K1.2

EB-2014-0073

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Festival Hydro Inc. for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2015.

SCHOOL ENERGY COALITION CROSS-EXAMINATION COMPENDIUM

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Report for

Ontario Energy Board

Third Generation Incentive Regulation Stretch Factor Updates for 2010 (EB-2009-0392)

February 17, 2010

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Power System
Engineering, Inc.

Table 4: Econometric Benchmarking Results

Performance Rankings Based on Econometric Benchmarks

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2006-2008	**0.623**	-0.377	0.000	1
Chatham-Kent Hydro	2006-2008	**0.699**	-0.301	0.001	2
Northern Ontario Wires	2006-2008	**0.720**	-0.280	0.002	3
Cambridge North Dumfries Hydro	2006-2008	**0.753**	-0.247	0.005	4
Grimsby Power	2006-2008	**0.767**	-0.233	0.008	5
Hydro 2000	2006-2008	**0.770**	-0.230	0.009	6
Hydro One Brampton Networks	2006-2008	**0.805**	-0.195	0.025	7
Oshawa PUC	2006-2008	**0.806**	-0.194	0.026	8
Kitchener-Wilmot Hydro	2006-2008	**0.814**	-0.186	0.032	9
Renfrew Hydro	2006-2008	**0.820**	-0.180	0.037	10
Barrie Hydro	2006-2008	**0.836**	-0.164	0.053	11
Waterloo North Hydro	2006-2008	**0.838**	-0.162	0.055	12
Festival Hydro	2006-2008	**0.844**	-0.156	0.063	13
Kingston Electricity	2006-2008	**0.859**	-0.141	0.084	14
E.L.K. Energy	2006-2008	**0.861**	-0.139	0.088	15
Welland Hydro-Electric	2006-2008	**0.864**	-0.136	0.092	16
Hearst Power	2006-2008	**0.875**	-0.125	0.113	17
Horizon Utilities	2006-2008	**0.880**	-0.120	0.125	18
Middlesex Power	2006-2008	**0.884**	-0.116	0.133	19
Lakeland Power	2006-2008	**0.888**	-0.112	0.142	20
Kenora Hydro	2006-2008	**0.896**	-0.104	0.159	21
Lakefront Utilities	2006-2008	**0.897**	-0.103	0.162	22
Rideau St. Lawrence Distribution	2006-2008	**0.902**	-0.098	0.177	23
Newmarket-Tay Hydro Electric	2006-2008	**0.913**	-0.087	0.205	24
Niagara-on-the-Lake Hydro	2006-2008	**0.913**	-0.087	0.205	25
Atikokan Hydro	2006-2008	**0.922**	-0.078	0.232	26
Halton Hills	2006-2008	**0.926**	-0.074	0.242	27
Innisfil Hydro	2006-2008	**0.927**	-0.073	0.246	28
North Bay Hydro	2006-2008	**0.935**	-0.065	0.271	29
Newbury Power	2005-2007	**0.935**	-0.065	0.272	30
Hydro Ottawa	2006-2008	**0.941**	-0.059	0.291	31
PUC Distribution	2006-2008	**0.951**	-0.049	0.326	32
Orangeville Hydro	2006-2008	**0.954**	-0.046	0.334	33
Veridian Connections	2006-2008	**0.958**	-0.042	0.350	34
Wasaga Distribution	2006-2008	**0.966**	-0.034	0.377	35
Peterborough Distribution	2006-2008	**0.966**	-0.034	0.379	36
Enersource Hydro Mississauga	2006-2008	**0.984**	-0.016	0.441	37
Espanola Regional Hydro	2006-2008	**0.989**	-0.011	0.459	38
Tillsonburg Hydro	2006-2008	**1.004**	0.004	0.485	39
Haldimand County Hydro	2006-2008	**1.011**	0.011	0.460	40
Burlington Hydro	2006-2008	**1.018**	0.018	0.437	41
Oakville Hydro	2006-2008	**1.019**	0.019	0.432	42
Milton Hydro	2006-2008	**1.020**	0.020	0.429	43
Grand Valley Energy	2006-2008	**1.031**	0.031	0.392	44
Brantford Power	2006-2008	**1.033**	0.033	0.384	45
Westario Power	2006-2008	**1.042**	0.042	0.355	46
Woodstock Hydro	2006-2008	**1.043**	0.043	0.351	47
Ottawa River Power	2006-2008	**1.045**	0.045	0.344	48
London Hydro	2006-2008	**1.046**	0.046	0.341	49
Parry Sound Power	2006-2008	**1.052**	0.052	0.325	50
Bluewater Power	2006-2008	**1.052**	0.052	0.322	51
Thunder Bay Hydro	2006-2008	**1.060**	0.060	0.300	52
Cooperative Hydro	2006-2008	**1.065**	0.065	0.283	53
Guelph Hydro	2006-2008	**1.068**	0.068	0.274	54
Sioux Lookout Hydro	2006-2008	**1.071**	0.071	0.269	55
Toronto Hydro Electric	2006-2008	**1.072**	0.072	0.265	56
Brant County Power	2006-2008	**1.075**	0.075	0.256	57
St. Thomas Energy	2006-2008	**1.076**	0.076	0.253	58
Wellington North Power	2006-2008	**1.078**	0.078	0.249	59

[1] Lower values imply better performance.

Table 8: Efficiency Cohort Groupings

Efficiency Cohort Grouping Results

Company	Cohort
Hydro Hawkesbury	1
Chatham-Kent Hydro	1
Northern Ontario Wires	1
Cambridge North Dumfries Hydro	1
Grimsby Power	1
Hydro 2000	1
Hydro One Brampton Networks	1
Kitchener-Wilmot Hydro	1
Renfrew Hydro	1
Barrie Hydro	1
Festival Hydro	1
Oshawa PUC	2
Waterloo North Hydro	2
Kingston Electricity	2
E.L.K. Energy	2
Welland Hydro-Electric	2
Hearst Power	2
Horizon Utilities	2
Middlesex Power	2
Lakeland Power	2
Kenora Hydro	2
Lakefront Utilities	2
Rideau St. Lawrence Distribution	2
Newmarket-Tay Hydro Electric	2
Niagara-on-the-Lake Hydro	2
Atikokan Hydro	2
Halton Hills	2
Innisfil Hydro	2
North Bay Hydro	2
Newbury Power	2
Hydro Ottawa	2
PUC Distribution	2
Orangeville Hydro	2
Veridian Connections	2
Wasaga Distribution	2
Peterborough Distribution	2
Enersource Hydro Mississauga	2
Espanola Regional Hydro	2
Tillsonburg Hydro	2
Haldimand County Hydro	2
Burlington Hydro	2
Oakville Hydro	2
Milton Hydro	2
Grand Valley Energy	2
Brantford Power	2
Westario Power	2
Woodstock Hydro	2

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Report for

Ontario Energy Board

Third Generation Incentive Regulation Stretch Factor Updates for 2011 (EB-2009-0392)

March 7, 2011

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2.4.3 Econometric Benchmarking Results

The OM&A performance evaluations are presented in Table 4 below. The ratio of the average actual OM&A costs of each company in the last three years to the model's benchmark cost projections over the same years is reported. A lower ratio of actual cost to predicted cost implies better performance. Distributors have been ranked according to this ratio.

P-value statistical tests were conducted for each utility to test the hypothesis of it being an average cost performer. If a distributor is a good cost performer with a p-value between 0 and 0.10, the hypothesis of average performance is rejected in favor of a statistically superior performer designation. Likewise, if a distributor is a poor cost performer with a p-value between 0 and 0.10, the hypothesis of average performance is rejected in favor of a statistically inferior performer designation. Fifteen distributors fit into each the statistically superior and statistically inferior classification.

Table 4: Econometric Benchmarking Results

Performance Rankings Based on Econometric

	Years Benchmarked	Actual/ Predicted [1]	P-Value	Rank[1]
Hydro Hawkesbury Inc.	2007-2009	**0.600**	0.000	1
Chatham-Kent Hydro Inc.	2007-2009	**0.729**	0.003	2
Northern Ontario Wires Inc.	2007-2009	**0.748**	0.005	3
Hydro One Brampton Networks Inc.	2007-2009	**0.769**	0.010	4
Hydro 2000 Inc.	2007-2009	**0.790**	0.019	5
Grimsby Power Incorporated	2007-2009	**0.791**	0.019	6
Waterloo North Hydro Inc.	2007-2009	**0.797**	0.022	7
Kitchener-Wilmot Hydro Inc.	2007-2009	**0.798**	0.023	8
Cambridge and North Dumfries Hydro Inc.	2007-2009	**0.817**	0.037	9
Middlesex Power Distribution Corporation	2007-2009	**0.829**	0.049	10
Renfrew Hydro Inc.	2007-2009	**0.834**	0.055	11
Festival Hydro Inc.	2007-2009	**0.837**	0.057	12
Oshawa PUC Networks Inc.	2007-2009	**0.854**	0.081	13
North Bay Hydro Distribution Limited	2007-2009	**0.860**	0.090	14
Lakefront Utilities Inc.	2007-2009	**0.862**	0.093	15
Halton Hills Hydro Inc.	2007-2009	**0.874**	0.117	16
Hearst Power Distribution Company Limited	2007-2009	**0.889**	0.148	17
Kingston Hydro Corporation	2007-2009	**0.895**	0.163	18
Veridian Connections Inc.	2007-2009	**0.898**	0.170	19
E.L.K. Energy Inc.	2007-2009	**0.930**	0.260	20
Newmarket - Tay Power Distribution Ltd.	2007-2009	**0.931**	0.262	21
Horizon Utilities Corporation	2007-2009	**0.931**	0.265	22
Oakville Hydro Electricity Distribution Inc.	2007-2009	**0.934**	0.273	23

Table 8: Efficiency Cohort Groupings

Efficiency Cohort Grouping Results

Company	Cohort
Chatham-Kent Hydro Inc.	1
Festival Hydro Inc.	1
Grimsby Power Incorporated	1
Hydro 2000 Inc.	1
Hydro Hawkesbury Inc.	1
Hydro One Brampton Networks Inc.	1
Kitchener-Wilmot Hydro Inc.	1
Lakefront Utilities Inc.	1
Middlesex Power Distribution Corporation	1
North Bay Hydro Distribution Limited	1
Northern Ontario Wires Inc.	1
Renfrew Hydro Inc.	1
Atikokan Hydro Inc.	2
Bluewater Power Distribution Corporation	2
Brant County Power Inc.	2
Brantford Power Inc.	2
Burlington Hydro Inc.	2
Cambridge and North Dumfries Hydro Inc.	2
Cooperative Hydro Embrun Inc.	2
E.L.K. Energy Inc.	2
Enersource Hydro Mississauga Inc.	2
EnWin Utilities Ltd.	2
Espanola Regional Hydro Distribution Corporation	2
Essex Powerlines Corporation	2
Fort Erie - Eastern Ontario Power (CNP)	2
Fort Frances Power Corporation	2
Guelph Hydro Electric Systems Inc.	2
Haldimand County Hydro Inc.	2
Halton Hills Hydro Inc.	2
Hearst Power Distribution Company Limited	2
Horizon Utilities Corporation	2
Hydro One Networks Inc.	2
Hydro Ottawa Limited	2
Innisfil Hydro Distribution Systems Limited	2
Kenora Hydro Electric Corporation Ltd.	2
Kingston Hydro Corporation	2

the power to help you succeed.

Report for

Ontario Energy Board

Third Generation Incentive Regulation Stretch Factor Updates for 2012 (EB-2011-0387)

December 1, 2011

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Power System
Engineering, Inc.

