EB-2017-0049

Hydro One Networks Inc.
Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

VECC COMPENDIUM

PANEL 7

JUNE 25, 2018

PANEL 7 COMPENDIUM INDEX

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TAB 1

Vulnerable Energy Consumers Coalition Interrogatory # 71

Issue:

Issue 43: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

Reference:

E1-02-01 Page: 9-10
E1-02-01 Page 39 – Table E.4
EB-2013-0416, Exhibit I, Tab 6.06, Schedule 6-VECC 79

Preamble: The response to VECC 79 stated: "For residential customers, the consensus forecast of housing starts is used to forecast the change in the number of households in Ontario and hence the change in the number of retail residential customers. Historical share of retail in the number of households in Ontario and its dynamics over time is taken into account. Over the forecast period, residential load growth also contributes to the forecast of the number of residential customers."

Interrogatory:

a) Please provide a schedule that sets out the actual derivation of the forecast residential customer count for each of the years 2017-2020. In doing so please provide all equations, inputs used and associated calculations.

b) Please explain how the forecast was broken down as between the various "residential classes" (including the residential classes for acquired utilities).

Response:

a) Please see I-43-VECC-71-01 (MS Excel file) which provides this information for all rate classes.

b) Retail residential customer count was broken down into various rate classes (R1, R2, Seasonal, and UR) based on their historical share. Next, the forecast by rate classes were adjusted for customer reclassification after 2017. Residential classes for acquired utilities were modeled in relation to changes in the number of households in Ontario as presented in the attachment to a).

TAB 2

Exhibit I, Tab 43, VECC 71, Excel Model, Rows 1-15

Forecasting Retail Total Number of Residential Customers:						
	2017	2018	2019	2020	2021	2022
Ontario Number of Households / Customers						
Level	5,160,306	5,216,630	5,273,377	5,330,182	5,386,556	5,441,607
Change	57,179	56,324	56,747	56,805	56,374	55,051
Retail Total Number of Residential Customers (R1 + R2 + Seasonal + UR)						
Change (1)	8,639	8,510	8,574	8,582	8,517	8,317
Level (2)	1,141,431	1,149,941	1,158,514	1,167,097	1,175,614	1,183,932

(1) Given the information available at the time of forecast, change in the total number of retail residential customers in 2017 was forecast to be 8,639, which is more than the 3-year average change since since 2014. For the years 2018 to 2022, the change varies in proportion to change in the forecast of Ontario number of households / customers.

(2) Forecast for each year equals change in the total number of customer in that year plus forecasst in the prior year.

TAB 3

Exhibit I, Tab 43, VECC 71, Excel Model, Rows 155-160; 182-187 and 206-211

Number of Customers for Norfolk						
Ontario Number of Households / Customers						
Change	57,179	56,324	56,747	56,805	56,374	55,051
Norfolk Residential						
Ratio	0.003	0.003	0.003	0.003	0.003	0.003
Change	172	169	170	170	169	165
Level	17672	17841	18011	18181	18350	18515

Number of Customers for Haldimand						
Ontario Number of Households / Customers						
Change	57,179	56,324	56,747	56,805	56,374	55,051
Haldimand Residential						
Ratio	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Change	87	86	86	87	86	84
Level	19074	19160	19246	19333	19419	19502

Number of Customers for Woodstock						
Ontario Number of Households / Customers						
Change	57,179	56,324	56,747	56,805	56,374	55,051
Woodstock Residential						
Ratio	0.003	0.003	0.003	0.003	0.003	0.003
Change	172	158	160	160	159	155
Level	14676	14834	14994	15153	15312	15467

