SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

EB-2017-0320

Hydro One/Orillia Motion to Review

Rate and Distribution Cost Comparison - 2017

Residential	800	kwh
GS<50	2000	kwh
GS>50	250	KW
Large	10000	KW

		Residential			GS<50			GS>50			Large		
30 Day Factor	1.014583	Fixed	kwh.	Typical	Fixed	kwh.	Typical	Fixed	KW	Typical	Fixed	KW	Typical
Algoma		$32.58	$0.0251	$52.66				$629.74	$3.2629	$1,445.47			
Bluewater (DRO)		$23.94	$0.0113	$32.98	$28.25	$0.0197	$67.65	$150.87	$4.3844	$1,246.97	$25,951.93	$1.9490	$45,441.93
Brantford		$17.80	$0.0076	$23.88	$30.14	$0.0079	$45.94	$232.03	$2.8051	$933.31			
Burlington (Applied)		$19.01	$0.0084	$25.73	$26.00	$0.0139	$53.80	$60.94	$3.0000	$810.94			
Canadian Niagara (Applied)		$29.45	$0.0112	$38.41	$30.92	$0.0252	$81.32	$166.12	$7.2864	$1,987.72			
Centre Wellington (Applied)		$21.06	$0.0074	$26.98	$18.48	$0.0192	$56.88	$170.53	$3.7187	$1,100.21			
COLLUS (Applied)		$17.67	$0.0103	$25.91	$21.05	$0.0140	$49.05	$100.56	$3.2888	$922.76			
E.L.K. (Applied)		$17.65	$0.0049	$21.57	$23.25	$0.0074	$38.05	$224.18	$1.8472	$685.98			
Embrun		$21.87	$0.0072	$27.63	$17.90	$0.0148	$47.50	$199.45	$3.6957	$1,123.38			
Energy Plus (Applied)		$18.01	$0.0093	$25.45	$13.65	$0.0147	$43.05	$114.79	$4.1783	$1,159.37	$8,913.52	$2.4753	$33,666.52
Enersource		$19.11	$0.0069	$24.63	$43.60	$0.0127	$69.00	$76.79	$4.6213	$1,232.12	$13,787.64	$2.9516	$43,303.64
Entegrus (DRO)		$20.99	$0.0052	$25.15	$30.53	$0.0101	$50.73	$98.97	$3.2782	$918.52			
EnWin (Applied)		$18.82	$0.0107	$27.38	$26.84	$0.0174	$61.64	$106.54	$4.9196	$1,336.44	$8,070.85	$2.3268	$31,338.85
Erie Thames (DRO)		$23.22	$0.0094	$30.74	$22.29	$0.0145	$51.29	$127.91	$3.1024	$903.51	$10,362.66	$1.9046	$29,408.66
Essex (Applied)		$20.35	$0.0079	$26.67	$35.20	$0.0120	$59.20	$233.15	$2.2145	$786.78			
Festival		$22.20	$0.0084	$28.92	$31.62	$0.0157	$63.02	$234.67	$2.5334	$868.02	$11,223.89	$1.1677	$22,900.89
Greater Sudbury (DRO)		$21.41	$0.0063	$26.45	$21.99	$0.0190	$59.99	$167.73	$4.3580	$1,257.23			
Grimsby		$22.45	$0.0067	$27.81	$24.75	$0.0190	$62.75	$206.63	$3.0217	$962.06			
Guelph		$22.36	$0.0098	$30.20	$16.59	$0.0139	$44.39	$179.86	$2.7403	$864.94	$1,093.75	$2.7331	$28,424.75
Halton Hills (DRO)		$20.28	$0.0068	$25.72	$28.03	$0.0101	$48.23	$85.80	$3.8123	$1,038.88			
Hearst (DRO)		$16.01	$0.0085	$22.81	$18.62	$0.0063	$31.22	$55.78	$1.7554	$494.63			
Horizon		$21.34	$0.0081	$27.82	$41.42	$0.0107	$62.82	$378.88	$2.5526	$1,017.03	$23,798.52	$1.4041	$37,839.52
Hydro 2000 (Applied)		$22.14	$0.0092	$29.50	$22.52	$0.0098	$42.12	$83.58	$1.4465	$445.21			
Hydro Hawkesbury		$11.90	$0.0051	$15.98	$15.47	$0.0061	$27.67	$100.99	$2.0470	$612.74			
Hydro One Brampton		$17.64	$0.0080	$24.04	$25.12	$0.0167	$58.52	$125.33	$2.8387	$835.01	$4,705.66	$2.4949	$29,654.66
Hydro One Networks (UR)		$24.78	$0.0094	$32.30	$23.30	$0.0262	$75.70	$93.97	$9.1837	$2,389.90			
Hydro One Networks (R1)		$33.77	$0.0230	$52.17	$27.87	$0.0560	$139.87	$89.48	$16.0236	$4,095.38			
Hydro Ottawa		$16.60	$0.0151	$28.68	$17.89	$0.0227	$63.29	$200.00	$4.3245	$1,281.13	$15,231.32	$3.7199	$52,430.32
Innpower (Applied)		$36.53	$0.0138	$47.57	$46.04	$0.0111	$68.24	$470.49	$2.7283	$1,152.57			
Kenora (DRO)		$25.10	$0.0074	$31.02	$39.22	$0.0062	$51.62	$542.71	$1.7292	$975.01			
Kingston		$18.54	$0.0082	$25.10	$14.59	$0.0151	$44.79	$107.49	$3.1010	$882.74	$5,164.00	$1.2160	$17,324.00

Kitchener-Wilmot	$16.64	$0.0084	$23.36	$27.11	$0.0130	$53.11	$178.91	$4.6515	$1,341.79	$16,783.62	$1.5365	$32,148.62
Lakefront	$16.00	$0.0076	$22.08	$23.96	$0.0082	$40.36	$84.19	$3.3735	$927.57			
Lakeland	$27.15	$0.0076	$33.23	$45.32	$0.0092	$63.72	$319.19	$2.8703	$1,036.77			
London (DRO)	$19.34	$0.0082	$25.90	$32.25	$0.0108	$53.85	$157.55	$2.7202	$837.60	$20,286.64	$2.2638	$42,924.64
Midland (DRO)	$23.20	$0.0107	$31.76	$22.62	$0.0167	$56.02	$63.93	$3.2581	$878.46			
Milton (Applied)	$21.74	$0.0074	$27.66	$16.81	$0.0177	$52.21	$79.38	$3.0630	$845.13	$2,487.74	$1.4893	$17,380.74
Newmarket-Tay (Applied)	$21.29	$0.0075	$27.29	$30.61	$0.0200	$70.61	$138.81	$4.7886	$1,335.96			
Niagara Peninsula (Applied)	$25.74	$0.0095	$33.34	$38.73	$0.0142	$67.13	$105.29	$3.4418	$965.74			
Niagara-on-the-Lake (DRO)	$24.02	$0.0066	$29.30	$39.06	$0.0117	$62.46	$279.14	$2.2028	$829.84			
North Bay (DRO)	$22.17	$0.0073	$28.01	$24.07	$0.0185	$61.07	$304.05	$2.5383	$938.63			
Northern Ontario Wires (Applied)	$31.70	$0.0097	$39.46	$33.29	$0.0186	$70.49	$191.60	$1.1866	$488.25			
Oakville (interim)	$21.95	$0.0082	$28.51	$36.26	$0.0161	$68.46	$123.74	$4.8388	$1,333.44			
Orangeville	$21.00	$0.0069	$26.52	$32.71	$0.0100	$52.71	$167.64	$2.2507	$730.32			
Orillia (Applied)	$21.45	$0.0087	$28.41	$38.09	$0.0168	$71.69	$346.73	$3.6470	$1,258.48			
Oshawa	$14.22	$0.0109	$22.94	$16.24	$0.0161	$48.44	$53.33	$4.5691	$1,195.61	$8,527.98	$2.0983	$29,510.98
Ottawa River (DRO)	$16.47	$0.0099	$24.39	$22.37	$0.0127	$47.77	$84.18	$3.4865	$955.81			
Peterborough (2016)	$15.20	$0.0094	$22.72	$31.13	$0.0088	$48.73	$159.12	$2.7120	$837.12	$6,393.02	$0.7468	$13,861.02
Powerstream	$18.51	$0.0130	$28.91	$28.74	$0.0183	$65.34	$140.97	$4.2037	$1,191.90	$6,073.68	$2.2421	$28,494.68
PUC Distribution (Applied)	$16.82	$0.0105	$25.22	$17.15	$0.0205	$58.15	$114.68	$5.4479	$1,476.66			
Renfrew	$17.30	$0.0115	$26.50	$31.25	$0.0153	$61.85	$189.27	$2.8636	$905.17			
Rideau St. Lawr. (Applied)	$17.91	$0.0128	$28.15	$30.52	$0.0121	$54.72	$290.85	$2.4285	$897.98			
St.Thomas	$20.47	$0.0086	$27.35	$24.00	$0.0164	$56.80	$74.79	$3.5803	$969.87			
Sioux Lookout	$35.56	$0.0060	$40.36	$43.55	$0.0082	$59.95	$386.97	$1.3481	$724.00			
Thunder Bay	$20.13	$0.0075	$26.13	$31.70	$0.0164	$64.50	$240.56	$3.0453	$1,001.89			
Tillsonburg (DRO)	$17.41	$0.0150	$29.41	$26.36	$0.0184	$63.16	$137.10	$2.0733	$655.43			
Toronto Hydro	$27.69	$0.0151	$40.19	$32.68	$0.0302	$93.62	$47.00	$7.3977	$1,924.08	$3,963.22	$6.2436	$67,367.54
Veridian (Applied)	$19.77	$0.0083	$26.41	$16.93	$0.0170	$50.93	$108.19	$3.3379	$942.67	$8,540.39	$2.9783	$38,323.39
Wasaga (Applied)	$17.56	$0.0081	$24.04	$15.04	$0.0152	$45.44	$34.42	$5.1924	$1,332.52			
Waterloo North	$23.82	$0.0105	$32.22	$32.47	$0.0162	$64.87	$121.29	$5.1459	$1,407.77	$7,087.33	$4.0839	$47,926.33
Welland (Applied)	$22.92	$0.0076	$29.00	$31.91	$0.0094	$50.71	$341.01	$2.9065	$1,067.64			
Wellington North	$27.95	$0.0103	$36.19	$42.31	$0.0182	$78.71	$279.90	$2.6697	$947.33			
WestCoast Huron	$25.65	$0.0116	$34.93	$32.17	$0.0110	$54.17	$154.18	$2.4101	$756.71	$9,836.55	$1.7707	$27,543.55
Westario (2016)	$16.31	$0.0121	$25.99	$24.74	$0.0111	$46.94	$228.37	$2.1458	$764.82			
Whitby	$24.57	$0.0076	$30.65	$21.39	$0.0210	$63.39	$206.66	$4.2316	$1,264.56			

ORILLIAPOWER
Energizing Our Community
1913 - 2013

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January 25, 2013

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON
M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Application for 2014 Electricity Rates
Orillia Power Distribution Corporation

Orillia Power Distribution Corporation ("Orillia") is scheduled to file a cost of service application for rates effective May 1, 2014.

In accordance with the Ontario Energy Board's ("the Board") letter of December 11, 2012, "Applications for 2014 Electricity Rates" and the transition plan contained in the October 18, 2012 Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach", Section 5.2, Option 1b - Distributor Rebases under 4th Generation IR, Orillia is seeking the Board's approval to:

- apply to have our rates effective January 1; and
- in accordance with Option 2 described in the Board's December 11, 2012 letter
    - delay rebasing by one year; and
    - file a cost of service application in accordance with the 4th Generation IR filing requirements including a consolidated capital plan for rates effective January 1, 2015.