Table 4: Econometric Benchmarking Results

Performance Rankings Based on Econometric Benchmarks

	Years Benchmarked	Actual/Predicted[1]	P-Value	Rank[1]
Hydro Hawkesbury Inc.	2008-2010	**0.600**	0.000	1
Northern Ontario Wires Inc.	2008-2010	**0.754**	0.006	2
Chatham-Kent Hydro Inc.	2008-2010	**0.777**	0.013	3
Hydro One Brampton Networks Inc.	2008-2010	**0.781**	0.014	4
Kitchener-Wilmot Hydro Inc.	2008-2010	**0.785**	0.016	5
Grimsby Power Incorporated	2008-2010	**0.786**	0.017	6
Waterloo North Hydro Inc.	2008-2010	**0.788**	0.017	7
Hydro 2000 Inc.	2008-2010	**0.799**	0.023	8
North Bay Hydro Distribution Limited	2008-2010	**0.820**	0.039	9
Middlesex Power Distribution Corporation	2008-2010	**0.825**	0.044	10
Renfrew Hydro Inc.	2008-2010	**0.829**	0.048	11
Cambridge and North Dumfries Hydro Inc.	2008-2010	**0.836**	0.056	12
Festival Hydro Inc.	2008-2010	**0.839**	0.060	13
Halton Hills Hydro Inc.	2008-2010	**0.857**	0.086	14
Lakefront Utilities Inc.	2008-2010	**0.865**	0.100	15
Oshawa PUC Networks Inc.	2008-2010	**0.868**	0.105	16
Greater Sudbury Hydro Inc.	2008-2010	**0.895**	0.162	17
Niagara-on-the-Lake Hydro Inc.	2008-2010	**0.903**	0.182	18
Oakville Hydro Electricity Distribution Inc.	2008-2010	**0.904**	0.186	19
Veridian Connections Inc.	2008-2010	**0.918**	0.223	20
Peterborough Distribution Incorporated	2008-2010	**0.918**	0.224	21
E.L.K. Energy Inc.	2008-2010	**0.923**	0.240	22
Horizon Utilities Corporation	2008-2010	**0.924**	0.241	23
Hearst Power Distribution Company Limited	2008-2010	**0.931**	0.264	24
Kingston Hydro Corporation	2008-2010	**0.937**	0.281	25
Newmarket - Tay Power Distribution Ltd.	2008-2010	**0.957**	0.349	26
Guelph Hydro Electric Systems Inc.	2008-2010	**0.959**	0.356	27
PUC Distribution Inc.	2008-2010	**0.960**	0.357	28
Milton Hydro Distribution Inc.	2008-2010	**0.963**	0.370	29
Welland Hydro-Electric System Corp.	2008-2010	**0.966**	0.380	30
Rideau St. Lawrence Distribution Inc.	2008-2010	**0.975**	0.413	31
Hydro Ottawa Limited	2008-2010	**0.977**	0.417	32
Essex Powerlines Corporation	2008-2010	**0.983**	0.440	33
Espanola Regional Hydro Distribution Corporation	2008-2010	**0.984**	0.445	34
Wasaga Distribution Inc.	2008-2010	**0.991**	0.468	35
Haldimand County Hydro Inc.	2008-2010	**0.996**	0.486	36
Ottawa River Power Corporation	2008-2010	**0.996**	0.487	37
Kenora Hydro Electric Corporation Ltd.	2008-2010	**1.005**	0.482	38
Burlington Hydro Inc.	2008-2010	**1.007**	0.477	39
Orangeville Hydro Limited	2008-2010	**1.007**	0.475	40

Table 8: Efficiency Cohort Groupings

Efficiency Cohort Grouping Results

Company	Cohort
Chatham-Kent Hydro Inc.	1
Festival Hydro Inc.	1
Grimsby Power Incorporated	1
Hydro 2000 Inc.	1
Hydro Hawkesbury Inc.	1
Hydro One Brampton Networks Inc.	1
Kitchener-Wilmot Hydro Inc.	1
Lakefront Utilities Inc.	1
Middlesex Power Distribution Corporation	1
Northern Ontario Wires Inc.	1
Renfrew Hydro Inc.	1
Waterloo North Hydro Inc.	1
Atikokan Hydro Inc.	2
Bluewater Power Distribution Corporation	2
Brantford Power Inc.	2
Burlington Hydro Inc.	2
Cambridge and North Dumfries Hydro Inc.	2
Chapleau Public Utilities Corporation	2
Clinton Power Corporation	2
Cooperative Hydro Embrun Inc.	2
E.L.K. Energy Inc.	2
Enersource Hydro Mississauga Inc.	2
Espanola Regional Hydro Distribution Corporation	2
Essex Powerlines Corporation	2
Fort Erie - Eastern Ontario Power (CNP)	2
Fort Frances Power Corporation	2
Greater Sudbury Hydro Inc.	2
Guelph Hydro Electric Systems Inc.	2
Haldimand County Hydro Inc.	2
Halton Hills Hydro Inc.	2
Hearst Power Distribution Company Limited	2
Horizon Utilities Corporation	2
Hydro One Networks Inc.[1]	2
Hydro Ottawa Limited	2
Innisfil Hydro Distribution Systems Limited	2
Kenora Hydro Electric Corporation Ltd.	2
Kingston Hydro Corporation	2
Lakeland Power Distribution Ltd.	2

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Report for

Ontario Energy Board

Third Generation Incentive Regulation Stretch Factor Updates for 2013

November 27, 2012

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Table 4: Econometric Benchmarking Results

Performance Rankings Based on Econometric Benchmarks

	Years Benchmarked	Actual/Predicted[1]	P-Value	Rank[1]
Hydro Hawkesbury Inc.	2009-2011	**0.628**	0.000	1
Northern Ontario Wires Inc.	2009-2011	**0.741**	0.003	2
Hydro One Brampton Networks Inc.	2009-2011	**0.754**	0.005	3
Waterloo North Hydro Inc.	2009-2011	**0.769**	0.009	4
Kitchener-Wilmot Hydro Inc.	2009-2011	**0.788**	0.015	5
Halton Hills Hydro Inc.	2009-2011	**0.794**	0.018	6
Grimsby Power Incorporated	2009-2011	**0.796**	0.019	7
North Bay Hydro Distribution Limited	2009-2011	**0.801**	0.022	8
Entegrus Powerlines Inc. (Chatham-Kent Hydro Inc.)	2009-2011	**0.812**	0.029	9
Festival Hydro Inc.	2009-2011	**0.850**	0.070	10
Renfrew Hydro Inc.	2009-2011	**0.853**	0.074	11
Cambridge and North Dumfries Hydro Inc.	2009-2011	**0.854**	0.075	12
Entegrus Powerlines Inc. (Middlesex Power Dist. Corp.)	2009-2011	**0.856**	0.079	13
Oshawa PUC Networks Inc.	2009-2011	**0.857**	0.080	14
Hydro 2000 Inc.	2009-2011	**0.881**	0.124	15
Veridian Connections Inc.	2009-2011	**0.881**	0.125	16
Peterborough Distribution Incorporated	2009-2011	**0.893**	0.153	17
Niagara-on-the-Lake Hydro Inc.	2009-2011	**0.906**	0.184	18
E.L.K. Energy Inc.	2009-2011	**0.908**	0.191	19
Lakefront Utilities Inc.	2009-2011	**0.914**	0.205	20
Greater Sudbury Hydro Inc.	2009-2011	**0.915**	0.209	21
Horizon Utilities Corporation	2009-2011	**0.920**	0.224	22
Oakville Hydro Electricity Distribution Inc.	2009-2011	**0.934**	0.267	23
Essex Powerlines Corporation	2009-2011	**0.945**	0.305	24
Newmarket - Tay Power Distribution Ltd.	2009-2011	**0.947**	0.311	25
Sioux Lookout Hydro Inc.	2009-2011	**0.960**	0.355	26
Milton Hydro Distribution Inc.	2009-2011	**0.961**	0.360	27
Espanola Regional Hydro Distribution Corporation	2009-2011	**0.962**	0.361	28
Haldimand County Hydro Inc.	2009-2011	**0.963**	0.363	29
Hydro Ottawa Limited	2009-2011	**0.965**	0.373	30
Westario Power Inc.	2009-2011	**0.966**	0.376	31
Wasaga Distribution Inc.	2009-2011	**0.970**	0.392	32
Norfolk Power Distribution Inc.	2009-2011	**0.970**	0.392	33
Brantford Power Inc.	2009-2011	**0.977**	0.415	34
PUC Distribution Inc.	2009-2011	**0.977**	0.416	35
Hearst Power Distribution Company Limited	2009-2011	**0.979**	0.424	36
Burlington Hydro Inc.	2009-2011	**0.987**	0.454	37
Enersource Hydro Mississauga Inc.	2009-2011	**0.988**	0.455	38
Rideau St. Lawrence Distribution Inc.	2009-2011	**0.993**	0.474	39
Kingston Hydro Corporation	2009-2011	**0.993**	0.474	40
Ottawa River Power Corporation	2009-2011	**0.996**	0.486	41
Guelph Hydro Electric Systems Inc.	2009-2011	**0.998**	0.494	42

[1] Lower values imply better performance.

Table 8: 2013 Efficiency Cohort Groupings

2013 Efficiency Cohort Grouping Results

Company	Cohort
Entegrus Powerlines Inc. (Chatham-Kent Hydro Inc.)	1
Festival Hydro Inc.	1
Grimsby Power Incorporated	1
Hydro Hawkesbury Inc.	1
Hydro One Brampton Networks Inc.	1
Kitchener-Wilmot Hydro Inc.	1
Entegrus Powerlines Inc. (Middlesex Power Distribution Corporation)	1
North Bay Hydro Distribution Limited	1
Northern Ontario Wires Inc.	1
Renfrew Hydro Inc.	1
Atikokan Hydro Inc.	2
Bluewater Power Distribution Corporation	2
Brantford Power Inc.	2
Burlington Hydro Inc.	2
Cambridge and North Dumfries Hydro Inc.	2
Chapleau Public Utilities Corporation	2
Cooperative Hydro Embrun Inc.	2
E.L.K. Energy Inc.	2
Enersource Hydro Mississauga Inc.	2
EnWin Utilities Ltd.	2
Espanola Regional Hydro Distribution Corporation	2
Essex Powerlines Corporation	2
Fort Erie - Eastern Ontario Power (CNP)	2
Fort Frances Power Corporation	2
Greater Sudbury Hydro Inc.	2
Guelph Hydro Electric Systems Inc.	2
Haldimand County Hydro Inc.	2
Halton Hills Hydro Inc.	2
Hearst Power Distribution Company Limited	2
Horizon Utilities Corporation	2
Hydro 2000 Inc.	2
Hydro One Networks Inc.[1]	2
Hydro Ottawa Limited	2
Innisfil Hydro Distribution Systems Limited	2
Kenora Hydro Electric Corporation Ltd.	2
Kingston Hydro Corporation	2
Lakefront Utilities Inc.	2
Lakeland Power Distribution Ltd.	2
London Hydro Inc.	2
Midland Power Utility Corporation	2

Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update

Report to the Ontario Energy Board

July 2014

Pacific Economics Group Research, LLC

The views expressed in this report are those of Pacific Economics Group Research, and do not necessarily represent the views of, and should not be attributed to, the Ontario Energy Board, any individual Board Member, or Ontario Energy Board staff.

Table 3

Summary of Benchmarking Results

	Actual Cost less Predicted Cost			
	2010-2012 Final Results	2013	2011-2013	Difference from 2010-2012
Algoma Power Inc.	65.5%	71.1%	68.5%	3.0%
Atikokan Hydro Inc.	18.5%	12.0%	17.5%	-1.0%
Bluewater Power Distribution Corporation	1.6%	5.8%	4.6%	3.0%
Brant County Power Inc.	16.5%	5.0%	13.0%	-3.5%
Brantford Power Inc.	2.0%	0.5%	0.9%	-1.1%
Burlington Hydro Inc.	-7.9%	-7.9%	-8.0%	-0.1%
Cambridge And North Dumfries Hydro Inc.	-7.0%	0.0%	-3.7%	3.4%
Canadian Niagara Power Inc.	14.0%	13.9%	13.2%	-0.8%
Centre Wellington Hydro Ltd.	-4.4%	0.0%	-1.5%	2.9%
Chapleau Public Utilities Corporation	18.8%	20.7%	19.8%	1.0%
Collus Power Corporation	-6.3%	-12.5%	-7.7%	-1.5%
Cooperative Hydro Embrun Inc.	-20.9%	-20.1%	-21.2%	-0.3%
E.L.K. Energy Inc.	-26.6%	-33.2%	-28.3%	-1.7%
Enersource Hydro Mississauga Inc.	-11.7%	-11.3%	-12.3%	-0.6%
Entegrus Powerlines	-12.5%	-12.6%	-12.3%	0.2%
Enwin Utilities Ltd.	19.5%	10.0%	16.9%	-2.6%
Erie Thames Powerlines Corporation	11.1%	7.9%	8.7%	-2.3%
Espanola Regional Hydro Distribution Corporation	-20.0%	-19.3%	-18.9%	1.1%
Essex Powerlines Corporation	-15.5%	-17.5%	-15.7%	-0.2%
Festival Hydro Inc.	19.6%	19.5%	19.2%	-0.3%
Fort Frances Power Corporation	12.3%	6.5%	9.6%	-2.8%
Greater Sudbury Hydro Inc.	9.5%	4.9%	11.9%	2.4%
Grimsby Power Incorporated	-17.1%	-17.4%	-15.2%	1.9%
Guelph Hydro Electric Systems Inc.	8.3%	-0.1%	4.2%	-4.2%
Haldimand County Hydro Inc.	-23.5%	-23.8%	-22.2%	1.3%
Halton Hills Hydro Inc.	-26.5%	-36.2%	-29.5%	-3.0%