TAB 4

Broad Annual Series

	Cooling Degree Days	Heating Degree Days	Ontario GDP in 2007 $M	Ontario Population (1000's)	Ontario Disposable Income in 2002 $M	Ontario Commercial GDP in 2007 $M	Ontario Industrial GDP in 2007 $M	Ontario Number of Households (1000's)
1961	305.9	3,958.1	112,560.5	6,296.3	66,457.7	84,181.8	26,355.3	1,662.7
1962	271.5	4,073.6	120,375.6	6,414.1	67,129.0	74,561.7	28,055.6	1,705.3
1963	253.6	4,106.3	125,923.5	6,546.4	77,394.6	78,619.6	29,756.0	1,743.4
1964	213.5	4,087.6	135,098.7	6,696.2	74,474.9	84,346.7	32,584.0	1,798.0
1965	159.4	4,268.1	143,605.4	6,854.4	80,002.2	90,344.7	35,243.9	1,849.1
1966	246.9	4,211.6	153,593.8	7,026.9	85,649.8	98,344.0	37,669.7	1,916.1
1967	157.4	4,250.3	160,019.6	7,196.4	89,372.2	103,297.2	39,441.8	1,972.5
1968	179.0	4,221.9	170,542.0	7,333.9	93,924.3	110,135.1	41,924.1	2,039.9
1969	257.1	4,212.4	180,448.2	7,462.7	99,438.1	117,279.2	44,144.2	2,119.6
1970	234.2	4,238.9	184,449.2	7,627.9	103,751.8	123,836.8	44,802.7	2,188.7
1971	201.0	4,089.4	195,366.4	7,849.0	110,523.9	130,591.0	47,374.4	2,265.0
1972	168.9	4,440.0	207,448.2	7,963.1	119,793.0	137,873.0	50,837.4	2,333.6
1973	306.1	3,887.1	217,451.3	8,075.5	129,932.6	146,860.5	56,687.5	2,412.9
1974	187.0	4,152.7	224,256.1	8,204.3	137,480.1	154,088.3	57,120.2	2,503.3
1975	279.1	3,910.2	225,681.2	8,319.8	144,705.8	158,817.7	52,040.3	2,581.9
1976	186.9	4,369.3	241,112.6	8,413.8	151,966.4	166,213.9	56,125.4	2,652.5
1977	207.0	4,102.7	250,216.3	8,504.1	156,522.5	172,182.5	57,841.0	2,727.2
1978	231.6	4,391.0	260,422.7	8,590.1	163,226.7	178,742.3	59,165.1	2,786.4
1979	204.2	4,179.2	269,568.9	8,662.1	167,928.1	185,381.2	61,247.6	2,856.6
1980	243.7	4,308.9	268,127.8	8,746.0	170,398.1	192,874.0	57,534.1	2,916.0
1981	205.8	4,074.6	281,577.0	8,812.3	177,272.9	201,316.2	59,158.0	2,970.0
1982	140.6	4,113.8	272,527.0	8,920.3	179,018.2	198,647.0	52,049.7	3,015.6
1983	378.2	3,991.4	286,504.0	9,039.6	181,806.7	204,542.5	57,197.8	3,073.4
1984	239.5	4,048.6	311,861.8	9,167.5	190,090.7	216,748.2	67,833.8	3,135.4
1985	198.5	4,033.1	327,841.0	9,294.7	197,410.1	228,858.5	71,496.7	3,185.1
1986	197.4	3,920.4	339,930.0	9,437.4	199,722.8	242,642.6	72,049.3	3,258.6
1987	347.1	3,704.6	356,441.0	9,637.9	204,735.3	253,148.5	74,062.5	3,342.7
1988	388.5	4,025.5	372,718.0	9,838.6	214,382.0	265,702.2	78,674.5	3,432.0
1989	278.7	4,197.8	385,055.0	10,103.3	220,024.9	277,695.8	78,804.5	3,520.0
1990	280.8	3,593.3	378,829.3	10,295.8	218,315.4	274,771.6	73,687.4	3,599.8
1991	394.2	3,657.9	366,074.0	10,431.3	215,517.7	271,884.8	67,806.3	3,656.5
1992	104.9	4,045.8	370,697.0	10,572.2	220,512.6	271,157.2	68,805.5	3,723.7
1993	267.8	4,096.9	376,057.0	10,690.0	222,873.9	272,735.4	71,573.9	3,785.1
1994	251.7	4,082.8	396,536.0	10,819.1	225,425.7	282,481.0	76,016.8	3,847.6
1995	350.5	3,992.9	409,324.0	10,950.1	227,417.0	288,320.7	81,610.5	3,895.0
1996	234.8	4,129.6	416,265.0	11,082.9	226,486.1	293,728.8	82,340.7	3,944.1
1997	248.9	3,955.5	436,414.3	11,227.7	233,756.7	305,283.6	87,375.9	3,993.0
1998	397.6	3,197.0	456,248.3	11,365.9	244,600.2	319,322.0	92,495.7	4,058.7
1999	448.8	3,488.9	487,831.0	11,504.8	252,759.1	345,554.0	99,158.7	4,125.4

