0.37
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.13	16.30	0.59	1.32	2.69	0.67
SAIFI *(Average number of times power interrupted)*	0.78	3.57	0.43	0.59	1.72	0.37
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.00	1.12	0.59	1.32	1.11	0.67
SAIFI *(Average number of times power interrupted)*	0.74	1.35	0.43	0.59	1.11	0.37

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Lakeland Power Distribution Ltd.	London Hydro Inc.	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	99.20	96.60	100.00	99.60	100.00	92.70
High Voltage Connections *(OEB Min. Standard: 90%)*	100.00	100.00	N/A	N/A	N/A	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	90.60	67.00	99.90	96.70	81.80	83.00
Appointments Met *(OEB Min. Standard: 90%)*	98.60	99.90	99.40	100.00	99.80	99.80
Written Response to Enquiries *(OEB Min. Standard: 80%)*	95.90	100.00	100.00	100.00	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	97.30	100.00	100.00	96.40	97.10
Emergency Rural Response *(OEB Min. Standard: 80%)*	100.00	N/A	N/A	100.00	N/A	93.50
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	2.00	3.10	N/A	1.60	1.50	0.90
Appointments Scheduling *(OEB Min. Standard: 90%)*	99.80	98.80	94.40	100.00	100.00	100.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	100.00	N/A	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	99.20	98.90	100.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	91.43	N/A	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.86	99.71	75.61	99.99	99.99	99.74
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	7.21	0.99	6.58	0.81	1.14	1.69
SAIFI *(Average number of times power interrupted)*	2.66	1.24	1.89	0.72	1.04	1.41
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.01	0.97	3.23	0.74	1.05	1.52
SAIFI *(Average number of times power interrupted)*	0.73	1.03	1.27	0.59	1.02	1.38
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.01	0.97	0.68	0.74	0.42	1.52
SAIFI *(Average number of times power interrupted)*	0.73	1.03	0.70	0.59	0.57	1.38

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Niagara-on-the-Lake Hydro Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	98.90	100.00	100.00	81.20	100.00	100.00
High Voltage Connections *(OEB Min. Standard: 90%)*	100.00	100.00	100.00	N/A	N/A	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	86.20	83.60	100.00	72.80	99.50	96.60
Appointments Met *(OEB Min. Standard: 90%)*	99.50	99.90	100.00	100.00	99.80	100.00
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	86.10	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	N/A	100.00	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	100.00	100.00	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	0.40	6.10	N/A	2.70	0.40	0.10
Appointments Scheduling *(OEB Min. Standard: 90%)*	100.00	100.00	100.00	100.00	100.00	97.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	N/A	N/A	100.00	N/A
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	98.20	99.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	100.00	N/A	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.83	99.70	99.87	99.92	99.96	99.98
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	0.34	2.37	4.50	0.50	1.57	0.53
SAIFI *(Average number of times power interrupted)*	1.03	2.01	2.65	0.90	1.32	1.39
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.34	2.29	3.46	0.50	0.69	0.52
SAIFI *(Average number of times power interrupted)*	1.03	1.98	1.90	0.90	1.12	1.10
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	0.34	2.29	3.46	0.50	0.69	0.52
SAIFI *(Average number of times power interrupted)*	1.03	1.98	1.90	0.90	1.12	1.10

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Peterborough Distribution Incorporated	PowerStream Inc.	PUC Distribution Inc.	Renfrew Hydro Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	92.60	100.00	97.00	99.50	98.90	100.00
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	N/A	100.00	100.00	100.00	N/A
Telephone Accessibility *(OEB Min. Standard: 65%)*	73.70	99.90	84.60	75.90	81.30	91.90
Appointments Met *(OEB Min. Standard: 90%)*	100.00	100.00	99.60	99.20	98.30	95.70
Written Response to Enquiries *(OEB Min. Standard: 80%)*	99.50	100.00	100.00	99.60	99.20	99.40
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	96.10	89.80	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	100.00	100.00	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	1.30	-	1.30	1.30	1.50	-
Appointments Scheduling *(OEB Min. Standard: 90%)*	100.00	99.60	93.60	100.00	98.50	98.40
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	N/A	N/A	100.00	100.00	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	100.00	100.00	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	100.00	N/A	85.00	92.26	N/A	N/A
Billing Accuracy *(OEB Min. Standard: 98%)*	99.94	99.99	99.78	99.15	99.97	99.43
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	2.61	3.36	2.21	2.74	2.53	0.34
SAIFI *(Average number of times power interrupted)*	2.08	1.18	2.52	1.41	2.21	0.28
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.61	3.31	2.01	1.93	2.46	0.34
SAIFI *(Average number of times power interrupted)*	2.06	1.15	2.34	1.33	2.11	0.28
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	2.61	1.55	2.01	0.88	1.49	0.34
SAIFI *(Average number of times power interrupted)*	2.06	0.84	2.34	0.93	1.41	0.28

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	100.00	100.00	98.40	100.00	97.60	97.70
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	N/A	N/A	100.00	N/A	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	74.20	94.00	75.80	93.30	64.00	64.70
Appointments Met *(OEB Min. Standard: 90%)*	94.50	91.70	100.00	100.00	98.30	99.50
Written Response to Enquiries *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	100.00	100.00	93.10
Emergency Urban Response *(OEB Min. Standard: 80%)*	100.00	100.00	100.00	95.70	100.00	91.80
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	100.00	N/A	100.00	N/A	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	2.30	2.80	2.10	0.30	8.20	3.10
Appointments Scheduling *(OEB Min. Standard: 90%)*	99.10	93.30	94.30	99.20	98.90	72.00
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	100.00	100.00	N/A	N/A	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	100.00	100.00	100.00	99.70
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	N/A	N/A	100.00	100.00	N/A	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.70	99.84	99.95	99.81	98.91	98.86
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	2.46	25.28	1.07	1.78	6.41	0.95
SAIFI *(Average number of times power interrupted)*	1.05	5.18	1.75	2.95	3.11	1.40
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.01	1.74	1.04	1.69	2.09	0.91
SAIFI *(Average number of times power interrupted)*	0.38	1.18	1.49	2.70	1.11	1.28
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.01	0.67	1.04	1.69	1.42	0.91
SAIFI *(Average number of times power interrupted)*	0.38	0.57	1.49	2.70	0.77	1.28

N/A - Denominator is zero.

Service Quality Requirements For the year ended December 31	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	West Coast Huron Energy Inc.
Service Quality Requirements						
Low Voltage Connections *(OEB Min. Standard: 90%)*	98.10	100.00	100.00	100.00	100.00	100.00
High Voltage Connections *(OEB Min. Standard: 90%)*	100.00	N/A	100.00	N/A	N/A	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	76.20	100.00	86.70	98.60	99.90	98.50
Appointments Met *(OEB Min. Standard: 90%)*	100.00	100.00	98.10	98.50	99.00	97.70
Written Response to Enquiries *(OEB Min. Standard: 80%)*	99.80	97.30	100.00	100.00	100.00	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	96.30	100.00	100.00	100.00	100.00	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	100.00	N/A	100.00	N/A	N/A	N/A
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	2.40	N/A	4.60	1.00	-	1.20
Appointments Scheduling *(OEB Min. Standard: 90%)*	93.40	100.00	99.90	99.70	99.70	95.20
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	N/A	N/A	100.00	100.00	100.00	100.00
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	100.00	100.00	99.80	100.00	100.00
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	97.37	100.00	100.00	100.00	100.00	100.00
Billing Accuracy *(OEB Min. Standard: 98%)*	99.85	99.84	99.73	99.99	99.47	99.81
System Reliability Indicators						
Total Outages						
SAIDI *(Average number of hours power interrupted)*	1.97	2.86	2.86	0.83	5.05	8.65
SAIFI *(Average number of times power interrupted)*	1.97	2.57	2.99	1.27	3.01	2.06
Loss of Supply Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.24	2.71	2.60	0.63	0.69	0.15
SAIFI *(Average number of times power interrupted)*	1.29	2.54	2.63	0.72	0.28	0.06
Loss of Supply and Major Event Adjusted						
SAIDI *(Average number of hours power interrupted)*	1.24	1.11	0.71	0.63	0.34	0.15
SAIFI *(Average number of times power interrupted)*	1.29	1.35	1.15	0.72	0.20	0.06

N/A - Denominator is zero.

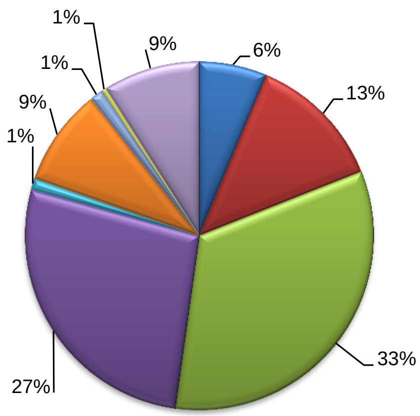
Service Quality Requirements For the year ended December 31	Westario Power Inc.	Whitby Hydro Electric Corporation
Service Quality Requirements		
Low Voltage Connections *(OEB Min. Standard: 90%)*	92.10	95.10
High Voltage Connections *(OEB Min. Standard: 90%)*	N/A	100.00
Telephone Accessibility *(OEB Min. Standard: 65%)*	82.90	80.60
Appointments Met *(OEB Min. Standard: 90%)*	100.00	99.60
Written Response to Enquiries *(OEB Min. Standard: 80%)*	96.40	100.00
Emergency Urban Response *(OEB Min. Standard: 80%)*	57.10	100.00
Emergency Rural Response *(OEB Min. Standard: 80%)*	N/A	100.00
Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)*	1.60	1.10
Appointments Scheduling *(OEB Min. Standard: 90%)*	99.70	96.70
Rescheduling a Missed Appointment *(OEB Standard: 100%)*	N/A	-
Reconnection Performance Standards *(OEB Min. Standard: 85%)*	100.00	99.50
New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)*	N/A	78.95
Billing Accuracy *(OEB Min. Standard: 98%)*	99.96	99.81
System Reliability Indicators		
Total Outages		
SAIDI *(Average number of hours power interrupted)*	5.97	0.99
SAIFI *(Average number of times power interrupted)*	1.67	1.23
Loss of Supply Adjusted		
SAIDI *(Average number of hours power interrupted)*	2.41	0.99
SAIFI *(Average number of times power interrupted)*	0.63	1.23
Loss of Supply and Major Event Adjusted		
SAIDI *(Average number of hours power interrupted)*	2.41	0.99
SAIFI *(Average number of times power interrupted)*	0.63	1.23

N/A - Denominator is zero.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

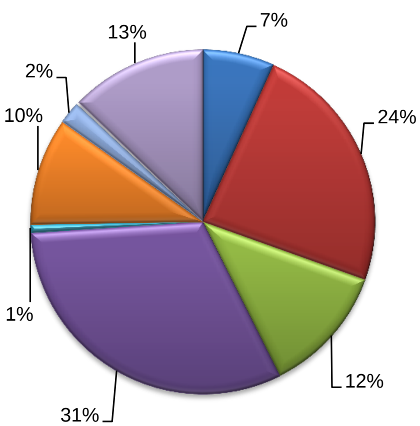
Algoma Power Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,839	-
1 - Scheduled Outage	5,715	-
2 - Loss of Supply	14,968	-
3 - Tree Contacts	12,186	-
4 - Lightning	477	-
5 - Defective Equipment	4,057	-
6 - Adverse Weather	580	-
7 - Adverse Environment	12	-
8 - Human Element	171	-
9 - Foreign Interference	4,038	-
Total	**45,043**	**-**

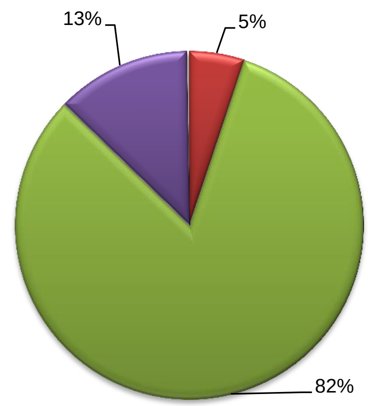
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	4,911	-
1 - Scheduled Outage	17,252	-
2 - Loss of Supply	8,827	-
3 - Tree Contacts	22,817	-
4 - Lightning	564	-
5 - Defective Equipment	7,317	-
6 - Adverse Weather	1,538	-
7 - Adverse Environment	10	-
8 - Human Element	160	-
9 - Foreign Interference	9,324	-
Total	**72,720**	**-**

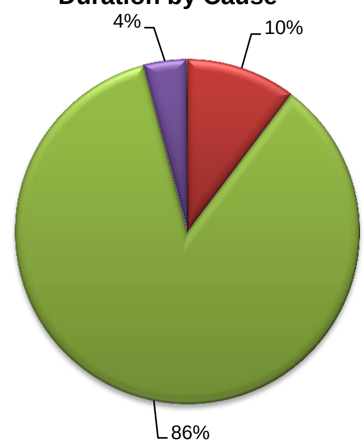
Atikokan Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	102	-
2 - Loss of Supply	1,650	1,650
3 - Tree Contacts	250	-
4 - Lightning	1	-
5 - Defective Equipment	3	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	2	-
9 - Foreign Interference	-	-
Total	**2,008**	**1,650**

Duration by Cause



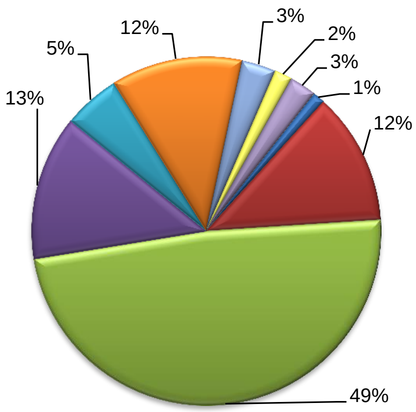
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	1,189	-
2 - Loss of Supply	9,900	9,900
3 - Tree Contacts	460	-
4 - Lightning	2	-
5 - Defective Equipment	7	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	4	-
9 - Foreign Interference	-	-
Total	**11,562**	**9,900**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

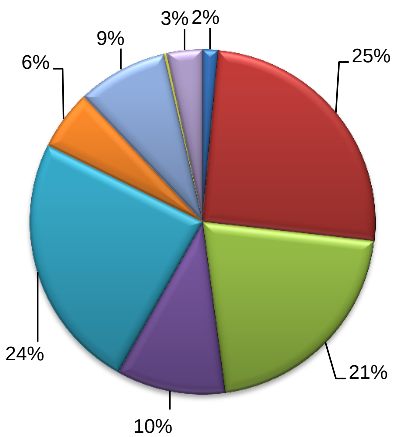
Bluewater Power Distribution Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,100	-
1 - Scheduled Outage	11,926	-
2 - Loss of Supply	47,055	-
3 - Tree Contacts	13,016	-
4 - Lightning	5,123	-
5 - Defective Equipment	11,819	-
6 - Adverse Weather	3,048	-
7 - Adverse Environment	-	-
8 - Human Element	1,595	-
9 - Foreign Interference	2,385	-
Total	**97,067**	**-**

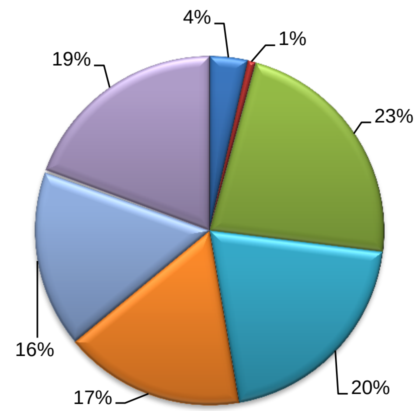
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	938	-
1 - Scheduled Outage	16,090	-
2 - Loss of Supply	13,420	-
3 - Tree Contacts	6,518	-
4 - Lightning	15,367	-
5 - Defective Equipment	3,587	-
6 - Adverse Weather	5,375	-
7 - Adverse Environment	-	-
8 - Human Element	187	-
9 - Foreign Interference	2,102	-
Total	**63,583**	**-**

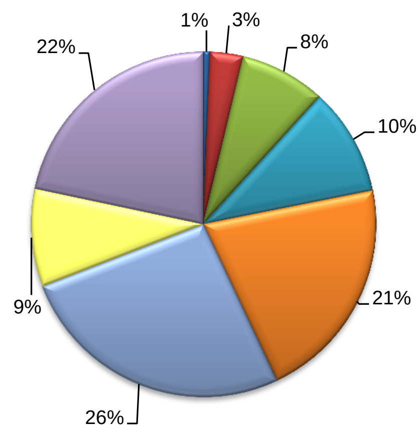
Brantford Power Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,679	-
1 - Scheduled Outage	564	-
2 - Loss of Supply	17,173	-
3 - Tree Contacts	-	-
4 - Lightning	15,407	-
5 - Defective Equipment	12,676	-
6 - Adverse Weather	12,404	9,999
7 - Adverse Environment	-	-
8 - Human Element	194	-
9 - Foreign Interference	14,660	-
Total	**75,757**	**9,999**

Duration by Cause



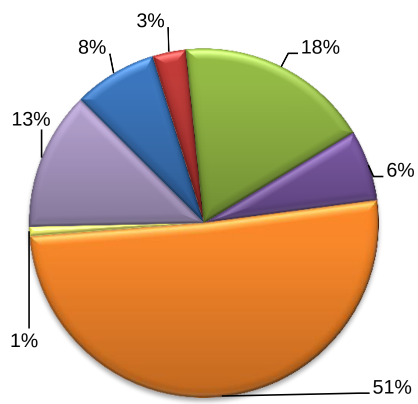
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	152	-
1 - Scheduled Outage	794	-
2 - Loss of Supply	2,049	-
3 - Tree Contacts	-	-
4 - Lightning	2,565	-
5 - Defective Equipment	5,367	-
6 - Adverse Weather	6,653	5,847
7 - Adverse Environment	-	-
8 - Human Element	2,328	-
9 - Foreign Interference	5,511	-
Total	**25,419**	**5,847**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

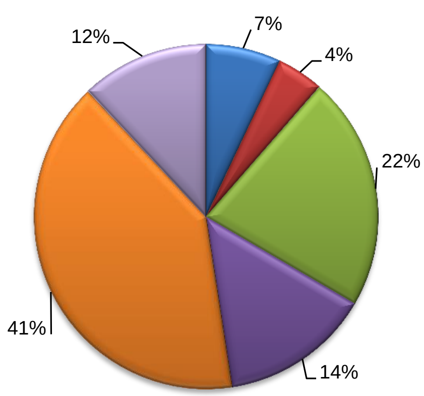
Burlington Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,776	-
1 - Scheduled Outage	1,505	-
2 - Loss of Supply	8,758	-
3 - Tree Contacts	3,202	-
4 - Lightning	-	-
5 - Defective Equipment	24,754	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	425	-
9 - Foreign Interference	6,247	-
Total	**48,667**	**-**

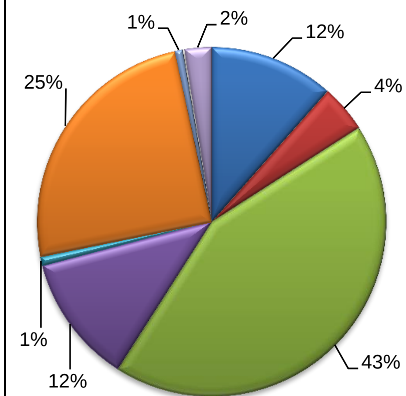
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	5,928	-
1 - Scheduled Outage	3,681	-
2 - Loss of Supply	18,471	-
3 - Tree Contacts	11,894	-
4 - Lightning	-	-
5 - Defective Equipment	33,936	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	53	-
9 - Foreign Interference	10,074	-
Total	**84,037**	**-**

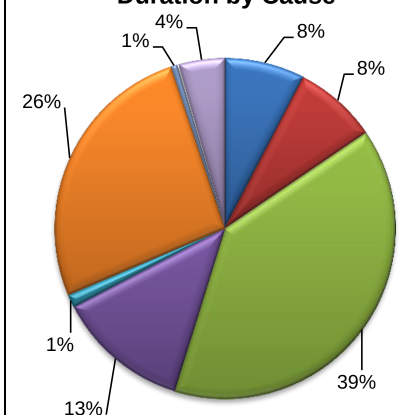
Canadian Niagara Power Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	13,418	-
1 - Scheduled Outage	5,117	-
2 - Loss of Supply	50,042	-
3 - Tree Contacts	13,873	-
4 - Lightning	985	-
5 - Defective Equipment	28,843	-
6 - Adverse Weather	847	-
7 - Adverse Environment	35	-
8 - Human Element	109	-
9 - Foreign Interference	2,903	-
Total	**116,172**	**-**

Duration by Cause



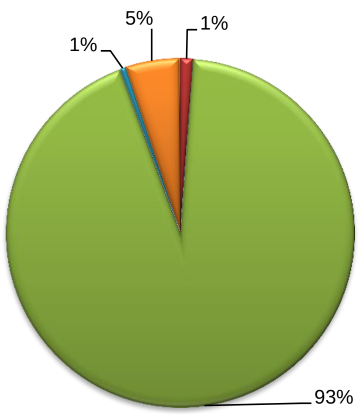
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	12,495	-
1 - Scheduled Outage	13,019	-
2 - Loss of Supply	64,792	-
3 - Tree Contacts	20,766	-
4 - Lightning	2,013	-
5 - Defective Equipment	43,263	-
6 - Adverse Weather	976	-
7 - Adverse Environment	94	-
8 - Human Element	166	-
9 - Foreign Interference	7,215	-
Total	**164,797**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

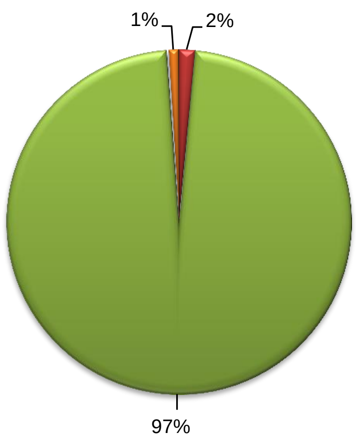
Centre Wellington Hydro Ltd.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	133	-
2 - Loss of Supply	10,757	10,757
3 - Tree Contacts	-	-
4 - Lightning	63	-
5 - Defective Equipment	571	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	14	-
Total	**11,538**	**10,757**

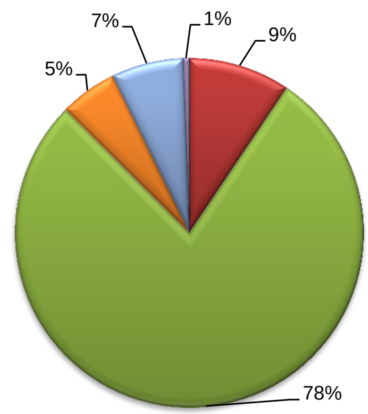
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	383	-
2 - Loss of Supply	25,449	25,449
3 - Tree Contacts	-	-
4 - Lightning	53	-
5 - Defective Equipment	230	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	20	-
Total	**26,135**	**25,449**

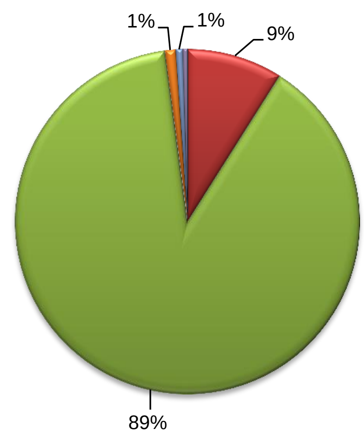
Chapleau Public Utilities Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	339	-
2 - Loss of Supply	2,811	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	191	-
6 - Adverse Weather	240	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	21	-
Total	**3,602**	**-**

Duration by Cause



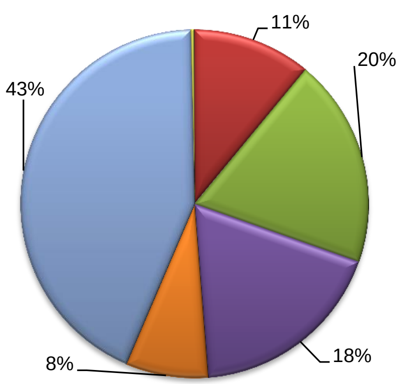
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	1,849	-
2 - Loss of Supply	18,321	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	208	-
6 - Adverse Weather	135	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	86	-
Total	**20,599**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

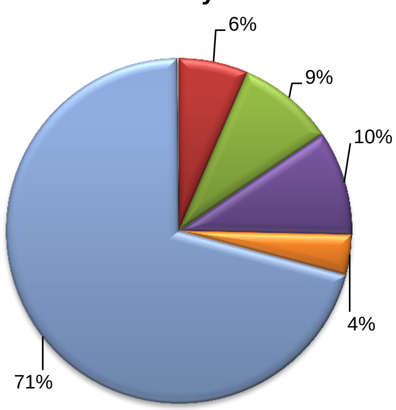
COLLUS PowerStream Corp.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	3,806	-
2 - Loss of Supply	6,718	-
3 - Tree Contacts	6,357	-
4 - Lightning	-	-
5 - Defective Equipment	2,657	-
6 - Adverse Weather	14,969	13,813
7 - Adverse Environment	-	-
8 - Human Element	99	-
9 - Foreign Interference	20	-
Total	**34,626**	**13,813**

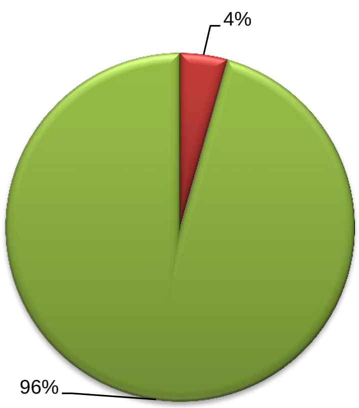
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	6,476	-
2 - Loss of Supply	9,105	-
3 - Tree Contacts	9,769	-
4 - Lightning	-	-
5 - Defective Equipment	3,762	-
6 - Adverse Weather	70,713	65,016
7 - Adverse Environment	-	-
8 - Human Element	84	-
9 - Foreign Interference	83	-
Total	**99,992**	**65,016**

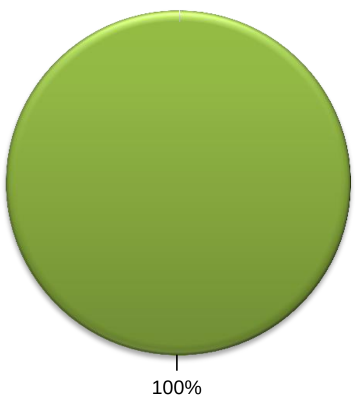
Cooperative Hydro Embrun Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	485	-
2 - Loss of Supply	10,622	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	-	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	-	-
Total	**11,107**	**-**

Duration by Cause



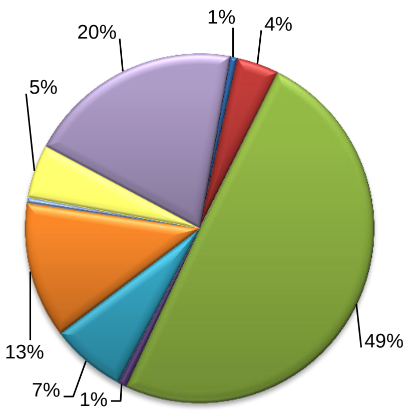
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	88	-
2 - Loss of Supply	53,070	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	-	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	-	-
Total	**53,158**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

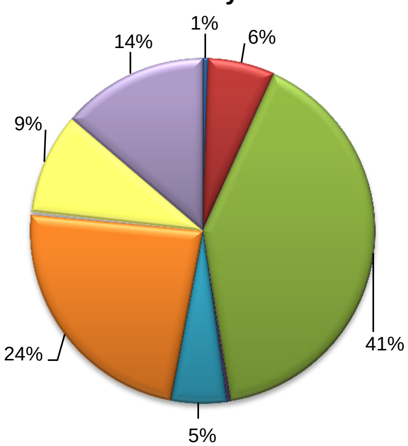
E.L.K. Energy Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	14	-
1 - Scheduled Outage	79	-
2 - Loss of Supply	1,000	-
3 - Tree Contacts	16	-
4 - Lightning	141	-
5 - Defective Equipment	254	-
6 - Adverse Weather	10	-
7 - Adverse Environment	1	-
8 - Human Element	100	-
9 - Foreign Interference	403	-
Total	**2,018**	**-**

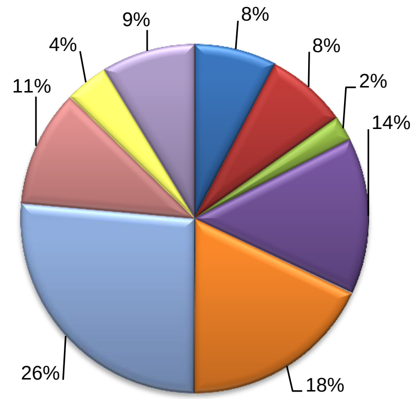
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	24	-
1 - Scheduled Outage	308	-
2 - Loss of Supply	2,000	-
3 - Tree Contacts	17	-
4 - Lightning	257	-
5 - Defective Equipment	1,155	-
6 - Adverse Weather	13	-
7 - Adverse Environment	2	-
8 - Human Element	465	-
9 - Foreign Interference	677	-
Total	**4,918**	**-**

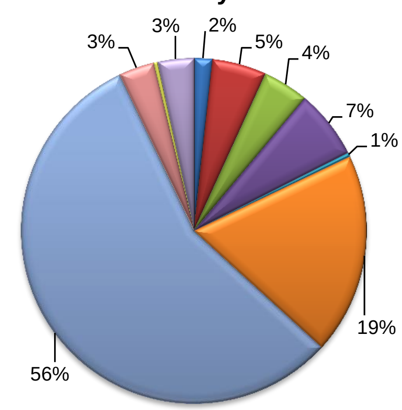
Energy+ Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	9,830	1
1 - Scheduled Outage	9,711	-
2 - Loss of Supply	3,057	-
3 - Tree Contacts	18,594	6,231
4 - Lightning	150	-
5 - Defective Equipment	23,162	8
6 - Adverse Weather	33,928	24,704
7 - Adverse Environment	14,012	14,011
8 - Human Element	5,184	-
9 - Foreign Interference	11,210	-
Total	**128,838**	**44,955**

Duration by Cause



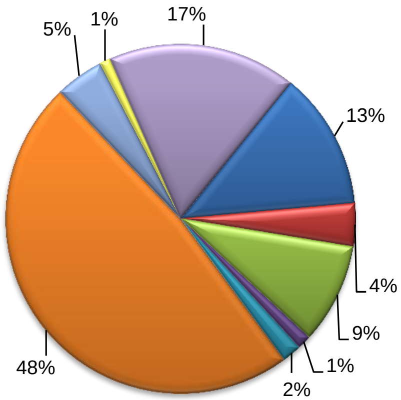
Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	2,110	46
1 - Scheduled Outage	6,218	-
2 - Loss of Supply	5,281	-
3 - Tree Contacts	7,915	5,351
4 - Lightning	474	-
5 - Defective Equipment	23,088	50
6 - Adverse Weather	68,899	67,934
7 - Adverse Environment	4,068	4,065
8 - Human Element	449	-
9 - Foreign Interference	4,127	-
Total	**122,629**	**77,446**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

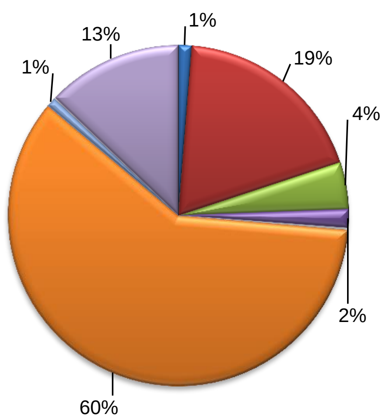
Enersource Hydro Mississauga Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	29,421	-
1 - Scheduled Outage	9,114	-
2 - Loss of Supply	21,398	-
3 - Tree Contacts	2,951	-
4 - Lightning	4,091	-
5 - Defective Equipment	110,651	-
6 - Adverse Weather	10,279	-
7 - Adverse Environment	19	-
8 - Human Element	2,312	-
9 - Foreign Interference	40,135	-
Total	**230,371**	**-**

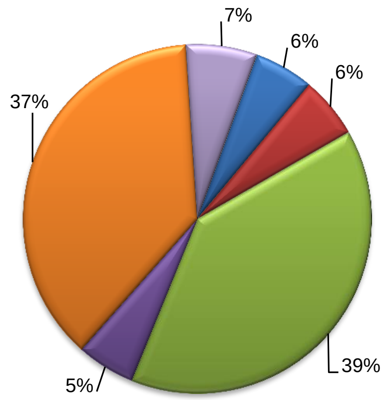
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,106	-
1 - Scheduled Outage	30,940	-
2 - Loss of Supply	7,388	-
3 - Tree Contacts	2,853	-
4 - Lightning	325	-
5 - Defective Equipment	98,945	-
6 - Adverse Weather	1,511	-
7 - Adverse Environment	2	-
8 - Human Element	128	-
9 - Foreign Interference	21,314	-
Total	**165,513**	**-**

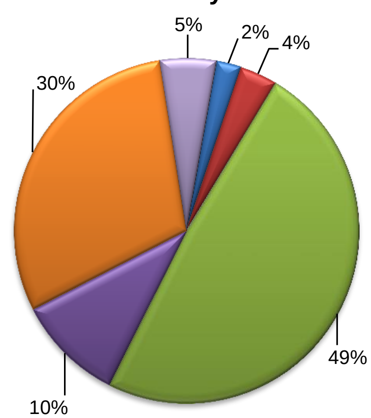
Entegrus Powerlines Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,510	-
1 - Scheduled Outage	1,554	-
2 - Loss of Supply	10,811	-
3 - Tree Contacts	1,484	-
4 - Lightning	-	-
5 - Defective Equipment	10,248	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	1,813	-
Total	**27,420**	**-**