Table 3

Summary of Benchmarking Results

	Actual Cost less Predicted Cost			
	2010-2012 Final Results	2013	2011-2013	Difference from 2010-2012
Hearst Power Distribution Company Limited	-28.3%	-33.1%	-30.6%	-2.3%
Horizon Utilities Corporation	-11.2%	-5.7%	-8.8%	2.4%
Hydro 2000 Inc.	-9.3%	-1.0%	-4.7%	4.6%
Hydro Hawkesbury Inc.	-59.0%	-51.2%	-55.5%	3.5%
Hydro One Brampton Networks Inc.	-7.4%	-6.9%	-7.8%	-0.4%
Hydro One Networks Inc.	58.2%	27.4%	47.8%	-10.4%
Hydro Ottawa Limited	1.7%	8.2%	4.5%	2.8%
Innisfil Hydro Distribution Systems Limited	-5.2%	-3.0%	-3.9%	1.3%
Kenora Hydro Electric Corporation Ltd.	-7.1%	-10.5%	-6.8%	0.3%
Kingston Hydro Corporation	1.6%	3.7%	2.8%	1.2%
Kitchener	-22.2%	-19.8%	-21.1%	1.0%
Lakefront Utilities Inc.	-15.3%	-7.6%	-12.9%	2.4%
Lakeland Power Distribution Ltd.	-10.4%	-6.5%	-10.05%	0.3%
London Hydro Inc.	-12.7%	-11.2%	-10.8%	1.9%
Midland Power Utility Corporation	17.7%	18.1%	18.2%	0.5%
Milton Hydro Distribution Inc.	-14.9%	-6.6%	-15.7%	-0.8%
Newmarket	-18.3%	-19.8%	-20.1%	-1.7%
Niagara Peninsula Energy Inc.	6.9%	0.8%	5.4%	-1.5%
Niagara-On-The-Lake Hydro Inc.	5.6%	-1.0%	2.7%	-2.9%
Norfolk Power Distribution Inc.	0.5%	1.1%	1.5%	1.0%
North Bay Hydro Distribution Limited	5.0%	5.2%	5.5%	0.5%
Northern Ontario Wires Inc.	-33.3%	-21.4%	-27.6%	5.7%
Oakville Hydro Electricity Distribution Inc.	10.2%	13.2%	12.0%	1.8%
Orangeville Hydro Limited	-0.1%	-0.2%	0.7%	0.8%
Orillia Power Distribution Corporation	-3.1%	-4.9%	-3.5%	-0.5%
Oshawa PUC Networks Inc.	-18.1%	-17.6%	-16.7%	1.4%

Table 3

Summary of Benchmarking Results

	Actual Cost less Predicted Cost			
	2010-2012 Final Results	2013	2011-2013	Difference from 2010-2012
Ottawa River Power Corporation	-0.1%	4.3%	2.3%	2.4%
Parry Sound Power Corporation	3.9%	14.1%	7.0%	3.1%
Peterborough Distribution Incorporated	14.3%	14.5%	14.4%	0.2%
Powerstream Inc.	-4.2%	2.2%	-1.0%	3.2%
PUC Distribution Inc.	-0.1%	22.6%	10.2%	10.4%
Renfrew Hydro Inc.	17.3%	15.5%	17.4%	0.1%
Rideau St. Lawrence Distribution Inc.	-10.4%	-7.3%	-9.3%	1.1%
Sioux Lookout Hydro Inc.	2.1%	2.9%	2.9%	0.8%
St. Thomas Energy Inc.	-1.4%	-0.5%	0.6%	2.0%
Thunder Bay Hydro Electricity Distribution Inc.	4.9%	8.1%	4.4%	-0.5%
Tillsonburg Hydro Inc.	12.2%	19.3%	14.1%	1.9%
Toronto Hydro-Electric System Limited	44.8%	48.3%	47.0%	2.2%
Veridian Connections Inc.	-2.3%	-4.8%	-2.3%	-0.1%
Wasaga Distribution Inc.	-43.6%	-42.1%	-42.1%	1.6%
Waterloo North Hydro Inc.	2.5%	10.1%	7.0%	4.4%
Welland Hydro-Electric System Corp.	-15.4%	-15.3%	-14.0%	1.4%
Wellington North Power Inc.	12.7%	17.5%	16.1%	3.4%
West Coast Huron Energy Inc.	21.7%	41.2%	30.7%	9.0%
Westario Power Inc.	-1.5%	2.0%	0.2%	1.7%
Whitby Hydro Electric Corporation	-3.2%	-2.2%	-4.1%	-0.9%
Woodstock Hydro Services Inc.	31.8%	28.1%	30.0%	-1.8%
Average	-0.89%	-0.08%	-0.17%	0.73%

Table 5

Stretch Factor Assignments by Group

Group I	Group II	Group III	Group IV	Group V
Stretch Factor = 0%	Stretch Factor = 0.15%	Stretch Factor = 0.30%	Stretch Factor = 0.45%	Stretch Factor = 0.60%
E.L.K. Energy Inc.	Cooperative Hydro Embrun Inc.	Bluewater Power Distribution Corporation	Atikokan Hydro Inc.	Algoma Power Inc.
Halton Hills Hydro Inc.	Enersource Hydro Mississauga Inc.	Brantford Power Inc.	Brant County Power Inc.	Hydro One Networks Inc.
Hearst Power Distribution Company Limited	Entegrus Powerlines	Burlington Hydro Inc.	Canadian Niagara Power Inc.	Toronto Hydro-Electric System Limited
Hydro Hawkesbury Inc.	Espanola Regional Hydro Distribution Corporation	Cambridge And North Dumfries Hydro Inc.	Chapleau Public Utilities Corporation	**West Coast Huron Energy Inc.**
Northern Ontario Wires Inc.	Essex Powerlines Corporation	Centre Wellington Hydro Ltd.	Enwin Utilities Ltd.	Woodstock Hydro Services Inc.
Wasaga Distribution Inc.	Grimsby Power Incorporated	Collus Power Corporation	Festival Hydro Inc.	
	Haldimand County Hydro Inc.	**Erie Thames Powerlines Corporation**	**Greater Sudbury Hydro Inc.**	
	Kitchener	**Fort Frances Power Corporation**	Midland Power Utility Corporation	
	Lakefront Utilities Inc.	Guelph Hydro Electric Systems Inc.	Oakville Hydro Electricity Distribution Inc.	
	Lakeland Power Distribution Ltd.	**Horizon Utilities Corporation**	Peterborough Distribution Incorporated	
	London Hydro Inc.	Hydro 2000 Inc.	**PUC Distribution Inc.**	
	Milton Hydro Distribution Inc.	Hydro One Brampton Networks Inc.	Renfrew Hydro Inc.	
	Newmarket	Hydro Ottawa Limited	Tillsonburg Hydro Inc.	
	Oshawa PUC Networks Inc.	Innisfil Hydro Distribution Systems Limited	Wellington North Power Inc.	
	Welland Hydro-Electric System Corp.	Kenora Hydro Electric Corporation Ltd.		
		Kingston Hydro Corporation		
		Niagara Peninsula Energy Inc.		
		Niagara-On-The-Lake Hydro Inc.		
		Norfolk Power Distribution Inc.		
		North Bay Hydro Distribution Limited		
		Orangeville Hydro Limited		
		Orillia Power Distribution Corporation		
		Ottawa River Power Corporation		
		Parry Sound Power Corporation		
		Powerstream Inc.		
		Rideau St. Lawrence Distribution Inc.		
		Sioux Lookout Hydro Inc.		
		St. Thomas Energy Inc.		
		Thunder Bay Hydro Electricity Distribution Inc.		
		Veridian Connections Inc.		
		Waterloo North Hydro Inc.		
		Westario Power Inc.		
		Whitby Hydro Electric Corporation		

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	295,600	285,868	-3.3%	609,000	439,986	-27.8%	364,000	503,122	38.2%	452,000	272,227	-39.8%	315,000		-100.0%	321,500	328,000	334,500	341,000	347,500
System Renewal	2,468,400	2,116,936	-14.2%	2,111,000	2,306,268	9.3%	2,146,000	1,759,913	-18.0%	1,706,500	2,036,400	19.3%	1,688,000		-100.0%	1,490,000	1,513,000	1,539,000	1,565,000	1,592,000
System Service	496,000	377,833	-24.1%	200,000	93,154	-53.4%	465,000	523,091	12.5%	881,500	673,952	-23.5%	310,000		-100.0%	310,000	314,000	316,000	318,000	320,000
General Plant	465,000	359,166	-25.9%	471,500	219,406	-53.5%	434,000	505,287	16.4%	403,000	405,208	0.5%	460,000		-100.0%	500,000	427,000	826,000	445,000	415,000
TOTAL EXPENDITURE	3,747,000	3,139,803	-16.2%	3,391,500	3,058,814	-9.8%	3,409,000	3,291,413	-3.4%	3,443,000	3,387,787	-1.6%	2,773,000	-	-100.0%	2,621,500	2,582,000	3,015,500	2,669,000	2,674,500
Increase in major spare parts		41,549			-			66,863			-									
smart meters and related computer equipment reclassified from USOA 1555								3,694,577												
contributed capital USOA 1995	- 390,000	- 474,049			- 106,480			- 342,654			- 154,030		- 150,000			- 120,000	- 120,000	- 120,000	- 120,000	- 120,000
TS CWIP USOA 2205		879,452			312,730			7,830,663			5,860,659									
Non Rate-Regulated Utility Property USOA 2017 (solar)		44,951			249,738			-			-									
TOTAL EXPENDITURE		3,631,705			3,514,802			14,540,863			9,094,416		2,623,000			2,501,500	2,462,000	2,895,500	2,549,000	2,554,500
System O&M	$1,472,730	$ 1,446,517	-1.8%	$1,509,548	$1,539,820	2.0%	$ 1,539,739	$2,202,237	43.0%			–	$1,929,022		-100.0%	$2,104,096	$2,084,956	$2,123,978	$2,171,021	

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. histrical budgets by category

System Access - historical budget vs forecast is stable over the planning horizon. System access is mostly driven by 3rd party work and no major changes are expected. The forecast period budget is 10% below historical actual to date
System Renewal - forecasted budget for SR projects decreases compared to historical budget due to the age and system condition of assets as defined in the asset management report. spending stays stable over the forecast budget
System service - forecasted budget for SS decreases slightly from the historical to forecast period, but spending remains stable.
General plant - forecast vs historical budget remains flat for general plant over the planning horizon. There is a single year with variability in the forecast period due to the replacement of a large fleet vehicle

Notes on year over year Plan vs. Actual variances for Total Expenditures

There is one historical year the variance exceeds +-10 percent of spending, 2010. As was described in the DSP, $515,000 was removed from the 2010 budget do to additional spending required in the smart meter roll out.

Notes on Plan vs. Actual variance trends for individual expenditure categories

System Access - The variance for this category is attributed to the amount of actual work required to be completed by customers. All work in this category is customer driven for which FHI has no control.
System Renewal - Although system renewal had year to year variances the total variance over the 4 year reported period is less than 1%. this can be attributed to timing.
System Service - The 2010 variance can be attributed to the removal of projects described above, the 2011 variance can be attributed to a distribution automation project being contracted as a service as opposed to capitalized.The 2012 variance can be attributed to unforseen costs of replacing live front with dead front switchgear (1st time project). The 2013 can be attributed to automation work being charge to the TS project as opposed to the capital budget
General Plant - The variation of GP spending can be attributed to the reduced replacement of large fleet vehicles from the original plan.

Appendix 2-AA
Capital Projects Table

Projects	2010	2011	2012	2013	2014 Bridge Year	2014 Year to date	2015 Test Year
Reporting Basis							
System Access							
Subdivisions	199,708		240,986	40,177			
Customer Connection/Extension		305,005		88,353			
Goderich St reet E (LTLT)			60,719				
Capital Additions					200,000	28,894	204,000
New Upgraded Services					115,000	66,934	117,500
Sub-Total	199,708	305,005	301,705	128,530	315,000	95,828	321,500
Miscellaneous	86,160	134,981	201,417	143,697			
[redacted]							
General Plant							
Truck 4 - Single Bucket	226,311						
Truck 22 - Backhoe		75,425					
Computer Equipment		76,969	90,259	293,712	290,000	60,686	245,000
Truck #2 - RBD			322,414				
Land and Buildings					80,000	0	90,000
Electric Vehicle							70,000
Sub-Total	226,311	152,394	412,673	293,712	370,000	60,686	405,000
Miscellaneous	132,855	67,012	92,614	111,496	90,000	8,628	95,000
[redacted]							
System Renewal							
Centre St. & Helen St. - spun secondary	$104,383						
Cobourg Area 1F1 Phase 2 - conversion	$303,048						
Delamere (Mornington to Romeo)	$229,748						
St. George St.	$154,788						
9M4 - Northwest Section	$182,440						
Brantford - rear lot conversion	$73,024						
Transformers	$203,773	$188,460	$93,776	$232,841	$200,000	$110,311	$205,000
Distribution Meters	$198,305	$147,080	$152,023	$91,138	$190,000	$28,280	$175,000
Switchgear at MS#1	$66,713						
St. David Rebuild (Downie to Church)		$194,855					
Devon St. Rebuild (Romeo to T.S.)		$177,240					
Lorne Ave. W. Rebuild (Boyd to St. Vincent)		$305,866					
9M4-Northwest Section Ph 2		$113,385					
Cemetery @ Charles St.		$63,412					
Market St. Rebuild (High to deadend)		$66,917					
Flora St. to Turnberry St.		$180,012					
M.S. #8 Phase 1 - Conversion		$170,086					
Packham Road - Rebuild (3ph double circuit)			$320,190				
Park Street Rebuild (east of Romeo)			$74,838				
M1 Feeder - Cemetry to James St. South			$146,227				
Turnberry Rebuild (Flora to PME)			$170,856				
West Gore Rebuild (John to Sewage Plant)				151,110			
Victoria Street M4 Rebuild (RRX to Wellington)				85,535			
Jones St W Rebuild & Salina St S				160,436			
Queen St. Rebuild				177,154			
Sports Drive, Thomas & Maple				123,534			
Brunswick Street (Romeo to Queen)					$145,000	$190,958	
Mornington St. Rebuild (Delamere to Quinlan)					$255,000	$107,412	
Elgin St (Ontario to West End & Warner)					$130,000	$106,644	
Chuch St. N. & Egan St.					$110,000	$22,541	
CN Road, Princess St., Albert St.					$100,000	$90,616	
Dunedin Drive Rebuild (Turnberry to Burgess)					$65,000	$38,919	
M.S. #8 Ph 2					$180,000	$6,690	
M8 Feeder Rebuild (Ontario to Douro)							$125,000
Trinity Street (Brunswick to Regent)							$90,000
King Street (Albert to Douro)							$60,000
Elgin Street (Church to James)							$90,000
Jones Street (James to Church & Peel)							$60,000
John Street (High St to Sparling)							$75,000
Jarvis Street & Lloyd Eisler St.							$150,000
M.S. #9 Conversion Ph 1							$230,000
Sub-Total	1,516,223	1,607,313	957,911	1,021,748	1,375,000	702,371	1,260,000
Miscellaneous	600,713	698,955	802,002	1,014,652	313,000	155,647	230,000
[redacted]							
System Service							
Wrigt Blvd. Extension & Gibb Road tie line	$159,056						
TS Conduit	$142,562						
Switchgear Replacement			259,867	112,695	110,000		110,000
Line Re-insulation			232,385	96,812	150,000	84,841	150,000
O'Loane Feeder Tie				306,280			
Forman Feeder Tie				132,318			
Sub-Total	301,618	0	492,252	650,105	260,000	84,841	260,000
Miscellaneous	76,215	93,154	30,839	23,847	50,000	13,281	50,000
[redacted]							
Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	1,121,282	2,621,500
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(Input as negative)*							
Total	3,139,803	3,058,814	3,291,413	3,387,787	2,773,000	1,121,282	2,621,500

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.
2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category.