	Cooling Degree Days	Heating Degree Days	Ontario GDP in 2007 $M	Ontario Population (1000's)	Ontario Disposable Income in 2002 $M	Ontario Commercial GDP in 2007 $M	Ontario Industrial GDP in 2007 $M	Ontario Number of Households (1000's)
2000	243.9	3,787.3	518,657.8	11,683.3	264,028.6	363,492.7	107,303.5	4,204.3
2001	389.6	3,387.0	528,036.0	11,897.4	264,161.6	376,013.3	103,062.8	4,219.4
2002	521.4	3,590.2	545,852.0	12,093.3	268,496.9	390,733.5	103,964.1	4,308.7
2003	321.1	3,932.0	552,082.0	12,243.8	272,261.7	399,707.9	103,606.2	4,382.4
2004	236.1	3,748.5	567,600.0	12,390.1	279,476.0	414,571.8	103,617.1	4,453.2
2005	537.7	3,724.5	585,843.0	12,528.0	283,019.4	428,618.1	104,325.3	4,519.4
2006	386.4	3,335.6	596,797.0	12,661.6	296,121.8	442,142.4	100,939.2	4,583.1
2007	442.6	3,644.8	601,735.0	12,764.2	303,443.8	457,831.9	96,246.7	4,641.3
2008	286.5	3,782.4	601,723.0	12,882.6	309,531.0	462,778.5	89,369.7	4,699.9
2009	208.3	3,767.1	582,904.0	12,997.7	318,360.2	460,287.1	73,033.3	4,750.3
2010	453.8	3,456.3	600,131.0	13,135.1	313,467.4	471,205.9	78,033.6	4,794.2
2011	440.1	3,572.9	614,605.8	13,263.5	311,737.6	482,113.8	81,505.9	4,846.4
2012	495.1	3,173.4	622,717.0	13,413.7	313,662.4	488,754.5	82,501.4	4,899.4
2013	337.1	3,722.7	631,871.0	13,556.2	322,964.5	496,727.9	82,444.9	4,948.2
2014	271.3	4,033.9	648,890.0	13,685.2	324,235.2	508,086.6	85,575.1	4,994.6
2015	369.1	3,704.0	665,034.0	13,797.0	335,482.0	521,750.3	84,662.0	5,045.6
2016	576.7	3,408.4	682,212.6	13,983.0	345,862.7	537,404.0	84,481.0	5,103.7
2017	345.4	3,737.4	697,789.7	14,144.3	353,247.2	550,536.2	85,494.9	5,161.9
2018	345.4	3,737.4	712,665.5	14,305.3	358,605.7	563,501.5	86,076.0	5,216.7
2019	345.4	3,737.4	727,128.0	14,452.5	364,591.1	576,071.6	86,663.8	5,272.4
2020	345.4	3,737.4	741,175.2	14,583.6	370,890.8	587,990.9	87,517.5	5,329.6
2021	345.4	3,737.4	756,002.0	14,708.9	377,555.2	600,552.0	88,704.8	5,386.2
2022	345.4	3,737.4	770,631.1	14,846.8	384,388.5	612,653.3	90,062.6	5,442.0