Should the Board have any questions or require evidence in support of the requested approval, please contact the undersigned.

Yours truly,

Keith McAllister, P.Eng.
President & CEO

Ontario Waterpower Association
360 West St. S., P.O. Box 398, Orillia ON L3V 6J9
info@orilliapower.ca www.orilliapower.ca
Keith McAllister, P.Eng. - President & Chief Executive Officer
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November 28, 2013

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Request for Deferral of Cost of Service Distribution Rate Application

In our letter dated January 25, 2013, Orillia Power Distribution Corporation ("Orillia Power") opted to delay rebasing by one year, and in order to align its rate year with its fiscal year, file a Cost of Service rate application in accordance with the 4th Generation IR filing requirements including a Consolidated Capital Plan for rates effective January 1, 2015.

Orillia Power is requesting permission of the Board to defer the timing of its Cost of Service rate application one additional year, for approval of rates effective January 1, 2016.

Orillia Power believes it is able to manage its resources and financial needs within existing approved rates, providing its customers with stable rates over the foreseeable horizon. It is well suited to the IR adjustment mechanism under the Annual Index IR rate methodology and sees this as an opportunity to minimize regulatory costs otherwise arising out of filing and defending a Cost of Service rate application in rate years that are not expected to generate a material difference from existing rates.

However, Orillia Power is proposing to file a Cost of Service rate application for rates effective January 1, 2016 in order to dispose of a Smart Meter Incremental Rate Rider (SMIRR), currently in its Tariff of Rates and Charges, and amounts accumulating in PP&E Deferral Account 1576. This would accomplish the following:

- Smart meter capital will be incorporated into proposed rates;
- PP&E Deferral Account 1576 Credit Balance attributable to depreciation expense accounting policy changes under CGAAP effective January 1, 2013, recorded this year and each subsequent year until the next Cost of Service rate application will be returned to customers over an approved amortization period;
- Transition to calendar year rates in order to align its rate year with its fiscal year.

Orillia Power does not foresee any compliance issues related to the reliability of its distribution system. The table below summarizes SAIDI and SAIFI for the past 3 years.

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Keith McAllister, P.Eng. - President & Chief Executive Officer
Patrick J. Hurley, B.Math, CMA - Chief Financial Officer

Service Reliability Indicators						
Index	Includes Loss of Supply			Excluded Loss of Supply		
	2010	2011	2012	2010	2011	2012
SAIDI	1.317	1.551	1.135	0.244	0.929	0.558
SAIFI	1.690	1.660	2.534	0.859	1.265	1.888

3 Year Historical Average

SAIDI			1.335			0.577
SAIFI			1.961			1.338

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Orillia Power's regulatory rate of return has remained within ±300 basis point of its approved rate of return since rebasing in 2010 and it does not anticipate significant deviations over the 2013-2015 period. The table below provides actual and forecasted regulatory rates of return compared to the Board-approved rate of return for the period 2011 to 2013.

Regulated Rate of Return on Deemed Equity			
Last COS	2011	2012	2013 Forecast
9.85	9.93	11.56	10.06

Orillia Power is required to file a Consolidated Capital Plan by May 1, 2015. Orillia Power believes this requirement will be met within the timeframe of a Cost of Service rate application for rates effective January 1, 2016. The proposed one year deferral will also allow Orillia Power additional time to prepare a robust Distribution System Plan (DSP) for reasons described below:

- A new GIS system put in place this year and ongoing work with Orillia Power's supplier to optimize and design businesses processes to support its Asset Management Plan (AMP) will be integral to developing components of its consolidated DSP and in general, support a more comprehensive approach to network investment planning;
- A recently hired Manager of Engineering will benefit from the additional time to fully leverage the capabilities of this powerful GIS tool to enable Orillia Power to develop a comprehensive AMP and DSP;
- Orillia Power is part of Group 2 for Regional Infrastructure Planning (RIP) studies with implementation scheduled to begin in 2014 – 2015; its capital plans will be better informed on renewable generation expansion or enabling investment needs;
- Activities and other efforts to engage customers are in early planning stages and Orillia Power will gain insight into customers' needs and expectations over time, enabling it to better align services with customer preferences.

Orillia Power respectfully asks the Board to approve its request to defer its Cost of Service rate application for approval of rates effective January 1, 2016. Should the Board have questions in support of this request, please contact the undersigned.

Respectfully,

Keith McAllister, P.Eng.
President & CEO

ORILLIAPOWER

Energizing Our Community

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January 27, 2015

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: 2016 Cost of Service Distribution Rate Application

Orillia Power Distribution Corporation ("Orillia Power") is on the list of distributors whose rates will be scheduled for rebasing for the 2016 rate year. Orillia Power has previously stated its intention to align rates with its fiscal year end and to apply for rates effective January 1, 2016.

Orillia Power is requesting to defer its Cost of Service rate application and submit in August 2015 for rates effective May 1, 2016. Orillia Power will be requesting a move to January 1 rates in this application to be implemented thereafter, in an IR year. This request is based on a need for more time to satisfy Chapter 2 Filing Requirements, Section 2.4.3 – customer engagement to better align distributor operational plans and customer needs and expectations.

Respectfully,

Keith McAllister, P.Eng.
President & CEO

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April 24, 2015

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: 2016 Cost of Service Distribution Rate Application EB-2015-0024

In a letter dated January 27, 2015, Orillia Power Distribution Corporation ("Orillia Power") requested permission to submit a Cost of Service rate application for rates effective May 1, 2016 in August 2015 this year. Orillia Power is requesting to defer rebasing until August 2016 for rates effective May 1, 2017 at this time. If earnings and key indicators remain favorable, Orillia Power may request further deferral until August 2017 for rates effective May 1, 2018.

If the Board's permission is granted, Orillia Power intends to submit an application for an interim rate 'credit' towards disposition of a significant balance accumulating in Account 1576 – CGAAP Accounting Changes. The balance in this account at Dec 31, 2014 is $1.3M and is expected to increase an estimated $0.6M annually. Orillia Power would like to begin crediting customer bills as soon as November 2015 if approved by the Board. The regulatory balance would be trued up and disposed of at the time of the next rebasing.

Orillia Power expects to manage its resources and financial needs, while minimizing regulatory costs and providing its customers with stable rates over the foreseeable horizon within existing approved rates under the 4th Generation Price Cap Adjustment Mechanism. Since rebasing in 2010 and up to the year ending December 31, 2014, Orillia Power's regulatory rate of return has remained within ±300 basis point of its approved rate of return. The table below provides rates of return for the period 2011 to 2014. Orillia Power acknowledges the potential need for rebasing should its rate of return fall outside of the dead band.

Regulated Rate of Return on Deemed Equity				
Last COS	2011	2012	2013	2014
9.85	9.9	11.6	11.7	12.7

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EDA Representing Ontario's Electricity Distributors

The table below summarizes SAIDI and SAIFI for the last 5 years. Two anomalies occurred during 2014 resulting in indicators outside Orillia Power's historic trend:

1. Higher SAIDI and SAIFI (including Cause Code 2 outages) in 2014 were due to multiple Cause Code 2: Loss of Supply outages that occurred between May 2014 and June 2014 affecting all Orillia Power customers for the duration of the outages.
2. Higher SAIDI (excluding Cause Code 2 outages) in 2014 was due to a severe wind storm Sep 5/14 in our service area that involved extensive restoration efforts.

Service Reliability Indicators										
Index	Includes Cause Code 2: Loss of Supply					Excludes Cause Code 2: Loss of Supply				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
SAIDI	1.320	1.550	1.140	1.640	2.190	0.240	0.930	0.560	1.130	2.150
SAIFI	1.690	1.660	2.530	2.380	6.020	0.860	1.270	1.890	1.030	1.280

5 Year Historical Average

SAIDI					1.568					1.002
SAIFI					2.856					1.266

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Should the Board have questions in support of this request, please contact the undersigned.

Respectfully,

Keith McAllister, P.Eng.
President & CEO

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Ontario

BY E-MAIL

May 21, 2015

Pauline Welsh
Orillia Power Distribution Corporation
360 West Street South
P.O. Box 398
Orillia ON L3V 6J9

Dear Ms. Welsh:

Re: Applications for 2016 Electricity Rates

The OEB is in receipt of your letter requesting that Orillia Power Distribution Corporation be permitted to defer the rebasing of its rates beyond the 2016 rate year.

The OEB has considered the rationale for deferral set out in your letter, as well as the following:

- Orillia Power's financial position, as shown in its audited financial statements and financial reporting to the OEB; and
- Orillia Power's 3-year performance with respect to system reliability indicators and electricity service quality requirements/indicators, as reported to the OEB.

Based on these considerations, the OEB has concluded that it will not require Orillia Power's 2016 rates to be set on a cost of service basis. The OEB will place Orillia Power on the list of distributors whose rates will be scheduled for rebasing for the 2017 rate year.

If Orillia Power intends to seek a rate adjustment for 2016 rates, the OEB expects Orillia Power to adhere to the process for Price Cap Incentive Rate-setting applications for the 2016 rate year as may be determined by the OEB.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

ORILLIAPOWER
Energizing Our Community

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January 4, 2016

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Applications for 2016 Electricity Rates

Orillia Power Distribution Corporation ("Orillia Power") is on the list of distributors whose rates are scheduled for rebasing for the 2017 rate year. Orillia Power is submitting a request to defer rebasing until August 2017 for rates effective May 1, 2018 based on the following rationale.

Financial Position

We believe that Orillia Power can continue to manage its resources and financial needs, while minimizing regulatory costs and providing its customers with stable rates over the foreseeable horizon within existing approved rates under the 4th Generation Price Cap Adjustment Mechanism. Key indicators of Orillia Power's financial position and performance with respect to system reliability indicators as reported in OEB RRRs are provided in the following tables:

Regulated Return on Equity on a Deemed Basis

Regulated Return on Equity on a Deemed Basis			
2010 COS	2013	2014	2015 Estimated
9.85	11.70	12.11	10.75

Orillia Power's regulatory rate of return is expected to remain within ±300 basis point ("the dead band") of its last OEB approved rate of return as shown above. Orillia Power acknowledges that rebasing may be indicated sooner in the event its rate of return falls outside of the dead band.

Service Reliability Indicators – 3-year performance

Service Reliability Indicators						
Index	**Including Code 2 Outages**			**Excluding Code 2 Outages**		
	2013	**2014**	**2015 Estimate**	**2013**	**2014**	**2015 Estimate**
SAIDI	1.640	2.190	0.948	1.130	2.150	0.936
SAIFI	2.380	6.020	2.020	1.030	1.280	1.667

Orillia Power's target ranges for SAIDI and SAIFI (excluding Code 2 outages) reported in its 2014 Scorecard are:

SAIDI - at least within 0.24 – 1.13, and

SAIFI - at least within 0.86 – 1.89

2015 estimates for system reliability are within these target ranges. Orillia Power exceeded its target for SAIDI in 2014 due to a severe wind storm Sep 5/14 in our service area that involved extensive restoration efforts.

Other Considerations

The City of Orillia, the sole shareholder of Orillia Power Corporation, is currently exploring an economic development opportunity with Hydro One Networks Inc. which would include the acquisition of the distribution company, Orillia Power Distribution Corporation. In light of this, Orillia Power submits that it would be prudent to defer rebasing until August 2017 in addition to the rationale presented above.