38. 2. OEB STAFF 15

Ref: Appendix 2-AA and E2/T2/S1, DSP – Attachment 1, Section 5.4.1, p. 36; Asset Management Plan, Appendix 11

In section 5.4.1 d), Festival Hydro lists a description of material projects, including the replacement of 100 poles for a total capital expenditure of $650,000 over a ten-year period.

a) Please identify capital spending amount for pole replacement included in the 2015 test year capital budget and compare that amount to the historical, annual capital expenditure for pole replacement.

b) Appendix 11, Pole Inspection Report 2013, p. 9 states that based on the relatively low rate of decay found during the 2013 pole inspection program, "Festival Hydro is justified in proceeding with a treat based on condition approach".

i. Please provide further detail regarding Festival Hydro's pole replacement program, including number of poles to be replaced in the test year and percentage of total number of poles.

ii. Does Festival Hydro track interruptions caused by pole failure? If not, why not? If so, why aren't interruptions caused by pole failure a proposed performance metric?

iii. What is the average cost per replaced pole? Is Festival Hydro realizing any efficiency on a unit cost basis?

Response:

a) The 2015 capital spending on pole replacements is $650,000 for 100 poles. The annual historical spending is as follows:

   2011 - $1,226,278 for 191 poles = $6420/pole
   2012 - $829,178 for 116 poles = $7148/pole
   2013 - $787,021 for 146 poles = $5390/pole
   2014 - $840,000 for 130 poles = $6461/pole

b) Festival Hydro has established a replacement program that would keep the number of wood poles over 40 years old kept to the same level in 10 years as today. This would require a replacement of 100 wood poles per year to maintain current system conditions (1.6% of the total pole inventory on a year over year basis). A pole inspection program (third party contract) identifies individual poles or areas that are a priority for replacement or treatment. The data on pole condition is used to establish the current years capital expenditures and also identifies areas were pole treatment can be used to increase the useful life of assets.

   i. Festival Hydro has established a replacement program that would keep the number of wood poles over 40 years old kept to the same level in 10 years as today. This would require a replacement of 100 wood poles per year to maintain current system conditions (1.6% of the total pole inventory on a year over year basis). A pole inspection program (third party contract) identifies individual poles or areas that are a priority for replacement or treatment. The data on pole condition is used to establish the current years capital expenditures and also identifies areas were pole treatment can be used to increase the useful life of assets.

ii. Festival Hydro tracks equipment failure in the outage database. The type of equipment failure that led to an outage is noted in the Details section of the outage record. When equipment failure related outages are reviewed to determine if any trends exist, the details are then used to group the failures by equipment type. In the past ten years, the numbers of pole failures, resulting in an outage, have been too few to trigger a change in the pole replacement program.

iii. The average cost per pole replaced as part of the 2015 budget is $6500 per pole. The cost per pole replacement is in line with actual costs over the last 3 years.

39. 2. OEB STAFF 16

Ref: E2/T2/S1/Att. 1/p. 5 – 5.2.1 Distribution System Plan Overview

At page 5 of the reference, under the title "4 kV system conversions", it is indicated that conversion of the 4 kV system to a 27.6 kV system in the City of Stratford will standardize the voltage and reduce system losses.

a) Please provide a copy of the original business case study justifying the conversion project investment and any updates to that study that includes justification for the continued conversion investment in this DSP period.

b) Please identify the steps that were taken to elicit the views of customers on this project, its merits, and the willingness of customers to abide the associated rate increases

c) Please indicate how customers' views were factored into the plan and its timing.

Response:

a) The "4kV System Conversions" is a multi-year project initiated over 10 years ago when the municipal substations began to reach end of life. A "business case" for the conversion program was not created as the evaluation process results in an obvious conclusion and is comparable to conversion programs done at other municipal LDCs in Ontario. Each municipal substation and the area supplied by it are evaluated as they approach end of life to determine the best option for replacement. In many cases, the distribution circuits supplied by the municipal substation (poles, crossarms, insulators) require replacement before the station reaches end of life. Rather than simply replace the components "like-for-like", upgrading to a higher voltage class through a voltage conversion provides a better long term solution. In most cases, the higher voltage circuit is on the same pole line (or within the same duct bank) as the 4 kV circuit, so upgrades generally consist of replacing the end-of-life 4 kV transformers with higher voltage transformers (replacing the pole if at end-of-life) and removing the 4 kV circuit. On side streets with only 4 kV, the upgrades are incremental (higher voltage class insulators, marginally taller poles). As these distribution circuits are converted, the remaining load on the municipal substations decreases to the point where replacement of the municipal substation equipment (switchgear and transformer) is not warranted nor needed. The savings associated with the elimination of the substation and reduced line losses are intuitively greater than the incremental costs associated with voltage upgrades.

Failure modes and condition defects of MUSs include the typical defects that station transformers, switches, fuses and reclosers experience. Additional defects that a MUS can experience compared to that of a station can include damage to MUS feeder connection cables or trailer rust. The number of MUS defects Hydro One Distribution has noted is shown in Table 5 below.

Table 5: MUS Defects

Year	*Number of MUS Defects*
2010	40
2011	49
2012	32
2013	31

Trends and Impacts

On average two mobile unit substations have been refurbished each year under the Mobile Unit Substation program. Hydro One Distribution is proposing to maintain this level of refurbishments annually, as described in Exhibit D1, Tab 3, Schedule 2.

2.2 DISTRIBUTION LINES ASSETS

2.2.1 Poles

Poles comprise the single largest component of Hydro One Distribution's lines asset base. They are used to keep conductor and line equipment at a safe distance from the ground and other objects.

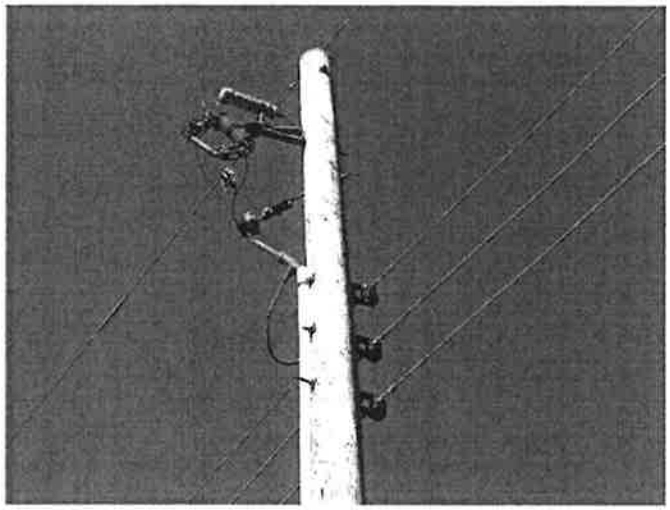

Figure 11: Picture of a Wood Pole

As shown in Table 6, Hydro One Distribution utilizes poles primarily made from wood, though concrete, steel and composite poles are used in specific situations.

Table 6: Pole by Material Type

Material	*Number of Poles*
Wood	1,550,000
Steel	6,000
Concrete	3,000
Composite	less than 1,000

As wood is the dominant pole material, and as wood exhibits the most variation in degradation over time, wood poles require careful management in order to mitigate the risk associated with their deterioration.

Hydro One Distribution's asset strategy for the management of distribution poles centers around their age and condition. The demographic profile enables the projection of long term pole replacement rates; whereas the condition information aids in the selection and prioritization of specific poles to be replaced annually. Hydro One endeavours to replace individual poles when they are observed to be near the end of their service lives, but before they fail, pose a safety hazard, or cause a service interruption. Where possible, these replacements are made in conjunction with other activities on the distribution system to increase efficiency and minimize the number of planned outages. At the same time, Hydro One carefully manages the demographics of the entire pole population to ensure a sustainable work program in the long term.

Demographics

A key indicator of the degradation of wood poles is their age. Older poles exhibit more advanced deterioration and are at a higher risk of failure. Analysis of wood pole failures has indicated that the expected life of a wood pole is approximately 62 years. Based on the current demographics of the Hydro One Distribution wood pole population, 180,000 poles are at least 62 years old, with an additional 140,000 poles reaching 62 over the next five years. The age distribution of wood poles owned by Hydro One Distribution is shown in Figure 12.

While not all of these poles require immediate replacement, they are at a higher risk of failure in the short term and are prioritized in the pole replacement program. The long term management of the high number of poles reaching their expected end of life requires increased funding for the pole replacement program as described in Exhibit D1, Tab 3, Schedule 2.

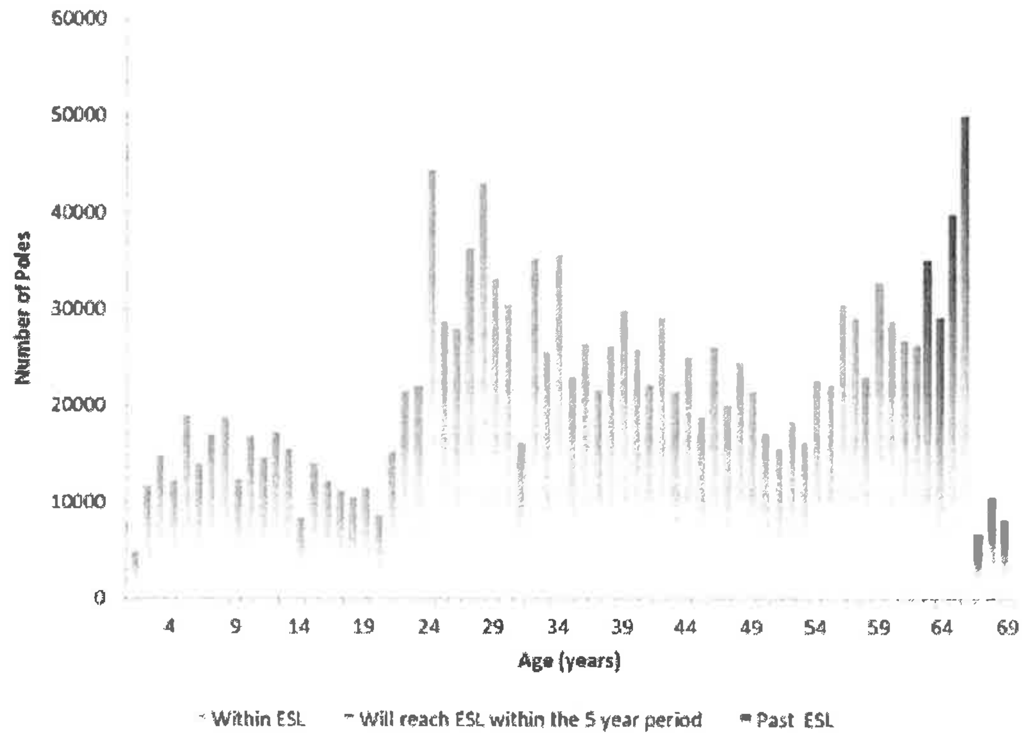

Figure 12: Demographics of the Wood Poles

<u>Condition</u>

The condition of the poles, as determined by distribution line patrols impacts pole replacement, line refurbishment and defect correction investment plans. The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, or other factors that reduce the structural integrity of the pole. The number and type of pole related defects on the distribution system are illustrated in Figure 13.