Residential Building Permit Index in 2007 $

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1970	0.19626	0.20145	0.35802	0.669798	0.76137	0.750583	0.567137	0.66874	0.854872	0.950795	0.676054	0.572368
1971	0.28137	0.50401	0.64181	0.9663	1.02468	1.16545	0.989229	0.81639	0.816879	0.838113	0.68372	0.47851
1972	0.35683	0.47384	0.75367	1.063558	1.14666	1.207789	0.923904	0.92839	0.885338	0.81835	0.777141	0.556187
1973	0.43255	0.52816	0.86891	0.876244	1.27267	1.13227	0.988571	1.33338	0.890436	1.090474	1.196305	0.834207
1974	0.3806	0.55037	0.94078	0.933707	1.12137	0.697324	0.717294	0.67314	0.624276	0.632387	0.40521	0.355714
1975	0.24543	0.43772	0.58647	0.888459	1.00386	0.935981	0.999891	1.00802	0.904536	0.947411	0.707134	0.557108
1976	0.34303	0.4489	0.76579	0.890108	0.88321	1.014851	0.773467	0.79972	0.881681	0.814848	0.789379	0.408048
1977	0.24757	0.32875	0.8258	0.959127	1.0953	1.02469	0.874429	0.80229	0.774065	0.606082	0.686711	0.47913
1978	0.18977	0.35412	0.43754	0.724839	1.10823	0.953034	0.80169	0.86131	0.752931	0.785152	0.587597	0.382507
1979	0.14708	0.25195	0.48919	0.615015	0.87491	0.752305	0.675383	0.86815	0.626954	0.661616	0.551125	0.440148
1980	0.21167	0.14942	0.36188	0.47532	0.45636	0.538204	0.497584	0.4273	0.587012	0.652808	0.453688	0.328718
1981	0.21815	0.26116	0.58482	0.877075	0.9758	0.753422	0.73694	0.50828	0.398395	0.358049	0.526415	0.697955
1982	0.20714	0.14647	0.31619	0.401207	0.40487	0.399665	0.40682	0.45065	0.430016	0.554897	0.643717	0.502252
1983	0.2988	0.38688	0.68461	1.04711	0.68541	0.635992	0.722891	0.58576	0.671414	0.637152	0.549255	0.401475
1984	0.31198	0.39538	0.57639	0.785613	0.87199	0.788431	0.876516	0.60747	0.539397	0.605959	0.639135	0.321038
1985	0.28668	0.41435	0.76277	1.077012	1.1474	1.055396	1.071548	0.9538	1.071877	1.032854	0.811949	0.555193
1986	0.54506	0.65362	0.92454	1.261094	1.30607	1.224313	1.132783	1.15196	1.095149	1.123915	0.84111	0.740392
1987	0.72692	0.82438	1.5027	1.469345	1.47114	1.402664	1.223399	1.1717	1.215254	1.009834	0.856588	0.713414
1988	0.56353	0.69212	1.29215	1.456526	1.51599	1.598786	1.181832	1.2925	1.349431	0.908392	0.981956	0.906928
1989	0.70233	0.88463	1.2217	1.474176	1.36707	1.264688	1.207446	1.1332	1.026855	0.950497	0.927405	0.738454
1990	0.74871	0.6341	0.99012	1.09141	1.02214	0.839432	0.68325	0.8099	0.62859	0.807105	0.511383	0.335865
1991	0.25062	0.34693	0.54417	0.967285	1.114	1.0711	1.16874	0.93685	0.915335	1.041006	1.192259	0.375983
1992	0.36357	0.50718	0.85191	0.815913	0.82773	0.936063	0.711642	0.64349	0.673722	0.70891	0.50885	0.384157
1993	0.30606	0.31209	0.54857	0.676829	0.68518	0.784054	0.661467	0.67069	0.703293	0.58186	0.548998	0.360162