Duration by Cause



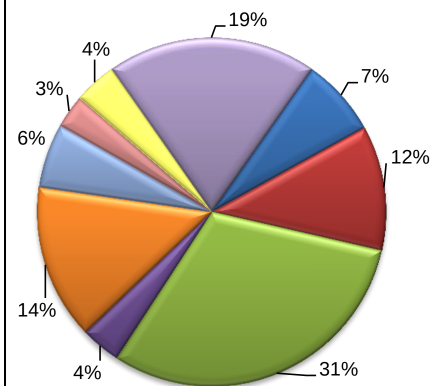
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	937	-
1 - Scheduled Outage	1,414	-
2 - Loss of Supply	19,658	-
3 - Tree Contacts	4,047	-
4 - Lightning	-	-
5 - Defective Equipment	12,113	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	2,118	-
Total	**40,287**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

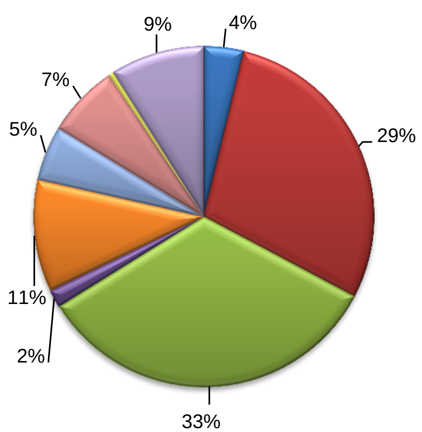
EnWin Utilities Ltd.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	13,545	-
1 - Scheduled Outage	21,524	91
2 - Loss of Supply	56,964	20,550
3 - Tree Contacts	6,834	-
4 - Lightning	-	-
5 - Defective Equipment	26,820	166
6 - Adverse Weather	11,119	-
7 - Adverse Environment	5,736	-
8 - Human Element	7,345	-
9 - Foreign Interference	36,176	-
Total	**186,063**	**20,807**

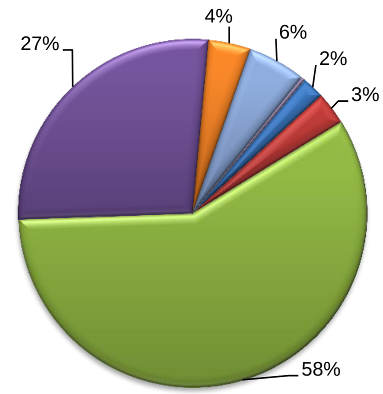
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,216	-
1 - Scheduled Outage	24,632	23
2 - Loss of Supply	28,425	14,008
3 - Tree Contacts	1,421	-
4 - Lightning	-	-
5 - Defective Equipment	9,064	571
6 - Adverse Weather	4,421	-
7 - Adverse Environment	5,892	-
8 - Human Element	383	-
9 - Foreign Interference	7,584	-
Total	**85,037**	**14,601**

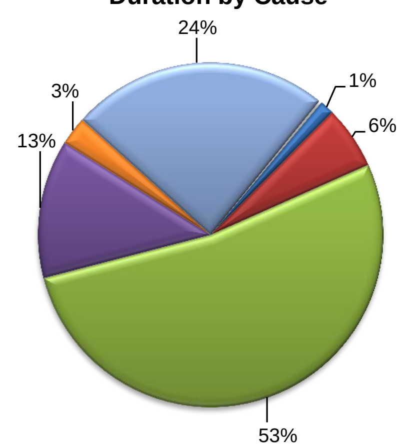
Erie Thames Powerlines Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	448	-
1 - Scheduled Outage	658	-
2 - Loss of Supply	12,562	3,000
3 - Tree Contacts	5,825	4,500
4 - Lightning	-	-
5 - Defective Equipment	846	-
6 - Adverse Weather	1,161	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	77	-
Total	**21,577**	**7,500**

Duration by Cause



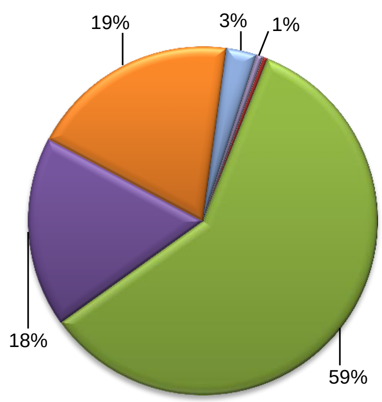
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,011	-
1 - Scheduled Outage	4,472	-
2 - Loss of Supply	39,869	10,550
3 - Tree Contacts	9,851	7,850
4 - Lightning	-	-
5 - Defective Equipment	2,021	-
6 - Adverse Weather	18,338	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	202	-
Total	**75,764**	**18,400**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

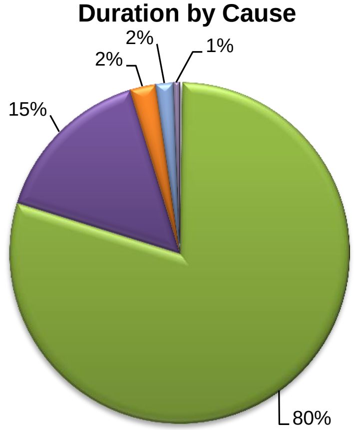
Espanola Regional Hydro Distribution Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	7	-
1 - Scheduled Outage	64	-
2 - Loss of Supply	8,972	3,286
3 - Tree Contacts	2,681	2,593
4 - Lightning	-	-
5 - Defective Equipment	2,941	-
6 - Adverse Weather	423	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	93	-
Total	**15,181**	**5,879**

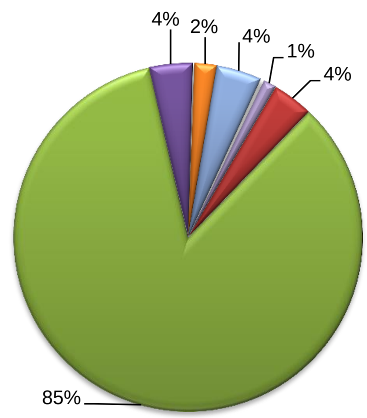
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	9	-
1 - Scheduled Outage	73	-
2 - Loss of Supply	27,256	1,669
3 - Tree Contacts	5,315	5,186
4 - Lightning	-	-
5 - Defective Equipment	846	-
6 - Adverse Weather	568	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	198	-
Total	**34,265**	**6,855**

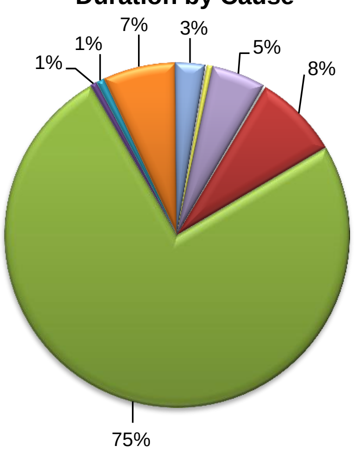
Essex Powerlines Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	59	-
1 - Scheduled Outage	3,514	-
2 - Loss of Supply	78,593	-
3 - Tree Contacts	3,675	-
4 - Lightning	166	-
5 - Defective Equipment	1,919	-
6 - Adverse Weather	3,901	-
7 - Adverse Environment	48	-
8 - Human Element	240	-
9 - Foreign Interference	1,123	-
Total	**93,238**	**-**

Duration by Cause



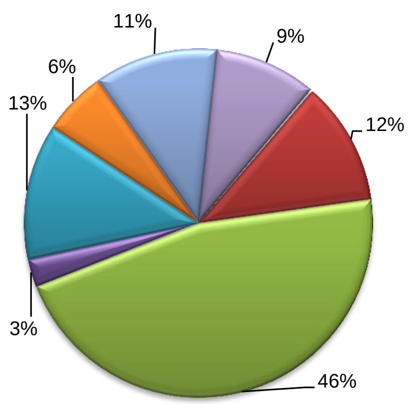
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	187	-
1 - Scheduled Outage	5,853	-
2 - Loss of Supply	55,502	-
3 - Tree Contacts	450	-
4 - Lightning	571	-
5 - Defective Equipment	5,014	-
6 - Adverse Weather	2,032	-
7 - Adverse Environment	102	-
8 - Human Element	429	-
9 - Foreign Interference	3,699	-
Total	**73,838**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

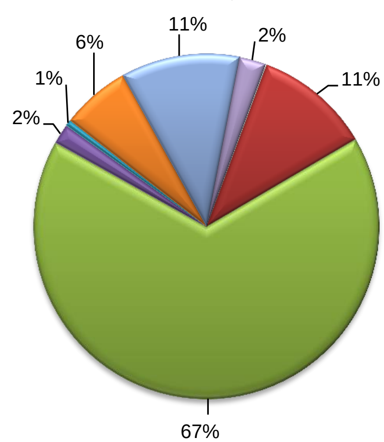
Festival Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	75	-
1 - Scheduled Outage	4,125	-
2 - Loss of Supply	16,620	14,066
3 - Tree Contacts	921	-
4 - Lightning	4,514	-
5 - Defective Equipment	2,144	17
6 - Adverse Weather	4,122	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	3,376	-
Total	**35,897**	**14,083**

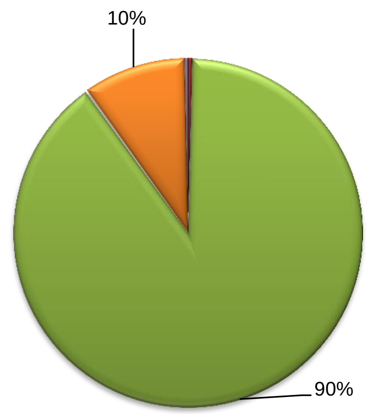
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	93	-
1 - Scheduled Outage	8,905	-
2 - Loss of Supply	54,413	48,120
3 - Tree Contacts	1,501	-
4 - Lightning	483	-
5 - Defective Equipment	5,267	17
6 - Adverse Weather	9,093	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	2,032	-
Total	**81,788**	**48,137**

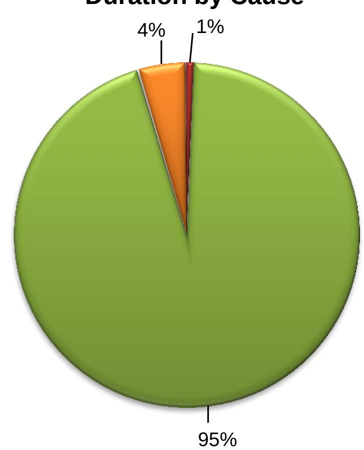
Fort Frances Power Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	48	-
2 - Loss of Supply	11,291	-
3 - Tree Contacts	2	-
4 - Lightning	26	-
5 - Defective Equipment	1,190	-
6 - Adverse Weather	7	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	36	-
Total	**12,600**	**-**

Duration by Cause



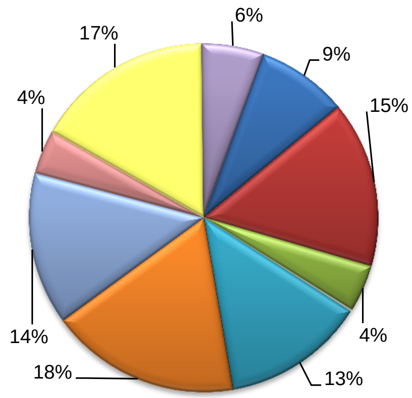
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	148	-
2 - Loss of Supply	22,202	-
3 - Tree Contacts	1	-
4 - Lightning	46	-
5 - Defective Equipment	1,012	-
6 - Adverse Weather	7	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	31	-
Total	**23,448**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

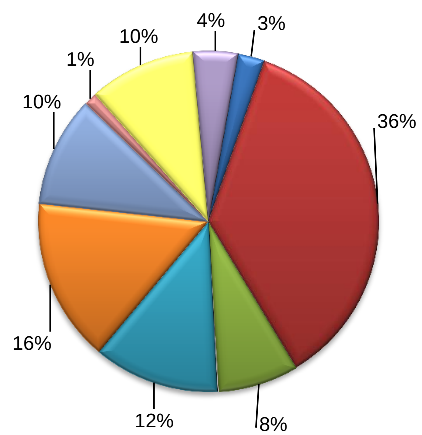
Greater Sudbury Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,685	-
1 - Scheduled Outage	6,701	-
2 - Loss of Supply	1,881	-
3 - Tree Contacts	85	-
4 - Lightning	5,771	-
5 - Defective Equipment	7,649	-
6 - Adverse Weather	6,154	-
7 - Adverse Environment	1,776	-
8 - Human Element	7,206	-
9 - Foreign Interference	2,487	-
Total	**43,395**	**-**

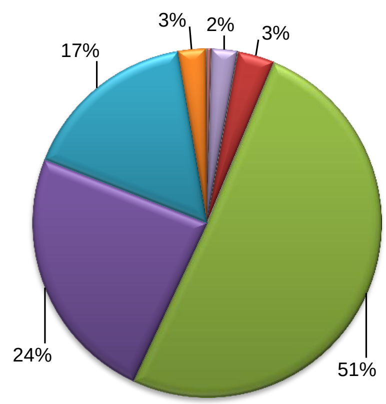
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,567	-
1 - Scheduled Outage	22,221	-
2 - Loss of Supply	4,683	-
3 - Tree Contacts	114	-
4 - Lightning	7,346	-
5 - Defective Equipment	9,587	-
6 - Adverse Weather	6,453	-
7 - Adverse Environment	763	-
8 - Human Element	6,241	-
9 - Foreign Interference	2,606	-
Total	**61,582**	**-**

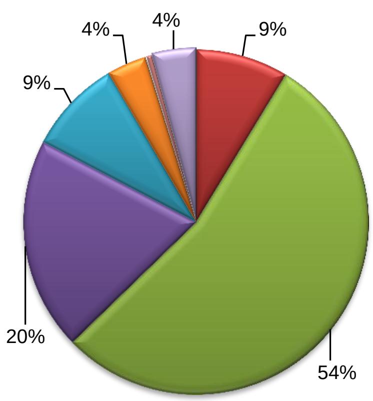
Grimsby Power Incorporated

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	15	-
1 - Scheduled Outage	531	-
2 - Loss of Supply	8,010	-
3 - Tree Contacts	3,785	-
4 - Lightning	2,587	-
5 - Defective Equipment	407	-
6 - Adverse Weather	15	-
7 - Adverse Environment	55	-
8 - Human Element	14	-
9 - Foreign Interference	371	-
Total	**15,790**	**-**

Duration by Cause



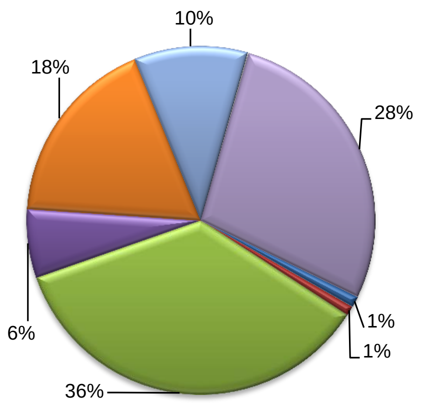
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	10	-
1 - Scheduled Outage	1,148	-
2 - Loss of Supply	7,197	-
3 - Tree Contacts	2,655	-
4 - Lightning	1,184	-
5 - Defective Equipment	492	-
6 - Adverse Weather	17	-
7 - Adverse Environment	66	-
8 - Human Element	1	-
9 - Foreign Interference	548	-
Total	**13,319**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

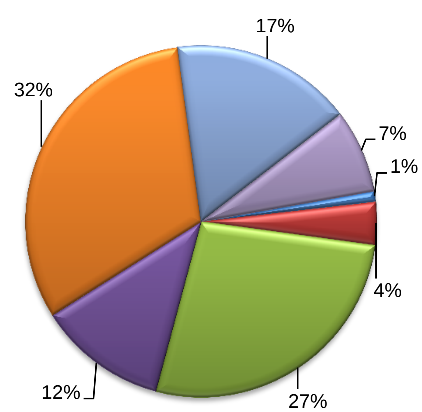
Guelph Hydro Electric Systems Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,190	-
1 - Scheduled Outage	1,071	14
2 - Loss of Supply	42,199	9,125
3 - Tree Contacts	7,559	183
4 - Lightning	3	-
5 - Defective Equipment	21,074	-
6 - Adverse Weather	12,478	3,952
7 - Adverse Environment	2	-
8 - Human Element	128	-
9 - Foreign Interference	32,970	-
Total	**118,674**	**13,274**

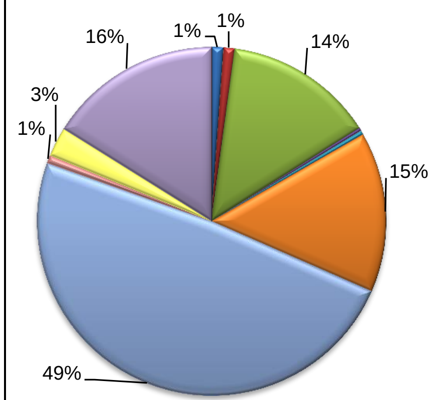
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	569	-
1 - Scheduled Outage	2,309	65
2 - Loss of Supply	15,702	9,308
3 - Tree Contacts	6,910	718
4 - Lightning	5	-
5 - Defective Equipment	18,517	-
6 - Adverse Weather	9,705	3,512
7 - Adverse Environment	5	-
8 - Human Element	19	-
9 - Foreign Interference	4,444	-
Total	**58,186**	**13,602**

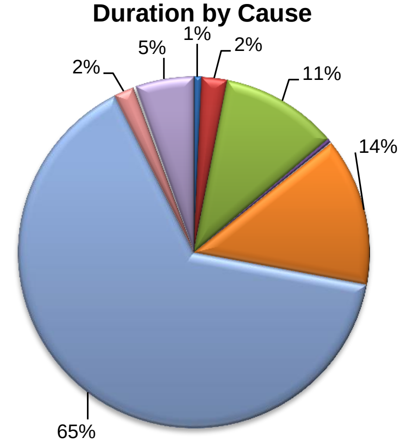
Halton Hills Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	789	-
1 - Scheduled Outage	746	-
2 - Loss of Supply	10,054	-
3 - Tree Contacts	212	-
4 - Lightning	280	-
5 - Defective Equipment	10,740	-
6 - Adverse Weather	35,323	25,217
7 - Adverse Environment	539	-
8 - Human Element	1,974	-
9 - Foreign Interference	11,645	-
Total	**72,302**	**25,217**

Duration by Cause



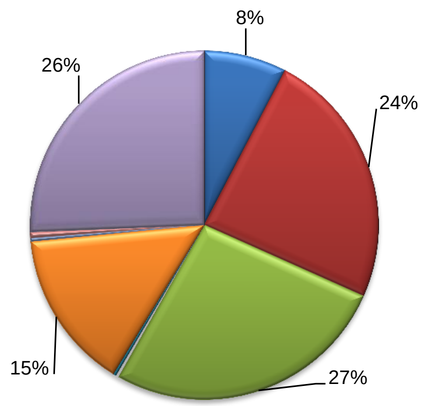
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	553	-
1 - Scheduled Outage	1,839	-
2 - Loss of Supply	8,407	-
3 - Tree Contacts	293	-
4 - Lightning	75	-
5 - Defective Equipment	10,680	-
6 - Adverse Weather	50,561	38,795
7 - Adverse Environment	1,437	-
8 - Human Element	172	-
9 - Foreign Interference	4,190	-
Total	**78,207**	**38,795**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

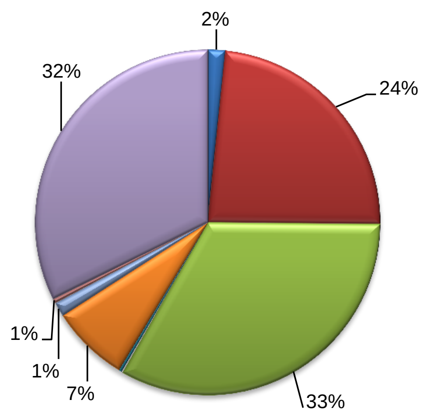
Hearst Power Distribution Company Limited

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	367	-
1 - Scheduled Outage	1,150	-
2 - Loss of Supply	1,271	-
3 - Tree Contacts	11	-
4 - Lightning	15	-
5 - Defective Equipment	707	-
6 - Adverse Weather	17	-
7 - Adverse Environment	25	-
8 - Human Element	-	-
9 - Foreign Interference	1,227	-
Total	**4,790**	**-**

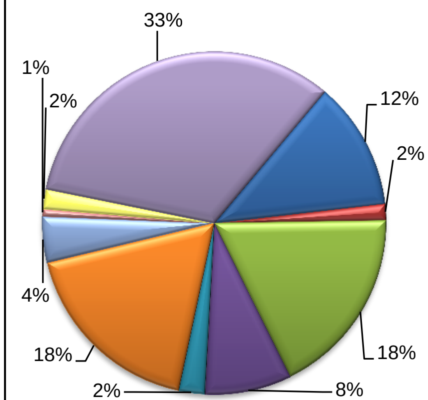
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	149	-
1 - Scheduled Outage	2,133	-
2 - Loss of Supply	2,999	-
3 - Tree Contacts	11	-
4 - Lightning	25	-
5 - Defective Equipment	664	-
6 - Adverse Weather	121	-
7 - Adverse Environment	37	-
8 - Human Element	-	-
9 - Foreign Interference	2,931	-
Total	**9,070**	**-**

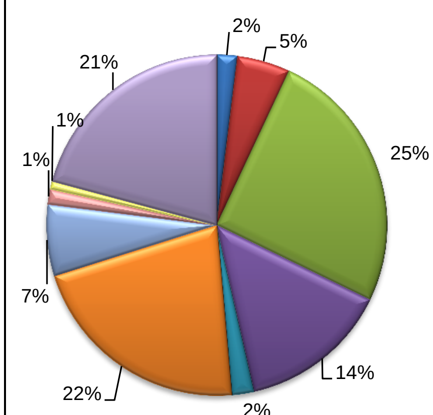
Horizon Utilities Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	58,774	39
1 - Scheduled Outage	7,253	-
2 - Loss of Supply	86,916	283
3 - Tree Contacts	39,589	5,898
4 - Lightning	11,918	-
5 - Defective Equipment	86,784	-
6 - Adverse Weather	20,991	6,595
7 - Adverse Environment	3,371	-
8 - Human Element	9,095	-
9 - Foreign Interference	159,449	-
Total	**484,140**	**12,815**

Duration by Cause



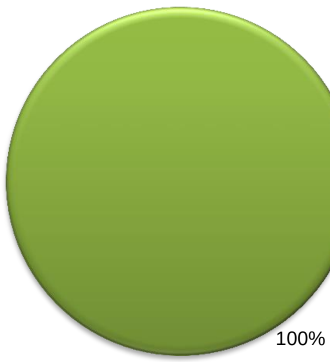
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	7,798	225
1 - Scheduled Outage	20,226	-
2 - Loss of Supply	101,253	1,296
3 - Tree Contacts	57,295	17,496
4 - Lightning	8,530	-
5 - Defective Equipment	86,693	-
6 - Adverse Weather	27,008	12,694
7 - Adverse Environment	5,751	-
8 - Human Element	3,168	-
9 - Foreign Interference	83,674	-
Total	**401,396**	**31,711**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

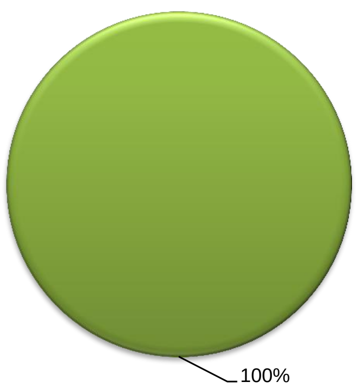
Hydro 2000 Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	-	-
2 - Loss of Supply	195	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	-	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	-	-
Total	**195**	**-**

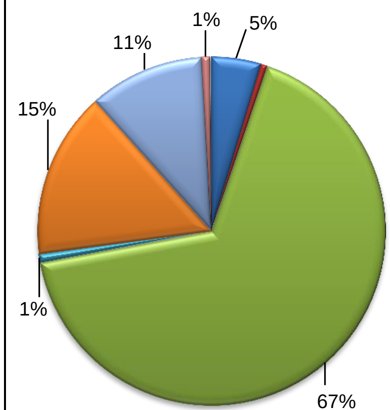
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	-	-
2 - Loss of Supply	18	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	-	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	-	-
Total	**18**	**-**

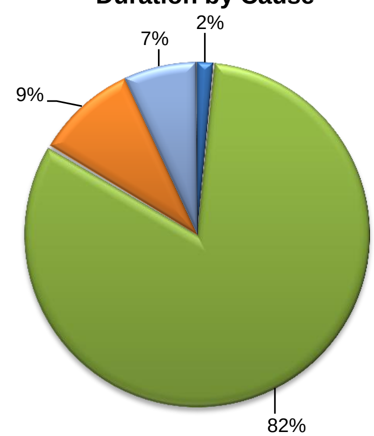
Hydro Hawkesbury Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	466	-
1 - Scheduled Outage	60	-
2 - Loss of Supply	6,751	-
3 - Tree Contacts	-	-
4 - Lightning	81	-
5 - Defective Equipment	1,561	-
6 - Adverse Weather	1,083	-
7 - Adverse Environment	78	-
8 - Human Element	-	-
9 - Foreign Interference	12	-
Total	**10,092**	**-**

Duration by Cause



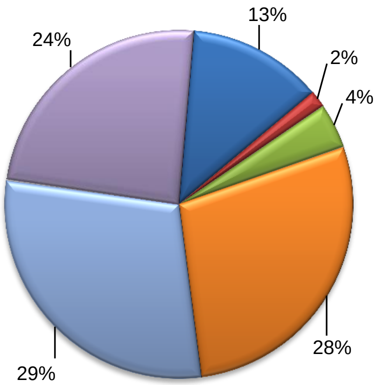
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	621	-
1 - Scheduled Outage	60	-
2 - Loss of Supply	34,655	-
3 - Tree Contacts	-	-
4 - Lightning	108	-
5 - Defective Equipment	3,987	-
6 - Adverse Weather	2,870	-
7 - Adverse Environment	58	-
8 - Human Element	-	-
9 - Foreign Interference	6	-
Total	**42,366**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

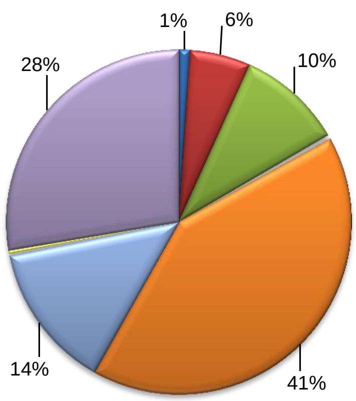
Hydro One Brampton Networks Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	14,145	-
1 - Scheduled Outage	1,758	-
2 - Loss of Supply	4,680	-
3 - Tree Contacts	66	-
4 - Lightning	27	-
5 - Defective Equipment	31,924	-
6 - Adverse Weather	33,015	-
7 - Adverse Environment	72	-
8 - Human Element	110	-
9 - Foreign Interference	27,195	-
Total	**112,992**	**-**

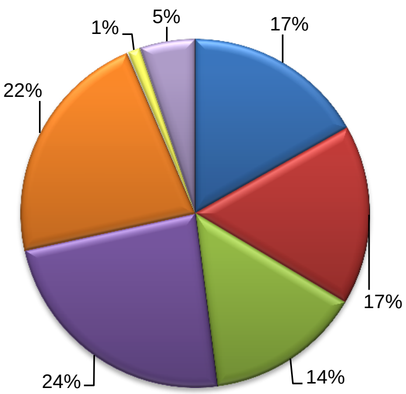
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	722	-
1 - Scheduled Outage	4,012	-
2 - Loss of Supply	6,946	-
3 - Tree Contacts	138	-
4 - Lightning	137	-
5 - Defective Equipment	28,966	-
6 - Adverse Weather	9,643	-
7 - Adverse Environment	115	-
8 - Human Element	234	-
9 - Foreign Interference	19,448	-
Total	**70,362**	**-**

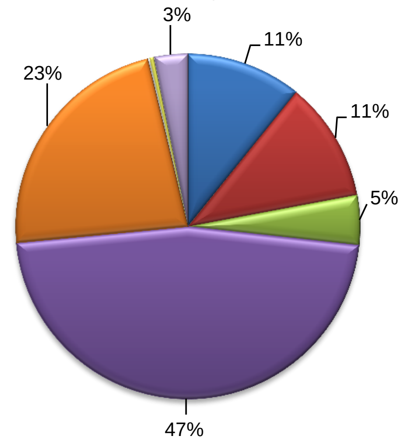
Hydro One Networks Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	769,293	89,488
1 - Scheduled Outage	766,013	15,234
2 - Loss of Supply	659,869	51,121
3 - Tree Contacts	1,080,478	279,005
4 - Lightning	-	-
5 - Defective Equipment	1,007,074	193,101
6 - Adverse Weather	-	-
7 - Adverse Environment	6,629	646
8 - Human Element	53,145	8,362
9 - Foreign Interference	233,624	12,493
Total	**4,576,125**	**649,450**

Duration by Cause



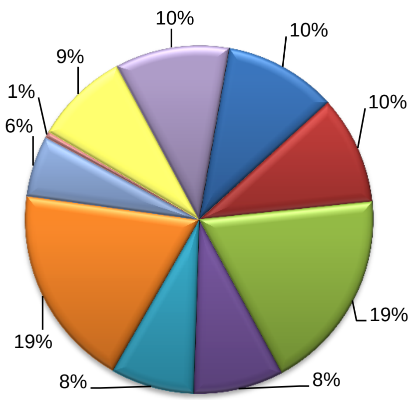
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,914,729	561,349
1 - Scheduled Outage	1,991,203	34,405
2 - Loss of Supply	822,705	240,947
3 - Tree Contacts	8,271,595	4,277,338
4 - Lightning	-	-
5 - Defective Equipment	4,021,763	1,450,408
6 - Adverse Weather	-	-
7 - Adverse Environment	42,442	2,824
8 - Human Element	72,253	3,017
9 - Foreign Interference	551,833	29,208
Total	**17,688,523**	**6,599,497**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

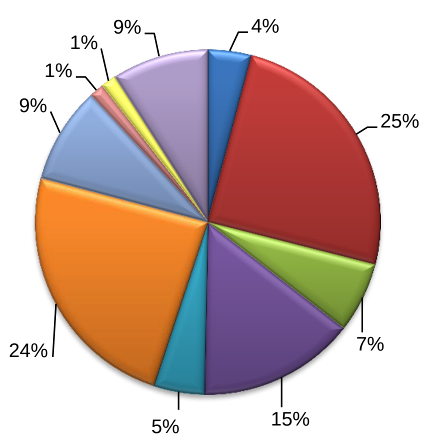
Hydro Ottawa Limited

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	32,593	-
1 - Scheduled Outage	31,446	-
2 - Loss of Supply	58,466	-
3 - Tree Contacts	26,006	1,058
4 - Lightning	24,130	4,341
5 - Defective Equipment	58,747	1
6 - Adverse Weather	17,467	6,897
7 - Adverse Environment	1,960	-
8 - Human Element	27,288	-
9 - Foreign Interference	32,989	-
Total	**311,092**	**12,297**

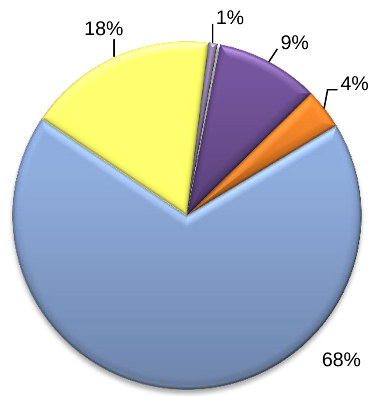
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	16,156	-
1 - Scheduled Outage	97,984	-
2 - Loss of Supply	26,002	-
3 - Tree Contacts	58,121	16,639
4 - Lightning	18,739	3,811
5 - Defective Equipment	94,802	10
6 - Adverse Weather	35,612	21,331
7 - Adverse Environment	5,389	-
8 - Human Element	5,624	-
9 - Foreign Interference	35,659	-
Total	**394,088**	**41,791**

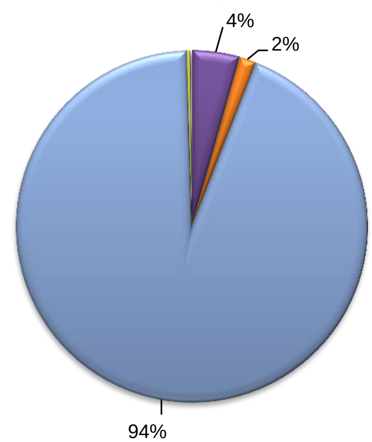
Innpower Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	161	-
1 - Scheduled Outage	5	-
2 - Loss of Supply	-	-
3 - Tree Contacts	5,575	4,150
4 - Lightning	11	-
5 - Defective Equipment	2,186	-
6 - Adverse Weather	39,685	32,132
7 - Adverse Environment	-	-
8 - Human Element	10,275	-
9 - Foreign Interference	455	-
Total	**58,353**	**36,282**

Duration by Cause



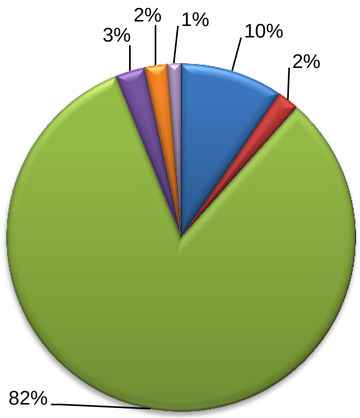
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	210	-
1 - Scheduled Outage	10	-
2 - Loss of Supply	-	-
3 - Tree Contacts	11,442	5,813
4 - Lightning	69	-
5 - Defective Equipment	4,060	-
6 - Adverse Weather	249,184	242,070
7 - Adverse Environment	-	-
8 - Human Element	857	-
9 - Foreign Interference	399	-
Total	**266,231**	**247,882**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