File Number:	EB 2014 0073
Exhibit:	4
Tab:	2
Schedule:	1
Attachment:	1
Date:	25-Apr-14

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Draft Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Operations	$ 658,190	$ 574,450	$ 616,923	$ 660,638	$ 748,926	$ 783,503	$ 924,800
Maintenance	$ 787,807	$ 872,068	$ 922,897	$ 1,541,600	$ 1,279,121	$ 1,205,307	$ 1,217,987
SubTotal	**$ 1,445,997**	**$ 1,446,518**	**$ 1,539,820**	**$ 2,202,238**	**$ 2,028,047**	**$ 1,988,810**	**$ 2,142,787**
%Change (year over year)			6.5%	43.0%	-7.9%	-1.9%	7.7%
%Change (Test Year vs Last Rebasing Year - Actual)						37.5%	48.1%
Billing and Collecting	$ 1,005,013	$ 866,998	$ 936,527	$ 893,996	$ 1,210,565	$ 1,195,792	$ 1,212,817
Community Relations	$ 42,930	$ 16,223	$ 15,232	$ 11,931	$ 6,777	$ 10,965	$ 11,249
Administrative and General	$ 1,486,736	$ 1,710,120	$ 1,511,205	$ 1,631,338	$ 1,705,519	$ 1,820,837	$ 1,777,398
SubTotal	**$ 2,534,679**	**$ 2,593,341**	**$ 2,462,964**	**$ 2,537,265**	**$ 2,922,861**	**$ 3,027,594**	**$ 3,001,464**
%Change (year over year)			-5.0%	3.0%	15.2%	3.6%	-0.9%
%Change (Test Year vs Last Rebasing Year - Actual)						16.7%	15.7%
Total	**$ 3,980,676**	**$ 4,039,859**	**$ 4,002,784**	**$ 4,739,503**	**$ 4,950,908**	**$ 5,016,404**	**$ 5,144,251**
%Change (year over year)			-0.9%	18.4%	4.5%	1.3%	2.5%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Draft Actuals	2014 Bridge Year	2015 Test Year
Operations	$ 658,190	$ 574,450	$ 616,923	$ 660,638	$ 748,926	$ 783,503	$ 924,800
Maintenance	$ 787,807	$ 872,068	$ 922,897	$ 1,541,600	$ 1,279,121	$ 1,205,307	$ 1,217,987
Billing and Collecting	$ 1,005,013	$ 866,998	$ 936,527	$ 893,996	$ 1,210,565	$ 1,195,792	$ 1,212,817
Community Relations	$ 42,930	$ 16,223	$ 15,232	$ 11,931	$ 6,777	$ 10,965	$ 11,249
Administrative and General	$ 1,486,736	$ 1,710,120	$ 1,511,205	$ 1,631,338	$ 1,705,519	$ 1,820,837	$ 1,777,398
Total	**$ 3,980,676**	**$ 4,039,859**	**$ 4,002,784**	**$ 4,739,503**	**$ 4,950,908**	**$ 5,016,404**	**$ 5,144,251**
%Change (year over year)			-0.9%	18.4%	4.5%	1.3%	2.5%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2010 BA – 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Draft Actuals	Variance 2013 Draft Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Draft Actuals	2015 Test Year	Variance 2015 Test Year vs. 2014 Bridge Year
Operations	$ 658,190	$ 574,450	$ 83,740	$ 616,923	$ 42,473	$ 660,638	$ 43,715	$ 748,926	$ 88,288	$ 783,503	$ 34,577	$ 924,800	$ 141,297
Maintenance	$ 787,807	$ 872,068	-$ 84,261	$ 922,897	$ 50,829	$ 1,541,600	$ 618,703	$ 1,279,121	-$ 262,479	$ 1,205,307	-$ 73,814	$ 1,217,987	$ 12,680
Billing and Collecting	$ 1,005,013	$ 866,998	$ 138,015	$ 936,527	$ 69,529	$ 893,996	-$ 42,531	$ 1,210,565	$ 316,569	$ 1,195,792	-$ 14,773	$ 1,212,817	$ 17,025
Community Relations	$ 42,930	$ 16,223	$ 26,707	$ 15,232	-$ 991	$ 11,931	-$ 3,301	$ 6,777	-$ 5,154	$ 10,965	$ 4,188	$ 11,249	$ 284
Administrative and General	$ 1,486,736	$ 1,710,120	-$ 223,384	$ 1,511,205	-$ 198,915	$ 1,631,338	$ 120,133	$ 1,705,519	$ 74,181	$ 1,820,837	$ 115,318	$ 1,777,398	-$ 43,439
Total OM&A Expenses	$ 3,980,676	$ 4,039,859	-$ 59,183	$ 4,002,784	-$ 37,075	$ 4,739,503	$ 736,719	$ 4,950,908	$ 211,405	$ 5,016,404	$ 65,496	$ 5,144,251	$ 127,847
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)													
Total Recoverable OM&A Expenses	$ 3,980,676	$ 4,039,859	-$ 59,183	$ 4,002,784	-$ 37,075	$ 4,739,503	$ 736,719	$ 4,950,908	$ 211,405	$ 5,016,404	$ 65,496	$ 5,144,251	$ 127,847

Variance from previous year		-$ 37,075	$ 736,719	$ 211,405	$ 65,496	$ 127,847	
Percent change (year over year)		-1%	18%	4%	1%	3%	
Percent Change: Test year vs. Most Current Actual			5.84%				
Simple average of % variance for all years			24.17%		5.82%		5.16%
Compound Annual Growth Rate for all years					4.43%		4.95%
Compound Growth Rate (2012 Actuals vs. 2010 Actuals)			5.47%				

Note:

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

File Number:	EB 2014 0073
Exhibit:	4
Tab:	2
Schedule:	1
Attachment:	3
Date:	25-Apr-14

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Bridge Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Number of Customers	19,828	19,647	19,832	20,069	20,210	20,381	20,554
Total Recoverable OM&A from Appendix 2-JB	$ 3,980,676	$ 4,039,859	$ 4,002,784	$ 4,739,503	$ 4,950,908	$ 5,016,404	$ 5,144,251
OM&A cost per customer	$ 200.76	$ 205.62	$ 201.83	$ 236.16	$ 244.97		$ 250.28
Number of FTEs	45	47	45	47	47	45	45
Customers/FTEs	441	418	441	427	430	453	457
OM&A Cost per FTE	$ 88,459.47	$ 85,954.45	$ 88,950.76	$ 100,840.50	$ 105,338.48	$ 111,475.65	$ 114,316.69

Notes:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. The method of calculating the number of customers must be identified.
3. The method of calculating the number of FTEs must be identified. See also Appendix 2-K
4. The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

File Number: EB 2014 0073
Exhibit: 4
Tab: 3
Schedule: 1
Attachment: 1

Date: 25-Apr-14

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Draft Actuals	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Draft Actuals)	Variance (Test Year vs. Last Rebasing Year (2010 Board-Approved)
Reporting Basis									
Distribution Stations									
Labour		12,257	8,326	5,817	6,656				
Materials		4,946	4,914	1,873	2,397				
Outside Services		9,977	14,195	7,069	2,835				
Other costs		1,914	1,137	994	584				
Sub-Total	41,793	29,094	28,572	15,753	12,452	15,306	13,622	1,170	-28,171
Transformer Station									
Sub-Total						0	140,000	140,000	140,000
Overhead Maintenance									0
Labour		267,783	242,771	266,011	255,457				0
Materials		102,435	57,597	39,346	79,595				0
Outside Services		2,390	4,887	15,498	20,104				0
Other costs		87,196	50,062	68,998	50,667				0
									0
Sub-Total	402,008	459,804	355,317	389,853	405,823	328,877	330,619	-75,204	-71,389
Tree Trimming									0
Labour		51,036	100,673	70,375	53,777				0
Materials		923	590	506	1,247				0
Outside Services		53,003	39,950	44,800	78,252				0
Other costs		12,892	21,071	18,464	9,477				0
									0
Sub-Total	170,517	117,854	162,284	134,145	142,753	159,371	162,743	19,990	-7,774
Load Dispatching									0
Labour		5,115	6,673	3,887	2,747				0
Materials			-356	0	20				0
Outside Services		715	5,808	24,679	530				0
Other costs		20,132	28,567	29,405	14,782				0
									0
Sub-Total	37,575	25,962	40,692	57,971	18,079	28,207	28,681	10,602	-8,894
Underground Maintenance									0
Labour		195,706	143,940	174,948	108,636				0
Materials		39,681	39,760	31,534	23,250				0
Outside Services		11,545	11,818	10,982	14,357				0
Other costs		39,776	31,210	29,183	19,648				0
									0
Sub-Total	246,702	286,708	226,728	246,647	165,891	168,426	172,078	6,187	-74,624
Distribution Transformer Operation									0
Labour		24,703	31,623	31,254	30,338				0
Materials		7,353	16,622	7,119	9,340				0
Outside Services		820	3,548	756	3,986				0
Other costs		5,924	7,169	8,102	5,168				0
									0
Sub-Total	52,908	38,800	58,962	47,231	48,832	58,840	60,161	11,329	7,253
Meter Expense									0
Labour		232,202	245,504	262,292	282,908				0
Materials		15,369	12,705	12,890	11,029				0
Outside Services		68,575	53,361	54,455	56,744				0
Other costs		25,165	33,708	580,795	36,611				0
									0
Sub-Total	280,911	341,311	345,278	910,432	387,292	381,504	382,556	-4,736	101,645
Customer Premises									0
Labour		129,145	127,623	142,341	169,613				0
Materials		3,410	2,333	3,143	2,166				0
Outside Services		420	212	6,591	6,316				0
Other costs		12,209	11,812	12,202	12,544				0
									0
Sub-Total	213,584	145,184	141,780	164,277	190,639	182,703	181,297	-9,342	-32,287
Billing & Settlement									0
Labour		130,245	163,186	179,809	268,854				0
Materials		13,638	26,482	27,063	31,091				0
Outside Services		67,691	59,457	75,983	148,184				0
Other costs		144,500	165,079	125,351	165,063				0
									0
Sub-Total	393,491	356,074	414,204	408,206	613,192	699,355	689,493	76,301	296,002
Meter Reading Expenses									0
Outside Services		105,732	104,973	62,666	130,064				0

Other costs		2,226	1,744	651	339				0
									0
Sub-Total	105,899	107,958	106,717	63,317	130,403	128,891	131,461	1,058	25,562
Collecting									0
Labour		107,947	116,635	114,420	144,963				0
Materials		75,731	58,201	59,690	83,172				0
Outside Services		34,956	38,010	30,230	33,662				0
Other costs		29,356	28,805	41,660	45,158				0
									0
Sub-Total	268,192	247,990	241,651	246,000	306,955	230,789	229,937	-77,018	-38,255
Building Maintenance									0
Outside Services									0
Other costs									0
									0
Sub-Total	142,249	165,072	179,278	164,794	167,779	179,204	181,518	13,739	39,269
Unallocated Engineering, Operations Supervision, Trucks, Stores									0
Sub-Total	24,371	-38,636	104,375	169,868	395,220	444,580	450,650	65,430	426,279
Customer Care									0
Labour		155,491	167,228	169,708	153,029				0
Materials		1,501	1,846	2,323	1,560				0
Outside Services		120	0	125	0				0
Other costs		4,742	9,285	4,909	5,803				0
									0
Sub-Total	213,049	161,854	178,359	177,065	160,392	158,789	162,700	2,308	-50,349
Training/Health & Safety									0
Sub-Total	42,930	20,621	47,016	44,382	246,218	222,525	222,642	-23,576	179,712
Misc. Office Expenses									0
Labour		1,012,704	940,355	1,098,608	1,053,687				0
Materials		18,681	19,671	23,138	20,030				0
Outside Services		183,333	190,679	191,229	195,500				0
Other costs		359,491	220,866	186,587	289,771				0
									0
Sub-Total	1,344,497	1,574,209	1,371,571	1,499,562	1,558,988	1,629,037	1,604,093	45,105	259,596
Total	3,980,676	4,039,859	4,002,784	4,739,503	4,950,908	5,016,404	5,144,251	193,343	1,163,575
	3,980,676	4,039,859	4,002,784	4,739,503	4,950,908	5,016,404	5,144,251		
	-	-	-	-	-	-	-		

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

b) Please state how much of this increase is due to smart meters.

c) Please explain the ongoing nature of these costs.

d) Board staff notes that meter reading expenses have also increased by approx. 24%. Please explain if and where Festival Hydro was able to realize some efficiency gains due to implementing the smart meter program.

e) If not, please provide more detailed explanation as to these costs.

Response:

a) A breakdown of this cost category is included in the table below.

Billing & Settlement Summary						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Supervision - Billing	11,870	13,103	12,617	14,591	14,182	14,534
Smart Meter Billing Costs			17,917	92,977	118,049	119,938
Customer Billing	293,129	362,423	337,941	469,083	498,917	512,543
Billing - STR Processing	1,547	350	290	296	249	246
Billing - Other Retailer Services	40,859	32,500	29,052	25,380	26,391	-
SSS Admin Charge	40,912	40,912	40,912	40,913	41,567	42,232
Reconnection Charge Offset	- 32,243	- 35,084	- 30,523	- 30,048	-	-
	356,074	414,204	408,206	613,192	699,355	689,493

b) Based on the table above – smart meter billing costs are estimated at $120K in 2015 and were zero in our last rebasing year.

c) The smart meter billing costs include costs relating to Festival's ODS service provider, Web presentment provider, head end system software support, and verification, editing, and estimation service provider. All of these costs are considered to be ongoing in nature.

d) The meter reading cost driver includes costs for smart meter data backhaul averaging around $100K/year which is a new cost as a result of smart meters. Festival continues to pay approximately $30K/year for manual meter reads for meters that are not a part of the smart meter program. Festival notes that we have reduced our meter reading costs by approximately $84K/year as a result of the implementation of smart meters.

e) Refer to efficiency response in 38d.