1994	0.30987	0.28639	0.64155	0.739019	0.88447	0.922485	0.751913	0.7595	0.796938	0.604784	0.516754	0.505927
1995	0.31989	0.25713	0.50824	0.574388	0.63276	0.625896	0.515836	0.54931	0.533942	0.586844	0.456588	0.351446
1996	0.3134	0.38949	0.64233	0.633936	0.72049	0.649065	0.736156	0.65818	0.629024	0.661161	0.642549	0.420616
1997	0.51365	0.43342	0.67036	0.967638	0.92378	0.856042	1.01539	0.82435	0.907649	0.84057	0.728112	0.503215
1998	0.4101	0.43513	0.96141	0.996416	0.88856	0.796495	0.842335	0.74588	0.839241	0.729476	0.827278	0.613496
1999	0.45008	0.5039	0.96278	1.019877	1.1047	1.076386	1.107466	0.96901	0.950063	0.937823	1.064739	0.70735
2000	0.53126	0.5888	1.1025	0.881036	1.14926	1.069938	1.033746	1.11871	0.947899	0.996365	1.008763	0.549524
2001	0.64705	0.76046	1.11559	0.863163	1.27013	1.195021	1.042529	1.0018	0.941882	0.975415	1.126935	0.671673
2002	0.75222	0.70433	1.15051	1.570418	1.48988	1.273642	1.251434	1.346	1.088774	1.228311	1.068764	0.705266
2003	0.80095	0.65002	1.12241	1.199247	1.36291	1.47839	1.329618	1.10971	1.289799	1.149723	1.216319	0.771141
2004	0.67487	0.63557	1.24149	1.387077	1.11912	1.547938	1.331882	1.37867	1.094666	1.140955	0.920455	1.044957
2005	0.65404	0.7432	1.10954	1.109536	1.2931	1.350938	1.095715	1.02362	1.011054	0.98707	0.922922	1.464362
2006	0.77939	0.62178	0.90609	0.960951	1.25594	1.176492	1.077678	1.26114	0.988436	1.082333	0.858725	0.737469
2007	0.82476	0.50129	0.90069	0.925702	1.16142	1.245872	1.117984	1.02731	1.232199	1.194281	0.987417	0.881078
2008	0.59803	0.63541	0.92318	1.204072	1.14784	1.208103	1.165885	0.9505	0.852921	0.841322	0.588451	0.664842
2009	0.4052	0.36529	0.54251	0.606895	0.9173	0.901634	0.699979	0.8445	0.945888	1.003434	1.063339	0.830663
2010	0.75185	0.51871	1.0738	1.065965	1.07949	1.004805	0.980431	0.9353	1.059442	0.765509	0.755261	1.035019
2011	0.68881	0.38892	1.22968	0.838227	1.04977	1.030025	1.037893	0.86318	0.925156	0.900012	0.897152	1.166198
2012	0.94977	0.6931	0.91857	0.910238	1.07545	1.314281	1.179428	1.01994	1.158725	1.065146	0.681686	0.458713
2013	0.6438	0.52637	0.76088	1.08129	1.29928	1.099559	1.109244	0.95294	0.971739	1.089184	0.882285	0.691146
2014	0.7927	0.56685	0.77762	0.93793	1.08156	1.216052	1.438385	0.84397	1.112375	1.036423	1.034585	0.887973
2015	0.76476	0.48886	0.98458	1.230164	1.10494	1.255866	1.401296	1.26554	1.085773	1.132101	0.966645	0.919223
2016	0.6064	0.59857	1.09248	1.213903	1.24722	1.21136	1.180149	1.2267	1.355273	1.352045	1.189864	1.406004
2017	0.92067	0.61652	1.24097	1.083974	1.23429	1.289906	1.23161	1.08551	1.210647	1.051713	0.898975	1.024469
2018	0.88007	0.58933	1.18624	1.036175	1.17986	1.233026	1.177301	1.03765	1.157261	1.005336	0.859334	0.979293