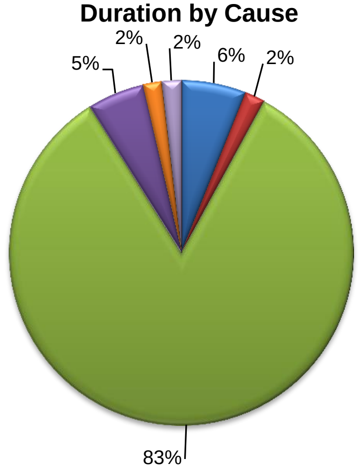
Kenora Hydro Electric Corporation Ltd.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	1,286	-
1 - Scheduled Outage	277	-
2 - Loss of Supply	11,144	-
3 - Tree Contacts	370	-
4 - Lightning	-	-
5 - Defective Equipment	284	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	168	-
Total	**13,529**	**-**

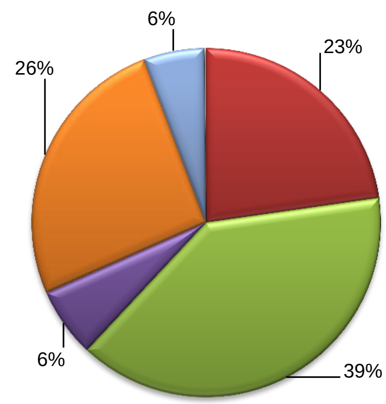
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	1,188	-
1 - Scheduled Outage	374	-
2 - Loss of Supply	16,345	-
3 - Tree Contacts	1,046	-
4 - Lightning	-	-
5 - Defective Equipment	344	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	361	-
Total	**19,657**	**-**

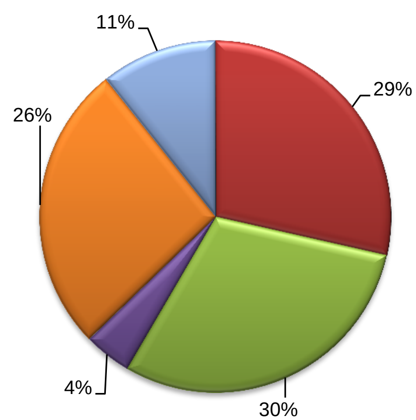
Kingston Hydro Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	-	-
1 - Scheduled Outage	6,016	-
2 - Loss of Supply	10,388	-
3 - Tree Contacts	1,692	-
4 - Lightning	-	-
5 - Defective Equipment	6,829	-
6 - Adverse Weather	1,484	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	45	-
Total	**26,454**	**-**

Duration by Cause



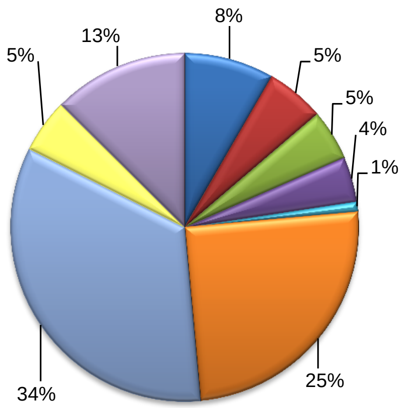
Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	-	-
1 - Scheduled Outage	14,716	-
2 - Loss of Supply	15,433	-
3 - Tree Contacts	2,241	-
4 - Lightning	-	-
5 - Defective Equipment	13,677	-
6 - Adverse Weather	5,511	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	21	-
Total	**51,599**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

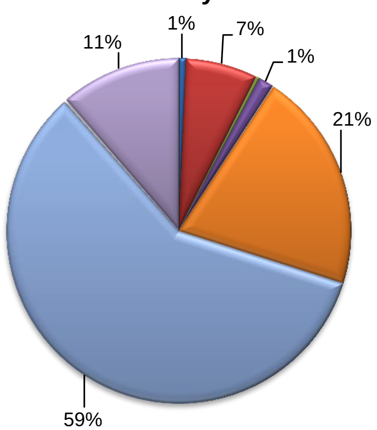
Kitchener-Wilmot Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	14,127	-
1 - Scheduled Outage	9,177	-
2 - Loss of Supply	8,000	-
3 - Tree Contacts	7,102	-
4 - Lightning	1,588	-
5 - Defective Equipment	42,299	-
6 - Adverse Weather	57,456	57,372
7 - Adverse Environment	-	-
8 - Human Element	8,475	-
9 - Foreign Interference	21,316	-
Total	**169,540**	**57,372**

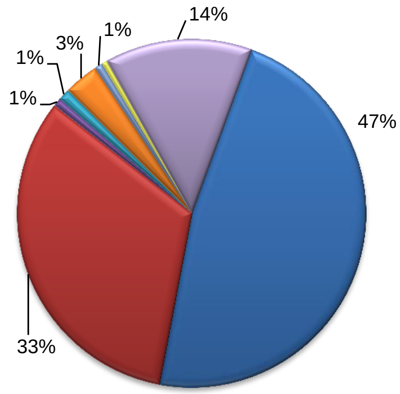
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,708	-
1 - Scheduled Outage	17,050	-
2 - Loss of Supply	800	-
3 - Tree Contacts	3,578	-
4 - Lightning	320	-
5 - Defective Equipment	52,242	-
6 - Adverse Weather	148,207	147,908
7 - Adverse Environment	-	-
8 - Human Element	635	-
9 - Foreign Interference	28,583	-
Total	**253,123**	**147,908**

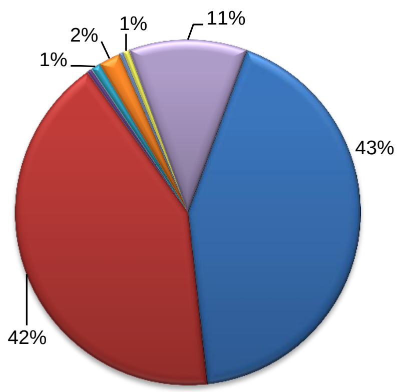
Lakefront Utilities Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,807	-
1 - Scheduled Outage	1,242	-
2 - Loss of Supply	1	-
3 - Tree Contacts	31	-
4 - Lightning	40	-
5 - Defective Equipment	122	-
6 - Adverse Weather	29	-
7 - Adverse Environment	-	-
8 - Human Element	20	-
9 - Foreign Interference	518	-
Total	**3,810**	**-**

Duration by Cause



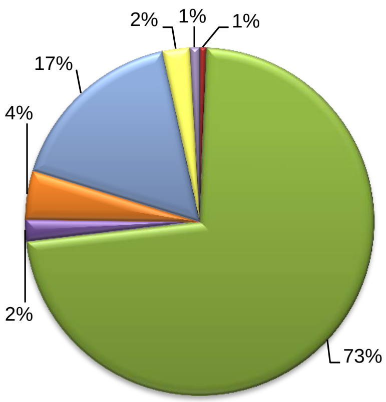
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,950	-
1 - Scheduled Outage	2,897	-
2 - Loss of Supply	1	-
3 - Tree Contacts	31	-
4 - Lightning	63	-
5 - Defective Equipment	140	-
6 - Adverse Weather	28	-
7 - Adverse Environment	-	-
8 - Human Element	40	-
9 - Foreign Interference	765	-
Total	**6,915**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

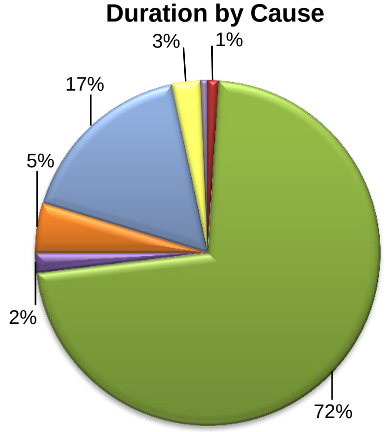
Lakeland Power Distribution Ltd.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	216	-
2 - Loss of Supply	25,907	-
3 - Tree Contacts	712	-
4 - Lightning	-	-
5 - Defective Equipment	1,617	-
6 - Adverse Weather	6,001	-
7 - Adverse Environment	4	-
8 - Human Element	912	-
9 - Foreign Interference	314	-
Total	**35,683**	**-**

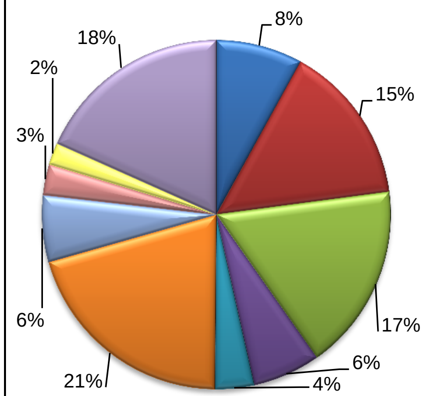
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	969	-
2 - Loss of Supply	69,876	-
3 - Tree Contacts	1,795	-
4 - Lightning	-	-
5 - Defective Equipment	4,521	-
6 - Adverse Weather	16,410	-
7 - Adverse Environment	0	-
8 - Human Element	2,651	-
9 - Foreign Interference	619	-
Total	**96,840**	**-**

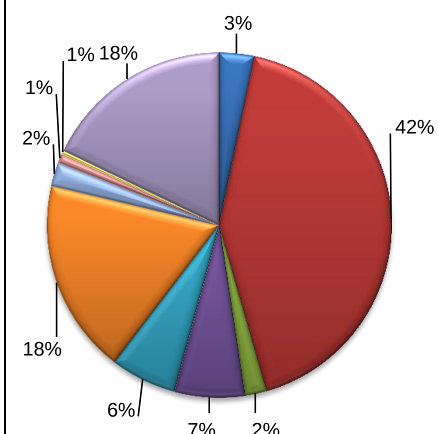
London Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	15,404	-
1 - Scheduled Outage	28,619	-
2 - Loss of Supply	33,231	-
3 - Tree Contacts	12,088	-
4 - Lightning	6,952	-
5 - Defective Equipment	39,381	-
6 - Adverse Weather	11,785	-
7 - Adverse Environment	5,501	-
8 - Human Element	3,909	-
9 - Foreign Interference	35,181	-
Total	**192,051**	**-**

Duration by Cause



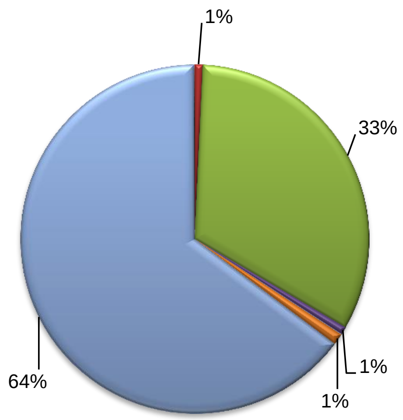
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	5,011	-
1 - Scheduled Outage	64,624	-
2 - Loss of Supply	3,084	-
3 - Tree Contacts	10,051	-
4 - Lightning	9,528	-
5 - Defective Equipment	27,897	-
6 - Adverse Weather	3,363	-
7 - Adverse Environment	1,320	-
8 - Human Element	557	-
9 - Foreign Interference	27,326	-
Total	**152,761**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

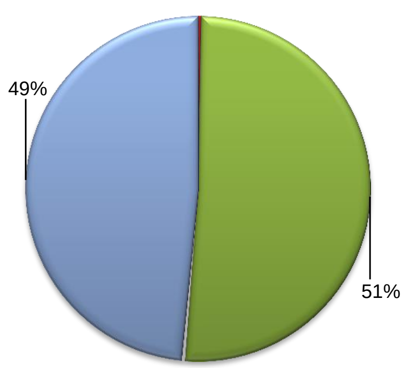
Midland Power Utility Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	101	-
2 - Loss of Supply	4,452	301
3 - Tree Contacts	98	-
4 - Lightning	-	-
5 - Defective Equipment	145	-
6 - Adverse Weather	8,808	4,158
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	10	-
Total	**13,614**	**4,459**

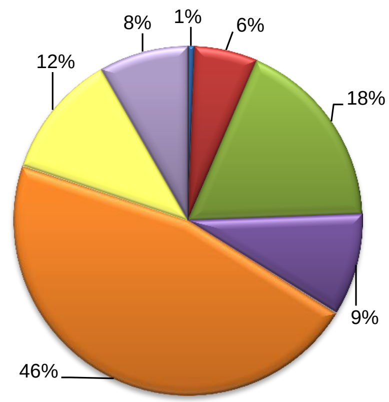
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	139	-
2 - Loss of Supply	24,134	4,214
3 - Tree Contacts	60	-
4 - Lightning	-	-
5 - Defective Equipment	116	-
6 - Adverse Weather	22,937	18,387
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	15	-
Total	**47,401**	**22,601**

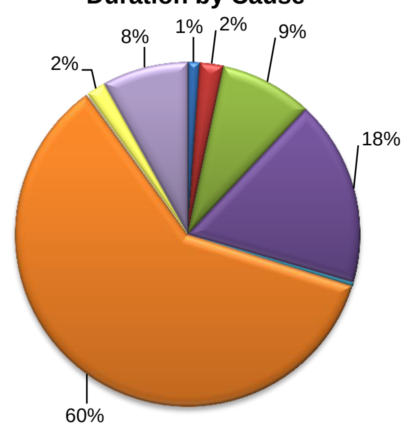
Milton Hydro Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	162	-
1 - Scheduled Outage	1,565	-
2 - Loss of Supply	4,803	-
3 - Tree Contacts	2,519	-
4 - Lightning	24	-
5 - Defective Equipment	12,333	-
6 - Adverse Weather	27	-
7 - Adverse Environment	-	-
8 - Human Element	3,102	-
9 - Foreign Interference	2,220	-
Total	**26,755**	**-**

Duration by Cause



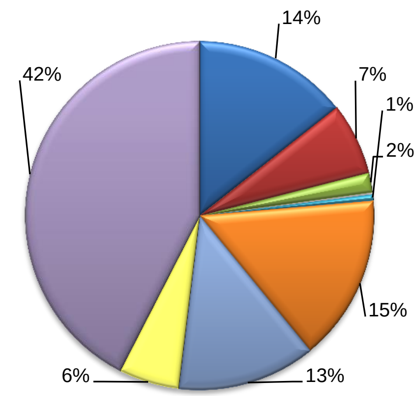
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	334	-
1 - Scheduled Outage	668	-
2 - Loss of Supply	2,604	-
3 - Tree Contacts	5,238	-
4 - Lightning	109	-
5 - Defective Equipment	18,058	-
6 - Adverse Weather	38	-
7 - Adverse Environment	-	-
8 - Human Element	546	-
9 - Foreign Interference	2,412	-
Total	**30,007**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

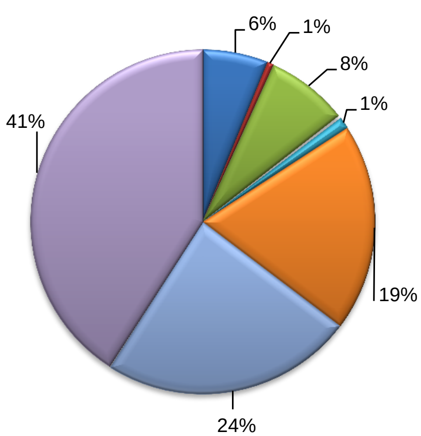
Newmarket-Tay Power Distribution Ltd.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	5,252	-
1 - Scheduled Outage	2,446	-
2 - Loss of Supply	652	-
3 - Tree Contacts	78	-
4 - Lightning	204	-
5 - Defective Equipment	5,636	-
6 - Adverse Weather	4,689	4,689
7 - Adverse Environment	-	-
8 - Human Element	2,042	-
9 - Foreign Interference	15,498	11,100
Total	**36,497**	**15,789**

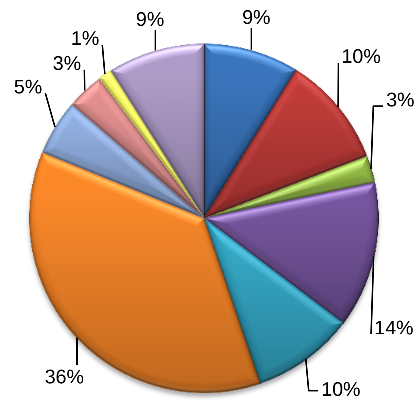
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	2,441	-
1 - Scheduled Outage	249	-
2 - Loss of Supply	3,075	-
3 - Tree Contacts	104	-
4 - Lightning	451	-
5 - Defective Equipment	7,798	-
6 - Adverse Weather	9,456	9,456
7 - Adverse Environment	-	-
8 - Human Element	40	-
9 - Foreign Interference	16,342	12,765
Total	**39,956**	**22,221**

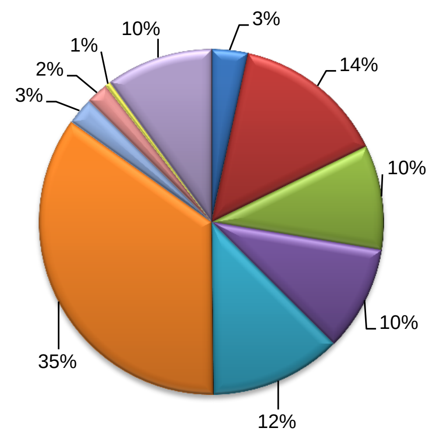
Niagara Peninsula Energy Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	6,724	-
1 - Scheduled Outage	7,855	-
2 - Loss of Supply	1,923	-
3 - Tree Contacts	10,278	-
4 - Lightning	7,220	-
5 - Defective Equipment	27,623	-
6 - Adverse Weather	3,931	-
7 - Adverse Environment	2,616	-
8 - Human Element	962	-
9 - Foreign Interference	6,799	-
Total	**75,931**	**-**

Duration by Cause



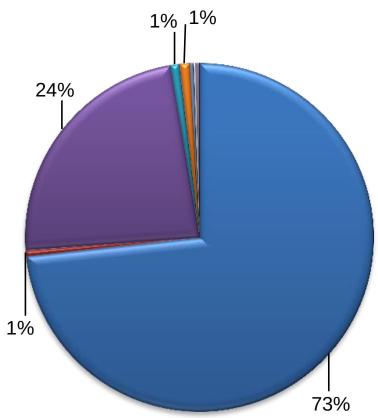
Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	3,095	-
1 - Scheduled Outage	12,978	-
2 - Loss of Supply	8,886	-
3 - Tree Contacts	8,916	-
4 - Lightning	11,194	-
5 - Defective Equipment	31,683	-
6 - Adverse Weather	2,298	-
7 - Adverse Environment	1,869	-
8 - Human Element	486	-
9 - Foreign Interference	9,043	-
Total	**90,448**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

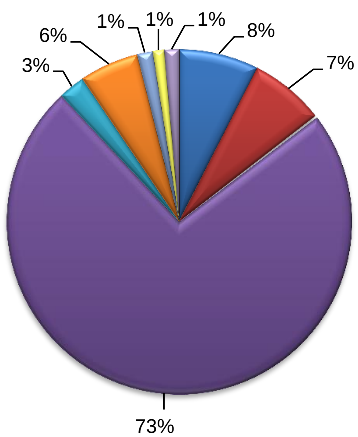
Niagara-on-the-Lake Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	6,873	-
1 - Scheduled Outage	47	-
2 - Loss of Supply	5	-
3 - Tree Contacts	2,202	-
4 - Lightning	79	-
5 - Defective Equipment	88	-
6 - Adverse Weather	32	-
7 - Adverse Environment	-	-
8 - Human Element	20	-
9 - Foreign Interference	31	-
Total	**9,377**	**-**

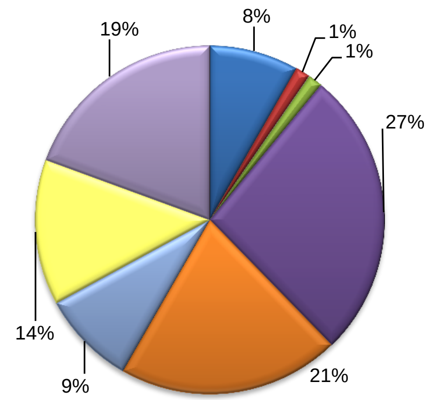
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	231	-
1 - Scheduled Outage	216	-
2 - Loss of Supply	6	-
3 - Tree Contacts	2,263	-
4 - Lightning	77	-
5 - Defective Equipment	171	-
6 - Adverse Weather	45	-
7 - Adverse Environment	-	-
8 - Human Element	33	-
9 - Foreign Interference	42	-
Total	**3,084**	**-**

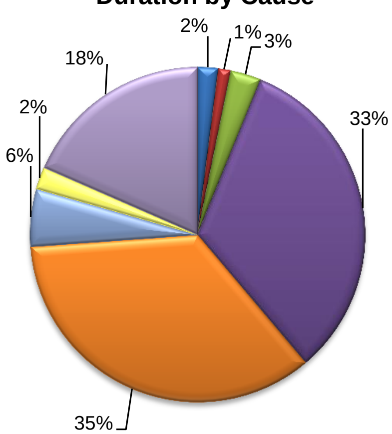
North Bay Hydro Distribution Limited

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	4,020	-
1 - Scheduled Outage	661	-
2 - Loss of Supply	651	-
3 - Tree Contacts	13,010	-
4 - Lightning	-	-
5 - Defective Equipment	10,007	-
6 - Adverse Weather	4,268	-
7 - Adverse Environment	6	-
8 - Human Element	6,566	-
9 - Foreign Interference	9,434	-
Total	**48,623**	**-**

Duration by Cause



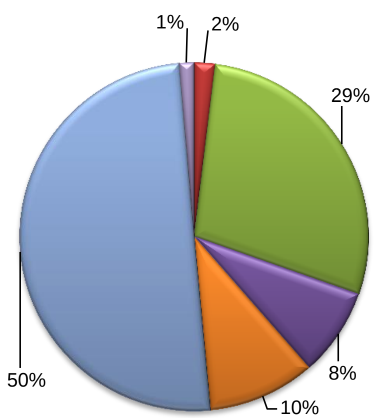
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,127	-
1 - Scheduled Outage	687	-
2 - Loss of Supply	1,703	-
3 - Tree Contacts	18,710	-
4 - Lightning	-	-
5 - Defective Equipment	20,054	-
6 - Adverse Weather	3,171	-
7 - Adverse Environment	3	-
8 - Human Element	1,225	-
9 - Foreign Interference	10,554	-
Total	**57,235**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

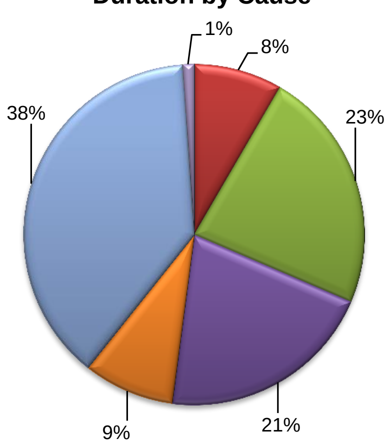
Northern Ontario Wires Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	309	-
2 - Loss of Supply	4,562	-
3 - Tree Contacts	1,313	-
4 - Lightning	-	-
5 - Defective Equipment	1,603	-
6 - Adverse Weather	8,047	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	217	-
Total	**16,051**	**-**

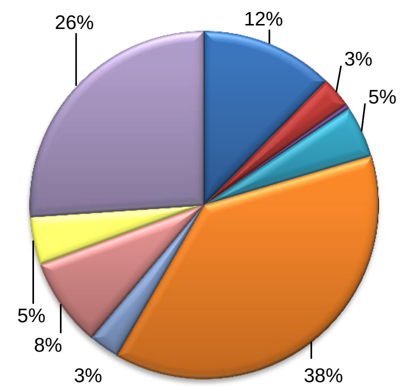
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	2,282	-
2 - Loss of Supply	6,273	-
3 - Tree Contacts	5,614	-
4 - Lightning	-	-
5 - Defective Equipment	2,347	-
6 - Adverse Weather	10,394	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	294	-
Total	**27,202**	**-**

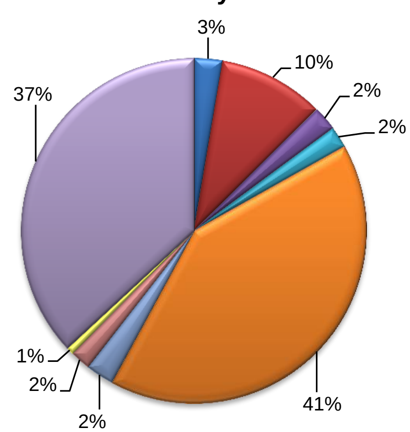
Oakville Hydro Electricity Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	7,634	-
1 - Scheduled Outage	1,767	-
2 - Loss of Supply	-	-
3 - Tree Contacts	272	-
4 - Lightning	2,959	-
5 - Defective Equipment	23,389	-
6 - Adverse Weather	1,752	-
7 - Adverse Environment	5,097	-
8 - Human Element	2,767	-
9 - Foreign Interference	16,104	-
Total	**61,741**	**-**

Duration by Cause



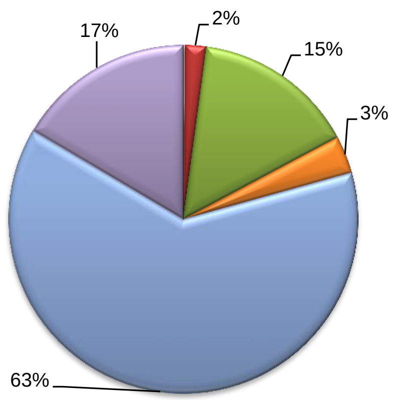
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	921	-
1 - Scheduled Outage	3,430	-
2 - Loss of Supply	-	-
3 - Tree Contacts	792	-
4 - Lightning	692	-
5 - Defective Equipment	14,193	-
6 - Adverse Weather	917	-
7 - Adverse Environment	657	-
8 - Human Element	228	-
9 - Foreign Interference	12,766	-
Total	**34,596**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

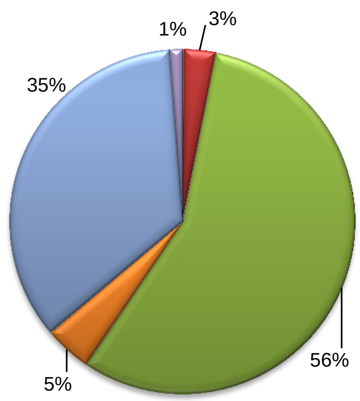
Orangeville Hydro Limited

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	25	-
1 - Scheduled Outage	309	-
2 - Loss of Supply	2,400	-
3 - Tree Contacts	2	-
4 - Lightning	3	-
5 - Defective Equipment	548	-
6 - Adverse Weather	9,981	-
7 - Adverse Environment	-	-
8 - Human Element	1	-
9 - Foreign Interference	2,621	-
Total	**15,890**	**-**

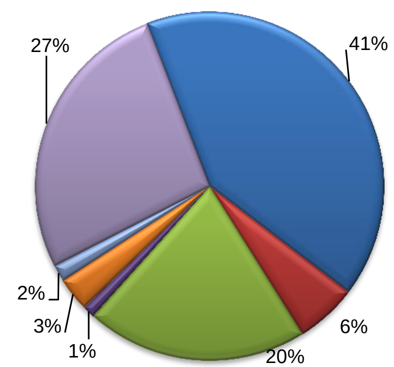
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	27	-
1 - Scheduled Outage	553	-
2 - Loss of Supply	10,627	-
3 - Tree Contacts	1	-
4 - Lightning	7	-
5 - Defective Equipment	828	-
6 - Adverse Weather	6,583	-
7 - Adverse Environment	-	-
8 - Human Element	1	-
9 - Foreign Interference	232	-
Total	**18,858**	**-**

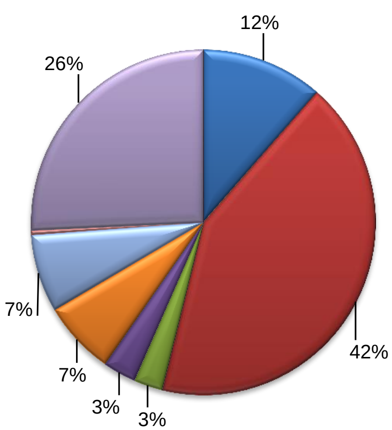
Orillia Power Distribution Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	7,700	-
1 - Scheduled Outage	1,065	-
2 - Loss of Supply	3,840	-
3 - Tree Contacts	208	-
4 - Lightning	-	-
5 - Defective Equipment	587	-
6 - Adverse Weather	290	-
7 - Adverse Environment	2	-
8 - Human Element	-	-
9 - Foreign Interference	4,993	-
Total	**18,685**	**-**

Duration by Cause



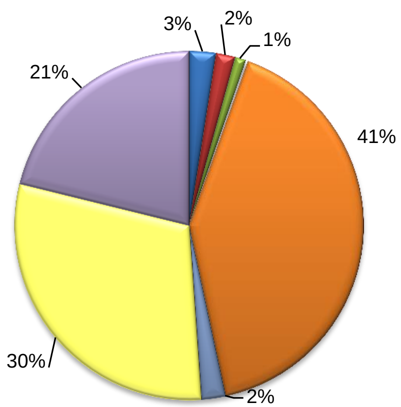
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	819	-
1 - Scheduled Outage	3,036	-
2 - Loss of Supply	192	-
3 - Tree Contacts	221	-
4 - Lightning	-	-
5 - Defective Equipment	493	-
6 - Adverse Weather	524	-
7 - Adverse Environment	31	-
8 - Human Element	-	-
9 - Foreign Interference	1,840	-
Total	**7,156**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

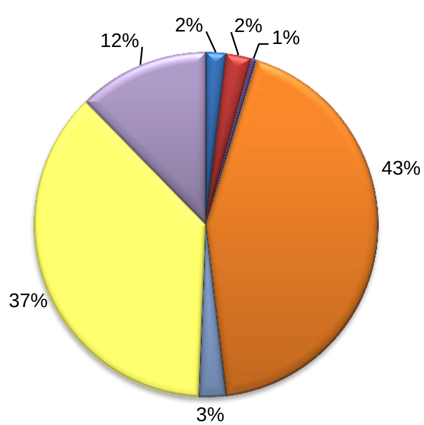
Oshawa PUC Networks Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,930	-
1 - Scheduled Outage	2,107	-
2 - Loss of Supply	1,176	-
3 - Tree Contacts	245	-
4 - Lightning	57	-
5 - Defective Equipment	48,976	-
6 - Adverse Weather	2,663	-
7 - Adverse Environment	-	-
8 - Human Element	35,621	-
9 - Foreign Interference	25,165	-
Total	**118,940**	**-**

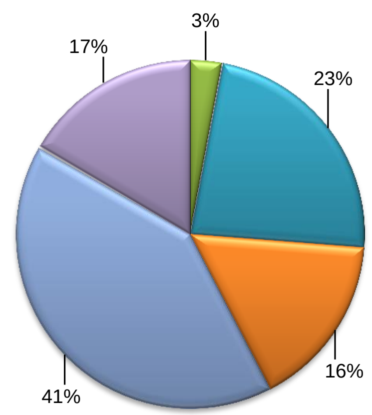
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,782	-
1 - Scheduled Outage	3,542	-
2 - Loss of Supply	22	-
3 - Tree Contacts	680	-
4 - Lightning	152	-
5 - Defective Equipment	64,591	-
6 - Adverse Weather	3,774	-
7 - Adverse Environment	-	-
8 - Human Element	55,165	-
9 - Foreign Interference	18,420	-
Total	**149,128**	**-**

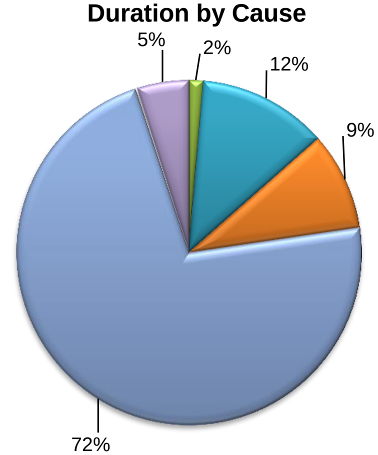
Ottawa River Power Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	-	-
2 - Loss of Supply	376	-
3 - Tree Contacts	14	-
4 - Lightning	3,009	-
5 - Defective Equipment	2,093	-
6 - Adverse Weather	5,294	3,429
7 - Adverse Environment	-	-
8 - Human Element	31	-
9 - Foreign Interference	2,144	-
Total	**12,961**	**3,429**

Duration by Cause



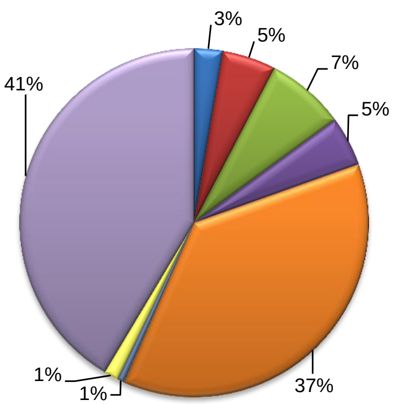
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	-	-
2 - Loss of Supply	496	-
3 - Tree Contacts	4	-
4 - Lightning	4,460	-
5 - Defective Equipment	3,375	-
6 - Adverse Weather	26,586	19,313
7 - Adverse Environment	-	-
8 - Human Element	66	-
9 - Foreign Interference	1,790	-
Total	**36,778**	**19,313**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

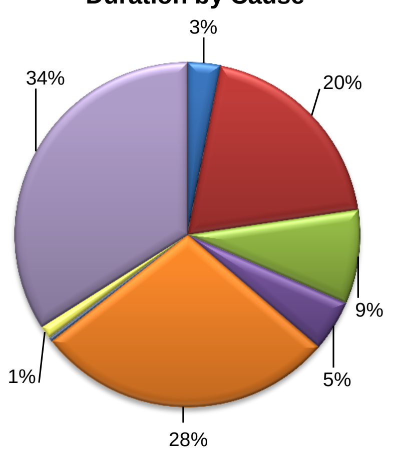
Peterborough Distribution Incorporated

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,441	-
1 - Scheduled Outage	4,596	-
2 - Loss of Supply	6,790	-
3 - Tree Contacts	4,236	-
4 - Lightning	-	-
5 - Defective Equipment	34,187	-
6 - Adverse Weather	596	-
7 - Adverse Environment	24	-
8 - Human Element	1,243	-
9 - Foreign Interference	38,266	-
Total	**92,379**	**-**