Should the Board have questions in support of this request, please contact the undersigned.

Respectfully,

Keith McAllister, P.Eng.
President & CEO

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

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BY E-MAIL

July 5, 2016

Keith McAllister
President & CEO
Orillia Power Distribution Corporation
P.O. Box 398
360 West Street S.
Orillia, ON L3V 6J9

kmcallister@orilliapower.ca

Dear Mr. McAllister:

Re: Applications for 2017 Electricity Rates

This letter is in response to your letter expressing an interest to defer Orillia Power Distribution Corporation's (Orillia Power) rebasing of its rates beyond the 2017 rate year.

The OEB has reviewed your letter, as well as Orillia Power's financial and non-financial scorecard performance from 2010 to 2015. Based on this review, the OEB has concluded that it will not require Orillia Power's 2017 rates to be set on a cost of service basis. The OEB will place Orillia Power on the list of distributors whose rates will be scheduled for rebasing for the 2018 rate year.

If Orillia Power intends to seek a rate adjustment for 2017 rates, the OEB expects Orillia Power to adhere to the process for Price Cap Incentive Rate-setting applications for the 2017 rate year.

This is the fourth year that Orillia Power has sought a deferral to filing a cost of service rate application. The Annual Incentive Rate-setting Index is the method that was developed for distributors intending longer periods without rebasing. In the absence of a 2018 cost of service rate application from Orillia Power, the OEB will apply the Annual IR Index method. The OEB will also consider whether a distribution system plan will be required at that time.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

ORILLIAPOWER
Energizing Our Community

Telephone: (705) 326-7315
Fax: (705) 326-0800

June 19, 2017

Ontario Energy Board
2300 Yonge St., 27th Floor
P.O. Box 2319
Toronto ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Application for 2018 Electricity Rates

Orillia Power Distribution Corporation ("OPDC") is on the list of distributors whose rates are scheduled for rebasing for the 2018 rate year. In light of the pending MAAD application with Hydro One and Score Card performance summarized in the following paragraphs, OPDC is requesting a deferral of its rebasing application.

MAAD Application

The City of Orillia and Orillia Power Corporation signed a share purchase agreement ("SPA") with Hydro One Inc to sell OPDC. The agreement was signed on August 15, 2016 subject to review and approval by the OEB. Final submissions in this matter, EB-2016-0276 were made on May 5, 2017. If approved, OPDC ratepayers will have their base distribution delivery rates reduced by 1% and frozen at that level for 5 years. A decision by the OEB is still pending as of the date of this letter.

Financial Position

OPDC is able to continue to manage its resources and financial needs, while minimizing regulatory costs and providing its customers with stable rates over the foreseeable horizon within existing approved rates. Key indicators of OPDC's financial position and performance with respect to system reliability indicators as reported in OEB RRRs are provided below.

Regulated Return on Equity

OPDC's regulatory rate of return has been within ±300 basis point ("the dead band") of its last OEB approved rate of return as shown below with the exception of 2016.

Regulated Rate of Return on Deemed Equity			
	2014	**2015**	**2016**
Deemed ROE	9.85%	9.85%	9.85%
Achieved ROE	12.11%	8.99%	-1.59%

OPDC's 2016 ROE was approximately 1100 basis points below deemed ROE. A breakdown by regulated net income and regulated deemed equity is shown in the following table.

Breakdown of 2016 ROE difference into Regulated Net Income and Regulated Deemed Equity				
Components of the ROE calculation	**Deemed last COS**	**Achieved**	**Variance $**	**Variance %**
ROE Amount ($)	$819,800	-$188,460	-$1,008,260	-122.99%
Regulated Deemed Equity ($)	$8,322,400	$11,837,200	$3,514,800	42.23%
ROE (%)	9.85%	-1.59%	-28.69%	-11.44%

The largest contributing factor to the net variance of -11.44% is current taxes included in 2016 net income related to OPDC's exit from the PILs regime. On August 15, 2016, the date the SPA was signed, OPDC ceased to be exempt under section 149(1.1) of the Tax Act. Pursuant to section 149(10) of the Tax Act, OPDC then became liable to pay both federal and provincial income tax, with its first tax year starting at that time. OPDC was also deemed to have disposed of all of its assets, and reacquired them, at fair market value for income tax purposes immediately prior to August 15, 2016. OPDC filed a final tax return as of August 14, 2016 with the Ministry of Finance for Ontario. As a result of the fair market value "bump", OPDC was subject to applicable taxes from income and losses up to this date including the impact of the deemed disposition ("departure taxes") payable to the Ministry of Finance estimated at $1,065,000.00.

Service Reliability Indicators

OPDC continues to perform well and is actively monitoring system reliability. Performance statistics for the past 3 years are shown in the following table.

Service Reliability Indicators						
Index	Including Code 2 Outages			Excluding Code 2 Outages		
	2014	2015	2016	2014	2015	2016
SAIDI	2.190	1.080	0.530	2.150	1.060	0.520
SAIFI	6.020	3.110	1.390	1.280	2.440	1.100

Other Considerations

In the absence of rebasing and the pending OEB decision on the MAAD application, OPDC requests permission to file a rate application for 2018 rates using the 'Price Cap Incentive model with 0% price cap', similar to its 2017 rate application EB-2016-0321. In this application, OPDC did not apply for the price cap adjustment due to the MAAD Application before the OEB. This continues to be the main driver of OPDC's request to defer rebasing.

As part of an application, OPDC will continue to follow the OEB's process regarding the filing of annual applications for the review and potential disposition of Group 1 deferral and variance account balances and to continue the implementation of the transition to fully fixed distribution rates for the residential class. In addition, OPDC has customers migrating into Class A (Global Adjustment and CBR) in 2017. As these customers are new to the Class A program, OPDC believes that it is important to address the clearing of related deferral and variance balances on a timely basis. OPDC intends to propose separate kWh rate riders for these customers to dispose of amounts they contributed to the Global Adjustment (GA) and Capacity Based Recovery (CBR) variance balances while they were Class B consumers.

Please contact the undersigned if more information is required.

Respectfully submitted,

Grant Hipgrave, CPA, CMA
Interim President & CEO

Table 1: Projected Norfolk Acquisition OM&A and Capital Expenditure Savings

Low Case Scenario (Low case scenario based on a 20% reduction in savings from medium scenario)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
NPDI Mgmt Forecast	-20%										
OM&A	$ 4.6	$ 4.6	$ 4.7	$ 4.8	$ 4.9	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	
Capex	$ 4.0	$ 3.7	$ 3.7	$ 3.5	$ 3.6	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7	
Total	$ 8.6	$ 8.4	$ 8.4	$ 8.3	$ 8.5	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	
Hydro One Forecast	-20%										
OM&A	$ 4.6	$ 2.1	$ 2.1	$ 2.2	$ 2.2	$ 2.2	$ 2.3	$ 2.3	$ 2.4	$ 2.4	
Capex	$ 2.5	$ 2.3	$ 2.3	$ 2.4	$ 2.5	$ 1.9	$ 1.9	$ 2.0	$ 2.0	$ 2.0	
Total	$ 7.1	$ 4.4	$ 4.5	$ 4.5	$ 4.7	$ 4.2	$ 4.2	$ 4.3	$ 4.4	$ 4.4	
Projected Savings (OM&A and Capex)											
Scenario: Low Forecast	$ 1.4	$ 3.9	$ 3.9	$ 3.8	$ 3.8	$ 4.4	$ 4.4	$ 4.3	$ 4.3	$ 4.2	**$ 38.5**

Medium Case Scenario

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
NPDI Mgmt Forecast (Status Quo)											
OM&A	$ 5.7	$ 5.8	$ 5.9	$ 6.0	$ 6.1	$ 6.2	$ 6.2	$ 6.2	$ 6.2	$ 6.2	
Capex	$ 5.0	$ 4.7	$ 4.6	$ 4.4	$ 4.5	$ 4.6	$ 4.6	$ 4.6	$ 4.6	$ 4.6	
Total	$ 10.7	$ 10.5	$ 10.5	$ 10.4	$ 10.6	$ 10.8	$ 10.8	$ 10.8	$ 10.8	$ 10.8	
Hydro One Forecast											
OM&A	$ 5.8	$ 2.6	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.8	$ 2.9	$ 2.9	$ 3.0	
Capex	$ 3.1	$ 2.9	$ 2.9	$ 3.0	$ 3.1	$ 2.4	$ 2.4	$ 2.5	$ 2.5	$ 2.6	
Total	$ 8.9	$ 5.6	$ 5.6	$ 5.7	$ 5.8	$ 5.2	$ 5.3	$ 5.4	$ 5.5	$ 5.5	
Projected Savings (OM&A and Capex)											
Scenario: Medium Forecast	$ 1.8	$ 4.9	$ 4.9	$ 4.7	$ 4.8	$ 5.5	$ 5.5	$ 5.4	$ 5.3	$ 5.2	**$ 48.1**

High Case Scenario (High case scenario based on a 20% increase in savings from medium scenario)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
NPDI Mgmt Forecast	20%										
OM&A	$ 6.8	$ 7.0	$ 7.1	$ 7.2	$ 7.3	$ 7.4	$ 7.4	$ 7.4	$ 7.4	$ 7.4	
Capex	$ 6.0	$ 5.6	$ 5.5	$ 5.3	$ 5.4	$ 5.5	$ 5.5	$ 5.5	$ 5.5	$ 5.5	
Total	$ 12.8	$ 12.6	$ 12.6	$ 12.5	$ 12.7	$ 12.9	$ 12.9	$ 12.9	$ 12.9	$ 12.9	
Hydro One Forecast	20%										
OM&A	$ 7.0	$ 3.1	$ 3.2	$ 3.2	$ 3.3	$ 3.4	$ 3.4	$ 3.5	$ 3.5	$ 3.6	
Capex	$ 3.7	$ 3.5	$ 3.5	$ 3.6	$ 3.7	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 3.1	
Total	$ 10.7	$ 6.7	$ 6.7	$ 6.8	$ 7.0	$ 6.3	$ 6.3	$ 6.4	$ 6.5	$ 6.7	
Projected Savings (OM&A and Capex)											
Scenario: High Forecast	$ 2.2	$ 5.9	$ 5.9	$ 5.7	$ 5.7	$ 6.7	$ 6.6	$ 6.5	$ 6.4	$ 6.3	**$ 57.7**

Table 2: Projected LDC Acquisition OM&A and Capital Expenditure Savings

$M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Scenario	3.9	4.6	4.0	4.1	4.2	4.3	4.4	4.8	4.7	4.7
Hydro One Forecast	1.7	2.2	1.6	1.4	1.4	1.4	1.5	1.8	1.7	1.6
Projected Savings - Base Case Scenario	2.3	2.3	2.4	2.7	2.7	2.8	2.9	2.9	3.0	3.1
Low Cost Scenario - Projected Savings [1]										
Lower OM&A, Higher Savings Scenario	2.6	2.8	2.7	3.0	3.0	3.1	3.2	3.3	3.3	3.4
High Cost Scenario - Projected Savings [2]										
Higher OM&A, Lower Savings Scenario	1.9	1.9	2.0	2.4	2.5	2.5	2.6	2.6	2.7	2.8
Capital										
Status Quo Scenario	2.4	2.5	2.5	2.6	2.6[3]	2.7	2.8	2.8	2.9	2.9
Hydro One Forecast	2.2	2.9	3.2	1.8	2.1[3]	1.8	2.1	1.7	1.9	2.0
Projected Savings - Base Case Scenario	0.2	(0.5)	(0.7)	0.8	0.5	0.9	0.7	1.2	0.9	0.9
Low Cost Scenario - Projected Savings [1]										
Lower Capital, Higher Savings Scenario	0.6	0.1	(0.0)	1.1	1.0	1.3	1.1	1.5	1.3	1.3
High Cost Scenario - Projected Savings [2]										
Higher Capital, Lower Savings Scenario	(0.3)	(1.1)	(1.3)	0.4	0.1	0.5	0.3	0.8	0.5	0.5