Ontario GDP in 2007 million $

	Month											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1971	184654.7	189962	187894.2	186696.1	194090.8	200619.2	200350.5	200279.5	194159	201483.8	199795.9	204411.6
1972	201810.9	200571	205741.9	202299.7	205587.5	212647.4	210133.3	208286.2	204607.2	209455.7	212579.6	215658.3
1973	211901.4	217207	219613.8	212454.1	215589.4	222630.4	218721.6	218350.9	211655.3	217922.6	220826.7	222542.9
1974	222008.9	224999	226406.2	216950.2	223989.5	228457.6	226456.4	227280.3	221739.9	224198.2	223619.6	224967.7
1975	225171.6	226564	219706.8	223913.7	223734.6	227168.4	227412.9	224755.7	224678.6	225006.7	227616	232445.3
1976	234296.9	235769	239114.1	241160.9	241812.3	241419.2	242729.2	244847.5	244132.8	239721.4	245130.8	243217
1977	244687.6	247206	248013.7	247079.2	249151.5	249644.1	252731.9	249477.4	248923.4	253494.1	256160.1	256026.4
1978	254698.7	258204	256625.4	256507.3	259544.8	262822.7	259757.8	260530.3	263288	261455	265636.5	266001.8
1979	267608.7	273173	271438.7	266358.6	265669.1	271052.8	271985.2	273525.1	268528.7	270647.6	267478.6	267361.2
1980	271736.2	263989	268886	265395.3	267346.1	268227	265756.6	264168.2	266023.5	270633.2	273649.9	271722.4
1981	274802.2	277561	281415.2	280106.2	282669.1	279651.7	287819.5	278079.5	282234	285323.4	286409.5	282853.1
1982	276244.3	282020	275081.7	273760	275201	271887	264786.7	269678.1	269685.3	270982.4	272843.1	268154.5
1983	273202.2	272430	275708.2	281847.8	283481.5	286439.7	290982.8	293043.8	295546.4	290777	296070.4	298518.6
1984	302099.7	300253	300146.4	307038.5	309446.9	310061.6	312603.2	318545.8	316047.1	323216.4	323765.3	319117.3
1985	322580.3	322181	325093.5	321551.3	326458.4	326312.3	326536.5	325522.7	337106.8	331282.2	336214.2	333252.6
1986	340270.7	337572	329112.9	343232.6	341007.6	333545.8	343177.6	339146.7	342952.8	343255.5	341453.3	344432.2
1987	345549.5	349893	348116.4	351365.6	354015.1	355788.3	360563.2	356355	361767.9	361809.3	366573.7	365494.9
1988	365276.4	365254	374042.7	372483	368535	364389	371148	372806.1	377688.9	379115.5	379643.7	382233.8
1989	386184.3	380949	379884.1	387691.5	386530	380538.5	382668.4	383699.5	391443.1	385779.4	387394.5	387898.1
1990	383216.4	387026	385711.8	384382.1	382962.6	377944.3	376716.7	378400	370354.3	377725.5	370921.6	370589.9
1991	365086	362539	358267.2	360875.8	369017.5	365424.7	366465.3	366893.9	372140.8	370155	372386.3	363636.7
1992	366136.5	371572	371217.2	370835.4	368597.2	367504.4	362209.1	367360.4	374472.5	376493.7	379899.8	372065.4
1993	370417.6	373389	374836.2	375863	374676.2	372486.8	371236.1	376154.1	384173.8	379918.3	383723	375809.7
1994	385146	388978	390485.2	393005.1	392512.3	390590.5	394970.4	398141.5	406240.1	406618.2	410296.1	401448.8
1995	402470.7	407254	410006.1	409152.3	407860.1	405475.6	403848.2	409032.7	417749.2	413128.3	417260.6	408650.1
1996	408152.7	413004	415794.6	416863.5	415547	413117.5	411609.9	416894	425778.1	419590.1	423787	415041.9
1997	419224.7	424207	427073.9	430996.7	429635.6	427123.7	435769.3	441363.6	450769.1	450394.7	454899.7	445512.6
1998	450796.6	456154	459236.9	457621.5	456176.3	453509.2	449574.8	455346.3	465049.8	457298.6	461872.7	452341.6
1999	464635.4	470158	473334.8	483353.7	481827.2	479010.1	486652.7	492900.3	503404	506373.3	511438.3	500884.4
2000	505655.9	511666	515123.3	519959.9	518317.8	515287.4	514637.9	521244.7	532352.5	523362.1	528597	517689
2001	518752.3	524918	528464.9	530121	528446.8	525357.2	518853.5	525514.4	536713.2	533245.8	538579.6	527465.6
2002	534751.1	541107	544763.2	544008.2	542290.2	539119.6	541297.9	548246.9	559930.2	551724	557242.6	545743.5
2003	549043.2	555569	559323	554480.6	552729.5	549497.9	541241.8	548190.1	559872.1	551833	557352.7	545851.3
2004	549402.6	555932	559689	567526.4	565734.1	562426.5	565000.5	572253.8	584448.6	576422.9	582188.5	570174.6
2005	573417.5	580233	584153.7	586169.9	584318.7	580902.4	578892.7	586324.3	598819	592460.4	598386.4	586038.3
2006	591191.2	598218	602260.1	599995.9	598101	594604.1	586178.9	593704.1	606356	597151.7	603124.6	590678.7
2007	594211.4	601274	605336.8	604463.9	602555	599032.1	592991.6	600604.2	613403.2	602484.2	608510.5	595953.4
2008	597522.6	604624	608710	608797.5	606874.8	603326.7	594896.6	602533.7	615373.8	592837.5	598767.3	586411.3
2009	577982	584851	588803.5	580336.3	578503.5	575121.2	570131.7	577450.9	589756.4	590801.9	596711.3	584397.8
2010	591074.4	598100	602141.1	601360.4	599461.2	595956.4	592587.9	600195.4	612985.7	602738.2	608767.1	596204.7
2011	603088.8	610257	614380.5	611040.6	609110.8	605549.6	609026	616844.5	629989.5	622167.6	628390.8	615423.5
2012	616091.2	623414	627626.2	625279.2	623304.5	619660.3	613209.1	621081.3	634316.6	623047.9	629279.9	616294.2
2013	619473.6	626836	631072.1	632143	630146.6	626462.4	623899.7	631909.1	645375.2	638556.2	644943.3	631634.5
2014	633347.1	640875	645205.3	648154.8	646107.9	642330.3	642467.2	650715	664581.8	657815.6	664395.3	650685.1
2015	652026.5	659776	664234.4	664098.4	662001	658130.6	656989.4	665423.7	679603.9	672895.8	679626.4	665601.8
2016	671614.7	679597	684189.3	682425.5	680270.4	676293.1	673499.3	682145.5	696682.1	686803.1	693672.8	679358.3
2017	683709.2	691835	696510.3	698242.7	696037.6	691968.2	689188	698035.7	712910.9	705209.6	712263.4	697565.4
2018	700909.4	709240	714032.6	714012.1	711757.2	707595.8	703119.7	712146.2	727322.1	717483.8	724660.4	709706.5