104. 4. OEB STAFF 39

Benchmarking

Board staff notes that Festival Hydro seemingly did not undertake any studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators, and appears to have justified its proposed increases solely on the basis of its anticipated needs without any specific reference to any external comparators.

a) Please confirm whether or not Festival Hydro took into account any external comparators when determining these increases. If yes, please state what they were and how they impacted on what is proposed in the application. If not, please state why not, and explain the justification for the spending level in the absence of such information.

Response:

a) Yes, Festival Hydro did consider external comparators when determining compensation increases. Festival Hydro obtained 2013 contract settlement information from neighbouring utilities to determine market condition. A rate of 2.5% was estimated based on the information available. Festival Hydro's final contract negotiation resulted in a 2.02% increase which was amongst the lowest increases of neighbouring utilities.

105. 4. OEB STAFF 40

Ref: E4/T3/S2, Appendix 2-K – Compensation Strategy

With respect to Appendix 2-K, please explain the applicant's compensation strategy and its core HR objectives. Please explain how this strategy has resulted in a 13.4% increase in non-management compensation, while compensation for management has remained flat.

Response:

Festival Hydro compensation strategy is to pay competitively to ensure that Festival is able to attract and retain qualified employees. Employee continuity adds to institutional knowledge and avoids costs to find, hire and, and train new employees. Further, the strategy incorporates an employee's development and progression within the succession planning requirements of the organization. Specifically, as it relates to Appendix 2-K Festival's compensation strategy is to keep year over year increases (excluding overtime) in line with contract settlements of neighbouring utilities (as stated in 4-Staff-39) and to also keep increases between management and non-management equal.
The inequality that can been seen between management and non-management as it relates to increases since the last rebasing period can be attributed to changes in overtime worked (management is salary) and the fact that management employees were for the most part at the top of pay progression in 2010. Therefore all increase for management employees were as a result of cost of living increases where as many employees in the non-management group have moved from apprenticeship or step 1 category to the top of their grids over the last 5 years.

File Number:	EB 2014 0073
Exhibit:	4
Tab:	3
Schedule:	2
Attachment:	2
Date:	25-Apr-14

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	11	11	12	12	12	11	11
Non-Management (union and non-union)	34	36	33	35	35	34	34
Total	45	47	45	47	47	45	45
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 872,182	$ 1,095,323	$ 1,206,051	$ 1,251,645	$ 1,299,464	$ 1,170,301	$ 1,135,863
Non-Management (union and non-union)	$ 2,217,898	$ 2,203,848	$ 2,335,579	$ 2,350,858	$ 2,500,330	$ 2,456,962	$ 2,489,336
Total	$ 3,090,080	$ 3,299,171	$ 3,541,630	$ 3,602,503	$ 3,799,794	$ 3,627,263	$ 3,625,199
Total Benefits (Current + Accrued)							
Management (including executive)	$ 153,857	$ 209,762	$ 242,437	$ 281,993	$ 302,820	$ 264,811	$ 263,139
Non-Management (union and non-union)	$ 313,638	$ 477,560	$ 521,265	$ 550,963	$ 586,369	$ 580,559	$ 599,136
Total	$ 467,495	$ 687,322	$ 763,702	$ 832,956	$ 889,189	$ 845,370	$ 862,275
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 1,026,039	$ 1,305,085	$ 1,448,488	$ 1,533,638	$ 1,602,284	$ 1,435,112	$ 1,399,002
Non-Management (union and non-union)	$ 2,531,536	$ 2,681,408	$ 2,856,844	$ 2,901,821	$ 3,086,699	$ 3,037,521	$ 3,088,472
Total	$ 3,557,575	$ 3,986,493	$ 4,305,332	$ 4,435,459	$ 4,688,983	$ 4,472,633	$ 4,487,474

Total Compensation Allocated to OM&A		3,088,858	3,334,551	3,345,148	3,710,598	3,800,695	3,895,712
Total Compensation Allocated to Capital		897,635	970,781	1,090,311	978,385	671,938	591,762
						$ 3,263	$ 24,895

106. 4. OEB STAFF 41

Ref: E3/T3/S1/p. 9; E4/T3/S1; and Accounting Procedures Handbook, effective January 1, 2012

Festival indicated that it has recorded gains or losses related to the change in the discount rate for the Employee Future Benefit cost determination in Account 4335 Pension Actuarial Gains and Losses. It has also not recorded any amounts for gains and losses for 2014 and 2015 and is of the opinion that it should not be considered in its revenue requirement.

a) Per APH effective January 1, 2014, Account 4335 is for Profits and Losses from Financial Instrument Hedges that is be used to record profits and losses from financial instruments used as hedges against financial risks such as price risk credit risk, liquidity risk and cash flow risk. Please explain why Festival is not adhering to the APH's definition of Account 4335.

b) As Festival is proposing that actuarial gains and losses be excluded from its revenue requirement,

i. Please explain if Festival will be requesting any refund or recovery in the future when Festival actually incurs the actuarial gain or loss.

ii. From 2000 to 2005, please confirm that Festival recovered OPEB costs in rates on a cash basis.

iii. Please provide a table comparing the actuarial gain/loss included in Festival's revenue requirement to the actual actuarial gain/loss incurred from the year Festival first included the gain/loss in its revenue requirement to 2015.

iv. Please provide a table similar to the one below for each year from the first year Festival included Other Post-Employment Benefits ("OPEB") in rates on an accrual basis of accounting to 2015, comparing to amounts Festival actually paid.

4 Staff 48 table

ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule

with half year rule depreciaiotn in 2013; ull depn in 2014

	2013	2014	Jan 1, 2015 transfer
Opening, Jan 1	0	15,058,931	14,710,516
TS O & M Expenses	104,816	140,000	-244,816
Interest	17,623	217,469	-235,093
Transfer in from CWIP	15,311,782	0	-15,311,782
Depreciation & Amortization	168,822	337,647	-506,469
Accumulated Depreciation & Amort	-168,822	-337,647	506,469
Less ICM Rate Rider Recovery	-375,291	-705,884	1,081,174
Ending Bal, Dec 31	**15,058,931**	**14,710,516**	**-0**

Entry required for Jan 1, 2015 disposition:

		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	480,280.00	
Amort Exp	DR	5715	26,189.00	
Accum Depn	CR	2105		480,280.00
Accum Amort	CR	2120		26,189.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,298,159.85	16,298,159.85

Transfer back to fixed asssets1805,1815,1609 (gross)	15,311,782.22
Less Accuimulated Depreciation/Amortization	-506,469.00
Net book value upon transfer , Jan 1, 2015 with 2013 half year rule	14,805,313.22

With only one month depn in 2013:	
Net book value upon transfer , Jan 1, 2015	14,945,998.00
Reduction in NBV bt taking half year rule rather than one month depn for 2013	-140,684.78

114. 4. AMPCO 9

Ref: Exhibit 4, Tab 1, Schedule 1

a) Page 2 – Please confirm the effective date of Festival's latest collective agreement, the length of the agreement, and the annual increases.

Response:

The effective date of Festival's latest collective agreement is May 1, 2014 and it expires on April 30, 2017. A 1.75% increase was agreed to in each of the four years of the agreement. In addition, wage increases to the trades and semi-skilled workers categories were also agreed to. Festival's total cost increase considering the benefits impact of the wage increases and that Festival's Board of Directors approved a similar increase in 2014 for non-union staff, is 2.02%.

b) Page 4 – Please provide the $ amounts for the extraordinary cost items listed.

Response:

A summary table of these extraordinary cost drivers comparing 2015 to 2010 is included in E1/T2/S6/page 2 as well as their percentage impact of the total impact.

115. 4. AMPCO 10

Ref: Exhibit 4, Tab 2, Schedule 1

a) Page 3 – Please confirm when the Chief Operating Officer position was created and filled.

Response:

The COO position was created effective May 2011 and was filled by an internal resource in May 2011.

b) Page 4 – Please explain then increase need to hire an accounting clerk to aid in the volume of work performed by the accounting department.

Response:

The utility has taken on many new initiatives in recent years such as smart meters and conservation to name a few. In addition, there has been one significant legislative changes in this timeframe (the implementation of HST in Ontario) that has impacted the work in the accounting department, particularly given that Festival tracks restricted ITC's as a large corporation, and given the regulatory tracking to record PST recoverable that had previously been approved as an expense or capital item in our 2010 rate application. Each new initiative taken on by the utility generally impacts the accounting department in some way either through increased volume of payables, record keeping or increased retrofit payments as examples. Early in 2012 it was determined that the processes in the accounting department were taking too long to complete or were being completed inconsistently due mainly to work overload. Festival did consider overall headcount of the organization, as well as succession planning within the accounting department prior to making a decision to have a third resource hired. This resource was also trained in multiple jobs such as the cashier's position as well as on regulatory duties in order to gain efficiencies and balance workload. Also – as per response to 10d below – the receptionist position was not filled when it became vacant due to a retirement in customer service – and as such this new accounting position picked up various duties from that role including timesheet entry and balancing for payroll.

c) Page 5 – Please explain the need to hire an engineering technician to aid in the volume of engineering work.

Response:

An Engineering technician was hired in 2013 to address the backlog of design work arising from an increase in the number of projects initiated by customers and additional record keeping required through the implementation of ESA Reg 22/04. This position will be a key resource for the future implementation of GIS and OMS, and is part of the succession planning for the Engineering & Operations Department as two managers are expected to retire in the next two years and another manager could retire within five years.

d) Please discuss if any retirements over the 2011 to 2015 period are not backfilled and why.

Response:

A customer service representative retired in 2011 and was replaced internally. The receptionist position that became vacant due to this retirement and was not was not filled. As such that FTE was replaced by an accounting clerk in 2012 due to the reasons documented in 10b above. In 2013 a lineman retired and the lineman position was filled internally with a mechanic that began his lineman/journeyman apprenticeship in 2012. The mechanic position was not filled and that FTE position was replaced in 2013 with the hire of the engineering technician. In 2014 there has been one lineman position move into a management position due to a retirement. This lineman position was not filled. There was another retirement from the line crew in Q2 of 2014 that is not expected to be replaced. The reason these two line positions have not been backfilled in our projections is given the reduction in planned capital spend.

e) Please provide a summary of vacant positions over the period 2010 to 2015.

Response:

There were no vacant positions and are no projected vacant positions in our 2015 application.

f) Page 6 – The evidence indicates that 2014 includes the OM&A of labour costs of time the existing chief operating officer and VP of engineering and operations had been spending in prior years on transformer station capital work as well as conservation initiatives. Please explain further why prior year costs are included in 2014.

Response:

To clarify, prior year costs have not been included in Festival's 2014 OM&A projections. This statement was meant to indicate that in 2013 and prior, the COO charged much of his labour cost to the transformer station project. The VP of Engineering and Operations was also highly involved in the conservation strategy from 2011 – 2013 and as such some of his labour costs flowed through the OPA budget versus Festival's OM&A budget. The fact that both of these positions were logging more time outside of these projects in 2014 created a cost driver in Festival's 2014 OM&A.

g) Page 7 – Please confirm if the lineman that retired in 2014 will be replaced in 2014 or 2015.

Response:

Please refer to Festival's response and strategy as documented in 10d.

h) Page 8 – Please confirm if headcount has the same meaning as FTE

Response:

Festival confirms that on page 8 of E4/T2/S1 the reference to headcount has the same meaning as FTE.

i) Appendix 2-JA – Please provide 2013 audited actuals.

Response:

Festival confirms that while appendix 2-JA column heading still indicates 2013 draft actual figures – Festival's draft figures did agree to the final audited figures included in our final audited statements in E1/T4/S1/A3.

j) Appendix 2-JB – Please provide the overtime amounts plan vs. actual for 2011 to 2013 and 2014 and 2015 plan.

Response:

Festival does not plan overtime, but expects there will be circumstances every year (unplanned outages, scheduled outages during off peak hours to accommodate specific capital and maintenance projects, after hours re-connects, etc.) that will require the use of overtime and our annual budgets reflect a typical amount of overtime will be required during the year. There are circumstances outside of Festival's control (such as the two ice storms that Festival experienced in 2013) that can cause unplanned OT to be significant.

k) Appendix 2-JB – Please confirm the increase in overtime in 2013.

Response:

Appendix 2-JB indicated that overtime was a cost driver of OM&A in 2013 by $49K in error. Overtime worked as a result of the storms in April and December of 2013 was erroneously included in the overtime cost driver as well as the cost driver for labour-storm damage. As such – the cost driver for overtime in 2013 would be approximately $18K, most of which is the result of overtime paid to IT staff resulting from work performed in relation to smart meter verification, estimation, and editing processes with the MDMR. This work has since been subcontracted out to a third party and IT overtime has fallen back in line with prior years.

l) Please discuss the circumstances where double time is applicable.