[1] Low case scenario based on a 20% reduction in costs from Hydro One Forecast
[2] High case scenario based on a 20% increase in costs from Hydro One Forecast
[3] The Commerceway TS true-up has been eliminated from this analysis in Year 5

Table 2: Projected LDC Acquisition OM&A and Capital Expenditure Savings

$M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Forecast	8.2	8.3	8.5	8.6	8.8	8.9	9.1	9.3	9.4	9.6
Hydro One Forecast	6.4	4.4	4.5	4.6	4.8	4.9	5.0	5.1	5.2	5.2
Projected Savings	1.8	4.0	4.0	4.0	3.9	4.0	4.1	4.2	4.2	4.3
Projected Savings [1]										
Lower OM&A, Higher Savings Scenario	3.1	4.8	4.9	4.9	4.9	5.0	5.1	5.2	5.2	5.4
Projected Savings [2]										
Higher OM&A, Lower Savings Scenario	0.5	3.1	3.1	3.1	3.0	3.0	3.1	3.2	3.2	3.3
Capital										
Status Quo Forecast	6.4	6.1	5.4	5.6	5.3	5.4	5.5	5.5	5.6	5.7
Hydro One Forecast	4.2	3.2	3.3	3.4	5.9	3.9	4.0	4.0	4.1	4.2
Projected Savings	2.2	2.9	2.1	2.2	(0.6)	1.5	1.5	1.5	1.5	1.6
Projected Savings [1]										
Lower Capital, Higher Savings Scenario	3.0	3.5	2.8	2.8	0.6	2.2	2.3	2.3	2.4	2.4
Projected Savings [2]										
Higher Capital, Lower Savings Scenario	1.4	2.2	1.4	1.5	(1.8)	0.7	0.7	0.7	0.7	0.7

[1] Low case scenario based on a 20% reduction in costs from Hydro One Forecast

[2] High case scenario based on a 20% increase in costs from Hydro One Forecast

4. CAPITAL EXPENDITURE SUMMARY

4.1 TOTAL – ALL ACQUIRED UTILITIES

Table 8 - Total Spending - All Acquired Utilities

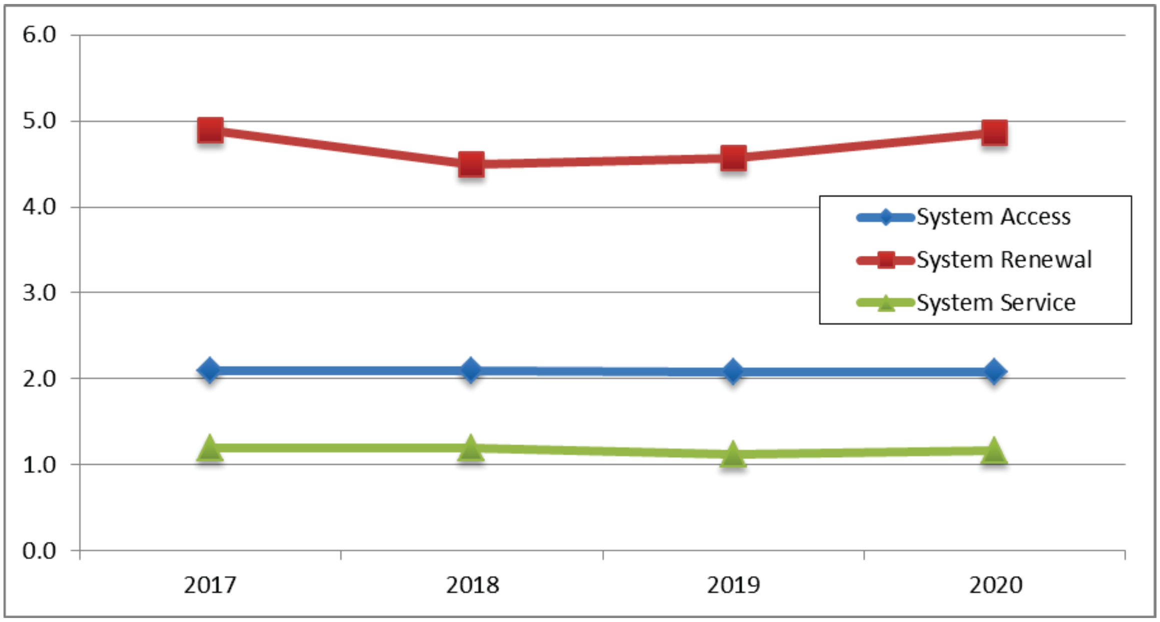
CATEGORY	Historical (previous actual)				Forecast		
	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test	2019 Test	2020 Test
	$M	$M	$M	$M	$M	$M	$M
System Access				2.1	2.1	2.1	2.1
System Renewal				4.9	4.5	4.6	4.9
System Service				1.2	1.2	1.1	1.2
General Plant				0.0	0.0	0.0	0.0
Total	13.6	12.4	7.6	8.2	7.8	7.8	8.1
System OM&A*	18.8	17.8	12.5	10.2	10.3	10.6	10.5

Capital spending for the acquired utilities on a total basis is relatively steady over the planning period, varying from $7.8 million in 2018 to $8.1 million in 2020. Approximately 60% of forecast spending is in System Renewal.

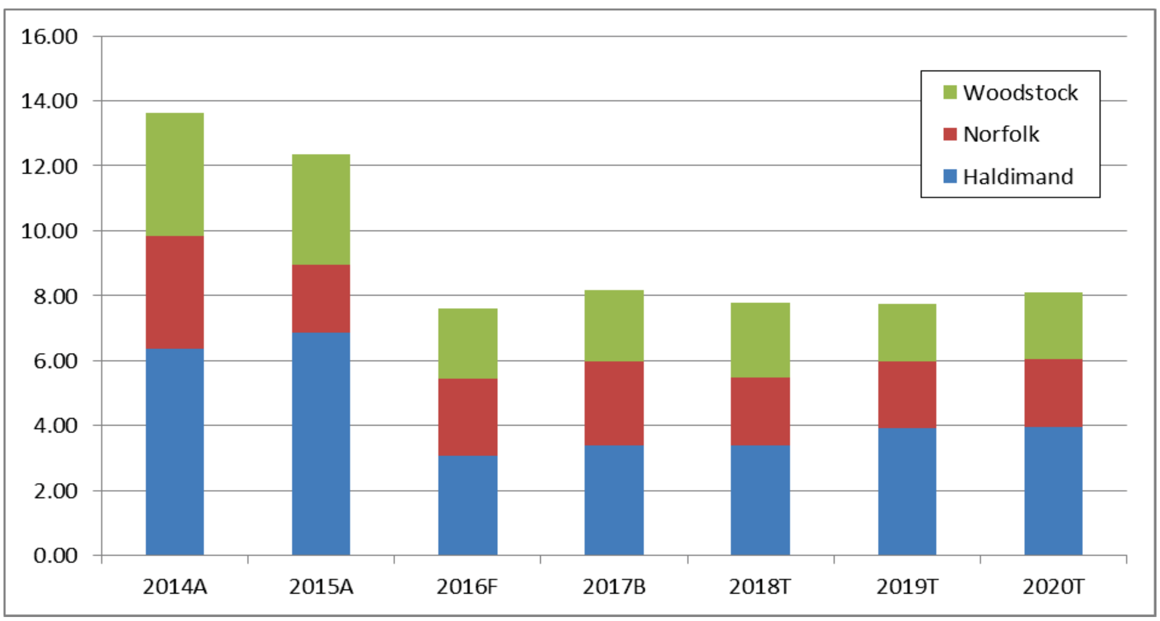
The variance in spending over the years of the planning period is almost exclusively in the System Renewal category, varying from a low of $4.5 million in 2018 to a high of $4.9 million in 2020.

Historical data on a combined basis is available since 2014. Spending over the planning period represents a decline from 2015 levels but slightly above 2016.

Specific variance explanations within projects and programs are contained in the material for each individual acquired utility included below.

1 

2 **Figure 5 - Total Forecast Capital Spending by Category**

3 

4 **Figure 6 - Total Capital Spending by Acquired Utility**

Witness: Lyla Garzouzi

4.1.1 HALDIMAND COUNTY HYDRO INC.

Table 9 - Total Spending - HCHI

	Historical (previous plan and actual)						Forecast (planned)		
	2014			2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Forecast	Bridge	Test	Test	Test
CATEGORY	$M		%	$M	$M	$M	$M	$M	$M
System Access						0.9	0.9	0.9	0.9
System Renewal						1.7	1.7	2.3	2.4
System Service						0.8	0.8	0.7	0.7
General Plant						0.0	0.0	0.0	0.0
Total	6.4	6.3	-1.2%	6.9	3.1	3.4	3.4	3.9	4.0
System OM&A*	8.2	7.5	-8.5%	6.0	5.0	5.1	5.1	5.2	5.3

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Forecast vs. Historical Variance

HCHI last rebased in 2014 (EB-2013-0134). Spending against 2014 approved amounts was generally consistent through 2014 and 2015. Spending was reduced in 2016 and 2017. The primary reduction in 2016 occurred due to the deferral of the following significant projects: (i) elimination of Jarvis DS Phase 1; (ii) underground (non-duct) Cable Replacements in Townsend; and (iii) Grand River Crossing in Caledonia.

Spending is expected to be steady throughout the planning period. A modest increase is expected in 2019 and 2020 based primarily on a $150k increase in the Transformer replacement program and a $400k increase in the Underground cable replacement program.

4.1.2 NORFOLK POWER DISTRIBUTION INC.

Table 10 - Total Spending – NPDI

	Historical (previous plan and actual)								Forecast (planned)		
	2012			2013	2014	2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Actual	Actual	Forecast	Bridge	Test	Test	Test
CATEGORY	$M		%	$M	$M	$M	$M	$M	$M	$M	$M
System Access								0.6	0.6	0.6	0.6
System Renewal								1.8	1.3	1.3	1.3
System Service								0.2	0.2	0.2	0.2
General Plant								0.0	0.0	0.0	0.0
Total	3.9	4.0	2.7%	3.5	3.5	2.1	2.4	2.6	2.1	2.1	2.1
System OM&A*	5.7	6.4	12.5%	6.0	7.2	5.9	2.8	3.1	3.1	3.2	3.2

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Forecast vs. Historical Variance

NPDI last rebased in 2012 (EB-2011-0272). Capital spending was slightly above approved amount in 2012. In 2013 and 2014 spending was reduced due to: (i) a $200k reduction in Transformer inventory; (ii) a $200k reduction in spending on Demand Meter inventory; and (iii) a $200k reduction in spending on Computer and SCADA equipment. For fiscal 2015 to 2017, capital spending came in lower due primarily to a reduction in pole ($300k) and transformer ($200k) replacements along with a deferral of a number of conversion projects that, in total, contributed an additional reduction of $300k. Spending is expected to be steady through 2018 to 2022 at $2.1 million per year.