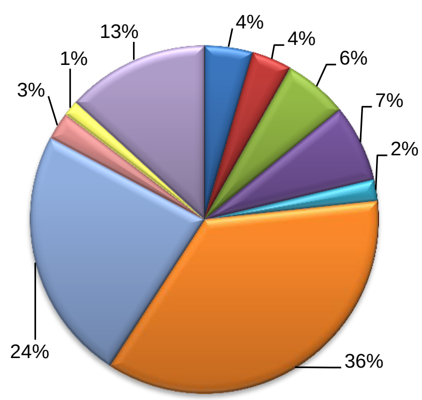
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,493	-
1 - Scheduled Outage	15,829	-
2 - Loss of Supply	7,126	-
3 - Tree Contacts	3,890	-
4 - Lightning	-	-
5 - Defective Equipment	22,742	-
6 - Adverse Weather	299	-
7 - Adverse Environment	18	-
8 - Human Element	970	-
9 - Foreign Interference	27,477	-
Total	**80,844**	**-**

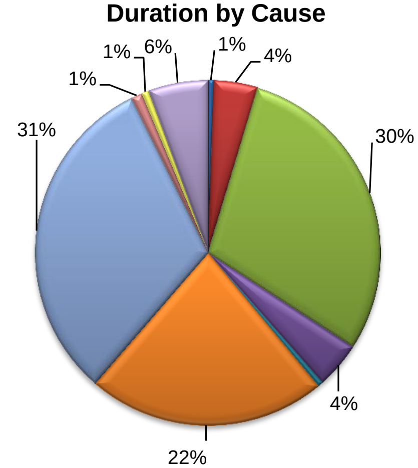
PowerStream Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	23,159	19
1 - Scheduled Outage	18,975	16
2 - Loss of Supply	30,703	20,384
3 - Tree Contacts	36,884	-
4 - Lightning	10,265	-
5 - Defective Equipment	184,501	36,569
6 - Adverse Weather	121,615	107,557
7 - Adverse Environment	13,064	91
8 - Human Element	7,509	-
9 - Foreign Interference	68,069	18
Total	**514,744**	**164,654**

Duration by Cause



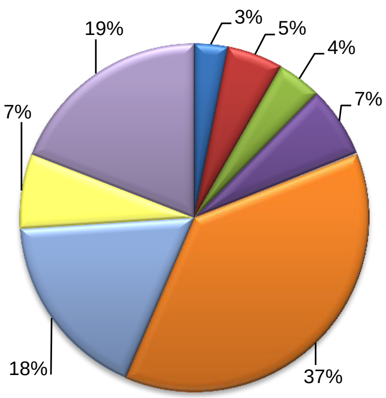
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	5,433	61
1 - Scheduled Outage	40,922	15
2 - Loss of Supply	295,491	286,159
3 - Tree Contacts	43,595	-
4 - Lightning	5,104	-
5 - Defective Equipment	223,490	72,712
6 - Adverse Weather	314,158	311,480
7 - Adverse Environment	10,287	1,192
8 - Human Element	6,875	-
9 - Foreign Interference	55,821	50
Total	**1,001,177**	**671,669**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

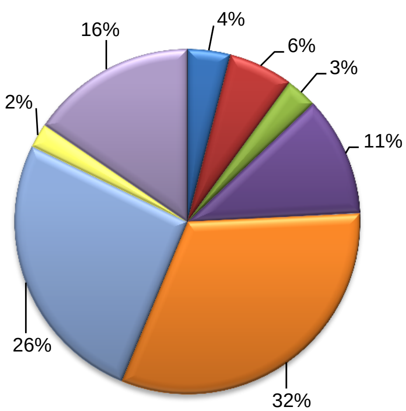
PUC Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,281	-
1 - Scheduled Outage	3,821	-
2 - Loss of Supply	3,045	-
3 - Tree Contacts	4,832	-
4 - Lightning	110	-
5 - Defective Equipment	27,643	-
6 - Adverse Weather	12,955	9,866
7 - Adverse Environment	8	-
8 - Human Element	5,142	-
9 - Foreign Interference	14,090	13,774
Total	**73,927**	**23,640**

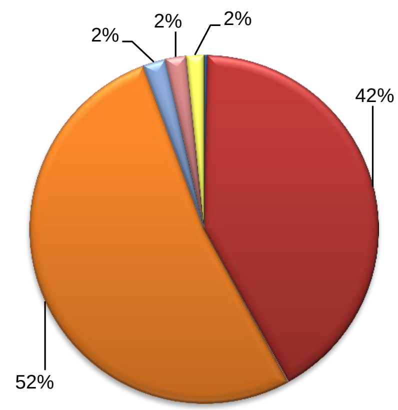
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,405	-
1 - Scheduled Outage	5,107	-
2 - Loss of Supply	2,487	-
3 - Tree Contacts	9,466	-
4 - Lightning	110	-
5 - Defective Equipment	27,123	-
6 - Adverse Weather	22,034	19,793
7 - Adverse Environment	1	-
8 - Human Element	1,922	-
9 - Foreign Interference	13,171	12,511
Total	**84,824**	**32,304**

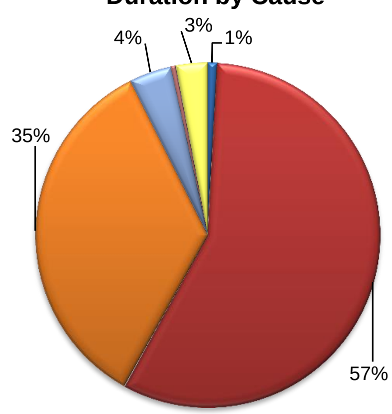
Renfrew Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	4	-
1 - Scheduled Outage	492	-
2 - Loss of Supply	-	-
3 - Tree Contacts	-	-
4 - Lightning	1	-
5 - Defective Equipment	619	-
6 - Adverse Weather	25	-
7 - Adverse Environment	23	-
8 - Human Element	19	-
9 - Foreign Interference	-	-
Total	**1,183**	**-**

Duration by Cause



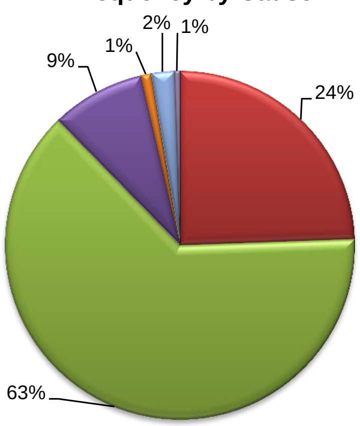
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	13	-
1 - Scheduled Outage	819	-
2 - Loss of Supply	-	-
3 - Tree Contacts	-	-
4 - Lightning	2	-
5 - Defective Equipment	495	-
6 - Adverse Weather	57	-
7 - Adverse Environment	6	-
8 - Human Element	42	-
9 - Foreign Interference	-	-
Total	**1,435**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

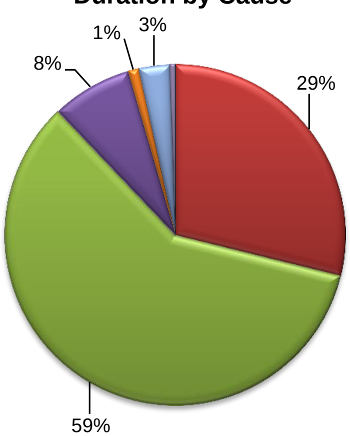
Rideau St. Lawrence Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	1,499	-
2 - Loss of Supply	3,886	-
3 - Tree Contacts	531	-
4 - Lightning	1	-
5 - Defective Equipment	59	-
6 - Adverse Weather	130	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	30	-
Total	**6,136**	**-**

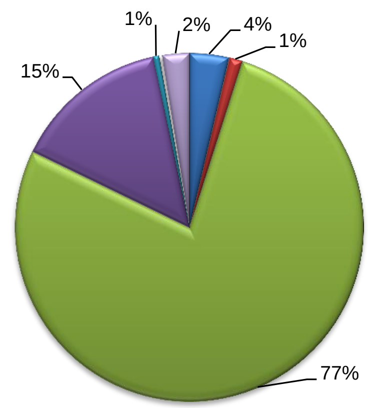
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	4,162	-
2 - Loss of Supply	8,523	-
3 - Tree Contacts	1,097	-
4 - Lightning	3	-
5 - Defective Equipment	152	-
6 - Adverse Weather	420	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	74	-
Total	**14,430**	**-**

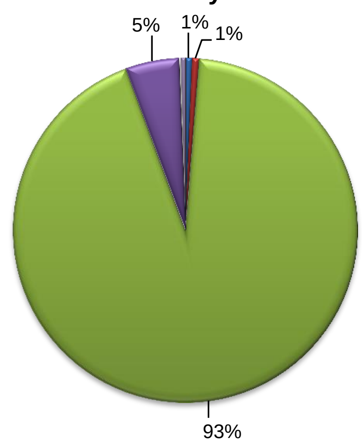
Sioux Lookout Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	530	-
1 - Scheduled Outage	180	-
2 - Loss of Supply	11,176	2,792
3 - Tree Contacts	2,098	1,700
4 - Lightning	81	-
5 - Defective Equipment	32	-
6 - Adverse Weather	6	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	361	-
Total	**14,464**	**4,492**

Duration by Cause



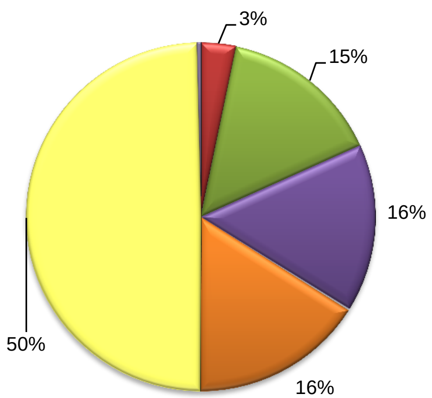
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	423	-
1 - Scheduled Outage	470	-
2 - Loss of Supply	65,798	15,551
3 - Tree Contacts	3,513	2,975
4 - Lightning	51	-
5 - Defective Equipment	92	-
6 - Adverse Weather	15	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	286	-
Total	**70,648**	**18,526**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

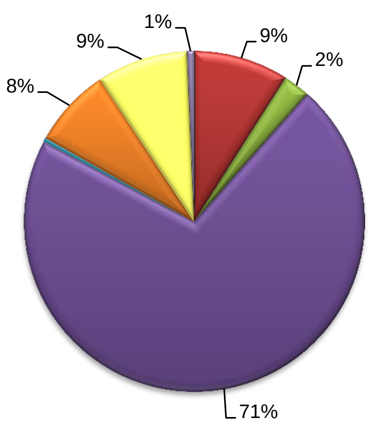
St. Thomas Energy Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	975	-
2 - Loss of Supply	4,527	-
3 - Tree Contacts	4,687	-
4 - Lightning	57	-
5 - Defective Equipment	4,842	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	14,933	-
9 - Foreign Interference	106	-
Total	**30,127**	**-**

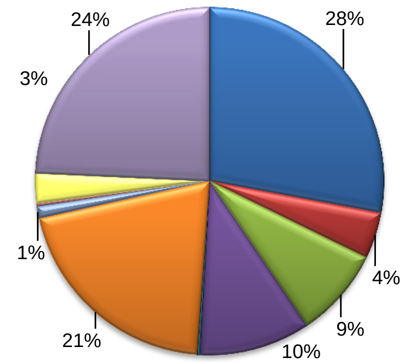
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	1,655	-
2 - Loss of Supply	462	-
3 - Tree Contacts	13,068	-
4 - Lightning	69	-
5 - Defective Equipment	1,384	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	1,586	-
9 - Foreign Interference	122	-
Total	**18,347**	**-**

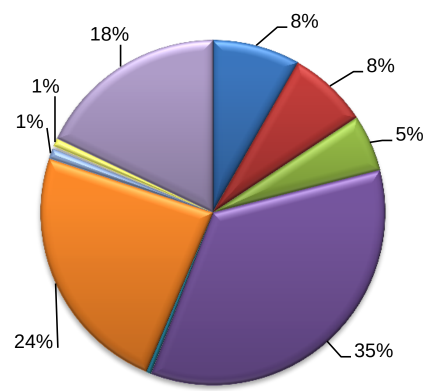
Thunder Bay Hydro Electricity Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	41,700	-
1 - Scheduled Outage	6,435	-
2 - Loss of Supply	12,483	-
3 - Tree Contacts	15,368	-
4 - Lightning	422	-
5 - Defective Equipment	30,465	-
6 - Adverse Weather	1,690	-
7 - Adverse Environment	433	-
8 - Human Element	4,115	-
9 - Foreign Interference	36,260	-
Total	**149,371**	**-**

Duration by Cause



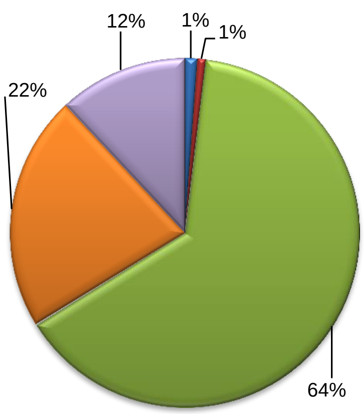
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	7,401	-
1 - Scheduled Outage	6,761	-
2 - Loss of Supply	4,818	-
3 - Tree Contacts	31,400	-
4 - Lightning	442	-
5 - Defective Equipment	21,407	-
6 - Adverse Weather	878	-
7 - Adverse Environment	231	-
8 - Human Element	703	-
9 - Foreign Interference	16,174	-
Total	**90,215**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

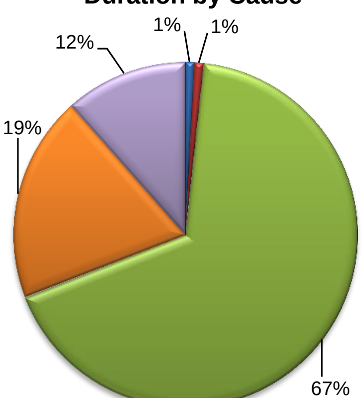
Tillsonburg Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	252	-
1 - Scheduled Outage	169	-
2 - Loss of Supply	14,231	-
3 - Tree Contacts	6	-
4 - Lightning	20	-
5 - Defective Equipment	4,823	-
6 - Adverse Weather	2	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	2,647	2,400
Total	**22,150**	**2,400**

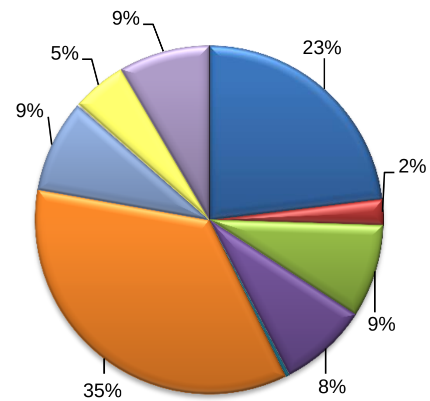
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	374	-
1 - Scheduled Outage	398	-
2 - Loss of Supply	30,761	-
3 - Tree Contacts	12	-
4 - Lightning	28	-
5 - Defective Equipment	8,807	-
6 - Adverse Weather	6	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	5,271	4,800
Total	**45,657**	**4,800**

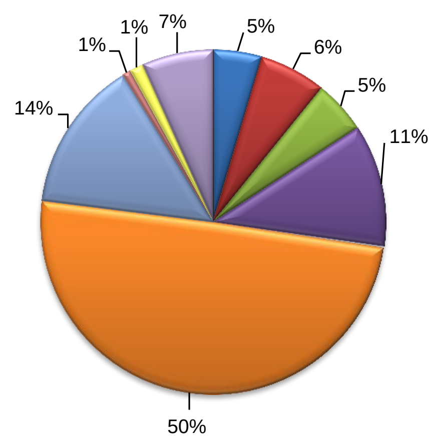
Toronto Hydro-Electric System Limited

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	244,876	-
1 - Scheduled Outage	25,226	-
2 - Loss of Supply	91,577	-
3 - Tree Contacts	87,477	-
4 - Lightning	3,747	-
5 - Defective Equipment	370,901	-
6 - Adverse Weather	90,771	-
7 - Adverse Environment	1,807	-
8 - Human Element	53,655	-
9 - Foreign Interference	89,150	-
Total	**1,059,187**	**-**

Duration by Cause



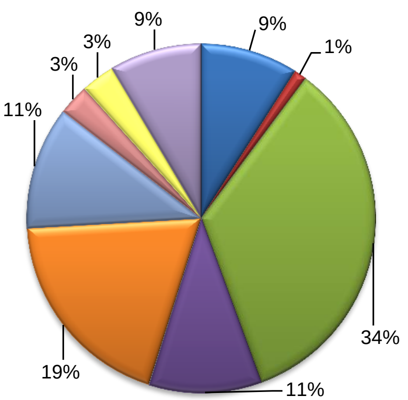
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	32,983	-
1 - Scheduled Outage	45,166	-
2 - Loss of Supply	35,866	-
3 - Tree Contacts	82,715	-
4 - Lightning	1,230	-
5 - Defective Equipment	358,473	-
6 - Adverse Weather	103,265	-
7 - Adverse Environment	5,570	-
8 - Human Element	9,344	-
9 - Foreign Interference	48,195	-
Total	**722,808**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

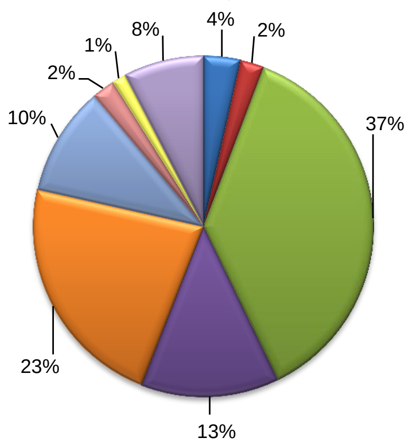
Veridian Connections Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	21,304	-
1 - Scheduled Outage	2,754	-
2 - Loss of Supply	80,732	-
3 - Tree Contacts	24,662	-
4 - Lightning	64	-
5 - Defective Equipment	45,377	-
6 - Adverse Weather	26,853	-
7 - Adverse Environment	6,689	-
8 - Human Element	7,419	-
9 - Foreign Interference	20,161	-
Total	**236,015**	**-**

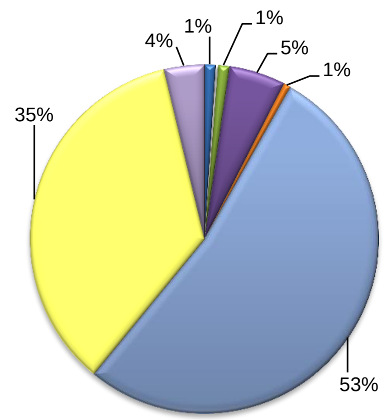
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	8,269	-
1 - Scheduled Outage	5,323	-
2 - Loss of Supply	87,574	-
3 - Tree Contacts	31,065	-
4 - Lightning	53	-
5 - Defective Equipment	53,250	-
6 - Adverse Weather	24,630	-
7 - Adverse Environment	5,146	-
8 - Human Element	3,122	-
9 - Foreign Interference	17,961	-
Total	**236,393**	**-**

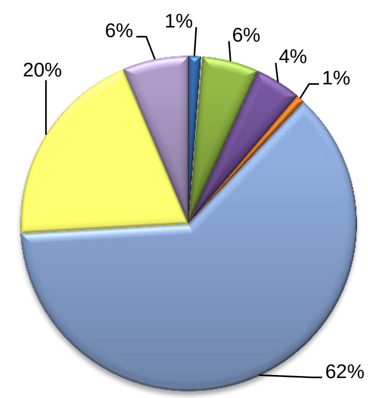
Wasaga Distribution Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	351	-
1 - Scheduled Outage	74	-
2 - Loss of Supply	366	-
3 - Tree Contacts	1,775	-
4 - Lightning	-	-
5 - Defective Equipment	235	-
6 - Adverse Weather	17,996	15,820
7 - Adverse Environment	-	-
8 - Human Element	12,056	-
9 - Foreign Interference	1,273	-
Total	**34,126**	**15,820**

Duration by Cause



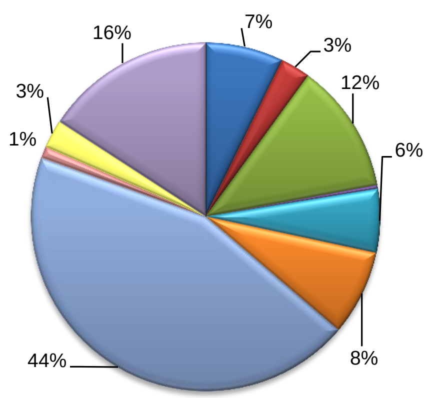
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	440	-
1 - Scheduled Outage	76	-
2 - Loss of Supply	2,061	-
3 - Tree Contacts	1,681	-
4 - Lightning	-	-
5 - Defective Equipment	307	-
6 - Adverse Weather	23,602	21,170
7 - Adverse Environment	-	-
8 - Human Element	7,435	-
9 - Foreign Interference	2,411	-
Total	**38,014**	**21,170**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

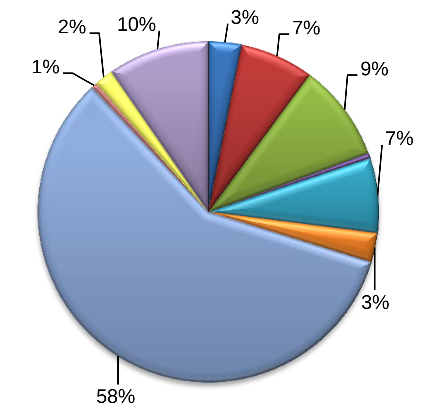
Waterloo North Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	12,026	1
1 - Scheduled Outage	4,587	24
2 - Loss of Supply	20,182	15,380
3 - Tree Contacts	580	3
4 - Lightning	9,778	8,027
5 - Defective Equipment	13,179	273
6 - Adverse Weather	73,622	72,847
7 - Adverse Environment	1,805	-
8 - Human Element	4,395	-
9 - Foreign Interference	26,299	1,184
Total	**166,453**	**97,739**

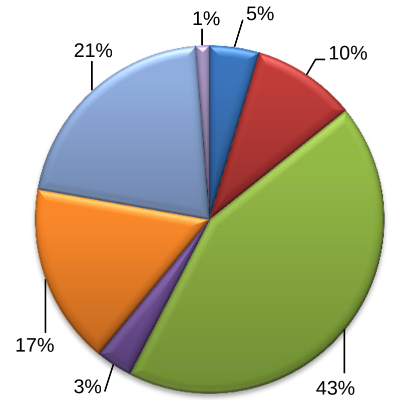
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	4,996	0
1 - Scheduled Outage	11,172	77
2 - Loss of Supply	14,793	13,210
3 - Tree Contacts	779	25
4 - Lightning	11,301	11,151
5 - Defective Equipment	4,447	14
6 - Adverse Weather	92,935	92,050
7 - Adverse Environment	913	-
8 - Human Element	2,812	-
9 - Foreign Interference	15,374	2,059
Total	**159,521**	**118,587**

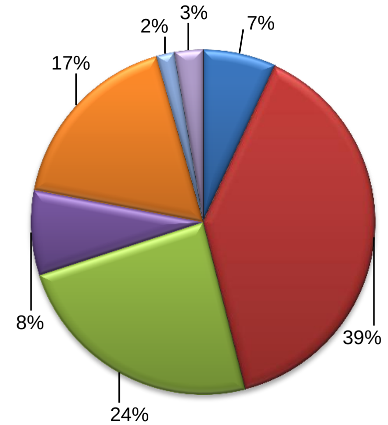
Welland Hydro-Electric System Corp.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	1,328	-
1 - Scheduled Outage	2,780	-
2 - Loss of Supply	12,505	-
3 - Tree Contacts	980	-
4 - Lightning	3	-
5 - Defective Equipment	4,855	-
6 - Adverse Weather	6,043	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	367	-
Total	**28,861**	**-**

Duration by Cause



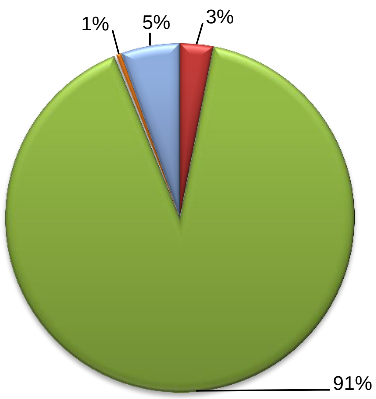
Number Customer-hours Interruptions		
Cause of Interruption	Total Outages	Major Events
0 - Unknown/Other	1,286	-
1 - Scheduled Outage	7,363	-
2 - Loss of Supply	4,497	-
3 - Tree Contacts	1,492	-
4 - Lightning	8	-
5 - Defective Equipment	3,310	-
6 - Adverse Weather	318	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	501	-
Total	**18,776**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

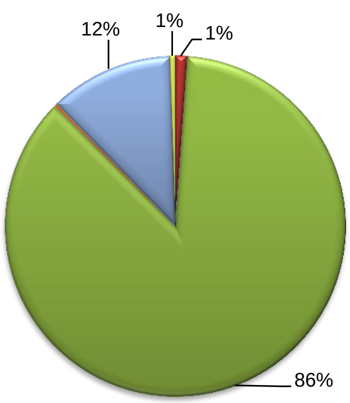
Wellington North Power Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1	-
1 - Scheduled Outage	346	-
2 - Loss of Supply	10,230	-
3 - Tree Contacts	28	-
4 - Lightning	-	-
5 - Defective Equipment	54	-
6 - Adverse Weather	609	284
7 - Adverse Environment	-	-
8 - Human Element	1	-
9 - Foreign Interference	1	-
Total	**11,270**	**284**

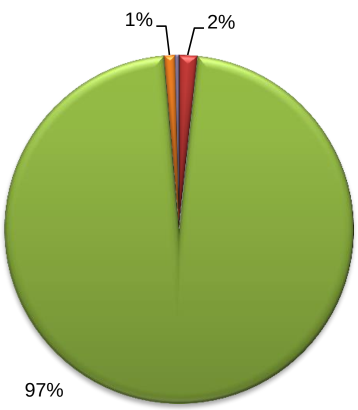
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	0	-
1 - Scheduled Outage	210	-
2 - Loss of Supply	16,331	-
3 - Tree Contacts	8	-
4 - Lightning	-	-
5 - Defective Equipment	55	-
6 - Adverse Weather	2,216	1,321
7 - Adverse Environment	-	-
8 - Human Element	95	-
9 - Foreign Interference	1	-
Total	**18,916**	**1,321**

West Coast Huron Energy Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	134	-
2 - Loss of Supply	7,722	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	81	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	27	-
Total	**7,964**	**-**

Duration by Cause

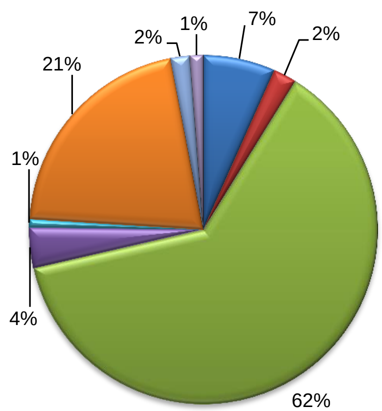
Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	-	-
1 - Scheduled Outage	396	-
2 - Loss of Supply	32,820	-
3 - Tree Contacts	-	-
4 - Lightning	-	-
5 - Defective Equipment	125	-
6 - Adverse Weather	-	-
7 - Adverse Environment	-	-
8 - Human Element	-	-
9 - Foreign Interference	48	-
Total	**33,388**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

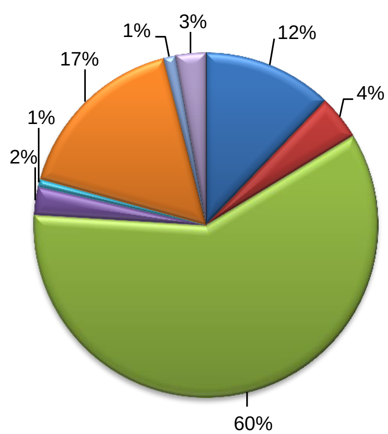
Westario Power Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,590	-
1 - Scheduled Outage	838	-
2 - Loss of Supply	24,345	-
3 - Tree Contacts	1,444	-
4 - Lightning	300	-
5 - Defective Equipment	8,164	-
6 - Adverse Weather	696	-
7 - Adverse Environment	7	-
8 - Human Element	1	-
9 - Foreign Interference	468	-
Total	**38,853**	**-**

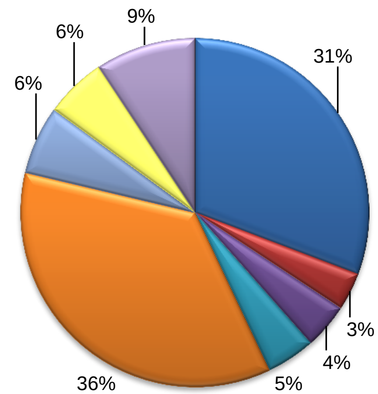
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	16,821	-
1 - Scheduled Outage	5,748	-
2 - Loss of Supply	82,624	-
3 - Tree Contacts	3,634	-
4 - Lightning	1,013	-
5 - Defective Equipment	23,135	-
6 - Adverse Weather	1,607	-
7 - Adverse Environment	14	-
8 - Human Element	5	-
9 - Foreign Interference	3,874	-
Total	**138,474**	**-**

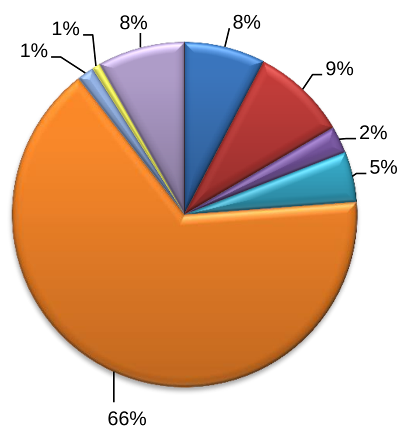
Whitby Hydro Electric Corporation

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	15,866	-
1 - Scheduled Outage	1,804	-
2 - Loss of Supply	-	-
3 - Tree Contacts	2,172	-
4 - Lightning	2,331	-
5 - Defective Equipment	18,426	-
6 - Adverse Weather	3,270	-
7 - Adverse Environment	-	-
8 - Human Element	2,935	-
9 - Foreign Interference	4,804	-
Total	**51,608**	**-**

Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,148	-
1 - Scheduled Outage	3,703	-
2 - Loss of Supply	-	-
3 - Tree Contacts	1,057	-
4 - Lightning	1,949	-
5 - Defective Equipment	27,169	-
6 - Adverse Weather	648	-
7 - Adverse Environment	-	-
8 - Human Element	323	-
9 - Foreign Interference	3,369	-
Total	**41,366**	**-**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

Glossary of Terms

FINANCIAL INFORMATION

	Aggregation of Trial Balance (RRR section 2.1.7) accounts
Cash & cash equivalents	1005-1070
Receivables	1100-1170
Inventory	1305-1350
Inter-company receivables	1200 + 1210
Other current assets	1180 + 1190 + 2290 debit + 2296 debit
Property plant & equipment	1605-2075
Accumulated depreciation & amortization	2105-2180
Regulatory assets	1505-1595 + 2405 + 2425 debit
Inter-company investments	1480-1490
Other non-current assets	1405-1475 + 1495 debit + 2350 debit
Accounts payable & accrued charges	2205-2220 + 2250-2256 + 2294
Other current liabilities	2264 + 2285-2292 credit + 2296 credit
Inter-company payables	2240 + 2242
Loans and notes payable, and current portion of long-term debt	2225, 2260, 2262, 2268, 2270, 2272
Long-term debt	2505-2525
Inter-company long-term debt & advances	2530 + 2550
Total debt	2225 + 2242 + 2260 + 2262 + 2270 + 2505-2525 + 2550
Regulatory liabilities	1505-1595 + 2405 + 2425 credit
Other deferred amounts & customer deposits	2305 + 2308-2348 + 2410 + 2415 + 2435 + 2440
Employee future benefits	2265+ 2306 + 2312 + 2313
Deferred taxes	2350 credit + 1495 credit
Shareholders' equity	3005-3090
Power and distribution revenue	4006-4080
Cost of power and related costs	4705-4751
Other income (loss)	4082-4245+ 4305-4420+ 6305
Operating expense	4505-4565 + 4805-4850 + 5005-5096
Maintenance expense	4605-4640 + 4905-4965 + 5105-5195
Administrative expense	5205-5215 + 5305-5695 + 6105 + 6205-6225 + 6310-6415
Depreciation and amortization expense	5705-5740
Financing expense	6005-6045
Current tax	6110
Deferred tax	6115
Other comprehensive income	7005-7030

FINANCIAL RATIOS

Liquidity Ratios measure the business' ability to cover short-term debt obligations.

Current Ratio measures whether the business has enough resources to pay its short-term debt obligations over the next 12 months.

Leverage Ratios determine the degree to which the business is leveraging itself through its use of borrowed money.

Debt to Equity Ratio measures the proportion of total debt and shareholders' equity to assess actual capital structure.

Debt Ratio measures debt financing as a proportion of total assets.

Interest Coverage Ratio measures the business' ability to pay interest on outstanding debt.

Profitability Ratios measure the business' use of its assets and control of its expenses to generate an acceptable rate of return.

Return on Assets Ratio measures how the business is efficiently using its assets to generate returns.