Response:

Staff are paid double time when they work greater than 8 hours in a day, or greater than 40 hours in a week.

m) Please provide the number of apprentices hired each year for the years 2011 to 2015.

Response:

One apprentice was hired in 2012. There were no apprentices hired in any of the other historical years and no apprentices have been projected to be hired in 2014 or 2015.

116. 4. AMPCO 11

Ref: Exhibit 4, Tab 3, Schedule 1, Attachment 1 Employee Compensation Breakdown

a) FTE Definition: Please explain the significance of 2080 base hours and the calculation of an FTE.

Response:

Festival has some full time staff that work 40 hours in a week (40hours x 52 weeks = 2,080 hours), and some that work 35 hours in a week (35hours x 52 weeks = 1,820 hours). Therefore, in our

File Number: EB 2014 0073
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				35,396,846	37,482,461	
Net Additions - Note 4				5,157,572	2,790,817	
Net Depreciation (amounts should be negative) - Note 4				-3,071,957	-3,175,328	
Closing net PP&E (1)				37,482,461	37,097,950	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				35,396,846	38,219,494	
Net Additions - Note 4				4,906,054	2,623,001	
Net Depreciation (amounts should be negative) - Note 4				-2,083,406	-1,900,978	
Closing net PP&E (2)				38,219,494	38,941,517	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-737,033	-1,843,567	

Effect on Deferral and Variance Account Rate Riders		
Closing balance in Account 1576	-	1,843,567
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	460,892
Amount included in Deferral and Variance Account Rate Rider Calculation	-	2,304,459

WACC	6.25%
# of years of rate rider disposition period	4

Notes:
revised CGAAP should be the same.
2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.
3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.
4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

171. 9. OEB STAFF 62

Ref: E9/T3/S12 and Filing Requirements for Electricity Distribution Rate Applications 2015 Rate Applications, dated July 18, 2014

a) Per Chapter 2, Section 2.5.2.7 of the Filing Requirements, please provide the account balances recorded under:

- *Account 1508 Other Regulatory Asset, Sub-account, Incremental Capital Expenditures, including a breakdown of the carrying charges*
- *Account 1508 Other Regulatory Asset, Sub-account, Depreciation Expense*

- *Account 1508 Other Regulatory Asset, Sub-account Accumulated Depreciation and*
- *Account 1508 Other Regulatory Asset, Sub-account Incremental Capital Expenditures Rate Rider, including a breakdown of the carrying charges*

Response:

The following is the breakdown of the account balances under Acct # 1508 ICM Rate Rider account as at December 31, 2004:

Account # 1508 ICM Account	**December 31, 2014**
ICM Capital Expenditures – Capital	$15,311,782
ICM Capital Expenditure–Carrying charges @1.47%	243,465
Total Capital	15,555,247
ICM Depreciation & Amort Expense	365,784
ICM Accumulated Depreciation & Amort	-365,784
ICM Rate Rider- Recoveries	-1,081,174
ICM Rate Rider – Interest on Recoveries @ 1.47%	-11,423
Total ICM Recoveries	-1,081,174
Balance prior to O & M Expenditures	14,461,325
TS O & M Expenditures (cost not in 2010 COS)	244,816
TS O & M Expenditures -Carrying charges @ 1.47%	3,051
Total Balance at December 31, 2014	**14,710,517**

172. 9. OEB STAFF 63

Ref: E9/T3/S12/p.2-3 and Supplemental Report of the Board on 3rd Generation Incentive Regulation, September 17, 2008 ("Supplemental Report")

For the ICM Rate Rider Account #1522 table,

a) Please confirm that the ICM Rate Rider Account #1522 should be Account 1508. If not, please explain what Account 1522 is.

b) On p. 30 of the Supplemental Report of the Board, the Board stated that the capital module is intended to be reserved for unusual circumstances...and where the distributor has no other options for meeting its capital requirements within the context of its financial capacity underpinned by existing rates. Festival Hydro is showing OM&A of $244,816 related to the TS.

vi.) Please explain what is included in this amount and why Festival Hydro is recording out-of-period OM&A expenses in account 1522.

vii.) Please state if these OM&A expenses where approved as part of Festival Hydro 2013 IRM-ICM application.

viii.) Please revise the evidence as necessary.

c) Please confirm whether or not the Interest line of $235,093 represents the carrying charges for Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. If not, please clarify what the interest amount is for.

d) Festival is proposing to transfer all accumulated depreciation to Account 2218 and depreciation expense to Account 5705. Please explain what Account 2218 is.

e) Please revise the evidence to reflect the accumulated amortization in Account 2105 Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment and Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles and the depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

Response:

a) Agreed. The account for the ICM Rate Rider is USOA # 1508. Account # 1522 as noted is used for internal record keeping purposes only.

b)
   i. Festival has adopted accounting practices for its ICM account similar to what was followed for Smart meter, whereby O & M costs were recorded into the smart meter variance account until time of disposition. As was the case for smart meters, for the TS there were no O & M expenses approved as part of 2010 Rate application for operation and maintenance. It is Festival's belief that these costs would be recorded into Account # 1508 and disposed of as part of the overall disposition of the ICM Variance account. The amount represents the December 2013 and 2014 operating costs actually incurred including such items as property taxes, insurance maintenance, monitoring costs (excluding depreciation), of which none of these costs were part of the 2010 O & M expense. As the ICM is intended for extraordinary capital expenses the resulting OM&A from such capital expenses should also be considered extraordinary and such costs should be considered in the same manner and recoverable.

   ii. In terms of approval of the expense, the 2013 IRM Decision and Order (EB-2012-0124) does not specifically state whether or not OM & A may be added to the ICM account # 1508.

   iii. Under 9 Staff 62 the table breaking down the contents of Acct # 1508 is shown before adding in the O & M expenses (and related interest) and the total including O & M expenses.

c) The $235,093 is the net carrying charges related to the Incremental Capital Expenditures, O & M expenses and Incremental Capital Expenditures rate rider. as broken down for 9 staff 62.

d) The accounts which Festival Hydro uses for recording are: 2105 Accumulated Depreciation of Electric Utility Plant - Property, Account 2120 Accumulated Amortization of Electric Utility Plant – Intangibles: Transformer station > 50 KV depreciation expense in Account 5705 and Account 5715 Amortization of Limited Term Electric Plant.

e) Evidence has been revised accordingly.

9 Staff 63 table

ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED -agrees to 2 staff 8)

	2013	2014	Jan 1, 2015 transfer
Opening, Jan 1	0	15,058,931	14,710,516
TS O & M Expenses	104,816	140,000	-244,816
Interest	17,623	217,469	-235,093
Transfer in from CWIP	15,311,782	0	-15,311,782
Depreciation & Amortization	28,137	337,647	-365,784
Accumulated Depreciation & Amort	-28,137	-337,647	365,784
Less ICM Rate Rider Recovery	-375,291	-705,884	1,081,174
Ending Bal, Dec 31	15,058,931	14,710,516	-0
(with one mth depn in 2013)			

Entry required for Jan 1, 2015 disposition:

		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	346,870.00	
Amort Exp	DR	5715	18,914.00	
Accum Depn	CR	2105		346,870.00
Accum Amort	CR	2120		18,914.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,157,474.85	16,157,474.85
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22	
Less Accuimulated Depreciation/Amortization			-365,784.00	
Net book value upon transfer , Jan 1, 2015			14,945,998.22	

173. 9. OEB STAFF 64

Ref: E9/T3/S12, pp. 1-9 – Incremental Capital Module True-up

Festival Hydro has provided a true-up of its new 62 MVA Transformer station, which was funded through an incremental capital module as part of its 2013 IRM application. As part of its current application Festival Hydro is requesting additional ICM rate riders to recover incremental revenue requirement as follows:

Festival proposes placing these costs for 2013 and 2014 into account # 1572 Extraordinary Event Costs. Festival has included these amounts on the EDVARR schedule to be disposed of as part of the Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.). The bill impacts under Undertaking JT 1.24 have been presented including the $244,815 in the variance account.

14. UNDERTAKING NO. JT1. 13:

Ref: Page 49

To update the response to 4-STAFF-75-TCQ regarding the employee future benefit accrual.

Response:

Festival incorrectly reported the amount of $44,850 as owing to Festival Hydro, when in fact it is owing to the customers as follows:

2015 DVA Account

Required:

Closing Accrual under CICA, Dec 31, 2014	1,401,958	(Festival accrued/expensed)
Closing Accrual under IAS19, Dec 31, 2014	1,357,108	(Accrual needed under IAS 19)
Difference arising on converting to IFRS	44,850	(owing to ~~Festival Hydro~~customers)

The deferral account, if directed by the Board to be established, will be recorded as a payable to customers. The amount does not meet the materiality level, however, from a causality point of view; it was Festival's belief that LDCs and the ratepayer would be held whole on amounts arising from the conversion from CGAAP to IFRS.

The bill impacts under Undertaking JT 1.24 have been presented including the $(44,850) in the DVA accounts. Festival has included it in the Acct 1572, as an offset to the $244,815 TS expenses for net amount of $199,965.

15. UNDERTAKING NO. JT1. 14:

Ref: Page 50

To provide a letter from Festival's auditor that under IFRS a bypass agreement would be considered an intangible asset.

Response:

Festival again contacted our auditors regarding a letter and their response was that they prefer not to provide an opinion to a governing body on a single accounting decision. As noted, in our previous submissions, the auditors have issued an unqualified opinion on the 2013 financial statements, which presents the permanent bypass as an intangible asset.

The discussion to date has related to whether the permanent bypass constitutes an intangible asset. At the technical conference, it was suggested by Board staff that it may be considered a penalty (i.e. expense). To support Festival's arguments for intangible asset treatment, as opposed to an expense or penalty item, the following analysis of assets versus expenditures is being presented.

Background

Festival Hydro Inc. ("Festival") constructed a new TS Station in Stratford. Festival's new TS Station was put into operation in December 2013, and had the capacity to service customers previously serviced by a Hydro One Inc. ("HONI") TS Station. Festival desired to connect these customers to its new TS Station in order to improve their service and reliability.

In order to energize the Festival TS Station and connect these customers by by-passing the HONI Stratford Station, Festival was given two options; a temporary or permanent by-pass agreement with HONI. Management's analysis showed that with the temporary by-pass arrangement, Festival had to ensure there was no loss revenue to HONI, so from a customer's financial perspective the customer was indifferent as to the bypass arrangement. However, through the $1.2 million permanent by-pass agreement, customers would receive an annual net benefit of $475,000 through a reduction of transmission connection charges to customers.

As the permanent by-pass agreement option provided a generous benefit to customers, Festival entered into an agreement with HONI to pay approximately $1,230,000 for the right to by-pass 20 MW of load from the HONI TS Station. The by-pass charge is directly related to both the capital spend on the new TS Station (i.e. the charge would not have been incurred if the new TS Station had not been built), the future benefit to customers (the permanent by-pass option benefits customers approximately $475,000 annually), and Festival's ability to improve service and reliability to its customers.

Accounting Treatment

Does the permanent by-pass charge represent an asset or expenditure?

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

1000.29 Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

1000.30 Assets have three essential characteristics:

(a) they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

(b) the entity can control access to the benefit; and

(c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

In Festival's case, the by-pass charge meets the definition of an asset. Only by payment of the permanent by-pass charge can the net benefit of future cash flows be realized. In addition, Festival controls the TS Station, by virtue of ownership. Customers cannot be connected through the TS Station unless Festival allows the connection, and cannot earn the financial benefit without the existence of the permanent bypass and existence of the TS itself. The transaction giving the right to or control of, the benefit occurred when the TS Station was put into operation and the by-pass agreement signed in December of 2013.

If we compare the definition of an asset to an expense, alternatively, expenses are defined in CPA HBV 1000.38 as:

Decreases in economic resources, either by way of outflows or reduction of assets or incurrences of liabilities, resulting from an entity's ordinary revenue generating or service delivery activities.

As expenses typically relate to the performance of service or revenue generating activities, they would typically be recorded when the full benefit of any outlay has been realized (i.e. revenue has been generated, or an asset has been used to completion). An expense could also be incurred if the future benefits from the expense could not be measured reliably.

In the case of the by-pass agreement charge, the outlay cannot be an expense as the charge provides the right to recover future cash flows from providing service to customers. The benefit of the charge will be realized in the current year and many future dates. This benefit can also be forecasted reliably by management. Furthermore, it is the future potential of revenue generation or service delivery activities that led to the charge, not current revenue or service delivery activities.

<u>What is the nature of the payment?</u>

It should also be considered as to what the actual by-pass charge is for. The calculation of the by-pass charge shows that the payment relates primarily to lost future transmission for HONI as the decommissioning costs are actually less than the salvage value of the HONI TS Station. If the decommissioning cost was higher than salvage, we would expect that a portion of the payment would be for past service used; however, this is not the case. As a result, it appears that Festival is paying for lost future transmission by HONI (essentially the right to the customer base). This is more indicative of an asset which relates to future economic benefit than an expense.

<u>Future Treatment under existing IFRS Standards</u>

The IFRS definition of an asset is more detailed, however, less prescriptive (IFRS "The conceptual framework for financial reporting – Chapter 4.8 – Assets"). Under IFRS, assets embody future economic benefits and result from a past transaction or event. However, control does not necessarily need to be established in order for an asset to exist.