4.1.3 WOODSTOCK HYDRO SERVICES INC.

Table 11 - Total Spending - WHSI

	Historical (previous plan and actual)									Forecast (planned)		
	2011			2012	2013	2014	2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Actual	Actual	Actual	Forecast	Bridge	Test	Test	Test
CATEGORY	$M		%	$M	$M	$M	$M	$M	$M	$M	$M	$M
System Access									0.5	0.5	0.5	0.5
System Renewal									1.4	1.5	1.0	1.2
System Service									0.3	0.3	0.3	0.3
General Plant									0.0	0.0	0.0	0.0
Total	2.9	6.6	127.2%	3.0	3.8	3.4	2.2	2.5	2.2	2.3	1.8	2.1
System OM&A*	4.0	3.8	-5.7%	4.0	4.3	4.1	4.2	3.8	2.1	2.1	2.3	2.1

Forecast vs. Historical Variance

Woodstock last rebased in 2011 (EB-2010-0145). Capital spending in 2011 was higher than approved primarily due to the Commerce Way Transmission Station Contribution of $2.5 million. Spending was reduced in 2015 through 2017 with the reduction in expenditures for underground conduit, overhead transformers, and general plant, including transportation equipment and software.

Spending throughout the application period is expected to be generally in line with 2017 levels. A decrease in 2019 is forecast based on a temporary $250k reduction in Large Sustainment Initiatives for 2019. There is also a $100k reduction in the Recloser upgrade program and a $150k reduction in the Station Component program in 2019. The increase in 2020 is largely driven by a $150k increase in Small Sustainment Initiatives.

Table 4-10: Employee Costs

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Number of Employees (FTE's)					
Management	6.1	7.2	7.3	7.3	7.3
Union	20.9	21.1	21.3	21.3	22.3
Total	27.0	28.3	28.6	28.6	29.6
Number of Part Time Employees					
Management					
Union	3.0	3.0	5.0	4.0	4.0
Total	3.0	3.0	5.0	4.0	4.0
TOTAL SALARIES AND WAGES					
Management	484,124	613,816	656,887	679,141	702,025
Union (includes part time employees)	1,355,124	1,362,960	1,462,913	1,525,926	1,637,731
Total Salaries and Wages	1,839,248	1,976,776	2,119,800	2,205,067	2,339,756
TOTAL BENEFITS					
Management	87,729	112,137	120,762	126,129	133,988
Union (includes part time employees)	241,691	243,660	262,021	279,214	309,472
Total Benefits	329,420	355,797	382,783	405,343	443,460
TOTAL COMPENSATION (SALARY, WAGES AND BENEFITS)					
Management	571,852	725,953	777,649	805,270	836,013
Union (includes part time employees)	1,596,815	1,606,621	1,724,933	1,805,140	1,947,203
Total Compensation	2,168,667	2,332,574	2,502,582	2,610,410	2,783,216

Question #8

Reference: Exhibit 4/Tab 3/Schedule 2, page 5 and page 12

a) Regarding the additional engineering technician hired, please elaborate with respect to "the increased regulatory requirements and additional requirements for internal engineering support" that this position addresses.

b) Please explain which regulatory requirements have increased such that regulatory officer hired in 2006 cannot handle them without the help of the engineering technician.

OPDC RESPONSE:

Response to (a):
The primary factor influencing the increase in regulatory costs is the need to add a staff member in the engineering department in order to adequately address the increased regulatory requirements and regulatory reporting to agencies such as the ESA and the OPA.

In particular, the newly hired engineering technician will be focused on ensuring compliance with Regulation 22/04. This regulation has resulted in substantial time demands on engineering staff to perform inspections, project reviews and documentation. In addition, Government initiatives such as the FIT and microFIT are placing an increased demand on engineering resources.

Response to (b):
The engineering technician and the regulatory officer, although both involved in regulatory tasks, have distinctly different functions within the organization and both require the dedication of a full-time resource. The engineering technician duties, detailed above, are focused on satisfying regulatory requirements in the engineering department and specifically the requirements of Regulation 22/04 from the ESA.

The regulatory officer, hired in 2006, is focused on satisfying regulatory issues related to the OEB. This includes, but is not limited to; numerous regulatory filings and reporting, monitoring information sources to identify regulatory issues that may impact OPDC, providing support to all departments on regulatory issues and directly responding to customer inquiries on regulatory matters.

Niagara On-The-Lake HYDRO

NIAGARA-ON-THE-LAKE HYDRO INC.

Analysis of Hydro One Acquisitions

AUGUST 2017

EXECUTIVE SUMMARY

Hydro One Networks Inc. (Hydro One") acquired 87 local distribution companies (LDCs) in 2000-2001 plus another in 2007. By harmonizing line loss rates and distribution rates of the customers of these LDCs with the Hydro One existing customer base, Hydro One has effectively used these acquisitions to subsidize its existing operations whose distribution rates are thus kept lower than they otherwise would have been. This despite the fact that Hydro One already has one of the fastest increasing distribution rates in Ontario with residential distribution rates rising 39-70% from 2005-2016. We estimate this subsidy to have been over $492 million from 2005-2016 and growing each year for both line loss rates ($77 million) and distribution rates ($415 million).

This analysis was prepared for the Board of Niagara-on-the-Lake Hydro (NOTL Hydro). As a result of the analysis it can be concluded that:

1. This harmonization created rate disparities between Hydro One customers and customers of other LDCs that are either neighbours or in similar sized municipalities. Customers of the acquired LDCs had distribution rate increases that average 262% from 2005-2016 and one municipality saw their rates increase by over 800%. These distribution rates are now over 73% higher than the highest rate grouping of municipally owned LDCs.
2. There is no evidence that Hydro One inappropriately profited from these acquisitions other than in the approved manner of a return on rate base. However, this high level of subsidization is an opportunity not available to other potential acquirers of LDCs and an incentive for Hydro One to increase the LDC purchase price to ensure success. Competitive acquirers would have to match this price increase or remain unsuccessful.
3. Since 2014, Hydro One has purchased three more LDCs and has agreements to purchase another two. By their actions and statements it is clear Hydro One intends to use these acquisitions to provide additional subsidies which we estimate could be another $26.7 million a year.
4. Every step taken by Hydro One has had regulatory approval. It is clear from the review of these regulatory proceedings that a number of opportunities to prevent these rate increases were missed. It is hoped with the recent adjournment of the Orillia acquisition proceeding that the regulator is going to address this issue. The NOTL Hydro Board supports the Ontario Energy Board in this regard.
5. To correct this situation the NOTL Hydro Board reiterates its recommendations that the Ontario Energy Board be made clearly independent and that Hydro One be broken up between its transmission and distribution businesses and further into multiple smaller distribution businesses. These steps are needed to try to reduce the current Hydro One distribution costs and to prevent further large rate increases.

INTRODUCTION

Hydro One has acquired a number of Ontario LDCs over the past few years (see chart below). The prices paid for these LDCs were higher than what some competing bidders felt they could reasonably offer while still remaining financially prudent. This raises a few questions:

1. Was Hydro One being financially irresponsible or does their position as the high cost provider of electricity distribution provide them with a perverse competitive advantage?

2. What is the rate impact of these acquisitions on the customers of the acquired LDCs and would that rate impact be different with another successful bidder.

3. What conditions should the regulator impose on these acquisitions?

It is too early to analyze the rate impacts of these acquisitions as the acquired LDCs are still in their initial 5 year rate freeze.

Recent Hydro One Acquisitions

Year	LDC Sold	Purchase Price ($ M)	# Customers	EBITDA ($ M)	Net Purchase Price ($ M)	LDC Equity ($ M)	Purchase Price Per Customer	Purchase Price EBITDA multiple	Purchase Price Equity Multiple
2014	Norfolk	$93.0	19,337	$6.4	$66.0	$30.7	$4,809	14.5	2.1
2015	Haldimand	$75.0	21,323	$6.4	$65.0	$38.9	$3,517	11.6	1.7
2015	Woodstock	$46.2	15,75	$4.2	$29.2	$14.9	$2,934	10.9	2.0
tbd	Orillia	$41.3	13,445	$3.1	$26.35	$12.6	$3,072	13.4	2.1
tbd	Peterborough	$105.0	36,317	$6.9	$62.7	$29.5	$2,891	15.3	2.1

Note: Customer count, EBITDA and Equity sourced from prior year Ontario Energy Board Yearbook of Electricity Distributors

It is noted that the Ontario Energy Board (OEB) has deferred their decision on the Orillia acquisition until a decision has been made on the rate increase requests for Norfolk, Haldimand and Woodstock in the recent Hydro One rate application.

This report will instead analyze the 87 LDCs Hydro One acquired in 2000 and 2001 and the impact their subsequent rates has had on Hydro One cash flows, Hydro One revenues and customer costs. It is expected that the results of this analysis can help answer the above questions.

HYDRO ONE ACQUISITIONS

Hydro One has acquired a total of 92 LDCs and has agreements to purchase two more LDCs (Orillia and Peterborough) subject to OEB approval. They have since divested one of the acquisitions (Brampton). Hydro One has also purchased the transmission business of Great Lakes Power. These acquisitions and their related good will is summarized below:

Breakdown of Hydro One Goodwill Balance

Year	Acquisition	Goodwill ($ Million)
2000	16 LDCs	6
2001	71 LDCs	67
2007	Terrace Bay	< 1
2014	Norfolk	40
2015	Haldimand	33
2015	Woodstock	22
2016	Great Lakes Power Transmission	159
	Total	**327**

In theory, the distribution rates of any customer are based on the cost of the assets used to serve the customer. Therefore, a customer should be indifferent as to the ownership of these assets. On an acquisition of an LDC, the value of the acquired assets is not restated to market value, as would be the case in the normal acquisition of a company, but is kept at its existing book value. This allows the regulator to continue to set rates based on actual costs. The difference between the purchase price and the book value is goodwill and is not included in rate calculations.

Reality is, naturally, somewhat messier. Rates are not set on a customer by customer basis but for a service territory.

- If ownership changes and the acquired service territory remains the same then rates should remain the same as they would otherwise have been.

- If ownership changes but the acquired service territory is merged with a lower cost service territory then rates in the acquired territory should fall. This can be seen with some of the mergers or sales of small LDCs to their larger, urban neighbours.

- If ownership changes but the acquired service territory is merged with a higher cost service territory then the rates in the acquired territory will rise. This has occurred with the Hydro One acquisitions.

The customers of the LDCs acquired in 2000 and 2001 all saw significant rate increases.

ANALYSIS METHODOLOGY

The purpose of the analysis was to estimate how much incremental revenue Hydro One realized from their 2000-2001 acquisitions and how this revenue affected Hydro One's financial results. For each acquisition, the annual revenue from the customer base at the time of the acquisition and for subsequent years was estimated. This was compared to the equivalent revenue a small LDC would have required based on current rates of small LDCs..

The most recent year for which data is available on the LDCs acquired in 2000 and 2001 is the 1997 Ontario Hydro Municipal Electric Utility Financial & Statistical Summary. This provides us with the following for each LDC:

- Number of residential and general service customers
- Book value of assets sold to Hydro One
- Average monthly kWh for residential and general service customers
- Line loss rate for 1997

Distribution rates are available for all current LDCs from 2005-2016. Rates for each acquired LDC are available from 2005-2010. From 2011 there were no specific rates for the acquired LDCs, only the general Hydro One rates which had been harmonized with all the acquired LDCs.