Return on Equity Ratio measures the actual rate of return on the balance sheet shareholders' equity.

GENERAL

Residential Customers applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation.

General Service < 50 kW Customers applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW Customers applies to a non residential account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW.

Large User Customers applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW.

Sub Transmission applies to an account who has embedded supply to Local Distribution Companies or an account that is directly connected to and supplied by the distributor's assets.

Unmetered Scattered Load refers to certain instances where connections can be provided without metering.

Total kWh Supplied represents total kWhs of electricity that has flowed into the distributor's distribution system from the IESO-controlled grid or from a host distributor and from all embedded generation facilities.

Total kWh Delivered (excluding losses) represents the total kWhs of electricity delivered to all customers in the distributor's licensed service area, including wholesale market participants and any embedded distributors.

Total kWh Delivered on Long-Term Load Transfer represents the total kWhs of electricity delivered to load transfer customers from a geographic distributor to a physical distributor. A load transfer arrangement optimizes load service to specific customers where the geographic distributor is constrained in its ability to otherwise provide that load service. The geographic distributor is licensed to service the load transfer customer. The physical distributor provides the delivery of electricity to the load transfer customer.

Total Distribution Losses (kwh) is the sum of distribution system line losses, metering error and energy theft.

Winter Peak (kW) is the peak load on the distributor system for the period from November 1st to April 30th including load of embedded distributors.

Summer Peak (kW) is the peak load on the distributor system for the period from May 1st to October 31st including load of embedded distributors.

Average Peak (kW) is the average of the totalized distributor’s monthly or hourly peaks including load of embedded distributors.

Capital Additions ($) represent the investment for assets (including high voltage assets) placed in-service.

High Voltage Capital Additions ($) represent the investment for high voltage assets placed in-service.

Metered kWh (meter read) refers to the yearly billed kWhs without the loss factor.

SERVICE QUALITY REQUIREMENTS

Low Voltage Connections is the percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

High Voltage Connections is the percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

Telephone Accessibility is the percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds. Must be met 65% of the time.

Appointments Met is the percentage of appointments met where customer presence is required. Must be met 90% of the time.

Written Response to Enquiries is the percentage of customer inquiries relating to a customer's account and requiring a written response where the response is provided within 10 working days of receipt of the inquiry. Must be met 80% of the time.

Emergency Urban Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call. Urban areas are defined by the respective municipality. Must be met 80% of the time.

Emergency Rural Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call. Rural areas are defined by the respective municipality. Must be met 80% of the time.

Telephone Call Abandon Rate is the percentage of qualified calls (abandoned after 30 seconds) to a distributor's customer care telephone number that are abandoned before they are answered. Must be less than 10%.

Appointment Scheduling is the percentage of when a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place with in 5 business days. Must be met 90% of the time.

Rescheduling a Missed Appointment is the percentage of missed appointments that the customer is contacted within 1 business day to reschedule the appointment. Must be met 100% of the time.

Reconnection Performance Standard is the percentage of customers disconnected for non-payment who were reconnected within two business days. Must be met 85% of the time.

New Micro-embedded Generation Facilities Connected is the percentage of new micro-embedded generation facilities connected to its distribution system within 5 business days. Must be met 90% of the time.

Billing Accuracy Measure is the percentage of accurate bills expressed as a percentage of total bills issued. Must be met 98% of the time.

SYSTEM RELIABILITY INDICATORS

Average Number of Customers Served (by month) by a distributor is the average number of customers served in the distributor's licensed service area during the month. It is calculated by adding the total number of customers served on the first day of the month and the total number of customers served on the last day of the month and dividing by two. On an annual basis, the average number of customers served is calculated as the sum of 12 months, divided by 12.

Interruption is the loss of electrical power, being a complete loss of voltage, of a duration of one minute or more, to one or more customers, including planned interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics. The "cause of interruption codes" are provided below.

Customer-hours of Interruptions is the total number of hours of interruptions that all customers experienced for all hours of interruptions. As an example, if a distributor experienced 2 interruptions, where the first affected 100 customers for 1 hour, and the second affected 200 customers for 1.5 hours, the total customer-hours of interruption would be 400 customer-hours.

Customer Interruptions is the total number of customers affected by all interruptions. As an example, if a distributor experienced 2 interruptions where the first affected 100 customers, and the second affected 200 customers, then the total customer interruptions would be 300.

SAIDI (System Average Interruption Duration Index) is an index of system reliability that expresses the average amount of time per reporting period that the supply to a customer is interrupted. It is calculated by dividing the total monthly duration of all interruptions experienced by all customers, in hours, by the average number of customers served.

It is expressed as follows: Total customer hours of interruptions/ Average Number of Customers Served.

SAIFI (System Average Interruption Frequency Index) is an index of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. The index is calculated by dividing the total number of interruptions experienced by all customers, by the Average Number of Customers Served.

It is expressed as follows: Total customer interruptions/ Average Number of Customers Served.

Loss of Supply Adjusted System Reliability Indicators exclude outages caused by a loss of supply. Loss of supply refers to customer interruptions due to problems in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on established ownership demarcation points.

Loss of Supply and Major Event Adjusted System Reliability Indicators exclude outages caused by a loss of supply and outages related to Major Event(s).

CAUSE OF INTERRUPTION CODES

Cause Code 0 (Unknown/Other) includes customer interruptions with no apparent cause that contributed to the outage.

Cause Code 1 (Scheduled Outage) includes customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

Cause Code 2 (Loss of Supply) includes customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.

Cause Code 3 (Tree Contacts) includes customer interruptions caused by faults resulting from tree contact with energized circuits.

Cause Code 4 (Lightning) includes customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.

Cause Code 5 (Defective Equipment) includes customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

Cause Code 6 (Adverse Weather) includes customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).

Cause Code 7 (Adverse Environment) includes customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.

Cause Code 8 (Human Element) includes customer interruptions due to the interface of distributor staff with the distribution system.

Cause Code 9 (Foreign Interference) includes customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

Major Event is defined as an event that is beyond the control of the distributor and is:
- a) unforeseeable;
- b) unpredictable;
- c) unpreventable; or
- d) unavoidable.

Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

"Beyond the control of the distributor" means events that include, but are not limited to, force majeure events and Loss of Supply events.

Distributors shall include all outages that occurred during the Major Event, including those that may be unrelated to the event itself, but occurred at the same time.

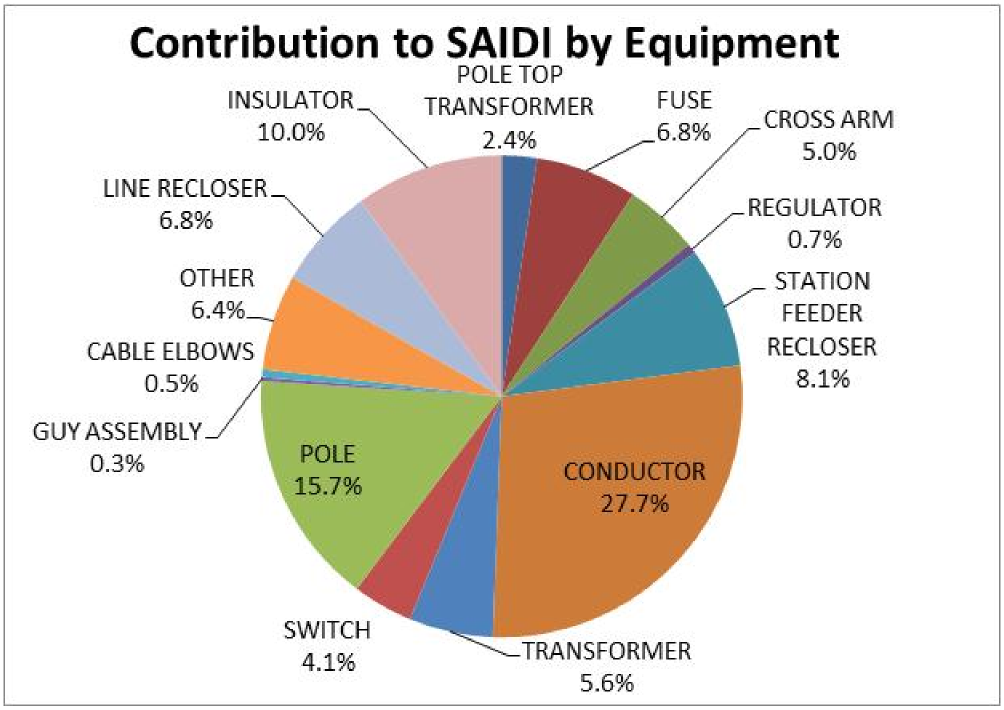
UNDERTAKING - TCJ1.05

Undertaking

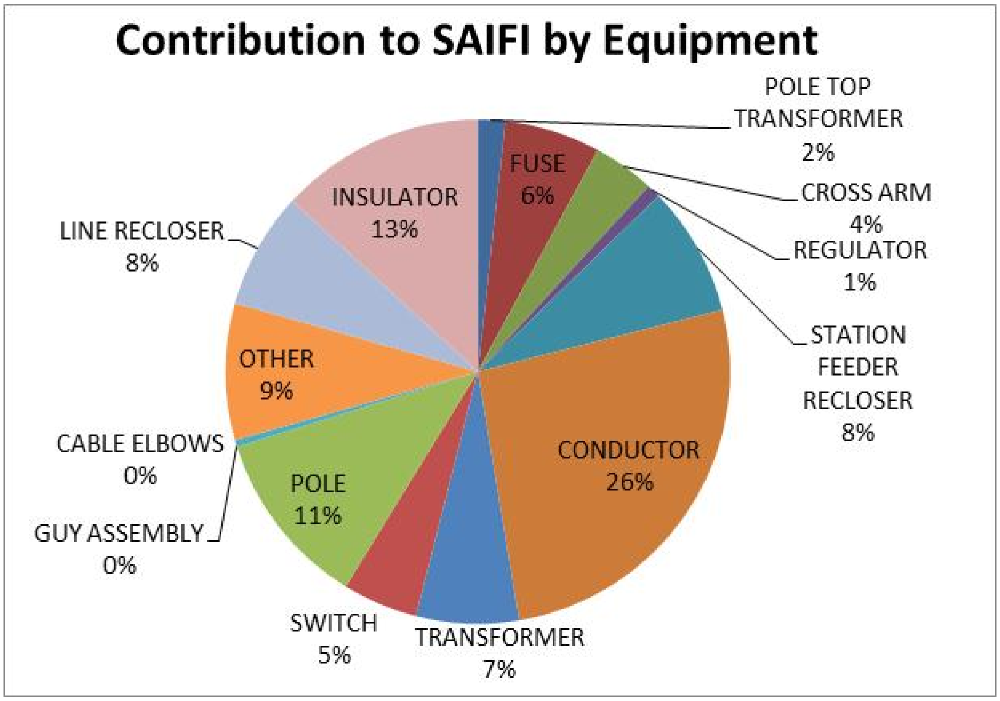
To provide a breakdown of the 10 percent of defective equipment that contributes to SAIDI, by equipment type, and a breakdown of the 14 percent defective equipment that contributes to SAIFI, by equipment type.

Response

In response to the question regarding defective equipment cited in Exhibit I, Tab 2.02, Schedule 14 AMPCO 4 and 5, the chart below shows the breakdown of the contribution to SAIDI of defective equipment by equipment type.



The chart below shows the breakdown of the contribution to SAIFI of defective equipment by equipment type.



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Ontario

ELECTRICITY REPORTING & RECORD KEEPING REQUIREMENTS
Version dated March 15, 2018

Table of Contents

1 GENERAL AND ADMINISTRATIVE PROVISIONS

1.1 The purpose of these reporting and record keeping requirements

These reporting and record keeping requirements set the minimum reporting and record keeping requirements with which a licensee must comply. Other reporting and record keeping requirements specific to a licensee may also be contained in codes, individual licences or regulatory instruments specific to a licensee (for example, in a rate order).

1.2 Definitions

"Act" means the Ontario Energy Board Act, 1998, c. 15, Schedule B;

"affiliate" has the meaning given to it under the Business Corporations Act (Ontario);

"Board" means the Ontario Energy Board;

"centralized service provider" means the centralized service provider engaged by the Board to administer the OESP on the Board's behalf;

"conditions of service" means the document developed by a distributor in accordance with section 2.4 of the Distribution System Code that describes the operating practices and connection policies of the distributor;

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

"distributor" means a person who owns or operates a distribution system and is licensed as a distributor by the Board;

"electricity storage provider" means a person who is licensed as an electricity storage provider by the Board;

"electricity transmission line" means a line, transformers, plant or equipment used for conveying electricity at voltages higher than 50 kilovolts; ("ligne de transport d'électricité") (section 89, OEB Act);

"eligible low-income customers" has the same meaning as in the Distribution System Code;

"generator" means a person who is licensed as a generator by the Board;

"IESO" means the Independent Electricity System Operator;

"information services" means computer systems, services, databases and persons knowledgeable about the utility's information technology systems;

"LEAP" means the Low-Income Energy Assistance Program established by the Board;

"OESP" means the Ontario Electricity Support Program established pursuant to section 79.2 of the Act;

"OESP tariff code" means the tariff code assigned to an OESP recipient by the centralized service provider;

"retailer" means a person who retails electricity and is licensed as a retailer by the Board;

“RPP” means the “Regulated Price Plan”, being the rates for commodity set by the Board from time to time under section 79.16 of the Act in accordance with the Standard Supply Service Code;

“SSS” means “standard supply service”, being the manner in which a distributor must fulfill its obligation to sell electricity under section 29 of the Electricity Act, 1998, including by giving or to give effect to RPP rates determined by the Board;

“transmitter” means a person who owns or operates a transmission system and is licensed as a transmitter by the Board;

“uniform system of accounts” means the system of accounts prescribed in the Board’s Accounting Procedures Handbook for Electric Distribution Utilities;

"unit sub-meter provider" means a person who is licensed as a unit sub-meter provider by the Board;

1.3 Interpretation and Computation of Time

Unless otherwise defined in these Electricity Reporting and Record Keeping Requirements, words and phrases shall have the meaning ascribed to them in the licences issued by the Board, the Act or the Electricity Act, 1998 as the case may be. Words importing the singular include the plural and vice versa. A reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document.

If the time for doing an act under these Electricity Reporting and Record Keeping Requirements expires on a day that is not a business day, the act may be done on the next day that is a business day. For this purpose, a “business day” means any day that is not a Saturday, a Sunday or a legal holiday in the Province of Ontario.

1.4 To whom these reporting and record keeping requirements apply

These Electricity Reporting and Record Keeping Requirements apply to all electricity distributors, transmitters, retailers, unit sub-meter providers, generators and electricity storage providers licensed by the Board under Part V of the Act and to the IESO. All licensed distributors, transmitters, retailers, unit sub-meter providers, generators and electricity storage providers and the IESO are obligated to comply with these Reporting and Record Keeping Requirements as a condition of their licence. However, the retailer provisions do not apply to distributors who are also licensed as retailers for the purpose of providing standard supply service.

1.5 Manner and format of reporting and record keeping

Licensed transmitters, distributors, retailers, unit sub-meter providers, generators and electricity storage providers and the IESO shall report and record information under these Electricity Reporting and Record Keeping requirements in the manner and form prescribed by the Board.

1.6 Periods for which information is reported

Annual reporting covers information for the entire calendar year, from January 1 to December 31. Quarterly reporting covers information for each quarter of the calendar year - from January 1 to March 31, April 1 to June 30, July 1 to September 30 and October 1 to December 31. Monthly reporting covers information for each entire month of the calendar year, from January to and including December.

1.7 Confidentiality of information

The Board intends to treat information filed under the specific sections of these Electricity Reporting and Record Keeping Requirements listed below in confidence. All other information filed will be publicly available.

> Distributor: 2.1.2 (b); 2.1.2 (c) and 2.1.2(d) to the extent that the information pertains to retailer customers; 2.3.1; 2.3.3; 2.3.5 (c), 2.3.5 (d); 2.3.6; 2.3.7; and 2.3.8
>
> Transmitter: 3.3.2; 3.3.4 (c and d); 3.3.5; and 3.3.6
>
> Retailer: 4.1.1; 4.1.2; 4.2.1; 4.2.2; 4.2.3; and 4.2.4

The Board reserves the right to disclose aggregated information as well as information in a form such that the identity of any individual cannot be determined. The Board cautions that information treated as confidential may still be disclosed in a proceeding before the Board. However, a party to that proceeding would be able to request the Board to hold the document in confidence in that proceeding. The Board further cautions that it is subject to the Freedom of Information and Protection of Privacy Act (Ontario).

2 DISTRIBUTORS

2.1 Reporting

2.1.1 A distributor shall provide in the form and manner required by the Board, quarterly, on the last day of the second month following the quarter end, balances of commodity deferral/ variance accounts referred to in the Accounting Procedures Handbook for Electric Distribution Utilities, their related sub- accounts and associated information required by the Accounting Procedures Handbook for Electric Distribution Utilities.

2.1.2 A distributor shall provide in the form and manner required by the Board, quarterly, by the end of the second month following the quarter end, a summary of the following market monitoring information:

a) Total number of customers on SSS for each rate class sub-divided by (i) customers on the RPP, broken down as required by (g) below if applicable; and (ii) customers not on the RPP, at the end of the preceding quarter;

b) The number of wholesale market participants connected to the distributor's distribution system, at the end of the preceding quarter;

c) For each of the first three quarters of the year, total number of customers successfully enrolled with retailers (completed enrollments accepted by the distributor for flow only) at the end of each quarter, broken down by rate class;

d) For the last quarter of the year, total number of customers successfully enrolled with retailers (completed enrollments accepted by the distributor for flow only) at the end of that quarter, broken down by individual retailer and by rate class;

e) For (a) above, by rate class, the total number of properties or complexes for which a declaration has been filed with the distributor under section 3.3.4 of the Standard Supply Service Code;

f) For each property or complex referred to in (e) above, the total number of units identified in the declaration; and

Distributors whose rates are not set by the Board are exempt from this reporting requirement.

2.1.3 Intentionally left blank.

2.1.4 A distributor shall provide, in the form and manner required by the Board, annually, by April 30, the information set out in sections 2.1.4.1 and 2.1.4.2 measuring its performance for the preceding calendar year for each of the service quality requirements set out in the Distribution System Code and for each of the system reliability indicators listed below.

2.1.4.1 Reporting on Service Quality Requirements

2.1.4.1.1 In respect of the service quality requirement for the “Connection of New Services” referred to in section 7.2 of the Distribution System Code:

a) Total number of new low voltage services connected in each month;

b) Number of new low voltage services connected in each month for which the service quality requirement set out in section 7.2 of the Distribution System Code was met;

c) Percentage of (b) with respect to (a);

d) Total number of new high voltage services connected in each month;

e) Number of new high voltage services connected in each month for which the service quality requirement set out in section 7.2 of the Distribution System Code was met; and

f) Percentage of (e) with respect to (d).

2.1.4.1.2 In respect of the service quality requirement for “Appointment Scheduling” as set out in section 7.3 of the Distribution System Code:

a) Total number of appointments described in section 7.3 of the Distribution System Code requested in each month;

b) Number of appointments in each month for which the service quality requirement set out in section 7.3 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a).

2.1.4.1.3 In respect of the service quality requirement for “Appointments Met” as set out in section 7.4 of the Distribution System Code:

a) Total number of appointments described in section 7.4 of the Distribution System Code requested or required in each month;

b) Number of appointments in each month for which the service quality requirement set out in section 7.4 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a).

2.1.4.1.4 In respect of the service quality requirement for “Rescheduling a Missed Appointment” as set out in section 7.4 of the Distribution System Code:

a) Total number of missed appointments described in section 7.5 of the Distribution System Code in each month;

b) Number of missed appointments in each month for which the service quality requirement set out in section 7.5 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a).

2.1.4.1.5 In respect of the service quality requirement for “Telephone Accessibility” as set out in section 7.6 of the Distribution System Code:

a) Total number of qualified incoming calls in each month;

b) Number of qualified incoming calls in each month for which the service quality requirement set out in section 7.6 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a).

2.1.4.1.6 In respect of the service quality requirement for “Telephone Call Abandon Rate” set out in section 7.7 of the Distribution System Code:

a) Total number of qualified incoming calls in each month;

b) Number of qualified incoming calls in each month that were abandoned before they were answered as described in section 7.7.2 of the

Distribution System Code; and

c) Percentage of (b) with respect to (a).

2.1.4.1.7 In respect of the service quality requirement for "Written Responses to Enquiries" as set out in section 7.8 of the Distribution System Code:

a) Total number of qualified enquiries received in each month;

b) Number of qualified enquiries in each month for which the service quality requirement set out in section 7.8 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a).

2.1.4.1.8 In respect of the service quality requirement for "Emergency Response" as set out in section 7.9 of the Distribution System Code:

a) Total number of emergency calls received in each month;

b) Number of emergency calls in each month for which the service quality requirement set out in section 7.9 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a)

2.1.4.1.9 In respect of the service quality requirement for "Reconnection Performance Standards" as set out in section 7.10 of the Distribution System Code;

a) Total number of reconnections in each month;

b) Number of reconnections in each month for which the service quality requirement as set out in section 7.10 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a)

2.1.4.1.10 In respect of the service quality requirement for new micro-embedded generation facility connections on time as set out in section 6.2.7 of the Distribution System Code:

a) Total number of new micro-embedded generation facilities connected in each month;

b) Number of new micro-embedded generation facilities connected in each month for which the service quality requirement as set out in section

6.2.7 of the Distribution System Code was met; and

c) Percentage of (b) with respect to (a)

2.1.4.2 Reporting on System Reliability Indicators

1. Filings due on April 30, 2014 for the reporting period January – December 2013, shall be in accordance with section 2.1.4.2 as it reads in the January 1, 2013 version of this document.

2. For filings due after April 30, 2014:

The following definitions apply for the purposes of monitoring and reporting on each of the system reliability indicators set out below:

Definitions:

1) The "Average Number of Customers Served" by a distributor is the average number of customers served in the distributor's licensed service area during the month, calculated by adding the total number of customers served on the first day of the month and the total number of customers served on the last day of the month and dividing by two.

   Bulk metered buildings with individual smart sub-metering installations shall be counted as a single customer, provided that any suite metering system is not operated by the distributor and that such customers are not billed by the distributor.

   Unmetered load customers should not be included in the customer count.

2) A "Customer" means a metered service for which an active account is established at a specific premise.

3) An "Interruption" means the loss of electrical power, being a complete loss of voltage, of a duration of one minute or more, to one or more customers, including planned interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics.

4) In calculating the duration of an interruption the start of the interruption shall be considered to have occurred on the earlier of:

   a) The time at which the distributor received a communication from a customer reporting the interruption; or

   b) The time at which the distributor otherwise determined that the interruption began.

5) In calculating the duration of an interruption, the end of the interruption shall be considered to have occurred when service has been restored to the customer demarcation point. This time may be determined by either the time the restoring crew reports the restoration was complete or the time at which the distributor otherwise determined the restoration was complete.

   The process of restoration may require restoring service in stages to small sections of the system until service has been restored to all customers. Each of these individual stages should be tracked, collecting the start time, end time and number of customers interrupted and restored for each stage. Any temporary restoration of supply which does not exceed 3 minutes shall be ignored and the interruption must be treated as continuous.

6) “Loss of Supply” means an interruption due to problems associated with assets owned and/or operated by another party, and/or the bulk electricity supply system.

7) “Major Event” is defined as an event that is beyond the control of the distributor and is:

   a) unforeseeable;
   b) unpredictable;
   c) unpreventable; or
   d) unavoidable.

   Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

   “Beyond the control of the distributor” means events that include, but are not limited to, force majeure events and Loss of Supply events.

   When assessing whether a substantial number of customers were affected and whether it took significantly longer to restore service than normal, distributors shall follow the Canadian Electricity Association’s <u>Major Event Determination Reference Guide</u>. As set out in the Guide distributors shall use one of the following approaches:

a) The IEEE Standard 1366 approach (preferred method);
b) The IEEE Standard 1366 approach, using a two day rolling average; or
c) The fixed percentage approach (i.e., 10% of customers affected).

Distributors shall include all outages that occurred during the Major Event, including those that may be unrelated to the event itself, but occurred at the same time.

2.1.4.2.1 System Average Interruption Duration Index (SAIDI)

SAIDI is an index of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted. It is determined by dividing the total monthly duration of all interruptions experienced by all customers, in hours, by the average number of customers served. SAIDI is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total customer hours of interruptions}}{\text{Average number of customers served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total number of customer-hours of interruptions in each month;

b) Average number of customers served in each month; and

c) SAIDI, being (a)/ (b).

2.1.4.2.2 SAIDI (Loss of Supply)

This index adjusts SAIDI for the effects of interruptions caused by Loss of Supply, and is calculated in the same way as described in section 2.1.4.2.1, except that the total customer-hours of interruptions caused by Loss of Supply events is deducted from the total customer-hours of interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total customer-hours of interruptions in each month;

b) Total customer-hours of interruptions in each month caused by a Loss of Supply;

c) Average number of customers served in each month; and

d) Adjusted SAIDI, being ((a) - (b))/(c).

2.1.4.2.3 System Average Interruption Frequency Index (SAIFI)

SAIFI is an index of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the average number of customers served.

SAIFI is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total customer interruptions}}{\text{Average number of customers served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total number of interruptions in the month;

b) Average number of customers served in each month; and

c) SAIFI, being (a)/ (b).

2.1.4.2.4 SAIFI (Loss of Supply)

This index adjusts SAIFI for the effects of interruptions caused by Loss of Supply, and is calculated in the same way as described in section 2.1.4.2.3, except that the total number of interruptions caused by Loss of Supply events is deducted from the total interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the calendar year:

a) Total number of customer interruptions in each month;

b) Total number of customer interruptions in each month caused by Loss of Supply;

c) Average number of customers served in each month; and

d) Adjusted SAIFI, being ((a) - (b))/(c).

2.1.4.2.5 Reporting Cause Codes

For each Cause of Interruption as set out below, a distributor shall, for each month, report the following data:

a) Name of the Cause of Interruption;

b) Number of interruptions that occurred as a result of the Cause of Interruption;

c) Number of customer interruptions that occurred as a result of the

Cause of Interruption; and

d) Number of customer-hours of interruptions that occurred as a result of the cause of interruption.

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	**Loss of Supply** Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits.
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system.
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.
10	**Major Event** Customer interruptions due to a Major Event. These interruptions should also be counted under the actual Cause of Interruption listed above.

2.1.4.2.6 Measuring and Reporting Practices

A distributor shall report to the Board if it has introduced, or is in the process of introducing, any new system reliability measuring and reporting practices or any new distribution system technologies that impacted its reported performance results for the current year in comparison to previous years.

This report shall describe the new practice or technology, the current status of the implementation of the new practice or technology, and the scope of the impact, including the percentage of change between the results reported in the previous year and the results reported in the current year.

2.1.4.2.7 Identifying Outage Start Time

A distributor shall report to the Board whether the greatest number of its outage start times were a) the time at which the distributor received a communication from a customer reporting the interruption; or b) the time at which the distributor otherwise determined that the interruption began.

2.1.4.2.8 SAIDI (Major Events)

This index adjusts SAIDI for the effects of interruptions caused by Major Events, and is calculated in the same way as described in section 2.1.4.2.1, except that the total customer-hours of interruptions caused by Major Events is deducted from the total customer-hours of interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total customer-hours of interruptions in each month;
b) Total customer-hours of interruptions in each month caused by Major Events;
c) Average number of customers served in each month; and
d) Adjusted SAIDI, being ((a) - (b))/(c).

2.1.4.2.9 SAIFI (Major Events)

This index adjusts SAIFI for the effects of interruptions caused by Major Events, and is calculated in the same way as described in section 2.1.4.2.3, except that the total number of interruptions caused by Major Events is deducted from the total interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the calendar year:

a) Total number of customer interruptions in each month;

b) Total number of customer interruptions in each month caused by Major Events;
c) Average number of customers served in each month; and
d) Adjusted SAIFI, being ((a) - (b))/(c).

2.1.4.2.10 Major Event Response Reporting

When a distributor determines an outage was caused by a Major Event, it shall file a report with the OEB that outlines the distributor's response to the Major Event, including answers to all of the questions set out below.

A distributor shall file this report with the OEB within 60 days of the end of the Major Event unless there are exceptional circumstances, in which case the report can be filed within 90 days of the end of the Major Event. The distributor shall also post this report on its website at the same time it is filed with the OEB.

Prior to the Major Event

1. Did the distributor have any prior warning that the Major Event would occur?
2. If the distributor did have prior warning, did the distributor arrange to have extra employees on duty or on standby prior to the Major Event beginning? If so, please give a brief description of arrangements.
3. If the distributor did have prior warning, did the distributor issue any media announcements to the public warning of possible outages resulting from the pending Major Event? If so, through what channels?
4. Did the distributor train its staff on the response plans for a Major Event? If so, please give a brief description of the training process.
5. Did the distributor have third party mutual assistance agreements in place prior to the Major Event? If so, who were the third parties (i.e., other distributors, private contractors)?

During the Major Event

1. Please explain why this event was considered by the distributor to be a Major Event.

2. Was the IEEE Standard 1366 used to identify the scope of the Major Event? If not, why not?
3. Please identify the Cause of Interruption for the Major Event as per the table in section 2.1.4.2.5.
4. Were there any declarations by government authorities, regulators or the grid operator of an emergency state of operation in relation to the Major Event?
5. When did the Major Event begin (date and time)?
6. What percentage of on-call distributor staff was available at the start of the Major Event and utilized during the Major Event?
7. Did the distributor issue any estimated times of restoration (ETR) to the public during the Major Event? If so, through what channels?
8. If the distributor did issue ETRs, at what date and time did the distributor issue its first ETR to the public?
9. Did the distributor issue any updated ETRs to the public? If so, how many and at what dates and times were they issued?
10. Did the distributor inform customers about the options for contacting the distributor to receive more details about outage/restoration efforts? If so, please describe how this was achieved.
11. Did the distributor issue press releases, hold press conferences or send information to customers through social media notifications? If so, how many times did the distributor issue press releases, hold press conferences or send information to customers through social media notifications? What was the general content of this information?
12. What percentage of customer calls were dealt with by the distributor’s IVR system (if available) versus a live representative?
13. Did the distributor provide information about the Major Event on its website? If so, how many times during the Major Event was the website updated?
14. Was there any point in time when the website was inaccessible? If so, what percentage of the total outage time was the website inaccessible?
15. How many customers were interrupted during the Major Event? What percentage of the distributor’s total customer base did the interrupted customers represent?
16. How many hours did it take to restore 90% of the customers who were interrupted?

17. Was any distributed generation used to supply load during the Major Event?
18. Were there any outages associated with Loss of Supply during the Major Event? If so, please report on the duration and frequency of Loss of Supply outages.
19. In responding to the Major Event, did the distributor utilize assistance through a third party mutual assistance agreement?
20. Did the distributor run out of any needed equipment or materials during the Major Event? If so, please describe the shortages.

After the Major Event

1. What steps, if any, are being taken to be prepared for or mitigate such Major Events in the future (i.e., staff training, process improvements, system upgrades)?
2. What lessons did the distributor learn in responding to the Major Event that will be useful in responding to the next Major Event?
3. Did the distributor survey its customers after the Major Event to determine the customers' opinions of how effective the distributor was in responding to the Major Event? If so, please describe the results.

2.1.5 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the information set out in sections 2.1.5.1 to 2.1.5.6 related to performance based regulation for the preceding calendar year.

2.1.5.1 Labour

a) Full time equivalent number of employees;

b) For employees whose earnings are charged to current operating expenses (Administrative, operating and maintenance):

   i. Average number of such employees for the year; and

   ii. Total salaries and wages for those employees;

c) For employees whose earnings are charged to new construction:

   i. Average number of such employees for the year; and

   ii. Total salaries and wages for those employees

The following rules apply for the purposes of this section:

   i. Report only in relation to employees and earnings associated with the utility (for example, excluding contractor staff and employees of affiliates);

ii. Report salaries and wages on the basis of gross earnings, including income tax, health insurance or employment insurance deductions, and should include all bonuses, overtime payments and the value of room and board where provided;

iii. Include salary and wages paid to part-time employees; and

iv. Report the total number of employees on a full-time equivalent basis.

The information referred to in (b) and (c) above is being collected on behalf of, and for purposes of communication to, Statistics Canada. See the 2008 Agreement Concerning the Disclosure of Energy Information by the Ontario Energy Board to Statistics Canada between the Board and Statistics Canada, available on the Board's website at *http://www.ontarioenergyboard.ca/documents/tools/efiling/statscan_signed_agre ement_2008.pdf*.

2.1.5.2 Capital

In reporting on the following, only regulated amounts should be included.

a) Changes in Gross Capital Assets

A distributor shall provide annually, by April 30, for the preceding calendar year, the dollar value of changes to gross property, plant and equipment and the breakdown in each category below, for total capital additions (including high voltage assets) and high voltage (HV) capital additions reported separately:

i. Gross capital additions for the current year

ii. Retirements/write offs/sales/asset impairment losses

iii. Contributed capital, and

iv. Other – please explain

b) Capital Expenditures:

In addition to the above, a distributor shall provide annually, by April 30, for the preceding calendar year, the breakdown of capital expenditures, as follows:

i. Direct labour (including benefits etc.)

ii. Equipment and materials

iii. Capitalized overhead

iv. Contract services

v. Other – please explain

c) Please provide an explanation if information in any of the categories is not available in the format required above.

2.1.5.3 Supply and Delivery Information

For the purposes of this section, all kWhs other than in relation to distribution losses shall be reported based on a reading of the applicable meter, without being grossed up for loss factor.

a) Supply:

i. Total kWhs of electricity that has flowed into the distributor's distribution system from the IESO-controlled grid or the distribution system of a host distributor; and

ii. Total kWhs of electricity that has flowed into the distributor's distribution system from all embedded generation facilities.

b) Delivery: Total kWhs of electricity delivered to all customers in the distributor's licensed service area and to embedded distributors.

c) Distribution losses in kWhs, calculated as the difference between the supply as reported in a(i) and a(ii) above, less delivery as reported in b) above.

d) The dollar amount charged by any host distributor for transmission or low voltage services.