Under existing IFRS standards, it is reasonable that the permanent by-pass charge would also be considered an asset.

Is the Payment to HONI an Intangible asset or an item of Property Plant and Equipment?

Property, Plant and Equipment ("PP&E")

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

3061.04, PP&E are identifiable tangible assets that meet all of the following criteria:

(a) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;

(b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and

(c) are not intended for sale in the ordinary course of business.

The by-pass charge, in and of itself, does not appear to directly meet the above criteria as it lacks physical substance (i.e., not tangible). However, the new transformer station that was constructed does meet this definition.

Under 3061.10, rate regulated PP&E are items of PP&E held for use in operations meeting all of the following criteria:

(a) The rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products.

(b) The regulated rates are designed to recover the cost of providing the services or products.

(c) It is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for any capitalized costs.

Based on our understanding of the use of the transformer station and the rate setting process, it is reasonable to assume that the transformer station itself is an item of rate regulated PP&E.

CPA Canada HBV 3061.05 defines the cost as "the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use".

Further guidance as to what is included in the cost of PP&E is provided in CPA Canada HBV 3061.17 as follows:

Purchase price and other acquisition costs such as option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.

While the Standard doesn't specially list by-pass costs, it is clear that the expenditure on the permanent bypass would not have occurred without the existence of the new transformer station into service; and can be argued that the charge is directly attributable.

Further to be considered is the recoverable amount of the charge, if included in PP&E. Assuming the regulator will permit the inclusion of the charge as a component of PP&E for the purposes of rate setting, it is reasonably certain that the amount will be recovered in future periods.

<u>*Intangible Asset*</u>

Since the by-pass charge lacks physical substance, it should be considered whether the charge is representative of an intangible asset.

CPA Canada HBV 3064.04 provides guidance with respect to the classification between PP&E and intangible assets:

Standards for the recognition, measurement, presentation and disclosure of tangible capital assets are provided in PROPERTY, PLANT AND EQUIPMENT, Section 3061. Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a license or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under Section 3061 or as an intangible asset under this Section, an entity uses judgment to assess which element is more significant. For example, computer software for a computer-controlled machine tool that cannot operate without that specific software is an integral part of the related hardware and it is treated as property, plant and equipment. The same applies to the operating system of a computer. When the software is not an integral part of the related hardware, computer software is treated as an intangible asset.

In Festival's case, the by-pass charge is a payment to compensate for the decommissioning of the existing asset or cost associated with the stranded asset. As it has been argued in the PPE discussion, this was a critical payment with the purpose of creating future economic benefits to Festival Hydro and to its customers. As a result, it may be more appropriate to recognize the by-pass charge as an asset separate from the TS Station.
CPA Canada HBV 3064.11 describes the criteria for recognition of intangible assets. First, an intangible asset needs to meet the definition of an intangible asset (identifiable, control, future economic benefits). Second, the recognition criteria must be met.

In meeting the definition criteria, identifiability is met as the by-pass charge arose from a contractual right (3064.12(b)). Control over future economic benefits has been established by virtue of ownership of the TS station and the payment of the by-pass fee, which gives Festival control over servicing the customer base. Finally, future economic benefits are expected from the by-pass agreement payment both to Festival, in being able to service customers reliably, and to the customers in terms of future savings. This is not possible without the payment to HONI, as is the situation in the temporary bypass arrangement.

The by-pass charge meets the recognition criteria (3064.21-23) since it is probable that the expected future economic benefits attributable to the asset will flow to the entity and the cost of the asset is measured reliably. As previously discussed, future economic benefits will be received as a result of the by-pass agreement, primarily through obtaining new customers. The cost of the asset is measured reliably as it is outlined in a calculation as part of the by-pass agreement.

Conclusion on classification

The nature of the by-pass payment is that it could be treated as either an intangible asset or PPE. The payment is for a right to access customers and obtain future economic benefit for Festival. This would lead towards treatment as a definite life intangible asset as the asset meets the criteria for recognition. Separate treatment from the PPE TS Station asset may be desirable as it would better highlight the underlying nature of the transaction and seems to comply more reasonably with the guidance in 3064 & 3061. However, the asset could also be reclassified to PPE and shown as a component of the TS Station, since the asset would not exist without the existence of the TS. In either event, the amortization of the asset would be consistent with the TS Station itself and would not have an impact on the amortization affecting the Statement of Operations. Furthermore, whether the classification should be PPE or Intangible is not significant or material to the financial statements as both asset classifications are long-term.

Treatment under current IFRS

The treatment for recognition of PPE (IAS 16.7) under IFRS is similar to CPA HB V. Assets are recognized as PPE when it is probable that future economic benefits associated with the item will flow to the entity and the cost of the item can be measured reliably. As discussed above, both of these arguments are met. Furthermore IAS16.11 indicates that initial costs may be PPE if they are directly or indirectly related to items of PPE to obtain future economic benefits. Under the current standards it is reasonable to assume that the asset would be able to be recognized as PPE under IAS16.

Similarly, IAS 38.11-24 Intangible Assets currently set out the same criteria as CPA HBV – 3064 (identifiability, control, future economic benefit, etc.). The guidance in both handbooks point to the asset meeting the recognition criteria. As we have noted above in the CPA HBV-3064 section, the following (IAS38.21-22) has been met as well using the same arguments:

IAS38.21 An intangible asset shall be recognized if, and only if:

(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and

(b) the cost of the asset can be measured reliably.

IAS38.22 An entity shall assess the probability of expected future economic benefits using reasonable and supportable assumptions that represent management's best estimate of the set of economic conditions that will exist over the useful life of the asset.

Additional considerations

The OEB has issued the Accounting Procedures Handbook ("APH") for Electricity Distributors in order to provide guidance in accounting for transactions. The following are excerpts from the APH related to intangible assets:

Article 220 (Balance Sheet Accounts) describes intangible assets:

1609 Capital Contributions Paid

This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset.

1610 Miscellaneous Intangible Plant

This account shall include the cost of patent rights, licenses, privileges, capitalizable load profile development costs and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

Article 410 (Property, Plant and Equipment and Intangible Assets) of the OEB Accounting Procedures Handbook describes accounting for contributions in aid of construction and states:

Contributions paid by a distributor: in some cases distributors will incur expenditures for amounts paid to other distributors or transmitters for capital projects. Distributors who incur such costs, should record the amounts in USoA Account 1609, Intangible Assets – Capital Contributions Paid.

Expenses

The APH does not provide guidance specific to 'penalty payments'.

It is reasonable to conclude that the APH guide suggest using 1609 Capital Contributions Paid (an intangible account). While the payment was not directly attributed to a capital project of another distributor, it was a payment to HONI to facilitate the full operation of the asset Festival constructed and the asset meets the requirements of IAS38.

Conclusion

It is Festival's opinion that after review of the transaction facts and applicable accounting guidance, the transaction embodies the characteristics of an asset and not an expense. Furthermore, the asset meets the definition of an intangible asset under CGAAP and IAS38. The asset could also be considered part of the PPE costs required to get the asset ready for its intended use. However, for accounting purposes, the impact to the financial statements would not be significantly different, aside from the intangible being reported on a separate line item than PPE.

The other factor that needs emphasized is that Festival entered in to this permanent bypass arrangement for the financial benefit to the customer. From Festival's perspective, the transfer of 20 MWh of load represents benefits interms of improved service and reliability. Not to forget, Festival could have entered into a temporary bypass which would have been revenue natural for customers and achieved the same results for Festival. Festival made a conscious decision to add this asset to their rate base and to invest the $1.2 million so as to pass along the $475,000 annual savings to its customers. It is arguably a good investment in terms of return on investment from the customer's perspective.

Festival had not looked into any other Board document or policy on guidance as to where the permanent bypass should be classified because Festival was confident it met the definition of an intangible asset and that it also met the criteria of USoA # 1609.

16. UNDERTAKING NO. JT1. 15:

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To provide the difference in cost or revenue requirement if Festival were to use a deferral account to recover the amount of the bypass penalty over three years.

Response:

Festival has completed an analysis comparing the NPV associated with treating the asset as an intangible asset within rate base compared to the recovery as a Deferral account over 3 years. As noted in the table below, including the costs in the rate base over a 45 year life span results in a much higher NPV value than treating it as an asset in a Deferral account.

With the deferral account method, there is a small positive net present value arise on the 3 year deferral account whether it is financed over a 25 year period or a 3 year period. This positive return is primarily due to the fact that the deferral account, which will be established effective January 1, 2014, will have the full value of the contract of $1,230,026 added to the account. At the OEB prescribed interest rate of 1.47%, that will result in $18,081 carrying charges being earned in 2014. Since Festival does not expect to borrow the funds until December 2014 at the earliest, the carrying charges earned in 2014 and 2015 to 2017 will more than offset the cost of borrowing associated with the loan over the three year period (the loan being calculated at 2.24% - the Infrastructure Ontario's current 5 year rate).

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Ms. Debbie Reece
Chief Financial Officer
Festival Hydro Inc.
187 Erie Street
PO Box 397
Stratford ON N5A 6T5

October 31, 2014

Dear Ms. Reece:

This letter is provided at the request of management of Festival Hydro Inc. ("Festival") with respect to Festival's application to the Ontario Energy Board ("OEB") for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015. Specifically, this letter addresses the accounting for a Bypass Compensation Agreement dated December 18, 2013 (the "Agreement") between Festival and Hydro One Networks Inc. ("HONI") under Canadian generally accepted accounting principles defined as *Accounting Standards published as Part V of the CPA Canada Handbook – Accounting, with rate regulated accounting* ("CGAAP").

We have audited the financial statements of Festival, which comprise the balance sheet as at December 31, 2013, and the statements of earnings and retained earnings and cash flows for the year then ended and notes, comprising a summary of significant accounting policies and other explanatory information. Our auditors' report on the financial statements was dated April 24, 2014. Our report was without modification.

In our role as auditor, we must remain independent of Festival in accordance with relevant rules of professional conduct, ethical requirements and KPMG policies.

In conducting our audit, we evaluated Festival management's accounting for the Agreement. Our evaluation was for the purpose of determining that the financial statements of Festival which included the payment required under the Agreement, were fairly presented, in all material respects, in accordance with CGAAP. We confirm that the information provided to the OEB by Festival's management's regarding the accounting for the Agreement as a long-term asset (as referenced below) is consistent with the information that management provided to us during the conduct of our audit.

Document	Date	Exhibit
2015 COS Application (EB-2014-0073)	filed May 29, 2014	Exhibit 1, Tab 4, Schedule 1, Attachment 3, 2013 Audited Financial Statements
		Exhibit 2, Tab 1, Schedule 1 pages 11 to 15, Intangible Assets included in USoA # 1609
		Exhibit 2, Tab 1, Schedule 1, Attachment 2.3, Permanent Bypass Agreement
Responses to Interrogatories	filed Aug 27,2014	Questions 2-OEB-9
Responses to Technical conference Questions	filed Sept 11, 2014	9-Staff-80 TCQ
Responses to Undertakings	filed Sept 24, 2014	JT1.12, 1.14, 1.15

In the context of financial reporting, management is responsible for selecting the appropriate accounting policies and applying them consistently from reporting period to reporting period. For financial reporting purposes, management selects accounting policies that are in accordance with CGAAP so as to ensure fair presentation of the annual financial statements. Management is also responsible for determining, in relation to the selected accounting policies, that the policies result in faithful representation of transactions undertaken by Festival and for documenting such analyses.

We undertook our audit in accordance with Canadian generally accepted auditing standards. Amongst other things, an audit includes evaluating the appropriateness of accounting policies used by management as well as evaluating the presentation of the financial statements taken as a whole. Once satisfied that we have gained sufficient, appropriate audit evidence, we express an opinion on the financial statements prepared by management. Our opinion covers the financial statements taken as a whole and is not specific to any single accounting matter or issue.

During our audit of the December 31, 2013 financial statements of Festival, we evaluated management's accounting for the Agreement as it was both a material and a non-routine transaction. We read the Agreement, discussed the issue with management, reviewed management's position relative to the chosen accounting treatment and evaluated the recognition and classification of the payment as a long-term asset in accordance with Festival's accounting policies and CGAAP.

Our audit of the December 31, 2013 financial statements comprised audit tests and procedures deemed necessary for the purpose of expressing an opinion on such financial statements taken as a whole. For neither the period referred to herein nor any other period did we perform audit tests for the purpose of expressing an opinion on individual balances of accounts or summaries of selected transactions such as those discussed in this letter, and, accordingly, we express no opinion thereon.

We believe that the audit evidence we obtained was sufficient and appropriate to provide the basis for our audit opinion on Festival's December 31, 2013 financial statements. As such, we issued an auditors' report without modification on Festival's financial position as at December 31, 2013 and the results of its operations and its cash flows for the year ended December 31, 2013 under the date of April 24, 2014.

This letter is solely for the information of the addressee and the Ontario Energy Board to assist the addressee with its application to the Ontario Energy Board for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015. It is not to be used, circulated, quoted, or otherwise referred to for any other purpose.

Yours very truly,

Ian J. Jeffreys
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