For the purpose of the analysis the following assumptions were made:

- The number of customers were assumed to remain at 1997 levels. This assumption provides a conservative estimate of the Hydro One incremental revenue as it is likely that the number of customers would have increased. It also allows for the fact that after the acquisition Hydro One would have paid the capital costs of connecting any new customers subject to their conditions of service.
- A few of the LDCs had a large general service customer. These were ignored for the purpose of this analysis as it is possible these customers may not have continued. Ignoring these few customers provides a more conservative incremental revenue estimate.
- The monthly kWh was assumed to decline by 1% per annum commencing in 2005. The decline is consistent with the experience of most LDCs who have seen per capita consumption decline over time.
- Most of the LDC customers were moved to the residential rate class R1 and its general service equivalent in 2011. Some of the larger acquired LDCs had customer bases sufficient that some or all of their customers were charged the lower residential rate class UR (urban) and its general service equivalent. For these larger LDCs we assumed all customers received the urban rates. We

ANALYSIS METHODOLOGY *CONT'D*

know this was not the case but as we did not have access to the breakdown between the urban and rural classes within these service areas this assumption provides a more conservative estimate of incremental revenue.

- Only the fixed service charge and the monthly variable rate were used for the analysis. Rate riders are more commonly cash flow and balance sheet related rather than revenue for the LDC so for simplicity were fully excluded from the analysis. As the rate riders were usually incremental charges (rather than credits) this also provided a more conservative estimate of incremental revenue.

- For comparative purposes the average annual rates of all the LDCs with less than 5,000 customers, as of 2016, was calculated for the purpose of determining the small LDC revenue requirement. LDCs with less than 5,000 customers were used as they have the highest rates of LDCs (other than Hydro One). Thought was given to using rates of LDCs that were made up of a number of merged smaller LDCs such as Westario, Rideau St. Lawrence or Ottawa River Power as this was another option for the LDCs that sold to Hydro One. However, as their rates were lower this would have been a less conservative comparative.

RESULTS OF THE ANALYSIS *- LINE LOSS RATES*

In 1997 the average line loss rate for all 87 LDCs was 5.1%. In the years 2005-2007, Hydro One used a line loss rate of 5.45%. Though this rate is a little higher it appears reasonable.

In 2008, Hydro One switched to using its harmonized line loss rates. This resulted in an average line loss rate of around 8.8% for rural rate customers and 8.5% for urban customers. These are combined residential and general service loss rates so the average will vary by service territory. The total cost increase to customers as a result of this change in line loss rates was over $6 million each year and the cumulative impact from 2008-2016 was $77.5 million.

Funds collected for line losses are not revenue for the LDC but are applied against the cost of power. This line loss rate increase therefore did not increase the revenue or net income of Hydro One.

In 2008, Hydro One also decreased their line loss rate for residential classes UR and R1 from 9.2% to 7.8% and 8.2% respectively. A review of the 2008 Hydro One rate application did not indicate any specific references to incorporating the acquired LDCs into this analysis. Rather, the line loss rates were derived from an analysis of Hydro One's full distribution system.

It appears that customers of the acquired LDCs are therefore subsidizing a reduction in rates for other Hydro One residential customers. Also, if overall line loss revenue increased it could also be argued that Hydro One was easing their requirement to make investments to manage their line losses.

Either way, what is clear is that customers of the acquired LDCs are paying significantly more in line losses than if their LDC had not been sold to Hydro One.

RESULTS OF THE ANALYSIS - *DISTRIBUTION REVENUE*

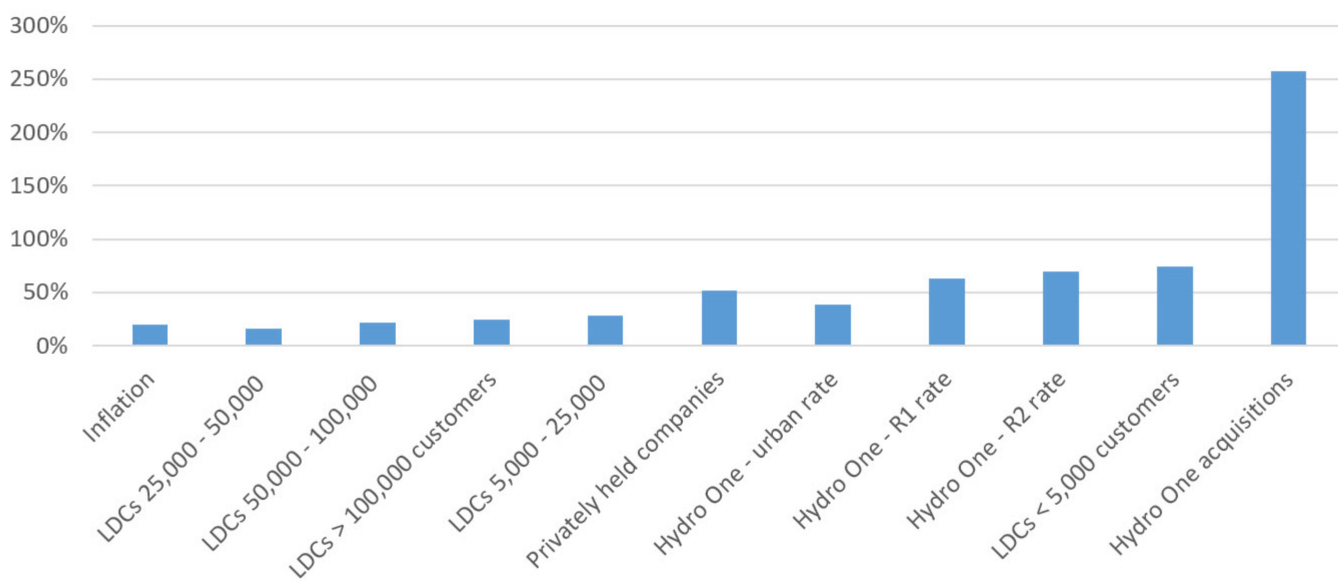
In 2005, the average distribution rates for the customers of the acquired LDCs were 17% lower than if they were charged the rates of the smallest municipally owned LDCs (those with less than 5,000 customers). By 2016, the average distribution rates for the customers of LDCs acquired by Hydro One was 73% higher.

The total excess cost to these customers over the period from 2005-2016 was $415 million and the annual excess cost was $58 million in 2016.

On average these customers have seen a 262% rate increase. The rate of inflation over this time period was 21%. The increases ranged from a 52% increase for the former customers of Caledon Hydro to an 816% increase for the customers of the Village of Arkona PUC.

By comparison, the increase in rates for customers of LDCs with less than 5,000 customers was 75% and for customers of municipally owned LDCs with more than 5,000 customers the rate increase was close to the rate of inflation of 21%.

Distribution Rate Increases by LDC Category 2005-2016



RESULTS OF THE ANALYSIS *- DISTRIBUTION REVENUE CONT'D*

Funds collected from distribution rates are revenue for Hydro One so a fair question is whether any of this $415 million in excess revenue provided Hydro One with a return in excess over what they would have been allowed to earn on their rate base. Put another way, did Hydro One earn a return on the $73 million of goodwill booked with these acquisitions? The format of rate applications makes it difficult to analyze the data easily but there does not appear to be an excess return for Hydro One over what they were entitled to earn on their rate base.

In 2005, rates were still low as already noted so no excess returns were earned that year. In 2006, rates jumped an average of 25% but this adjustment was a catch-up from previously deferred rate increases. Rates were now higher than those of smaller LDCs but by less than 2%. In 2007, rates increased at the rate of inflation. 2008 was the big jump when rates increased an average of 54%. However, Hydro One re-based their rates that year and included the acquired LDCs in their rebasing calculations. This means that Hydro One included the loads and costs of the acquired LDCs in calculating their revenue requirements and desired rates and, in doing so, would have limited their returns to those based on their actual cost structure not including the goodwill on the acquisitions.

2008 was also the year Hydro One was approved to harmonize the rates of the acquired LDCs with their own rates over a four year period. As a result, the average customer rates in the acquired LDCs rose 146% (more than doubling) between 2007 and 2011. By 2011 the distribution rates for Hydro One customers were almost double those of the smallest LDCs.

Since 2011, distribution rates for customers of the acquired LDCs have remained harmonized with the rates of the traditional Hydro One customers and have risen at an average of around 3% per year or just a little more than the rate of inflation.

If Hydro One as a corporation did not generate an excess return from the large increases in distribution rates for the acquired LDC customers, existing Hydro One customers certainly benefitted as the revenue requirement allocated to them is $415 million lower than it otherwise would have been. Yet these customers have seen some of the highest increases in distribution rates in the province with a 39% increase for urban UR customers, a 63% increase for the rural R1 customers and a 75% increase for rural R2 customers. If Hydro One had not acquired these LDCs their rate increases would have been even higher.

IMPLICATIONS FOR RECENT ACQUISITIONS

Working on the assumption that Hydro One will want to harmonize the rates of its more recent acquisitions we can calculate the potential average customer rate for these LDCs. The one challenge is we do not know if the customers will be considered an urban (UR) or rural customer (R1) for the purposes of Hydro One's customer rate classification system. Our best estimate is as follows:

Potential Rate Impact at Recent Hydro One Acquisitions

Acquired LDC	Rate Year	Urban Rates		Rural Rates	
		% Change in Rates	Financial Impact ($ million)	% Change in Rates	Financial Impact ($ million)
Norfolk	2013	(3.4%)	($0.4)	50.4%	$5.8
Haldimand	2014	(3.2%)	($0.4)	55.7%	$6.2
Woodstock	2014	47.0%	$3.5	130.7%	$9.7
Orillia	2015	28.8%	$2.1	115.9%	$8.3
Peterborough	2015	66.0%	$9.1	177.2%	$24.5

Note: Green shading indicates the expected rate increase based on customer density

Norfolk and Haldimand have customer densities well below 60 customers per km of line so it is expected their customers would be classified as rural for Hydro One rate purposes though some towns may be classified as urban. Woodstock, Orillia and Peterborough have customer densities of around 60 so it is expected that their customers would be classified as urban though it is possible that some outlining areas may be classified as rural.

Based on this analysis it would appear that, on average, customers in these municipalities will eventually have a 50% increase in rates (Orillia customers will see a lower increase). In general, the lower the rates in each municipality the greater will be the increase. This rate increase will be higher if Hydro One distribution rates continue to increase more than LDCs each year.

Combined this totals an increase in cash flow to Hydro One of $26.7 million each year which will help suppress rates for existing Hydro One customers as of the next rate rebasing.

It can also be questioned whether the annual financial drain to the municipality offsets the gain from the sale of the LDC at a high price. In the case of Norfolk, Hydro One paid $40 million above book value for the LDC. At $5.8 million a year, this gain will be offset in seven years after Norfolk rates are harmonized. The gain on the sale is held by the municipal government while the increase in distribution rates is born by individual residences and businesses.

REGULATORY OVERSIGHT

Every step in this process has been made with the approval of the Ontario Energy Board.

The initial acquisitions were approved in 2000 and 2001. This was not surprising given that most of the LDCs purchased by Hydro One had less than 2,000 customers so would likely not have survived on their own, nobody knew how the new electricity market was truly going to work and what the demands on LDCs would be and nobody knew that Hydro One's rate increases would be so high over the next ten years. However, in approving the sales it is not clear that thought had been given to how their rates would be managed in the future.

In 2006, after the five year rate freezes had expired, Hydro One applied to harmonize the rates within two years. The OEB did not approve this proposal with the substantial increase in rates being the reason given. The OEB requested Hydro One perform a cost allocation study to support its rate request.