2.1.5.4 Demand and Revenue

2.1.5.4.1 Annual consumption (kWhs & kWs) for customers, broken down as follows:

a) For customers on SSS, by rate class sub-divided by (i) consumption for customers on the RPP; and (ii) consumption for customers not on the RPP;

b) The billed kWhs for wholesale market participants connected to the distributor's distribution system;

c) For customers successfully enrolled with a retailer (completed enrollments accepted by the distributor for flow only), consumption in kWhs, broken down by individual retailer and by rate class; and

d) Total consumption in kWhs for each of street lighting connections and sentinel lighting connections (both as defined in the distributor's Board-approved tariff of rates and charges).

All kWhs and kWs shall be reported based on a reading of the applicable meter, without being grossed up for loss factor.

2.1.5.4.2 Annual Billings (in dollars) broken down by : Rate class, embedded distributors, wholesale market participants, connections for street lighting and connections for sentinel lighting (both as defined in the distributor's Board- approved tariff of rates and charges).

Distributors whose rates are not set by the Board are exempt from this reporting requirement.

2.1.5.5 Utility Characteristics

a) Licensed Service Area (Sq. Kms.) in total, and broken down by rural and urban.

b) Maximum Monthly Peak Load (kW) for each of winter and summer. This is the non-coincident peak reported both inclusive and exclusive of embedded generation.

c) Average Peak Load (kW), reported both inclusive and exclusive of embedded generation.

d) Average Load Factor (%), reported both inclusive and exclusive of embedded generation.

e) Circuit Kilometers of Line (route kms) in total, and broken down by overhead and underground.

2.1.5.6 Regulated Return on Equity (ROE)

A distributor shall report, in the form and manner determined by the Board, the regulatory return on equity earned in the preceding fiscal year. The reported return is to be calculated on the same basis as was used in establishing the distributor's base rates.

2.1.6 A distributor shall provide the Board annually, by April 30, audited financial statements for the preceding calendar year for the corporate entity regulated by the Board. Where the financial statements of the corporate entity regulated by the Board contain material businesses not regulated by the Board, or where the regulated entity conducts more than one activity regulated by the Board, the distributor shall disclose separately information about each operating segment in accordance with the Segment Disclosure provisions corporate entities are encouraged to adopt by the Canadian Institute of Chartered Accountants Handbook.

2.1.7 A distributor shall provide the Board annually, by April 30, a trial balance in uniform system of accounts format supporting the audited financial statements, for the preceding calendar year. A distributor may, for reporting purposes, include data relating to employee salaries in a similar salary account in the uniform system of accounts in cases where the number of distributor employees is such that separate reporting could result in the disclosure of an individual's salary information.

2.1.8 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the following information for the preceding calendar year with respect to residential customers and eligible low-income customers:

a) Number of Eligible Low-Income Customer Accounts

   i Number of eligible low-income customer accounts at year end.

b) Disconnections for Non-Payment

   i Number of residential customer accounts disconnected for non-payment during the course of the year; and ii Number of eligible low-income customer accounts disconnected for non-payment during the course of the year.

c) Arrears and Arrears Payment Agreements under the Distribution System Code

i Number of residential customer accounts in arrears at year end;

ii Number of eligible low-income customer accounts in arrears at year end;

iii Total dollar amount of arrears for residential customer accounts in arrears at year end;

iv Total dollar amount of arrears for eligible low-income customer accounts in arrears at year end;

v Number of arrears payment agreements entered into during the course of the year with residential customers;

vi Number of arrears payment agreements entered into during the course of the year with eligible low-income customers;

vii Total amount of monies owing under arrears payment agreements entered into during the course of the year with residential customers;

viii Total amount of monies owing under arrears payment agreements entered into during the course of the year with eligible low-income customers;

ix Number of arrears payment agreements with residential customers that were cancelled during the course of the year due to non-payment; and

x Number of arrears payment agreements with eligible low-income customers that were cancelled during the course of the year due to non-payment.

d) Write-offs

i Number of residential customer accounts written-off in whole or in part during the course of the year;

ii Number of eligible low-income customer accounts written-off in whole or in part during the course of the year;

iii Total dollar amount of write-offs for residential customer accounts during the course of the year; and

iv Total dollar amount of write-offs for eligible low-income customer accounts during the course of the year.

e) Equal Billing and Equal Monthly Payment Plans under the Standard Supply Service Code

i Number of residential customer accounts enrolled in equal billing plans at year end;

ii Number of eligible low-income customer accounts enrolled in equal billing plans at year end;

iii Number of residential customer accounts enrolled in equal monthly payment plans at year end; and

iv Number of eligible low-income customer accounts enrolled in equal monthly payment plans at year end.

f) Security Deposits

i Number of residential customer accounts with security deposits held at year end;

ii Total dollar amount of security deposits held in respect of residential customers at year end;

iii Number of eligible low-income customer accounts with security deposits held at year end; and

iv Total dollar amount of security deposits held in respect of eligible low-income customers at year end.

g) Load Control Devices

i Number of residential customer accounts where load limiter devices were installed during the course of the year;

ii Number of eligible low-income customer accounts where load limiter devices were installed during the course of the year;

iii Number of residential customer accounts where timed load interrupter devices were installed during the course of the year; and

iv Number of eligible low-income customer accounts where timed load interrupter devices were installed during the course of the year.

For the purposes of this section:

1. Reporting on information regarding residential customers shall cover all residential customers, including eligible low-income customers; and
2. The following definitions apply:

   "Arrears" means an account that is 30 or more days past the minimum payment period as determined according to section 2.6.3 of the Distribution System Code;

   "Eligible low-income customer" means an eligible low-income electricity customer, as defined in sections 1.2, 1.3.2 and 1.3.3 of the Distribution System Code, Retail Settlement Code or Standard Supply Service Code;

   "Equal billing plan" means a billing plan where the amount due in each bill is equalized over the course of the billing periods in the year, which may occur on a monthly, bi-monthly or quarterly basis;

   "Equal monthly payment plan" means a payment plan where an equalized amount is automatically withdrawn from a customer's account at a financial institution on a monthly basis, followed by a bill on a monthly, bi- monthly or quarterly basis;

"Load control device" has the same meaning as set out in the definition section of the Distribution System Code;

"Load limiter device" has the same meaning as set out in the definition section of the Distribution System Code;

"Timed load interrupter device" has the same meaning as set out in the definition section of the Distribution System Code.

2.1.9 Beginning in 2017, a distributor shall provide in the form and manner required by the Board, annually, by April 30, the following information related to the provision of the OESP in the preceding calendar year:

a) The number of OESP recipients at year end;

b) The number of OESP recipients in the year who were no longer receiving OESP at year end; and

c) The number of OESP recipients who also received a LEAP emergency financial assistance grant during the year.

2.1.10 Intentionally left blank.

2.1.11 Intentionally left blank.

2.1.12 Intentionally left blank.

2.1.13 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the uniform system of account balances mapped and reconciled to the audited financial statements.

2.1.14 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the following net metering and embedded generation information for the preceding calendar year:

a) Number of net metered generators (as defined in section 6.7.1 of the Distribution System Code) by renewable energy source;

b) Total installed capacity (kW) of net metered generators by renewable energy source;

c) Total installed capacity (kW) of storage devices used by net metered generators by renewable energy source;

d) Number of embedded generation facilities connected to the distributor's distribution system, excluding those counted in (a) above; and

e) Total installed capacity (kW) of the embedded generators referred to in (d) above.

2.1.14.1 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the annual maximum peak load (kW) for the distributor's licensed service area that is used to calculate the distributor's maximum "cumulative generation capacity from net metered generators” (as described in section 6.7.2 of the Distribution System Code). The information provided must be for the preceding three calendar years.

2.1.15 A distributor shall provide in the form and manner required by the Board, quarterly, on the last day of the second month following the quarter end, for each month in the quarter, the following information:

a) For renewable energy generation facilities that have a name-plate rated capacity of greater than 10 kW:

i The number of Connection Impact Assessments (“CIA”) completed in the quarter;

ii The total name-plate rated capacity (in kWs) of the renewable energy generation facilities for which CIAs were completed as reported under (i) above;

iii Of the CIAs completed as reported under (i) above, the number that were completed within the applicable timeline prescribed by Ontario Regulation 326/09 made under the Electricity Act, 1998; and

iv Of the number of CIAs completed as reported under (i) above, the number that were not completed within the applicable timeline prescribed by Ontario Regulation 326/09 made under the Electricity Act, 1998.

b) For renewable energy generation facilities that have a name-plate rated capacity of less than or equal to 10kW:

i The number of Offers to Connect made; and

ii The total name-plate rated capacity (in kWs) of the renewable energy generation facilities for which Offers to Connect were made as reported under (i) above.

2.1.16 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the following information related to the provision of LEAP emergency financial assistance in the preceding calendar year:

a) LEAP funds, in total and broken down as follows:

i Funds provided by the distributor to social agencies for: LEAP emergency financial assistance;

ii Unused funds carried forward from the previous year(s); and

iii Funds received by the distributor’s social agency partner(s) from non-distributor sources (i.e. donations) that were earmarked for, and used to top up, the LEAP emergency financial assistance funds.

Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s) shall be reported under item (iii)

Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

b) LEAP funds disbursed, in total and broken down as follows:

   i Money allocated for agency administration and program delivery;

   ii Grants provided to the distributor's customers; and

   iii Grants provided to customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

c) The month in which LEAP funds were depleted.

d) Number of applicants for LEAP emergency financial assistance, in total and broken down as follows:

   i Applicants that were the distributor's customers; and

   ii Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

e) Number of LEAP emergency financial assistance applicants assisted, in total and broken down as follows:

   i Applicants who were approved for and received assistance that were customers of the distributor; and

   ii Applicants who were approved for and received assistance that were customers of unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

f) Number of LEAP emergency financial assistance applicants denied, in total and broken down as follows:

   i Applicants that were customers of the distributor and that applied for assistance but were not approved; and

   ii Applicants that were customers of unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such, and that applied for assistance but were not approved.

g) Average grant per accepted applicant assisted, as follows:

   i Average grant amount allocated per applicant, for applicants that were customers of the distributor;

   ii Average grant amount allocated per applicant, for applicants that were customers of unit sub-metering providers operating in the distributor's service area; including the distributor if licensed as such; and iii Average grant amount allocated per applicant, measured across customers referred to in both (i) and (ii).

h) Confirmation that the distributor's social agency partner(s) has/have adhered to the processes and requirements set out in the "OESP & LEAP Program Manual".

i) Beginning in 2017, the number of applicants for LEAP emergency financial assistance in the preceding calendar year who had previously received LEAP emergency financial assistance in the calendar year before that (repeat applicants), in total and broken down as follows:

i Applicants who were the distributor's customers; and

ii Applicants who were customers of licensed unit sub-meter providers operating in the distributor's service area, including the distributor if licensed as such.

2.1.17 A distributor shall provide the Board annually, by April 30, the following information as at the end of the preceding calendar year for all customers whose annual distribution revenue exceeds five percent of the distributor's annual distribution revenues:

a) The nature of the customer's sector (e.g. municipalities, universities, schools and hospitals ("MUSH"), the resource sector, manufacturing, agriculture, forestry, telecom, technology, etc.)

b) The annual distribution revenues of each customer; and

c) The customer's annual load (kWh and kW) in the preceding calendar year.

2.1.18 A distributor shall immediately report to the Board any concern for a potential loss of customer(s) or an incurred loss of customer(s) as well as any material* reduction in customer load, as reported in its last annual filing.

**Materiality for a customer load reduction is considered when there is an impact of five percent or more on the distributor's annual distribution revenues.*

2.1.19 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the following information for the preceding calendar year:

a) First contact resolution;

b) Billing accuracy (as set out in section 7.11 of the Distribution System Code);

c) Customer satisfaction survey results;

d) Public safety; and

e) Distribution system plan implementation progress

For the purposes of Public Safety, RRR section 2.1.19 (d), the following definitions and targets apply:

"Public Awareness of Electrical Safety" means the level of public awareness within the electricity distributor's service territory of electrical safety information and precautions related to distribution network assets.

The performance target for Public Awareness of Electrical Safety will be established once three years of data is gathered from the electricity distributors. The target for Public Awareness of Electrical Safety will be set after the information for years 2015 to 2017 is collected from electricity distributors. The target will be shown on the scorecard for the 2018 performance data.

"Compliance with Ontario Regulation 22/04; Electrical Distribution Safety" means the level of the electricity distributor's compliance with Ontario Regulation 22/04- Electrical Distribution Safety as measured by:

- *Evaluation of annual audit of compliance submitted by electricity distributor (section 4-8) and declaration of compliance (sections 3,9-12)*
- *Evaluation of Due Diligence Inspection (DDIs) and Reports of Public Safety Concerns*

The performance target for level of compliance with Ontario Regulation 22/04 is for the distributor to be fully compliant with Ontario Regulation 22/04.

"Serious Electrical Incident Index" means the number of non-occupational (general public) serious electrical incidents involving electricity distributor owned assets as defined by Ontario Regulation 22/04 - Electrical Distribution Safety, as measured by the number of and rate of serious electrical incidents occurring on an electricity distributor's assets per 10,100 or 1000 km of line.

The performance target for Serious Electrical Incident Index will be set based on distributor's specific performance target using the distributor's historical data and prior performance.

2.1.20 A distributor shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the distributor has publicly traded securities; and

b) a list of affiliates of the distributor that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

2.1.21 A distributor shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

2.2 Certification

2.2.1 A distributor shall provide in the form and manner required by the Board, annually, by April 30, a self-certification statement signed by the chief executive officer of the utility confirming that the chief executive officer is satisfied that the utility has complied with the Affiliate Relationships Code for Electricity Distributors and Transmitters.

2.3 Record Keeping

2.3.1 A distributor shall maintain records of all complaints by consumers and market participants regarding services provided under the terms of the distributor's licence and responses for a period of two years and provide the following information, in a form and manner and at such times as may be requested by the Board:

a) The name and address of the complainant;

b) A description of the nature of the complaint including a copy of the written complaint;

c) A description of the remedial action taken; and

d) A copy of any correspondence received and/or sent with respect to each specific complaint.

2.3.2 Intentionally left blank.

2.3.3 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, detailed records of all economic evaluations conducted to comply with the requirements of by the Distribution System Code. The records are to be retained for two years beyond the end of the customer connection horizon specified in Appendix B to the Distribution System Code.

2.3.4 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, records on corporate relationships as follows:

a) A list of all affiliates with whom the utility transacts, including business addresses, a list of the officers and directors, and a description of the affiliate's business activity;

b) A corporate organization chart indicating relationships and ownership percentages; and

c) The utility's specific costing and transfer pricing guidelines, tendering procedures and all Services Agreement(s). (as defined in the Affiliate Relationships Code for Electricity Distributors and Transmitters).

2.3.5 Where the total cost of all transactions with a particular affiliate exceeds$100,000 on an annual basis, a distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, separate records showing:

a) The name of the affiliate;

b) The product, service, resource or use of asset in question;

c) The dollar value of each transaction and the form of price or cost determination; and

d) The date of each transaction and/or the start and completion dates for project-type transactions.

2.3.6 Where a distributor shares information services with an affiliate the distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, separate records substantiating all review(s) complying with the provisions of Canadian Standard on Assurance Engagements, Reporting on Controls at a Service Organization (CSAE 3416).

2.3.7 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, records substantiating the self- certification statement referred to in section 2.2.1 confirming compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters, including individual files for each compliance review containing working papers substantiating the compliance review report.

2.3.8 A distributor shall file with the Board, on request, copies of service agreements with retailers.

2.3.9 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, records of both annual summary reports of detailed patrol inspection activities of the condition of the distribution system that have taken place during the previous year as well as an outline of inspection plans (compliance plans) for the next year, as described in Appendix C of the Distribution System Code.

2.3.10 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, information on affiliate arrangements and transactions, as follows:

a) For each affiliate with which the distributor has or had an Affiliate Contract for the provision of a service, resource, product or use of asset from the distributor to the affiliate: (i) the name of the affiliate; (ii) the number of Affiliate Contracts with the affiliate; and (iii) the total annual dollar value of all transactions under each such Affiliate Contract;

b) For each affiliate with which the distributor has or had an Affiliate Contract for the provision of a service, resource, product or use of asset to the distributor from the affiliate: (i) the name of the affiliate; (ii) the number of Affiliate Contracts with the affiliate; and (iii) the total annual dollar value of all transactions under each such Affiliate Contract; and

c) The highest total dollar value of all financial support to all affiliates outstanding at any time during a specified period.

For the purposes of this section:

"Affiliate Contract" means a contract between a distributor and an affiliate, and includes a Services Agreement;

"financial support" means any form of financial support to an affiliate, including a loan to, a guarantee of indebtedness of and an investment in the securities of the affiliate; and;

"Services Agreement" means an agreement between a distributor and its affiliate for the purposes of section 2.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters

2.3.11 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, records on applications for the connection of embedded generation facilities to the distribution system, including connections to distribution systems embedded within the distributor's system, and that information shall include the following in relation to each application:

a) The name of the applicant and the date of the applicant's request for a preliminary meeting;
b) The proposed generation facility's fuel type, size, and location;
c) The dates the applicant is provided with an impact assessment, a capacity allocation, a detailed cost estimate, and an offer to connect;
d) The impact assessment, including metering requirements, the detailed cost estimate, and the offer to connect;
e) The date the distributor advises any directly connected transmitter or distributor under section 6.2.14A or 6.2.17 of the Distribution System Code;
f) The date and reasons for the removal of capacity previously allocated to an applicant; and
g) The date the distributor connects the generation facility to its distribution system.

2.3.12 Intentionally left blank.

2.3.13 A distributor shall record, retain and provide to the Board, on request and in the form and manner required by the Board, information regarding farm stray voltage as set out in the Distribution System Code.

3 TRANSMITTERS

3.1 Reporting

3.1.1 A transmitter shall provide in the form and manner required by the Board, quarterly, on the last day of the month following the quarter end, balances of all deferral/variance accounts, their related sub-accounts and associated information.

3.1.2 A transmitter shall provide in the form and manner required by the Board, annually, by April 30, information on affiliate arrangements and transactions for the preceding calendar year, as follows:

a) For each affiliate with which the transmitter has or had an Affiliate Contract for the provision of a service, resource, product or use of asset from the transmitter to the affiliate; (i) the name of the affiliate; (ii) the number of Affiliate Contracts with the affiliate; and (iii)the total annual dollar value of all transactions under each such Affiliate Contract;

b) For each affiliate with which the transmitter has or had an Affiliate Contract for the provision of a service, resource, product or use of asset from the affiliate to the transmitter: (i) the name of the affiliate; (ii) the number of Affiliate Contracts with the affiliate; and (iii) the total annual dollar value of all transactions under each such Affiliate Contract; and

c) The highest total dollar value of all financial support to all affiliates outstanding at any time during the reporting period.

For the purposes of this section:

“Affiliate Contract” means a contract between a transmitter and an affiliate, and includes a Services Agreement;

“Financial support” means any form of financial support to an affiliate, including a loan to, a guarantee of indebtedness of and an investment in the securities of the affiliate; and;

“Services Agreement” means an agreement between a transmitter and its affiliate for the purposes of section 2.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters.

3.1.3 A transmitter shall provide the Board annually, by April 30, audited financial statements for the preceding calendar year for the corporate entity regulated by the Board. Where the financial statements of the corporate entity regulated by the Board contain material businesses not regulated by the Board, or where the regulated entity conducts more than one activity regulated by the Board, the transmitter shall disclose separately information about each operating segment in accordance with the

Segment Disclosure provisions corporate entities are encouraged to adopt by the Canadian Institute of Chartered Accountants Handbook.

3.1.4 Regulated Return on Equity (ROE)

A transmitter shall report in the form and manner determined by the Board, annually by April 30, the regulatory return on equity earned in the preceding fiscal year. The reported return is to be calculated on the same basis as was used in establishing the transmitter's base rates.

3.1.5 A transmitter shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the transmitter has publicly traded securities; and

b) a list of affiliates of the transmitter that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

3.1.6 A transmitter shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

3.2 Certification

3.2.1 A transmitter shall provide in the form and manner required by the Board, annually, by April 30, a self-certification statement signed by the chief executive officer of the utility confirming that the chief executive officer is satisfied that the utility has complied with the Affiliate Relationships Code for Electricity Distributors and Transmitters.

3.3 Record Keeping

3.3.1 A transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, records of all requests made for connection to the transmitter's transmission system and their eventual disposition, including any customer impact assessments conducted by the transmitter and any system impact assessments conducted by the IESO.

3.3.2 A transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, detailed records of all economic evaluations conducted to comply with the requirements of the Transmission System Code, including the economic evaluations referred to in sections 6.2.24, 6.3.9 and 6.3.17 of the Transmission System Code. Each record must show the details of the economic evaluation and include, as applicable, the determination of the customer's risk classification and the resulting economic evaluation period, the load forecast, the project capital costs, the ongoing operation and maintenance costs, the project after tax incremental cost of capital, and the justification for all of the study parameters.

3.3.3 A transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, records on corporate relationships as follows:

a) A list of all affiliates with whom the utility transacts, including business addresses, a list of the officers and directors, and a description of the affiliate's business activity;

b) A corporate organization chart indicating relationships and ownership percentages; and

c) The utility's specific costing and transfer pricing guidelines, tendering procedures and all Services Agreement(s) as defined in the Affiliate Relationships Code for Electricity Distributors and Transmitters).

3.3.4 Where the total cost of all transactions with a particular affiliate exceeds $100,000 on an annual basis, a transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, separate records showing:

a) The name of the affiliate;

b) The product, service, resource or use of asset in question;

c) The dollar value of each transaction and the form of price or cost determination; and

d) The date of each transaction and/or the start and completion dates for project-type transactions.

3.3.5 Where a transmitter shares information services with an affiliate the transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, separate records substantiating all review(s) complying with the provisions of CSAE 3416.

3.3.6 A transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, records substantiating the self- certification statement referred to in section 3.2.3 confirming compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters, including individual files for each compliance review containing working papers substantiating the compliance review report.

3.3.7 A transmitter shall maintain and provide in a form and manner and at such times as may be requested by the Board, records of all transmission system circuit trips coincident with telecommunication failures described in section 10.1.9 of the Transmission System Code.

4 RETAILERS

4.1 Reporting

4.1.1 A retailer shall provide in the form and manner required by the Board, quarterly, by the last day of the second month following the period end, a summary of the following market monitoring information:

a) The total number of customers successfully enrolled (accepted by a distributor for flow), broken down as follows:

i Contracts with less than one year remaining in the term of the contract;

ii Contracts with greater than one year but less than three years remaining in the term of the contract; and

iii Contracts with between three and five years remaining in the term of the contract; and

b) The number of customers reported for each grouping in section (a) above shall be further broken down as follows: low volume consumers (less than 150,000kWh annually) and high volume consumers (150,000 kWh or more annually).

Retailers licensed to act as an agent only, are exempt from this requirement.

4.1.2 A retailer shall provide in the form and manner required by the Board, quarterly, on the last day of the second month following the quarter end, a summary of the following market monitoring information for the quarter pertaining to customers who are low volume consumers (as defined in the Electricity Retailer Code of Conduct):

a) Number of salespersons who have successfully enrolled a customer (accepted by a distributor for flow) or successfully renewed a contract;

b) Number of new enrolments (accepted by a distributor for flow);

c) Number of contract renewals;

d) Marketing Approach Percentages based on new enrolments (accepted by a distributor for flow) and renewed contracts during the reported quarter, broken down by: direct mail, in person, telesales, internet sales and other;

e) Number of consumer complaints;

f) Retail offers accepted by customers that have been successfully enrolled (accepted by a distributor for flow) during the quarter. Details include the contract length and all pricing details.

Retailers licensed to act as an agent only are exempt from this requirement.

4.1.3 A retailer shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the retailer has publicly traded securities; and

b) a list of affiliates of the retailer that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

4.1.4 A retailer shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

4.2 Record Keeping

4.2.1 A retailer with customers who are low volume consumers (as defined in the Electricity Retailer Code of Conduct) shall maintain for a period of two years, and provide in a form and manner and at such times as may be requested by the Board, records of all written complaints by consumers and market participants regarding services provided under the terms of the retailer's licence and responses, containing the following information:

a) The name and address of the complainant;

b) A description of the nature of the complaint including a copy of the written complaint;

c) A description of the remedial action taken; and

d) A copy of any correspondence received and/or sent with respect to each specific complaint.

Retailers licensed to act as agent only, are exempted from this requirement.

4.2.2 A retailer shall maintain for a period of two years, or two years beyond the end of the contract for items c), d), e) and f), and provide in a form and manner and at such times as may be requested by the Board, records of sales personnel and customer information containing the following information:

a) A list of its salespersons including their name and agent number where applicable;

b) A list of its contracted customers;

c) Permission from each customer, in writing, to submit a request to a distributor to allow the electricity retailer to supply electricity to the customer;

d) A contract with each customer, with the customer's signature, to purchase electricity from the electricity retailer;

e) For contracts entered on or after July 1, 2002, the notice of reaffirmation of the contract by the customer; and

f) For contracts renewed or extended for a period of more than one year on or after August 1, 2002, the notice of acceptance of the renewal or extension from the customer.

4.2.3 A retailer with customers who are low volume consumers (as defined in the Electricity Retailer Code of Conduct) shall maintain for a period of two years, and provide in a form and manner and at such times as may be requested by the Board, records of staff training material containing the following information:

a) Training manuals and other print material;

b) Training videos;

c) Codes of conduct;

d) Newsletters, bulletins, updates, circulars, notices, instruction sheets and other similar materials;

e) Scripts used for door-to-door solicitation of existing or prospective customers; and

f) Certification by each sales employee and sales agent that the training has been received and that the person is familiar with, and will abide by, the Electricity Retailer Code of Conduct.

4.2.4 A retailer with customers who are low volume consumers (as defined in the Electricity Retailer Code of Conduct) shall maintain for a period of two years, and provide in a form and manner and at such times as may be requested by the Board, marketing information containing the following:

a) Offers (defined as a proposal to enter into a contract, agency agreement, or any other agreement or combination thereof, made to an existing or prospective customer), including hard copies of Web pages containing offers;

b) Promotional material including pamphlets, brochures, bill inserts, coupons and flyers;

c) Application/ registration forms;

d) Form letters sent to existing and prospective customers;

e) Sample identity cards (including photograph), outerwear, business cards and contact information of sales representatives; and

f) Reference material including utility bills, price comparisons with details of price offers and forecasts (of the retailer) and other energy suppliers quoted, shown (or carried so as to be seen) or provided to existing or prospective customers (records shall be kept for each price change in the reference material).

5 Wholesalers (Discontinued Apr 4/'08)

6 Generators

6.1 Reporting

6.1.1 A generator shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the generator has publicly traded securities; and

b) a list of affiliates of the generator that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

6.1.2 A generator shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

6.1.3 An electricity storage provider shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the electricity storage provider has publicly traded securities; and

b) a list of affiliates of the electricity storage provider that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

6.1.4 An electricity storage provider shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

7 Independent Electricity System Operator

7.1 Reporting

7.1.1 The IESO shall provide in the form and manner required by the Board, quarterly, on the last day of the month following the quarter end, financial statements for all market accounts showing quarter end financial position and quarterly and year to date results of operations.

7.1.2 The IESO shall provide the Board with a copy of the results of all biennial audit reviews of settlements performed in accordance with CSAE 3416, as soon as they are available.

7.1.3 The IESO shall provide in the form and manner required by the Board, quarterly, on the last day of the month following the quarter end, the following information:

a) A list of all System Impact Assessments ("SIA") completed in the quarter in respect of renewable energy generation facilities;

b) The total name-plate rated capacity (in MWs) of the renewable energy generation facilities for which SIAs were completed as reported under a) above; and

c) The time (in days) taken to issue each SIA reported under a) above.

7.1.4 Beginning in 2016, the IESO shall provide in the form and manner required by the Board, monthly, by the last day of the following month, the following information related to the provision of the OESP in each month:

a) Funds collected through the OESP charge, in total and broken down by:

i Distributor; and

ii All other market participants.

b) OESP funds disbursed to customers of distributors and unit sub-meter providers, in total and broken down by:

i Distributor; and

ii Unit sub-meter provider.

c) For each OESP tariff code, the total number of OESP recipients and total funds disbursed to OESP recipients by:

i Distributor; and

ii Unit sub-meter provider.

d) Funds disbursed to the central service provider for program delivery and administration.

e) The variance between total funds collected through the OESP charge and total funds disbursed to OESP recipients and for program delivery and administration.

8 Unit Sub-Meter Providers

8.1 Reporting

8.1.1 Beginning in 2017, a unit sub-meter provider shall provide in the form and manner required by the Board, annually, by April 30, the following information with respect to the provision of the OESP and LEAP emergency financial assistance in the preceding calendar year:

a) The number of eligible low-income customer accounts at year end;

b) The number of customer accounts that received LEAP emergency financial assistance during the year;

c) The number of OESP recipients at year end;

d) The number of OESP recipients in the year who were no longer receiving OESP at year end; and

e) The number of OESP recipients who also received a LEAP emergency financial assistance grant during the year.

8.1.2 A unit sub-meter provider shall provide in the form and manner required by the Board, annually, by April 30, the following information:

a) whether or not the unit sub-meter provider has publicly traded securities; and

b) a list of affiliates of the unit sub-meter provider that have publicly traded securities (affiliate has the same meaning as in the Ontario Business Corporations Act).

8.1.3 A unit sub-meter provider shall provide in the form and manner required by the Board any changes to its status with respect to having publicly traded securities or any changes to its list of affiliates that have publicly traded securities within 10 days of the change occurring.

THUNDER BAY HYDRO
2015 ASSET CONDITION ASSESSMENT

August 11, 2016

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THUNDER BAY HYDRO
2015 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418914-RA-0001-R00

August 11, 2016

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Revision History

Revision Number	Date	Comments	Approved
R00	August 11, 2016	Final Report	Yury Tsimberg

SUMMARY

In 2015 Thunder Bay Hydro Electricity Distribution Inc. (TBH) determined a need to perform a condition assessment of its key distribution assets. This would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, and facilitate the development of a Distribution System Plan.

The asset groups included in the 2015 asset condition assessment (ACA) were as follows: substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at this year, this amounts to over 450 poles. Approximately 9% of 4 kV wood poles were also flagged for action this year. Because of the considerably smaller population, however, this equates to just over 230 poles. Approximately 19% of pole mounted transformers were classified under the very poor category. As such, 170 transformers need to be addressed.

Many asset groups (i.e. distribution transformers, overhead switches, and underground cables) had only age data available. Data gaps for these and all other asset categories were identified. It is recommended that TBH begin collecting information to fill these data gaps and to use such information for future assessments.

It is important to note that the flagged for action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Distribution System Plan.

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I INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (TBH) is a private local distribution company responsible for distributing electricity to over 50,000 customers via a network of more than 1,300 kilometers of overhead and underground power lines in the City of Thunder Bay. TBH is owned by the City of Thunder bay and is operated by the Thunder Bay Hydro Board.

TBH recently recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. Such an assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan.

In 2015 TBH engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on TBH's key distribution assets. This report presents the results of the study.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
    - 4 kV
    - 12 kV
- Breakers
- Wood Poles
    - 4 kV
    - 25 kV
- Distribution Transformers
    - Pad Mounted Transformers
    - Pole Mounted Transformers
    - Vault Transformers
- OH Switches
    - 4kV In-Line
    - 4kV Manual Air Break
    - 12 and 25kV In-Line
    - 12 and 25kV Manual Air Break
    - 25kV Motorized Load Break
- Underground Switches
    - 25kV Underground Load Break Switches
- Underground Cables
    - 4kV
    - 12 and 25kV

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included:
    - Health Index formula
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis.

II ASSET CONDITION ASSESSMENT METHODOLOGY

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weights, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS_m = \frac{\sum_{n=1}^{\forall n} \beta_n (SCPS_n \times WSCP_n) \times DR_n}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)} \times DR_m$$

Equation 2

CPS	Condition Parameter (CP) Score, 0-4
WCP	Weight of Condition Parameter
α_m / β_n	Data availability coefficient for condition parameter (1 if input data available; 0 if not available)
SCPS	Sub-Condition Parameter (SCP) Score, 0-4
WSCP	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. In the Kinectrics methodology, a condition criteria scoring system of 0 through 4 is used. A score of 0 is the "worst" possible score; a score of 4 is the "best" score. I.e. $CPS_{max} = SCPS_{max} = 4$.