Components of Manufacturing in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Manufacturing	74958	76494	75663	78464	77818	77673	78466	78983	79,574	80,309	81,363	82,588
Food	11373	11442	11584	11907	12087	12258	12388	12456	12,547	12,699	12,940	13,250
Textiles, Clothing & Leather	948	935	839	877	844	863	880	889	896	907	924	943
Wood	1082	1106	1161	1210	1222	1216	1205	1206	1,229	1,244	1,255	1,258
Paper	2509	2479	2338	2417	2410	2428	2423	2430	2,438	2,455	2,483	2,521
Printing	2296	2341	2403	2419	2293	2247	2262	2258	2,267	2,289	2,327	2,380
Petroleum & Coal	1591	1573	1484	1494	1427	1374	1407	1435	1,461	1,483	1,504	1,523
Chemical	6134	6343	6427	6520	6778	6879	6974	7077	7,102	7,150	7,235	7,345
Plastics & Rubber	4450	4553	4940	4925	5072	5105	5182	5251	5,304	5,356	5,421	5,487
Non-Metallic Minerals	1811	1805	1723	1720	1645	1591	1631	1662	1,690	1,714	1,739	1,760
Primary Metals	5450	5371	5246	5770	5393	5324	5348	5379	5,385	5,403	5,448	5,507
Fabricated Metals	5504	5756	5637	5860	5599	5586	5610	5645	5,699	5,755	5,823	5,894
Machinery	5589	5823	5645	5731	5492	5392	5451	5490	5,570	5,637	5,703	5,758
Computers	4405	3677	3167	3320	3382	3400	3457	3483	3,504	3,530	3,568	3,613
Electrical Products	1844	1771	1710	1781	1730	1731	1760	1768	1,781	1,796	1,816	1,838
Transportation Equipment	16366	18058	17395	18578	18326	18148	18296	18346	18,457	18,604	18,828	19,094
Furniture	1799	1814	1934	2004	2049	2053	2093	2096	2,107	2,130	2,170	2,223
Miscellaneous	1808	1645	2029	1931	2069	2077	2099	2112	2,138	2,159	2,179	2,195