In 2008, Hydro One again asked to harmonize rates but this time over a four year time period. This time the OEB agreed to the request. There were four features of interest in this decision.

1. As mentioned, the OEB in 2006 asked for a cost allocation study. Hydro One provided the cost allocation study but it allocated costs between the different proposed rate classes. The study did not analyze the costs between the acquired LDC territories and the "legacy" Hydro One territory. The reason given by Hydro One for not performing this analysis was that the operations had become so integrated that the study was no longer possible. By not addressing this issue at the time of the acquisition the OEB has allowed itself to be put in a position where it had no choice but to accept the Hydro One proposal.

2. By 2008 other LDCs had started building a history of rate increases. An analysis of LDCs comparable in size to the acquired LDCs, as we have used in our analysis, would have demonstrated that it was more than possible to manage these territories without requiring the rates that Hydro One was proposing. Instead of requiring this analysis during this hearing the OEB asked for it to be provided at future rate hearings at which point it would be too late.

3. Hydro One suggested that the low rates of the acquired LDCs were indicators that they were not recovering their costs. No evidence was provided for this argument and no suggestion of the alternative hypothesis that the smaller LDCs might have been more efficient. The intervenors did not accept this argument and the OEB avoided it in their decision.

4. In demonstrating the rate impact on customers of the acquired LDCs, Hydro One provided the impact of the increase as a percentage of the total customer bill. This is a standard analysis required by the OEB. The problem with this analysis is that it effectively assumes that all the other

REGULATORY OVERSIGHT - CONT'D

components of the customer bill remain unchanged. This is rarely the case. When this rate impact is combined with increases in other components of the customer bill such as the electricity commodity and regulated costs the total increase can be substantially more than 10%. It also allowed increases of over 50% in distribution costs to customers in a single year.

In 2014, Hydro One acquired Norfolk Power Distribution. Other than the acquisition of the small utility of Terrace Bay in 2007, which was included in the 2008 harmonization decision, this was the first acquisition since 2000-2001. As a result, a number of LDCs, including Niagara-on-the-Lake Hydro, intervened due to concerns Hydro One was using its higher rates to finance higher prices on acquisitions. The OEB approved the acquisition though there were features of interest in the decision.

1. As with previous acquisitions, Hydro One provided a five year rate freeze which was now enhanced by a 1% rate reduction. No commitments were made by Hydro One as to rates after the five years other than Hydro One would examine the options of a) create new rates classes for Norfolk customers, b) harmonize Norfolk rates with Hydro One rates as had been done with previous acquisitions or c) propose something else with rates. The OEB accepted this with the proviso that "it is the Board's expectation that at the time of rate rebasing Hydro One will propose rate classes for Norfolk customers that reflect costs to serve the Norfolk service area". It would be a concern if by the time of this rebasing Hydro One will once again have integrated the operations such that differentiating Norfolk customers is no longer possible.

2. The OEB focused on costs rather than prices in their decision-making. Presumably, the theory is that as Hydro One will reduce costs in consolidating Norfolk (this is accepted) and as there is a direct correlation between costs and rates any reduction in costs must be good for customers. The problem with this limited approach is that it ignores how costs are allocated. The OEB is effectively saying that it is acceptable for Norfolk customers to subsidize the rates of other Hydro One customers, as we saw with the previous Hydro One acquisitions, as long as the costs of the system as a whole decline.

3. Intervenors noted the past history of Hydro One rate increases for customers of acquired LDCs. The OEB's response was that "the Board does not consider that the rates of other acquired utilities are relevant to this proceeding". Given that the OEB noted in their decision that their number one objective under the Ontario Energy Board Act was "to protect the interests of consumers as to prices and the adequacy, reliability and quality of electrical service" this is a curious set of data to ignore.

REGULATORY OVERSIGHT - *CONT'D*

In 2017, Hydro One filed its rate application for the period from 2017-2022. This application includes rates for the new acquisitions Norfolk, Haldimand and Woodstock for 2021-2022. 2021-2022 is the expiry of the five year rate freezes provided at the time of the acquisitions. Hydro One is proposing new rates classes which will serve all three of these acquisition customers. Whether this proposal is for a permanent new rate class or is a step on the harmonization process will not be known until future rate applications. However, in its application Hydro One acknowledged that "the increase in revenue from these classes is offset by decreasing the revenue collected from the UR, R1, Seasonal and USL classes" so customers of these acquisitions will also be subsidizing existing Hydro One customers.

Later in 2017, the OEB adjourned its hearing on the proposed acquisition of Orillia Power by Hydro One until the above Hydro One rate application is settled. In its decision to adjourn the OEB noted "that the rates proposed for previously acquired utilities (Norfolk, Haldimand and Woodstock) in Hydro One's distribution rate application suggest large distribution rate increases for some customers of these acquired utilities once the deferred rebasing period elapses". It appears that previous rate experiences of acquired utilities is now relevant.

The arguments made by Hydro One are equally revealing. Hydro One submitted that intervenors "confused lower cost structures, which it states are used to test the validity of a merger or acquisition, with allocated costs used for rate setting" and that "how those costs are then allocated to rate classes is outside the merger or acquisition application". Given that the point of a regulatory review of proposed acquisitions is to protect the customers of the LDCs being acquired this is a curious argument.

REGIONAL COMPARISONS

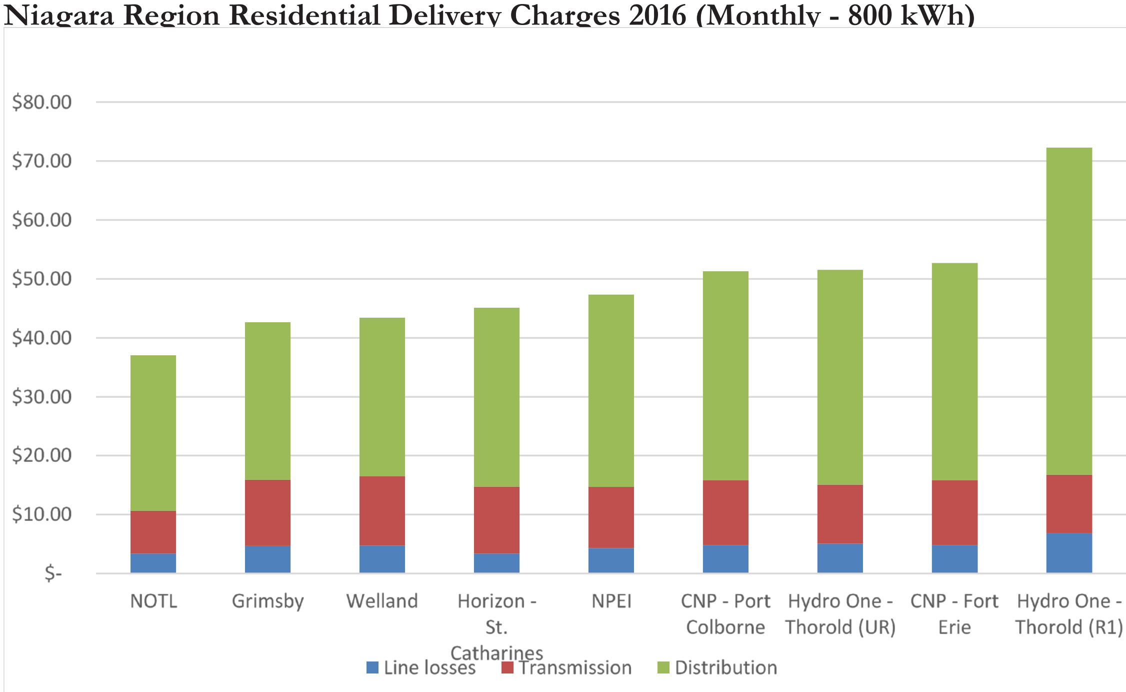
Hydro One's strategy of harmonizing rates creates some significant regional rate distortions. You could choose any small or mid-sized LDC and compare it to a similar sized community served by Hydro One and see significant rate differences. For the purposes of this analysis we will use the Region of Niagara as it is served predominantly by independent LDCs.

Grimsby, Niagara-on-the-Lake and Welland have their own LDCs, Niagara Peninsula Energy serves Niagara Falls, Lincoln, West Lincoln and the urban part of Pelham, Canadian Niagara Power (CNP) serves Fort Erie and Port Colborne and Hydro One serves Thorold, Wainfleet, and the rural part of Pelham.

Thorold has a sizable urban area which is indistinguishable from St. Catharines. Other parts of Thorold are rural and sparsely populated. Thorold was purchased by Hydro One in 2000-2001 and at that time had one distribution rate for all customers which was equivalent to its neighbours.

REGIONAL COMPARISONS - CONT'D

Niagara Region Residential Delivery Charges 2016 (Monthly - 800 kWh)



Rates for Thorold customers are now considerably higher than those of its neighbours; particularly for rural customers. The Hydro One rates would look worse if not for CNP's high rates.

Some other examples of regional distortions include:

Comparison of Rates at Hydro One and Similar Municipal LDC Territories

Hydro One Service area	Hydro One rate class	Delivery Charge	LDC Service Area	Delivery Charge	Difference	Reason for Comparison
Kemptville	R1	$66.12	Prescott, Rideau St. Lawrence	$45.53	$20.69	similar size and location
Brockville	UR	$45.66	Cobourg, Lakefront	$38.38	$7.28	similar size and location
Glanbrook	R1	$66.12	Dundas, Alectra	$39.78	$26.34	suburbs of Hamilton

OTHER CONSIDERATIONS

Municipal governments had a number of reasons for selling their LDC to Hydro One.

- This was the first time the municipalities were allowed to monetize what was previously close to being another department for delivering services though one that had to be kept separate for rate setting purposes. Many municipalities had a real requirement for these funds.
- There was considerable uncertainty as to what the demands on the LDCs would be in the new electricity market and whether the LDCs of this size would be able to meet the new requirements.
- In much of Eastern Ontario the ice storm of 1998 was still very much on everyone's mind and the need for adequate resources should something similar occur again.
- Hydro One was usually the first potential acquirer to provide structured offers to the municipal owners.
- No one could have forecast at this time the substantial rate increases for Hydro One customers.

However, many municipalities also chose not to sell but instead addressed their issues by merging with their neighbours to create LDCs of sufficient mass. Examples include Ottawa River Power and Rideau St. Lawrence in the east, Westario and Northern Ontario Wires further north and Entegrus, Erie Thames and Festival Hydro in the south west. Joining one of these merging entities was always an option and all have kept their rates reasonable.

Hydro One has characterized its acquisition strategy in terms of enhancing its return to investors. The acquisition strategy also had implicit Provincial Government support. This was probably driven by the Government's desire to reduce the number of LDCs which still appears to be Government policy. We can only speculate that the objective is to make LDCs more manageable from a policy perspective. This lessened the political objections to the increased rates of customers of the acquired LDCs.

Hydro One was aided in it acquisitions by the application of the transfer tax. The transfer tax was waived for significant periods of time if Hydro One or a municipally owned LDC was the acquirer. This gave Hydro one a competitive advantage over any potential private sector acquirer (Fortis, Enbridge, Borealis) that would also have access to the capital needed for multiple acquisitions. The transfer tax would be applied it they were the acquirer. Municipal LDCs, being newly created, were not in a position to compete extensively with Hydro One and did not have access to much additional capital. The structuring of the transfer tax was a political decision.