Note: From the formula, it can be seen that each parameter (condition or sub-condition) will have the following properties:

1. Weight
2. Availability coefficient (1 if asset has data for such parameter available; 0 otherwise)
3. Score (real value from 0 through 4)
4. Multiplier (real value)

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 $\le$ Health Index < 50%
Fair	50 $\le$ Health Index <70%
Good	70 $\le$ Health Index <85%
Very Good	Health Index $\ge$ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 Condition Based Flagged for Action Plan

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f = failure rate per unit time
t = time
γ, β = constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f = failure rate of an asset (percent of failure per unit time)
t = age (years)
α, β = constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f-e^{-\alpha\beta})/\beta}$$

Equation 5

P_f = cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} \;=\; 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

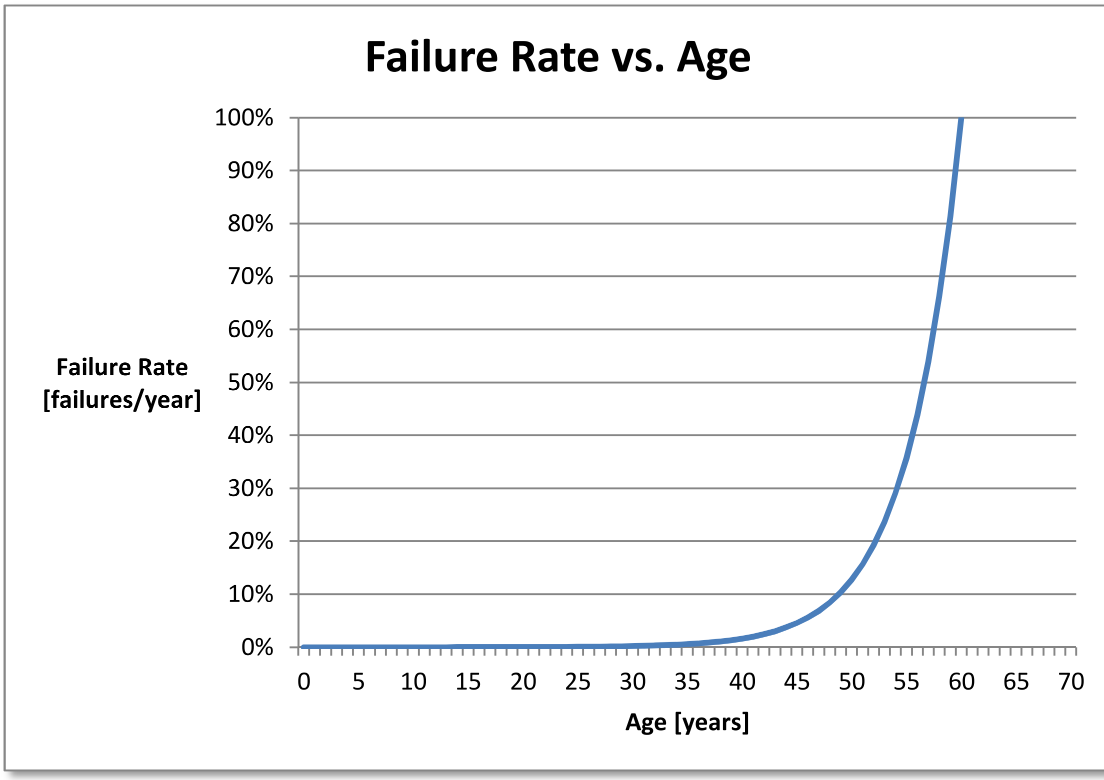

Figure II-1 Failure Rate vs. Age

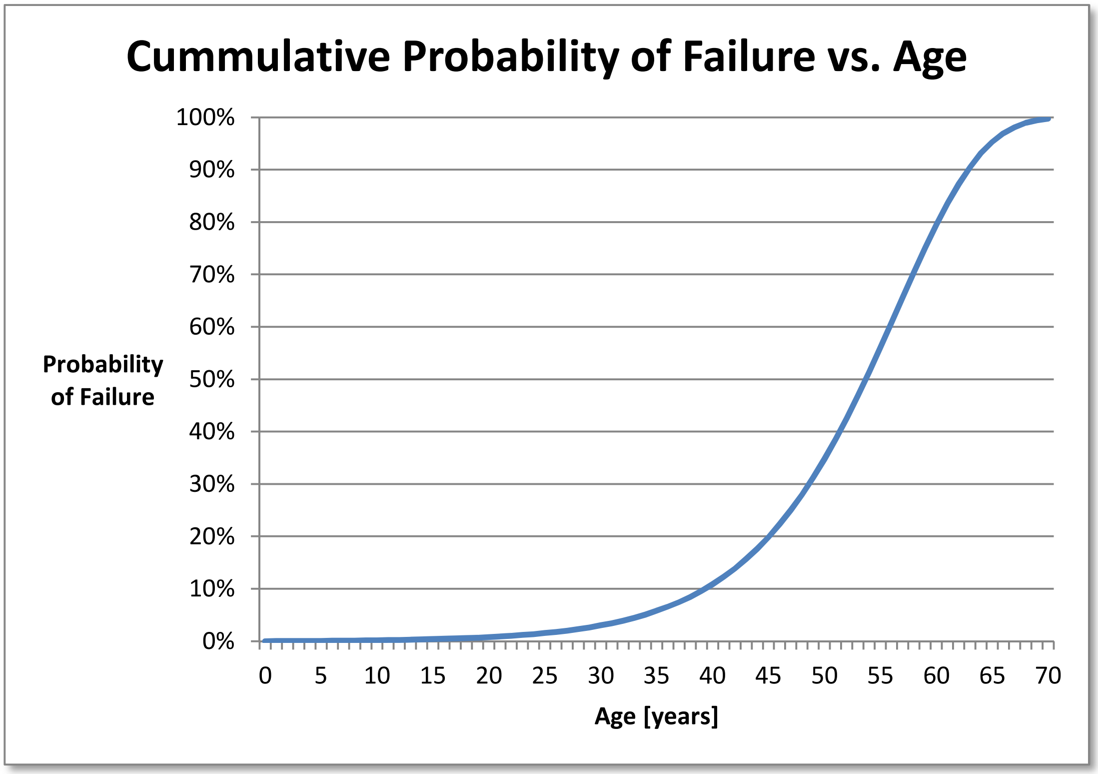

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

The Levelized Flagged for Action plan smooths or levelizes the peaks and valleys of the flagged for action plan.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

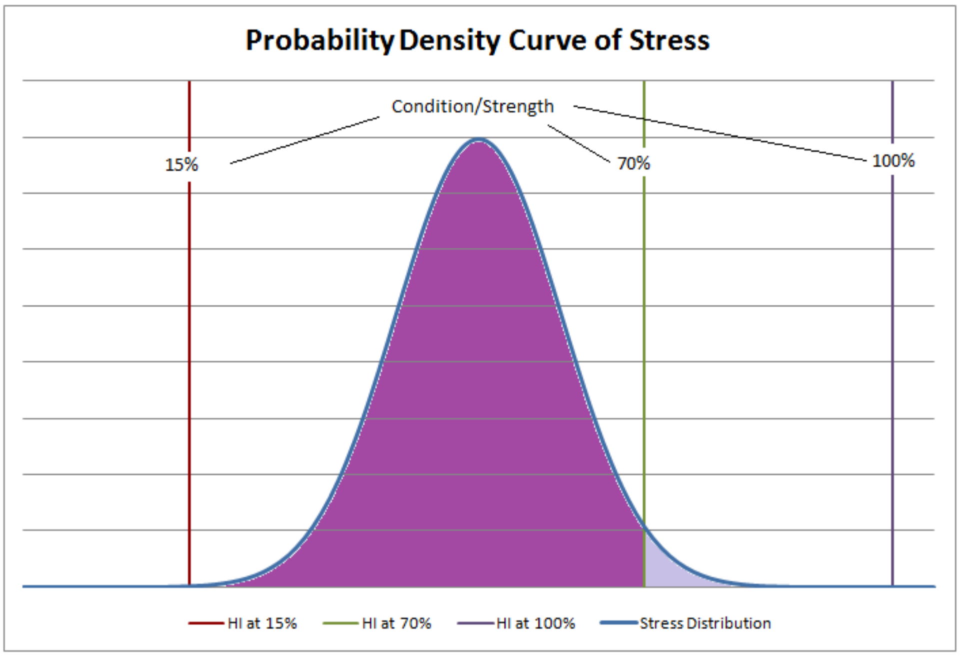

Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

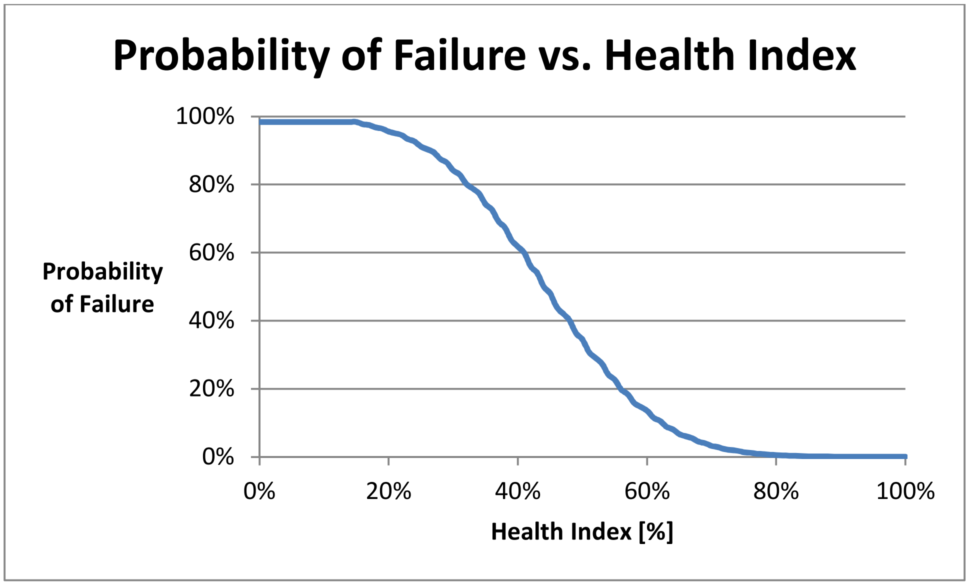

Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be 1.43*0.7 = 1 and it will be flagged for action.

II.3 Data Assessment

The condition data used in this study were provided by TBH and included the following:

- Test Results (e.g. Oil Quality, DGA, PCB)
- Inspection Records via Non-Conformance Logs
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\ m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCFn}{\sum_{n=1}^{\forall n} (WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	Name		n	Name		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$DAI_{CP1} = (1*1) / (1) = 1$
$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$
$DAI_{CP3} = (0*1) / (1) = 0$

$$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$$
$$= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)$$
$$= 35\%$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on TBH's available data. There are additional parameters or tests that TBH may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	✯ ✯ ✯
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	✯ ✯
Low	Helpful data; least indicative of asset deterioration	✯

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	✯ ✯	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and average age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in **Error! Reference source not found.**. Note that the Health Index distribution percentages are based on the asset group's sample size.

The 4 kV underground cables, on average as an asset group, were found to be in the worst condition. A total of 34% were in very poor condition, where another 14% were found in poor condition. This is primarily because with the average age of the population at 43 years, the population is fairly old. However, since the population size is minimal (44 conductor-km), this is not a significant concern.

A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Many distribution transformers were also found to be in bad condition. Approximately 9%, 19%, and 8% of pad-mounted, pole-mounted, and vault transformers respectively were classified under the very poor category. These include units that are leaking and that contain PCBs.

The wood pole asset category is also concerning. A total of 10% of all wood poles are in poor or very poor condition.

III.2 Condition-Based Flagged for Action Plan

When there is a large quantity of assets that are at or near the end of their service lives, there may be large quantities of assets flagged for action in the first year. This represents a "backlog" of assets that required attention from past years. As it would not be feasible or practical for a utility to address all assets immediately, a levelized flagged for action plan, where quantities to address are spread over subsequent years, is also given. The unlevelized and levelized flagged for action plans are shown in Table III-2, Table III-3, Figure III-6, and

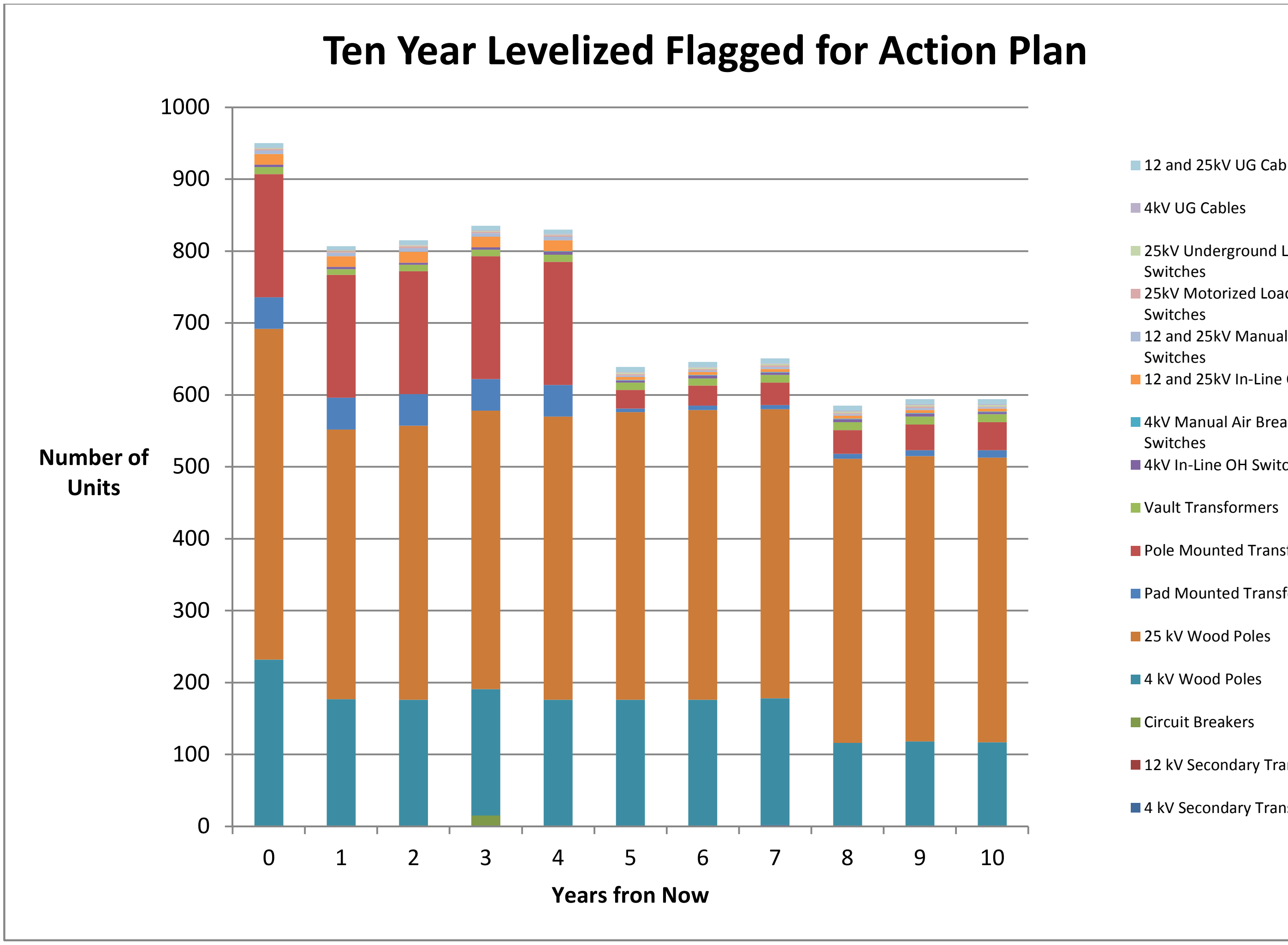

Figure III-7.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year (per the Levelized Plan in Table III-2), this amounts to over 450 poles. Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population, however, this equates to just over 230 poles. Pole mounted transformers also have large quantities requiring action in year 1. Per the Levelized Plan, more than 170 transformers (4% of the population) are flagged.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	23	23	88%	0%	4%	9%	4%	83%	52
	4 kV	17	17	86%	0%	6%	6%	12%	76%	54
	12 kV	6	6	94%	0%	0%	0%	0%	100%	47
Breakers	Breakers	77	77	72%	0%	18%	23%	12%	47%	56
Wood Poles	All	19813	19813	75%	1%	9%	34%	21%	34%	28
	4 kV	3862	3862	63%	4%	22%	39%	21%	15%	36
	25 kV	15951	15951	77%	< 1%	6%	33%	21%	39%	27
Distribution Transformers	Pad Mounted Transformers	2206	2206	87%	9%	1%	2%	12%	75%	25
	Pole Mounted Transformers	4143	4141	81%	19%	1%	1%	1%	77%	29
	Vault Transformers	285	285	78%	8%	3%	15%	26%	49%	33
OH Switches	All	729	305	76%	14%	5%	10%	12%	60%	32
	4kV In-Line	101	46	71%	26%	0%	9%	11%	54%	32
	4kV Manual Air Break	7	2	70%	0%	50%	0%	0%	50%	32
	12 and 25kV In-Line	399	148	80%	11%	7%	5%	8%	70%	31
	12 and 25kV Manual Air Break	183	74	78%	14%	4%	7%	9%	66%	33
	25kV Motorized Load Break	39	10	67%	10%	20%	20%	10%	40%	39
Underground Switches	25kV Underground Load Break Switches	80	30	81%	0%	13%	17%	3%	67%	31
Underground Cables*	All	432	374	80%	3%	3%	31%	4%	60%	29
	4kV	44	29	44%	34%	14%	21%	0%	31%	43
	12 and 25kV	387	344	84%	< 1%	2%	32%	4%	63%	28

* data is in conductor-km

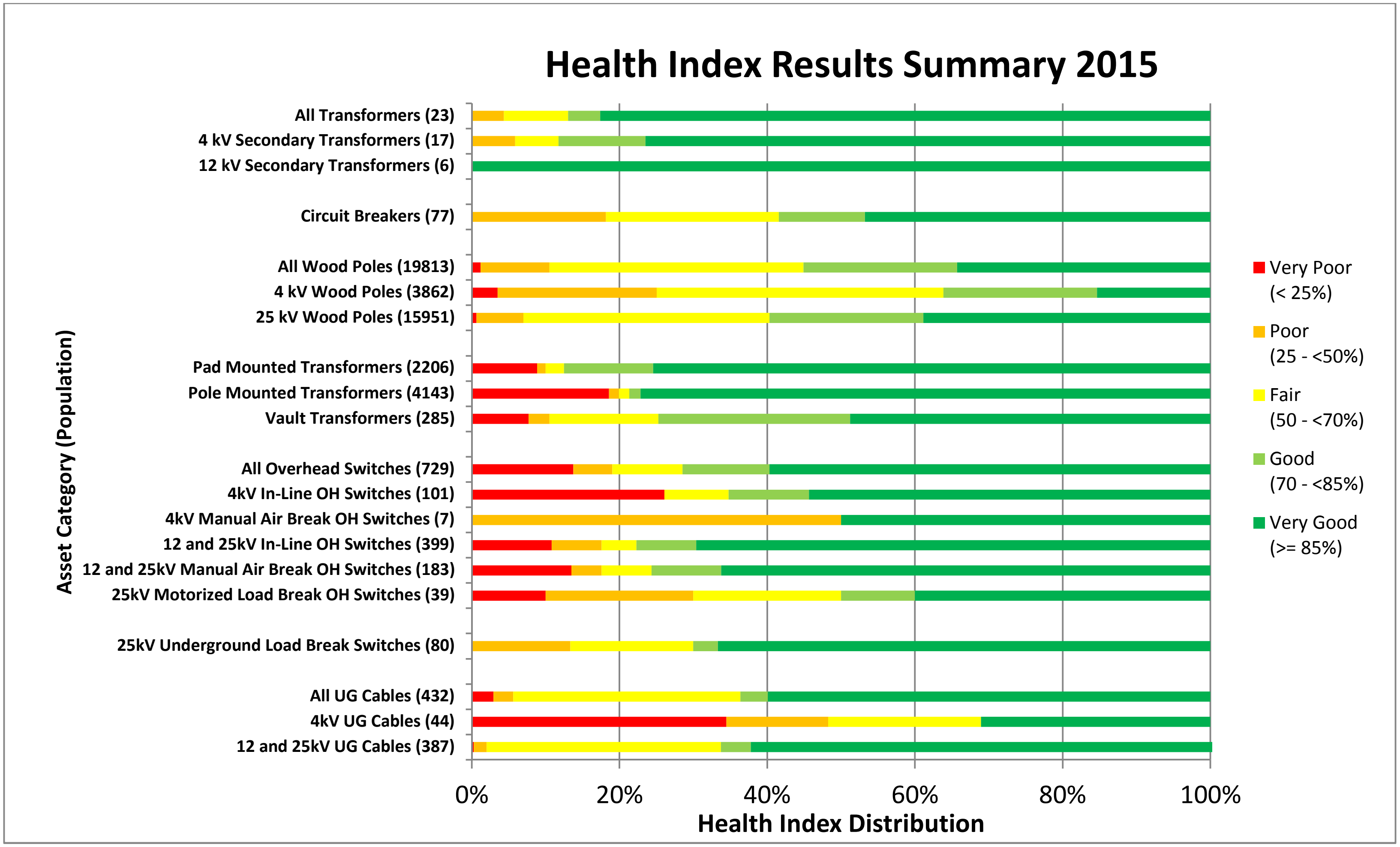

Figure III-5 Health Index Results Summary (Graphical)

Table III-2 Total Year 1 and 10-Year Total Flagged for Action Plan

Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
Substation Transformers	4 kV Secondary Transformers	0	0%	3	18%	0	0%	3	18%	proactive
	12 kV Secondary Transformers	0	0%	0	0%	0	0%	0	0%	proactive
Circuit Breakers	Circuit Breakers	0	0%	14	18%	0	0%	14	18%	proactive
Wood Poles	4 kV Wood Poles	364	9%	1636	42%	232	6%	1636	42%	proactive
	25 kV Wood Poles	544	3%	3964	25%	460	3%	3964	25%	proactive
Distribution Transformers	Pad Mounted Transformers	204	9%	240	11%	44	2%	240	11%	proactive
	Pole Mounted Transformers	625	15%	974	24%	171	4%	974	24%	reactive
	Vault Transformers	14	5%	93	33%	10	4%	93	33%	reactive
Overhead Switches	4kV In-Line OH Switches	3	3%	36	36%	3	3%	36	36%	reactive
	4kV Manual Air Break OH Switches	0	0%	4	57%	0	0%	4	57%	reactive

Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
	12 and 25kV In-Line OH Switches	30	8%	92	23%	15	4%	92	23%	reactive
	12 and 25kV Manual Air Break OH Switches	20	11%	36	20%	5	3%	36	20%	reactive
	12 and 25kV Motorized Load Break OH Switches	0	0%	16	41%	2	5%	16	41%	reactive
Underground Switches	25kV Underground Load Break Switches	0	0%	13	16%	1	1%	13	16%	reactive
Underground Cables*	4kV UG Cables	2	5%	4	9%	1	2%	4	9%	reactive
	12 and 25kV UG Cables	4	1%	59	15%	6	2%	59	15%	reactive

* data is in conductor-km

Table III-3 Ten Year Flagged for Action Plan

Replacement Year	Type (L = Levelized; Blank = Unlevelized)	Asset Category															
		Substation Transformers		Circuit Breakers	Wood Poles		Distribution Transformers			Overhead Switches					Underground Switches	Underground Cables*	
		4 kV Secondary Transformers	12 kV Secondary Transformers	Circuit Breakers	4 kV Wood Poles	25 kV Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line OH Switches	4kV Manual Air Break OH Switches	12 and 25kV In-Line OH Switches	12 and 25kV Manual Air Break OH Switches	25kV Motorized Load Break OH Switches	25kV Underground Load Break Switches	4kV UG Cables	12 and 25kV UG Cables
0	L	0	0	0	232	460	44	171	10	3	0	15	5	2	1	1	6
		0	0	0	364	544	204	625	14	3	0	30	20	0	0	2	4
1	L	0	0	0	177	375	44	171	8	3	0	15	5	2	1	1	5
		0	0	0	253	473	7	130	9	2	0	13	5	0	5	0	4
2	L	0	0	0	176	381	44	171	9	3	0	15	5	3	1	1	6
		0	0	0	210	447	3	42	10	7	0	8	2	4	0	1	6
3	L	1	0	14	176	387	44	171	9	3	0	15	5	2	1	1	6
		1	0	14	182	424	2	30	8	3	0	22	0	8	1	0	7
4	L	0	0	0	176	394	44	171	10	4	1	15	5	2	1	1	6
		0	0	0	153	412	2	28	10	2	0	0	0	0	0	0	7
5	L	0	0	0	176	400	5	26	10	3	1	4	2	2	2	1	7
		0	0	0	132	409	5	28	9	2	0	8	5	0	1	0	8
6	L	0	0	0	176	403	6	28	10	4	1	4	2	2	2	1	7
		0	0	0	119	411	6	27	12	7	0	3	2	4	3	0	8
7	L	2	0	0	176	402	6	31	11	3	1	4	3	2	2	1	7
		2	0	0	112	416	5	32	10	3	0	5	2	0	2	0	8
8	L	0	0	0	116	395	7	33	11	4	1	4	2	2	2	1	7
		0	0	0	111	428	6	32	11	7	4	3	0	0	1	1	7
9	L	1	0	0	117	397	8	36	11	4	1	4	3	2	2	1	7
		1	0	0	114	425	5	36	11	2	0	3	5	0	1	0	9
10	L	0	0	0	117	396	10	39	11	3	1	4	2	1	2	1	7
		0	0	0	115	418	9	39	12	3	0	0	0	0	1	1	7

* data is in conductor-km

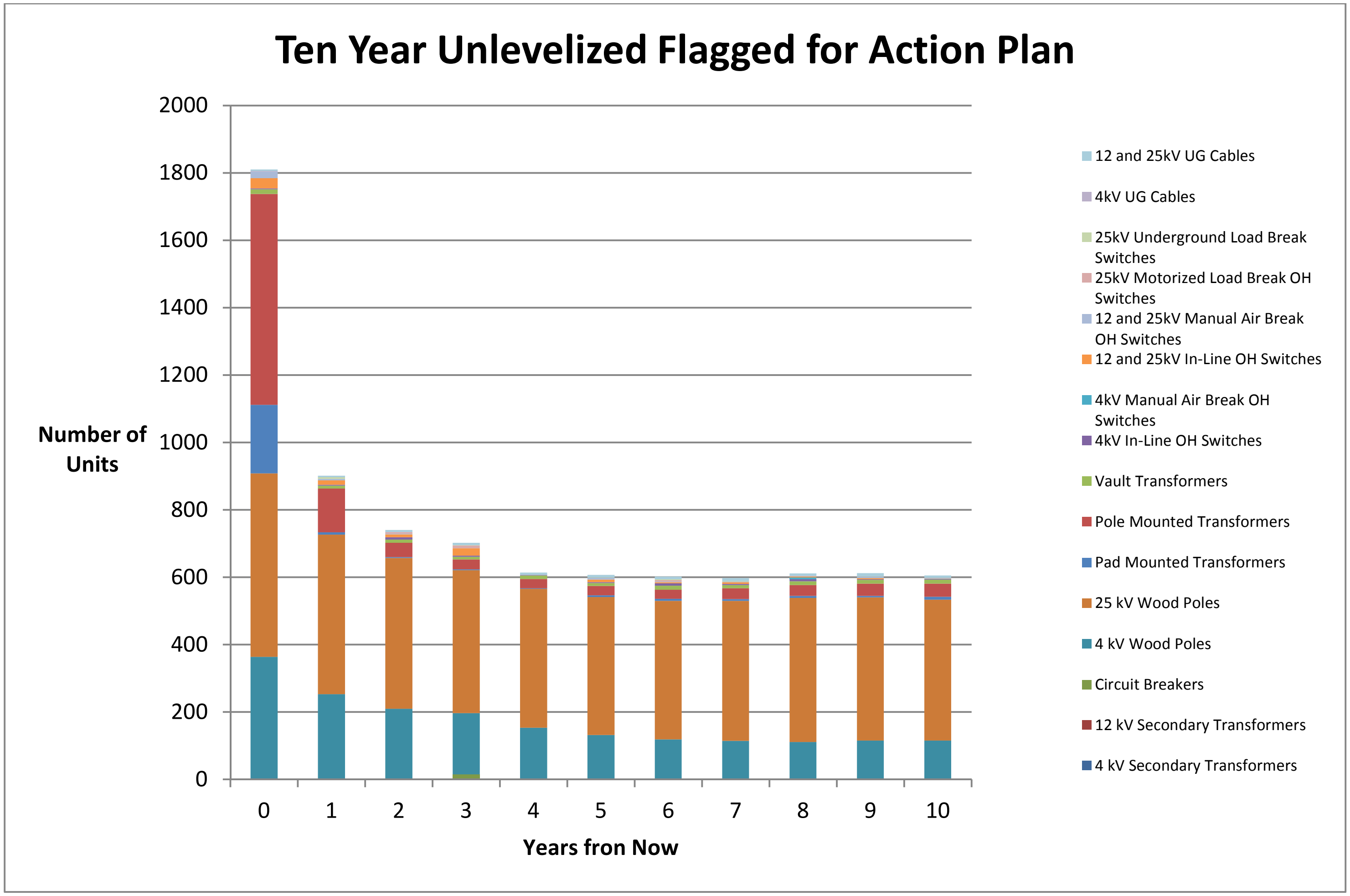

Figure III-6 Ten Year Unlevelized Flagged for Action Plan (Graphical)

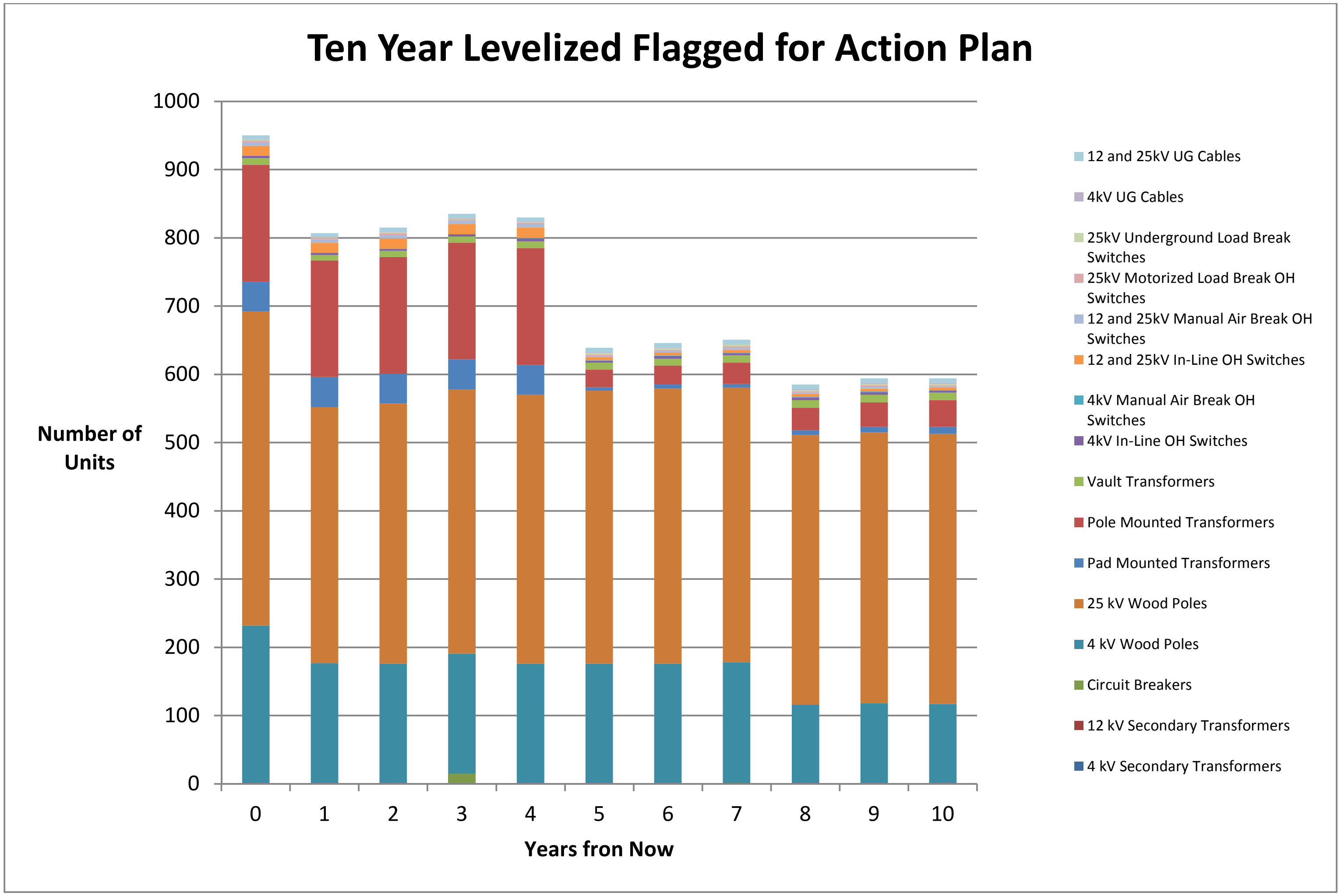

Figure III-7 Ten Year Levelized Flagged for Action Plan (Graphical)

III.3 **Data Assessment Results**

As mentioned described in Section II.3, the assessment of the available data was done by looking at the data availability indicator (DAI) and data gaps. Recall that the DAI is measurement that is relative to the information that TBH currently collects, whereas data gaps are information that TBH does not collect. As such, even if an asset group has a high DAI, this does not mean information for this asset group is complete. i.e. if there are numerous data gaps, the degree of confidence that the Health Index reflects true condition may still be low. Table III-4 shows the average DAI for each category. The Data Gap column indicates the extent of the data gap (i.e. "high" indicates that a significant amount of condition information can be collected for future assessments). Overall assessments for each asset category are summarized below. Additional details, including prioritized data gaps, are given in the data gap sections of Appendix A: Results for Each Asset Category.

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. Data that would be helpful for future assessments include power dissipation factor tests, inspection and/or corrective maintenance records.

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the operation counts, fault interruption counts, and fault level interrupted.

Age and overall risk rating based on inspection records were available for wood poles. Data gaps include more detailed inspection records and strength tests that give an objective, quantified assessment of the condition of wood poles.

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Only age and PCB content were available for pole-mounted and vault transformers. Loading and inspection/corrective maintenance information related to transformer condition (e.g. leaks, tank/enclosure condition, corrosion, connections).

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Underground cables had only age information. However, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan

Delta). Such information will provide good, objective condition data as input into the Health Index.

Table III-4 Data Assessment

<table>
<tr><th colspan="2">Asset Category</th><th>Average DAI</th><th>Data Gap</th></tr>
<tr><td rowspan="3">Station Transformers</td><td>All</td><td>93%</td><td rowspan="3">Low-Medium</td></tr>
<tr><td>4 kV</td><td>92%</td></tr>
<tr><td>12 kV</td><td>93%</td></tr>
<tr><td>Breakers</td><td>Breakers</td><td>61%</td><td>Low-Medium</td></tr>
<tr><td rowspan="3">Wood Poles</td><td>All</td><td>100%</td><td rowspan="3">Medium-High</td></tr>
<tr><td>4 kV</td><td>100%</td></tr>
<tr><td>25 kV</td><td>100%</td></tr>
<tr><td rowspan="3">Distribution Transformers</td><td>Pad Mounted Transformers</td><td>85%</td><td>Low-Medium</td></tr>
<tr><td>Pole Mounted Transformers</td><td>100%</td><td>Medium-High</td></tr>
<tr><td>Vault Transformers</td><td>100%</td><td>Medium-High</td></tr>
<tr><td rowspan="6">OH Switches</td><td>All</td><td>42%</td><td rowspan="6">High</td></tr>
<tr><td>4kV In-Line</td><td>46%</td></tr>
<tr><td>4kV Manual Air Break</td><td>29%</td></tr>
<tr><td>12 and 25kV In-Line</td><td>37%</td></tr>
<tr><td>12 and 25kV Manual Air Break</td><td>40%</td></tr>
<tr><td>12 and 25kV Motorized Load Break</td><td>26%</td></tr>
<tr><td>Underground Switches</td><td>25kV Underground Load Break Switches</td><td>38%</td><td>High</td></tr>
<tr><td rowspan="3">Underground Cables</td><td>All</td><td>48%</td><td rowspan="3">High</td></tr>
<tr><td>4kV</td><td>65%</td></tr>
<tr><td>12 and 25kV</td><td>47%</td></tr>
</table>

IV CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for TBH's key distribution assets, namely substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.

2. Of all the asset groups, 4kV underground cables were found, on average, to be in the worst condition. A total of 48% were found to be in poor or very poor condition. However, because of the small population, this is not a significant cause for concern.

3. A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Because the population of switches is relatively small, the number of assets flagged for action is not significant.

4. Approximately 19% of pole mounted transformers were classified under the very poor category. Per the levelized flagged for action plan over 170 transformers require action in the first year.

5. In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year, this amounts to over 450 poles.

   Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population than the 25 kV poles, however, this equates to just over 230 poles.

6. Age and inspection information were available for substation transformers, breakers, wood poles, and pad-mounted transformers. Additionally substation transformers had loading and oil tests. Only age was available for pole-mounted transformers, vault transformers, overhead and underground switches, and underground cables. Further, the age was only available for less than half of the switches and cables.

7. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. Data for all condition parameters used in the HI formulas should be collected for all assets. The low DAIs of switches and cables are of particular concern.

8. Data gaps were identified for each asset category, prioritized in the order of importance, in the Appendix of this report. It is recommended that the data be gathered in prioritized manner. Data may be gathered from inspections or corrective maintenance records. Additional sources of data would come from testing (e.g. pole strength testing or cable testing).

9. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is

recommended that TBH begin collecting failure information so failure models can be developed and used in future assessments.

10. It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Asset Management Plan.

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SUMMARY OF DISTRIBUTION BUSINESS

1.0 INTRODUCTION

Hydro One Networks Inc. is licensed by the Ontario Energy Board (the "Board") to own, operate and maintain electricity distribution facilities in the Province of Ontario.

Hydro One's mandate is "the safe, reliable and cost-effective transmission and distribution of electricity to Ontario electricity users." In delivering on its mandate, Hydro One operates as a commercial enterprise with an independent Board of Directors that will at all times exercise its fiduciary responsibility and duty of care to act in the best interests of Hydro One.

Hydro One's distribution system is one of the largest systems in North America, serving a predominately rural customer base. Hydro One's distribution facilities are the backbone of Ontario's electricity system, covering 75% of the province's geography and serving 28% of Ontario's customers. In recent years, Hydro One's distribution system has experienced changes such as the influx of distributed generation, the installation of advanced distribution equipment and the introduction of new tools leveraging existing technology.

1.1 Hydro One's Values

Hydro One is driven by the values of Safety, Stewardship, Excellence and Innovation with the ultimate goal of providing safe, reliable and affordable service. The company works in an environment that can be dangerous for both workers and the public, and so safety is of the utmost importance. The stewardship of critical provincial assets is a serious responsibility. The Company demonstrates sound stewardship in a manner that respects both customers' needs and the environment. Excellence is achieved through continuous training to ensure the Company is prepared and equipped to deliver high quality and affordable service. The Company values innovation because it is a key success factor for its future that allows it to find better ways to meet customer needs. Hydro One's Value Proposition is summarized in Figure 1.

Figure 1: Hydro One Value Proposition

Customers expect and deserve reliable power at reasonable rates. Hydro One's strategy and business plan must ensure rates can finance infrastructure investment needs while maintaining affordable and reliable service. While customer satisfaction with the Company's performance remains strong, customers face a growing array of changes and challenges, and they increasingly look to Hydro One to help them manage their use of power, maintain high levels of service reliability and keep prices reasonable. With the introduction of smart meters and the smart grid, Hydro One Distribution will face increasing demands from its customers. The Company is prepared to meet their expectations.

1.2 Strategic Goals and Performance Targets

The company's strategic objectives commit it to:

- Creating an injury-free workplace and maintaining public safety.
- Satisfying our customers.
- Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system.
- Building and maintaining reliable and affordable transmission and distribution systems.
- Protecting and sustaining the environment for future generations.
- Championing people and culture.
- Maintaining a commercial culture that increases value for our shareholder.
- Achieving productivity improvements and cost-effectiveness.

These strategic objectives do not stand alone and are inextricably linked. They drive the fulfillment of the Company's mandate and the achievement of its mission and vision, which is:

> "*Hydro One will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers.*"

The company will operate with clear operational and financial performance targets. Where data is available, Hydro One will benchmark its performance against that of other North American utilities and will put plans and programs in place to achieve its vision. The five-year goals associated with the Company's strategic objectives are shown in Table 1.

Table 1

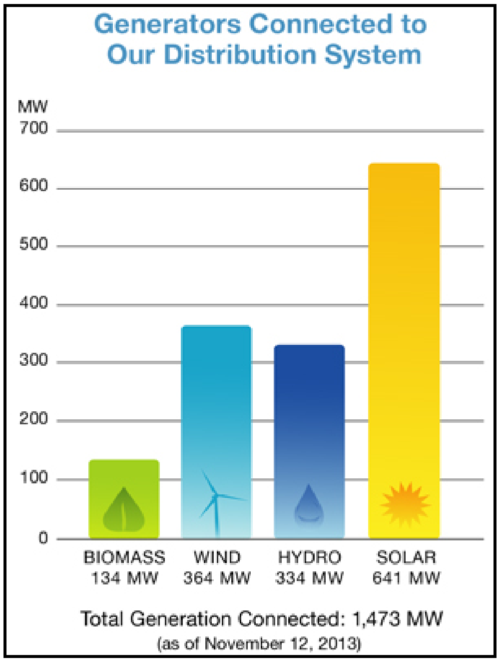
STRATEGIC OBJECTIVES	FIVE-YEAR VISION
Creating an injury-free workplace and maintaining public safety	Achieve world-class standing for medical attentions for utilities
Satisfying our customers	Achieve an on average of 90% customer satisfaction across all segments
Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system	Meet 100% of advanced distribution system plan
Building and maintaining reliable, affordable transmission and distribution systems	Maintain the current levels of reliability relative to comparable utilities, while we improve customer service and satisfaction
Protecting and sustaining the environment for future generations	Reduce our environmental footprint
Championing people and culture	Achieve and maintain employee engagement at top quartile of comparable utilities
Maintaining a commercial culture that increases value for our shareholder	Achieve the Return on Equity allowed by the Ontario Energy Board and maintain an "A" credit rating
Achieving productivity improvements and cost-effectiveness	Achieve top-quartile unit costs against comparable utilities

The strategic objectives identified in Table 1 underpin and drive the Company's business planning process and all of its activities going forward.

2.0 SYSTEM BACKGROUND

The Hydro One distribution system has evolved over more than 100 years. Hydro One manages over $5 billion in distribution assets supplying electricity to customers across the province of Ontario. The assets consist of about 120,000 circuit kilometers of distribution line and 1,004 distributing and regulating stations. The distribution system delivers electricity at voltages below 50 kV from Ontario's transmission and generation systems to 34 Local Distribution Companies and approximately 1.2 million Retail Customers and 44 directly connected large users (> 5MW). The system is also increasingly being used to serve distributed generators. As of November 2013, approximately 1,500 MW of generation has been connected, consisting of micro-embedded, small, medium and large sized facilities. This is displayed in Figure 2 below. Further, Hydro One forecasts that DG connections will continue to grow by an additional 1,380 MW by 2019. Hydro One plans to continue upgrading the distribution system to improve the operation and monitoring of these DG connections.

Figure 2: Generation Connected to H1 Distribution System



The Hydro One distribution system is mainly radial in design, with very little transfer capability in supply to customers, which is consistent with other rural systems. Because of this configuration, most component failures require immediate repair to restore service. To effectively manage the response to trouble calls from customers, the initial problem assessment and dispatching of a response is handled through a single facility, the Ontario Grid Control Centre ("OGCC").

The Hydro One distribution system typically operates in a service territory characterized by low customer densities. To cost-effectively provide operating, maintenance and restoration services there are a number of Service Centers located throughout the Province. These Service Centers provide base locations for field crews and related materials, tools and equipment.

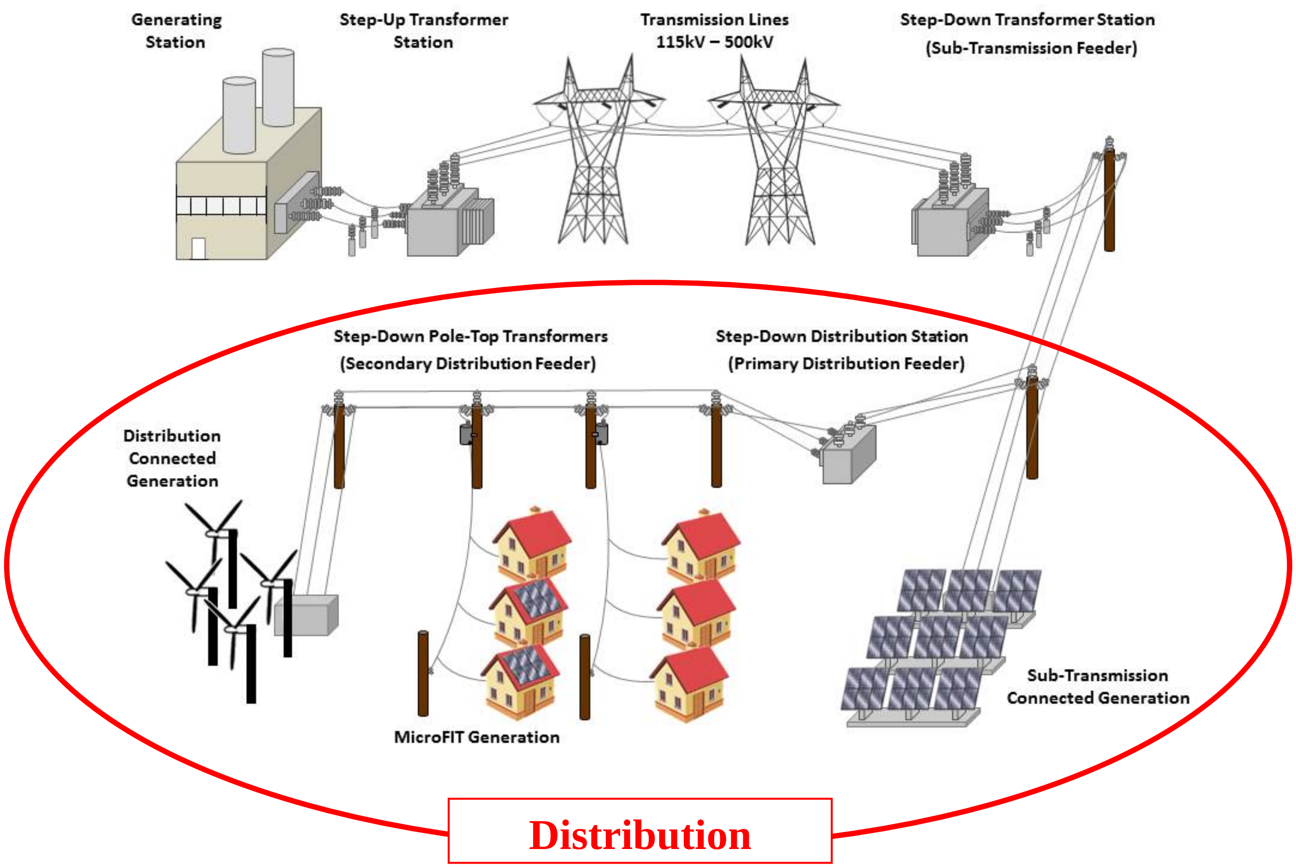
3.0 DISTRIBUTION SYSTEM COMPONENTS

The Hydro One Distribution system receives wholesale electricity from the transmission system and delivers it to consumers at lower voltages through a series of radial assets. It is also used to take electricity from distributed generation facilities connected directly to the distribution system. The system consists primarily of the following assets:

- Subtransmission feeders
- Distribution stations
- Primary distribution feeders
- Pole top and pad mounted transformers
- Secondary distribution feeders

Figure 3 provides a simplified illustration of Hydro One Networks' distribution system.

Figure 3: Hydro One Networks' Distribution System



3.1 Subtransmission Feeders

Hydro One's 25,000 circuit kilometers of subtransmission feeders predominately originate at transmission transformer stations and in some cases at distribution stations. They provide a link between Hydro One Networks' system and large distribution connected customers, (e.g. generators, distribution LDCs) and other end use customers. Typically, subtransmission feeders supply service at 44 kV, 27.6 kV, 25 kV, 22 kV and

13.8 kV directly to end-use customers or deliver service to distribution stations, owned by either Hydro One or other LDCs, where further voltage transformation takes place.

In some cases, regulating stations are used to maintain voltages on subtransmission feeders within the prescribed limits. This is needed because the line voltage increases or decreases depending on load variations at the distribution stations supplied by the sub-transmission feeders.

3.2 Distribution Stations

Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm, year-round residential and seasonal residential customers. When the output of distributed generation served from a distribution station exceeds the demand of load customers served by that station, the distribution station may also step up voltages back to the transmission or sub-transmission level as the flow reverses from the normal direction of serving load.

Distribution stations typically consist of one or two transformers, depending on the load that needs to be supplied. A loss of any one element (such as a transformer or a feeder) at a distribution station will normally result in the interruption of service to all customers served from that element until the failed component is repaired or replaced, or until an alternate service is enabled.

3.3 Primary Distribution Feeders

Hydro One Distribution has 95,000 circuit kilometers of primary distribution feeders operating from 4 kV to 13.8 kV. These feeders are radial circuits that deliver power from distribution stations to individual customers via pole top and pad mounted transformers, and include overhead circuits, underground cables and submarine cables. These feeders are also being used to serve increasing numbers of new generators. Since the system was originally designed to provide power flow in only one direction, upgrades to both equipment and protective devices are often required to ensure that unsafe flows from distributed generation facilities do not occur.

3.4 Pole Top and Pad Mounted Transformers

Hydro One has 450,000 pole top transformers that are used to step down primary distribution voltages to secondary voltage levels, the voltage level used by residential and small commercial customers. Hydro One’s system also has almost 50,000 pad mounted transformers which perform the same function when power is supplied by underground feeders.

Depending on the proximity of adjacent customers, each single-phase pole top or pad mounted transformer may supply several customers at 240/120 volts whereas a three-phase pole top or pad mounted transformer supplies a single customer at 600/347 volts or 208/120 volts.

3.5 Secondary Distribution Feeders

Hydro One Distribution’s system has approximately 52,000 kilometers of secondary distribution feeders to connect pole top or pad mounted transformers to individual customers with the secondary voltage levels described previously. These feeders could be either underground or overhead when originating from a pole top transformer and underground only when originating from a pad mounted transformer.

4.0 WORK PLANNING AND SYSTEM OPERATIONS

Hydro One's distribution investment needs are determined as part of the corporate business planning process discussed in Exhibit A, Tab 17, Schedule 1. Individual investments are developed taking into account various factors such as asset risk assessment, historical performance data, asset criticality, availability of spare equipment and material, asset demographics, load growth and future capacity requirements using the process described in Exhibit A, Tab 17, Schedule 3. Individual investments are submitted for further evaluation against all other investments proposed by the Company using the prioritization approach described in Exhibit A, Tab 17, Schedule 4.

The annual work plan is broadly grouped into Sustaining, Development and Operations categories, as further described below.

4.1 Sustaining

Asset sustaining work is defined as the work required to maintain existing infrastructure and facilities such that they operate at their required performance level. Hydro One Distribution plans and executes asset sustainment work to maintain customer delivery reliability system-wide while meeting applicable legislative, regulatory, safety and environmental requirements. The capital component of sustaining work deals primarily with refurbishment or replacement of end of life components or systems. The OM&A component of sustaining work addresses preventive and breakdown (corrective) maintenance within the useful life span of the asset.

The Sustainment OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2, respectively.

4.2 Development

Hydro One plans and executes development projects and programs on the distribution system to connect new load and generation customers, and to ensure that the system has sufficient capability to supply existing and forecast loads. These projects and programs also maintain service reliability to customers, ensure that service is within acceptable utility standards, and in some cases mitigate risks through improvements to network configuration. The work is largely driven by load and generator customer demand and involves both short-term and long-term system reinforcement projects. Funding levels are based on system reinforcement needs while meeting the requirements of the Distribution System Code and Hydro One's Conditions of Service.

The Development OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 3, respectively.

4.3 Operations

The Operations category primarily includes work to operate the distribution system on a day-to-day basis. The distribution system is operated through a combination of central control and dispatch via the OGCC, and local response by field crews operating from service centers across Hydro One Distribution's service territory. This approach allows for efficient problem-identification and dispatch of personnel as well as timely customer notification. Currently the Hydro One Distribution system relies on power-off calls by customers to identify interruptions except at locations where a sub-transmission feeder originates at a transformer station. Real time monitoring exists at these transformer stations, but not on other locations on the distribution system. With Smart Meters, there exists the potential to further develop monitoring and operational abilities. The operating environment is also evolving rapidly due to the impact of increased distributed generation connections. Hydro One has initiated pilot smart grid projects to test new technologies to leverage the potential benefits of smart meters and distributed generation while still satisfying high standards of safety and reliability.

The Operations OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 4 and Exhibit D1, Tab 3, Schedule 4, respectively.

5.0 ASSET MANAGEMENT MODEL

Hydro One has adopted an Asset Management model in designing the processes used to plan, approve and implement work. The key principles include having functions primarily responsible for defining the work requirements (Asset Management functions) and functions primarily responsible for delivering asset and customer based services in accordance with the defined work (Work Execution functions). Primary responsibility for planning and decision making associated with the management of distribution assets falls under the Asset Management functions, whereas primary responsibility for providing engineering, design, estimating, construction, maintenance, operating, and customer care services falls under the Work Execution functions.

Both components of the business participate in all phases of work planning and implementation. However, the focus created by this approach allows Hydro One Distribution to better create the competencies and cost-efficiencies to effectively plan and implement the work.

5.1 Asset Management Functions

Hydro One manages its distribution assets using two main processes, Strategy Development and System Investment.

5.1.1 Asset Stewardship & Strategy

The Asset Stewardship & Strategy function provides a managed approach for developing strategies, policies, and standards associated with the operation, maintenance and expansion of the distribution system. This function is specifically responsible for designing programs to:

- Ensure compliance with regulatory and reliability requirements.
- Achieve business objectives such as public and employee safety, reliability, productivity and customer service.
- Provide feedback for continually improving process effectiveness and asset/business performance.
- Incorporate new methodologies and refine existing methodologies to improve effectiveness and productivity of processes in place.

The Asset Stewardship & Strategy function provides the strategies and framework used by the System Investment function to develop programs and investments for Hydro One's distribution assets.

5.1.2 System Investment

Hydro One's distribution business strives to continually improve the efficiency and effectiveness of the regulated wires assets. This involves asset management processes and practices to ensure that the asset related decisions are consistent with customer service standards, are cost-efficient and effective. These decisions are aimed at developing a prioritized and rationalized investment plan for the operation, maintenance and upgrade of existing assets, and the addition of new assets.

Hydro One utilizes a planning approach which recognizes that the distribution business encompasses a portfolio of assets that must be managed over the long term and reflects the fact that not all assets have the same life cycle characteristics or the same criticality with respect to achieving business values and performance.

In preparing investment plans, the planning function utilizes asset risk assessment information described in Exhibit A, Tab 17, Schedule 7, historical performance data, asset criticality, availability of spares and asset demographics to develop a detailed list of specific work needs.

Each specific work need is evaluated against Hydro One's business values to establish the benefit of the work and the associated risks of not conducting it. Solutions are developed to mitigate these risks on a program-by-program basis. For each program the costs, benefits and risks are assessed to determine the impact ratings for each business value and all investments are then prioritized in accordance with the process described in Exhibit A, Tab 17, Schedule 4. This prioritized list of programs is then detailed, scheduled and implemented by the work execution functions.

Substantial new generation will continue to connect to Hydro One's distribution system over the next few years, and the distribution planning function has evolved to proactively accommodate this new generation, while continuing to maintain reliability and power quality for other customers, and ensuring the necessary operational and planning flexibility to respond to changing system needs.

5.2 Work Execution Functions

The primary work execution functions within Hydro One include Customer Operations, Grid Operations, Engineering and Construction Services.

5.2.1 Customer Operations

The Customer Operations function is responsible for the design, estimating, scheduling and completion of line construction and maintenance work for lines, including forestry and customer care support services. As well, the Customer Operations function has accountability for planning and connecting new retail customers to the distribution system and to address local system planning issues. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Process,
- Project Management Process,
- Customer Connection Process,
- Condition Assessment, Line Maintenance, and Lines Sustaining Capital work execution,
- Lines Trouble Response and Corrective Action Process,
- Lines Development Capital work execution,
- Work Program Management, and
- Work Reporting Processes.

Lines and Forestry services provide for the maintenance of overhead and underground distribution lines and for vegetation management. The vegetation management program is necessary to ensure that clearances to energized equipment are maintained and that these clearances provide a sustainable level of reliability.

Customer care services may be divided into the following high-level functions: meter reading; billing; settlements; customer contact handling; and collections.

5.2.2 Grid Operations

The Grid Operations function provides maintenance and technical services for stations and protection and control. This function also provides central operations and services for distribution which includes distribution system operation from the OGCC. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Processes,
- Condition Assessment, Station Maintenance, and Station Sustaining Capital work execution,
- Trouble Response and Corrective Action Process,
- Work Program Management, and
- Work Reporting Processes.

The OGCC coordinates an extensive outage program with various internal stakeholders and external customers to support Hydro One's distribution expansion and maintenance programs. Required outages are assessed and coordinated to minimize their impact on reliability and customer operation.

Grid Operations also maintains back-up operating facilities which serve as a fully redundant back-up to the OGCC.

5.2.3 Engineering and Construction Services

The Engineering and Construction Services functions provide services ranging from engineering and design to the construction and commissioning of new or enhanced facilities. These projects include the engineering, estimating, project management, and construction of stations, system protection and control, as well as engineering services as required. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Process,
- Project Management Process, and
- Project/Program Controls Process.

6.0 RELIABILITY

The reliability of the distribution system and its ability to deliver power to customers without interruption is measured using the following two OEB and industry metrics:

- System Average Interruption Duration Index ("SAIDI")
- System Average Interruption Frequency Index ("SAIFI")

SAIDI is a measure that indicates the amount of time without power that an average customer on Hydro One's distribution system experienced in a given year. SAIFI is a measure that indicates the number of times that an average customer on Hydro One's distribution system experienced an interruption in a given year.

Reliability performance is affected by the level of equipment maintenance and replacement programs, which ensure assets remain in good operating condition, and by the level of vegetation management, which ensures that outages caused by tree contacts are minimized. In addition, the time required to respond to a power interruption has a direct impact on restoration time and therefore impacts the SAIDI measure.

The following two figures illustrate Hydro One's reliability performance over the 2010 to 2013 period. Note that an event is considered *force majeure* when it impacts more that 10% of customers served by Hydro One.

Figure 4: Yearly SAIDI Performance

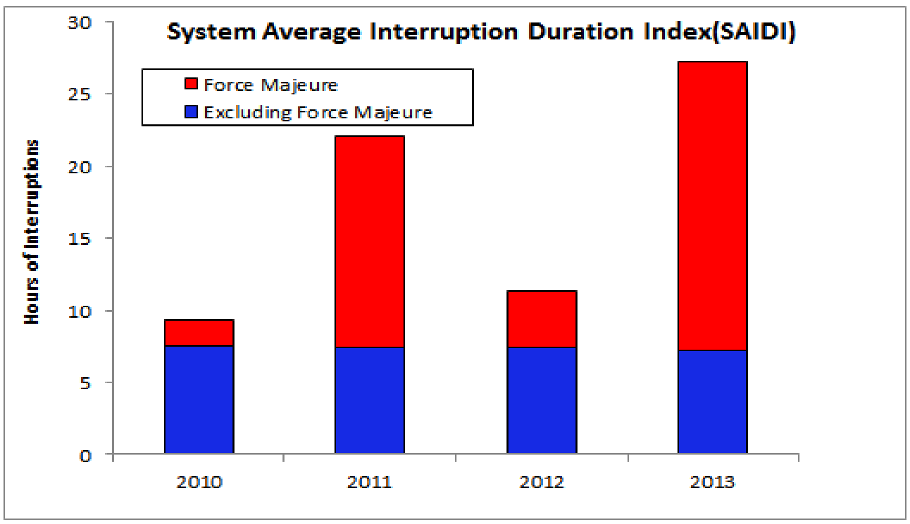
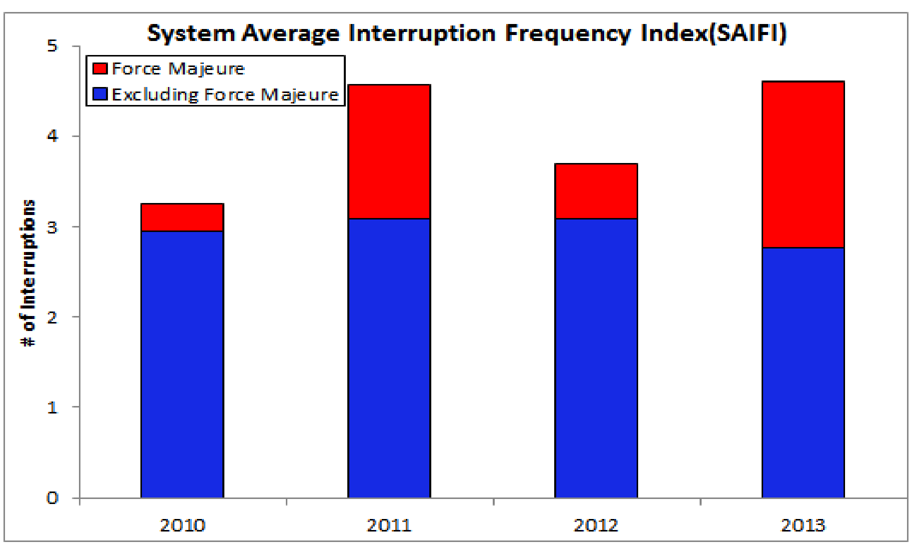


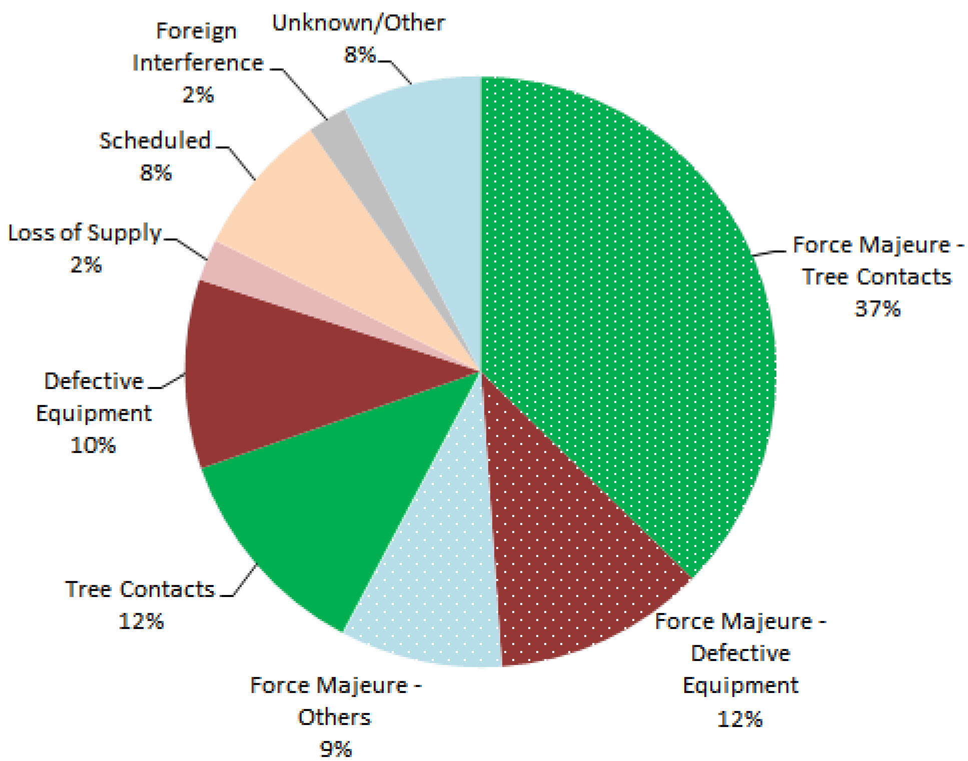
Figure 5: Yearly SAIFI Performance



Excluding *force majeure* events, performance for SAIDI and SAIFI has remained relatively consistent during the 2010 to 2013 period. Including *force majeure* events, performance has varied significantly from year to year due to variations in the number and severity of storms that have affected the Hydro One distribution system in a given year.

Figure 6 below illustrates the factors that contributed to the SAIDI performance over the 2010 to 2013 period.

Figure 6: Contributions to SAIDI - Four Year Average 2010 – 2013

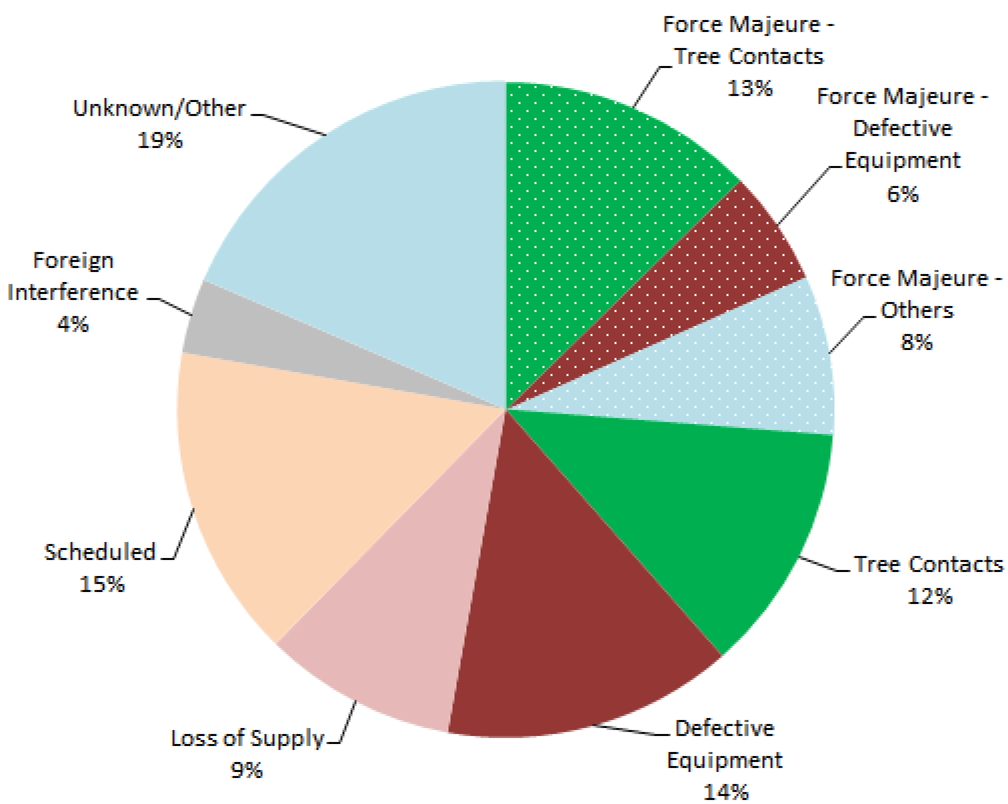


Outages attributed *to force majeure* events (e.g. high winds, ice or snow) contributed to 58% of SAIDI. With a focus on specific causes, it is noted that tree contacts account for

49% of total SAIDI (37% *force majeure* and a further 12% excluding *force majeure*). The next largest contributor to SAIDI was defective equipment at 22% (12% *force majeure* and a further 10% excluding *force majeure*).

Figure 7 below illustrates the factors that contributed to the SAIFI performance over the 2010 to 2013 period.

Figure 7: Contributions to SAIFI - Four Year Average 2010 – 2013



Tree contact was the main contributor to SAIFI totaling 25% (i.e. 13% *force majeure* and a further 12% excluding *force majeure*). The other significant contributor was defective equipment at 20% (i.e. 6% *force majeure* and a further 14% excluding *force majeure*).