Hydro One is now majority owned by independent investors but until recently, and at the time most of the acquisitions and rate-setting took place, was 100% owned by the Government of Ontario. Discussions with MPPs in the past have indicated they were aware of this subsidization by some Hydro One customers though had never had it quantified. Their worry was that if the very rural and northern Hydro One customers had to pay rates that more closely reflected their true costs this would create a big political issue. This benefit also served to lessen political objections.

RECOMMENDATIONS GOING FORWARD

The current policy of Hydro One subsidizing its existing customer base with rate increases for acquired customers is wrong for four reasons.

1. Customers of the acquired LDCs are seeing disproportionately large rate increases. This is unfair and wrong. No customer should be treated in such a fashion.
2. Customers have significantly different rates when the underlying cost structure of their locations are essentially the same. They may be neighbours served by different LDCs or they may be in similar municipalities served by different LDCs. The only significant difference is their LDC. This is also unfair and wrong. Sound policy should be to have their rates reflect their local underlying costs regardless of who the distributor is.
3. Some Hydro One customers are subsidizing other high cost customers while customers of other LDCs are not. We accept that it is appropriate to subsidize certain rural and northern customers. This is what the RRRP is for. A second hidden subsidy should not be tolerated.
4. The subsidization is hiding further inefficiencies of Hydro One. Hydro One has had the biggest rate increases since market opening. Yet, as the biggest LDC and as the biggest acquirer or other LDCs, Hydro One should have had the best opportunity to manage costs. Instead, Hydro One's rate increases would have been even bigger if not for the cost savings and subsidies of the acquisitions. As the LDC for most of rural Ontario it is accepted that Hydro One should have the highest rates. But they should not be increasing faster than other LDCs; that is inefficiency.

We have two recommendations to try tackle this problem.

1. Ensure the OEB has complete independence. Niagara-on-the-Lake Hydro's Board called for this with their August 1, 2017 press release. Only if the OEB has this independence will they be able and willing to stand up to the larger utilities on behalf of the customer and make the tough decisions. We are heartened by the Orillia adjournment and hope this is a first step in this direction. One wonders why this decision was only made now and not in 2008 or 2014. One is also left to wonder if the fact that the OEB and Hydro One ultimately answered to the same Minister had any influence.
2. Break-up Hydro One between distribution and transmission and then break-up the distribution business into a number of smaller regional LDCs. Niagara-on-the-Lake Hydro's Board called for this with their July 4, 2017 press release. It is posited that Hydro One is simply too big and unwieldy and that the inefficiencies of this scale have more than overcome any true efficiencies that consolidation provided. The relative performances of municipal LDCs and Hydro One is a demonstration that smaller, regionally focused LDCs are more efficient. The regional LDCs created by breaking up Hydro One will have distribution rates that will more accurately reflect the underlying costs in that region and the RRRP can be amended to openly subsidize those rural and northern customers that would be penalized.

CONCLUSION

A number of questions were raised at the start of this report. As a result of the analysis it can be concluded that:

1. Hydro One has a perverse competitive advantage in bidding to purchase other LDCs. As they have been allowed to harmonize rates they can use acquisitions as a means of lowering the cost of their services to existing customers. This allows Hydro One to present their rate management, though still poor, as better than it otherwise would have been. Other LDCs with lower rates do not have this option nor would any non-LDC acquirers.

2. Harmonization of rates have created the fastest rising rates by far in the Province of Ontario. Customers of the acquired LDCs have seen their distribution rates rise by over 250%. No other potential acquirer would have had anywhere near this impact.

3. Unfortunately, just fixing the rates of the acquired LDCs to make them comparable to other LDCs is not sufficient. All of Hydro Ones rates are higher than municipal LDCs due to their significant rate increases over the past 12 years. For this reason we have proposed the break-up of Hydro One as the best means of trying to bring down the existing rates for all Hydro One customers.

4. There is no evidence that Hydro One realized any excess cash flows or booked excess revenues as a result of these acquisitions. Rather, the one customer group from the acquired LDCs saw an excessive increase in rates while the other customer group of existing customers saw a rate increase that, while still very large, was lower than it would have been.

5. The customers of the acquired LDCs would have been better off if their LDC had been sold to another LDC or merged with other small local LDCs to create a bigger local LDC.

APPENDIX 1

2000-2001 Hydro One Acquisitions

Municipality	LDC (if different)	1997 Customer Count	1997 Book Value ($ thousands)	Hydro One Rate Type (density)	Subsidization 2005-2016 ($ thousands)	Rate Increase 2005-2016
Ailsa Craig	-	386	$355	Medium	$1,502	313%
Alexandria	North Glengarry	1,845	$2,385	Medium	$12,719	388%
Apple Hill	North Glengarry	113	$67	Medium	$312	388%
Arkona	-	236	$168	Medium	$528	816%
Arnprior	-	3,406	$5,191	Urban	$8,908	104%
Avonmore	North Stormont	156	$80	Medium	$378	658%
Bancroft	-	1,346	$2,093	Medium	$8,209	262%
Bath	-	639	$706	Medium	$2,033	317%
Blandford-Blenheim	-	899	$1,448	Medium	$4,756	283%
Bloomfield	Prince Edward	354	$215	Medium	$1,223	238%
Blyth	-	476	$518	Medium	$2,742	340%
Bobcaygeon	-	1,740	$2,059	Medium	$7,969	242%
Brighton	-	2,240	$2,642	Medium	$8,066	256%
Brockville	-	9,427	$14,652	Urban	$24,819	144%
Caledon	-	2,589	$5,561	Urban	$7,924	52%
Campbellford	Campbellford-Seymour	1,858	$4,281	Medium	$10,601	312%
Carleton Place	-	3,801	$3,671	Urban	$6,087	61%
Chatsworth	Georgian Bay	225	$206	Urban	$179	176%
Chalk River	-	412	$322	Medium	$1,562	203%
Chesley	Arran-Elderslie	949	$1,191	Medium	$3,622	449%
Chesterville	North Dundas	710	$1,141	Medium	$6,562	413%
Cobden	-	543	$698	Medium	$1,899	170%
Deep River	-	1,946	$2,915	Medium	$10,978	138%
Delaware	Middlesex Centre	376	$559	Medium	$1,135	285%
Deseronto	-	775	$1,013	Medium	$2,486	326%
Drayton	Mapleton	538	$779	Medium	$2,715	225%
Dryden	-	3,106	$3,503	Medium	$14,431	271%
Dundalk	-	777	$1,212	Medium	$4,003	213%
Durham	-	1,301	$1,514	Medium	$4,477	221%
Eganville	-	665	$1,073	Medium	$3,046	164%
Erin	-	1,062	$2,495	Medium	$15,288	198%
Exeter	-	2,265	$3,601	Medium	$11,741	315%
Fenelon Falls	-	1,158	$1,257	Medium	$4,953	379%

Flesherton	Artemesia	360	$429	Medium	$1,552	234%
Forest	-	1,373	$1,639	Medium	$6,847	250%
Frankford	Quinte West	910	$923	Medium	$1,242	266%
Georgina	-	1,400	$1,793	Medium	$6,752	261%
Glencoe	-	1,010	$1,049	Medium	$4,723	442%
Grand Bend	-	1,283	$1,474	Medium	$3,910	272%
Granton	Lucan Granton	144	$116	Medium	$555	261%
Hastings	-	612	$1,005	Medium	$2,653	197%
Havelock	Havelock-Bel-mont-Methuen	633	$758	Medium	$2,505	225%
Kemptville	North Grenville	1,558	$2,316	Medium	$8,912	202%
Kirkfield	-	140	$137	Medium	$590	273%
Lanark	-	413	$536	Medium	$1,597	221%
Lancaster	South Glengarry	413	$374	Medium	$1,715	429%
Larder Lake	-	497	$522	Medium	$1,791	230%
Latchford	-	216	$209	Medium	$693	480%
Lindsay	-	7,139	$11,008	Urban	$16,749	84%
Listowel	North Perth	2,394	$4,688	Medium	$17,571	244%
L'Orignal	Champlain	914	$1,173	Medium	$3,410	347%
Lucan	Lucan Granton	762	$835	Medium	$2,470	261%
Madoc	Centre Hastings	809	$1,103	Medium	$3,179	339%
Markdale	-	774	$1,055	Medium	$5,602	317%
Martintown	South Glengarry	131	$85	Medium	$377	429%
Marmora	-	771	$883	Medium	$3,146	405%
Maxville	North Glengarry	420	$306	Medium	$1,809	388%
McGarry	-	306	$368	Medium	$1,214	209%
Meaford	-	2,198	$2,193	Medium	$7,903	262%
Millbrook	Cavan-Millbrook-North Monaghan	561	$756	Medium	$2,136	219%
Milverton	Perth East	620	$748	Medium	$2,686	379%
Moorefield	Mapleton	189	$148	Medium	$832	225%
Napanee	-	2,599	$3,786	Medium	$12,309	254%
Nipigon	-	951	$1,137	Medium	$5,278	244%
North Dorchester	-	772	$687	Medium	$2,362	408%
Omemee	-	565	$700	Medium	$2,913	219%
Owen Sound	Georgian Bay	9,124	$13,147	Urban	$15,744	176%
Paisley	Arran-Elderslie	541	$668	Medium	$1,955	449%
Perth	-	3,289	$4,996	Urban	$7,396	122%
Picton	Prince Edward	2,408	$3,298	Medium	$10,911	238%
Priceville	Artemesia	127	$102	Medium	$295	234%

Rainy River	-	498	$396	Medium	$1,734	219%
Ramara	-	132	$120	Medium	$674	346%
Red Rock	-	405	$532	Medium	$1,662	163%
Rockland	Clarence-Rockland	3,166	$3,907	Medium	$13,751	476%
Rodney	West Elgin	555	$272	Medium	$1,951	367%
Russell	-	800	$675	Medium	$3,202	180%
Schreiber	-	843	$1,313	Medium	$4,733	143%
Severn	-	651	$864	Medium	$2,617	310%
Shelburne	-	1,498	$1,966	Medium	$6,472	303%
Smith Falls	-	4,523	$4,900	Urban	$10,220	155%
South River	-	557	$570	Medium	$1,998	220%
Springfield	Malahide	264	$200	Medium	$745	235%
Springwater	-	762	$719	Medium	$3,947	315%
Stirling	Stirling-Rawdon	957	$1,054	Medium	$3,830	252%
Tara	Arran-Elderslie	435	$385	Medium	$1,888	449%
Thedford	-	380	$325	Medium	$1,694	331%
Thessalon	-	676	$701	Medium	$3,223	238%
Thorndale	-	159	$104	Medium	$631	446%
Thorold	-	7,729	$9,268	Urban	$12,842	77%
Trenton	-	6,843	$12,046	Urban	$16,060	266%
Tweed	-	850	$708	Medium	$3,315	540%
Vankleek Hill	Champlain	996	$941	Medium	$3,073	347%
Wardsville	-	212	$124	Medium	$526	408%
Warkworth	-	337	$405	Medium	$1,501	224%
Wellington	Mapleton	891	$720	Medium	$3,246	225%
West Lorne	West Elgin	639	$857	Medium	$3,797	367%
Whitchurch-Stouffville	-	3,407	$5,177	Urban	$7,821	135%
Wiarton	South Bruce	1,129	$1,597	Medium	$6,344	177%
Winchester	North Dundas	1,050	$1,922	Medium	$10,609	413%
Woodville	-	354	$135	Medium	$953	322%
Wyoming	-	877	$669	Medium	$3,080	289%
Totals		**140,304**	**$190,230**		**$492,312**	**262%**