Components of Services in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wholesale Trade	37338	38662	38732	40727	41224	42257	43098	44221	45,381	46,593	47,960	49,397
Retail Trade	29738	29562	30494	31710	32651	33818	34761	35885	36,900	37,894	38,952	40,002
Transportation, Warehousing	16366	18058	17395	18578	18326	18148	18296	18346	18,457	18,604	18,828	19,094
Information, Culture	21417	21567	21925	21990	21953	22645	23157	23693	24,175	24,644	25,155	25,660
Finance, Insurance	51629	52786	55100	57440	60516	62352	63928	65426	66,867	68,398	70,172	72,065
Professional Services	35337	35879	36665	37814	38576	39868	41256	42260	43,336	44,314	45,293	46,188
Other Business Services	103510	104191	107086	108236	112028	116447	119688	122851	125,947	128,658	131,262	133,513
Education	33292	33975	34407	34557	35209	36153	36911	37720	38,380	39,117	40,019	41,013
Health, Social Assistance	39292	39631	40145	40597	41309	42253	43296	44276	45,105	46,038	47,179	48,443
Arts, Entertainment, Rec.	4369	4369	4479	4516	4788	4891	5016	5126	5,230	5,317	5,397	5,462
Accommodation	10589	10861	11150	11650	11670	12092	12389	12635	12,924	13,137	13,301	13,391
Other Services	10921	11118	11538	11809	11938	12260	12498	12747	13,063	13,276	13,415	13,455
Public Administration	42411	41733	41483	41894	42312	43523	44373	45376	46,352	47,244	48,155	48,995
Total Services	436209	442389	450599	461518	472500	486708	498666	510562	522,116	533,233	545,086	556,678

Agriculture/Forestry in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Agriculture & Fishing	4683	4689	4961	4968	4781	4966	5088	5196	5,312	5,446	5,590	5,734
Forestry & Logging	691	679	748	798	849	870	904	924	939	954	971	988

Other Components in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Mining	6548	6007	6781	7111	6844	6808	7029	7093	7,090	7,209	7,342	7,475
Construction	33891	34823	33951	34370	37099	38551	39485	40263	41,026	41,669	42,284	42,789
Utilities	12014	11542	12178	12198	12151	12145	12385	12677	12,929	13,088	13,182	13,186

Gross Electricity Usage, Including Losses, in GWh

	Retail Load	LDC Load
1970	8,807.5	
1971	9,396.5	
1972	10,433.2	
1973	11,279.7	
1974	12,311.7	
1975	13,190.4	
1976	14,479.8	
1977	14,896.6	8,410.5
1978	15,469.0	8,694.9
1979	16,066.7	8,897.9
1980	16,356.9	9,065.5
1981	16,233.3	9,336.9
1982	16,474.3	9,436.7
1983	17,086.9	9,920.1
1984	17,879.8	10,352.3
1985	18,477.2	10,726.5
1986	19,506.6	11,151.1
1987	20,378.4	11,742.5
1988	21,936.4	12,529.7
1989	23,246.6	13,142.0
1990	23,714.6	12,905.7
1991	23,087.5	13,091.1
1992	22,982.9	12,784.8
1993	22,128.7	12,959.9
1994	22,139.3	13,173.9
1995	21,914.8	13,336.1
1996	22,051.9	13,327.3
1997	22,605.4	13,470.8
1998	22,451.6	13,879.4
1999	22,137.5	14,204.1
2000	22,537.0	14,449.1
2001	22,688.5	14,566.0
2002	22,398.9	15,133.7
2003	22,711.2	14,572.3
2004	22,768.4	14,740.0
2005	23,182.3	14,488.7
2006	22,688.3	14,434.3
2007	23,356.8	14,894.9
2008	23,136.1	14,687.8
2009	22,930.5	14,772.5
2010	22,674.7	13,877.3
2011	22,594.4	13,352.0
2012	22,614.7	13,822.7
2013	23,100.3	13,319.1
2014	23,823.7	13,386.0
2015	23,743.2	12,737.9
2016	23,507.7	12,287.2

	Electricty Price	Natural Gas Price
2005	80,706.7	34,659.3
2006	80,706.7	40,061.4
2007	74,498.5	36,066.6
2008	74,498.5	34,795.5
2009	74,498.5	30,187.9
2010	86,914.9	29,166.5
2011	80,706.7	25,898.0
2012	86,914.9	24,513.5
2013	93,123.1	23,219.7
2014	100,556.8	22,379.9
2015	102,604.8	18,566.7
2016	104,678.2	19,338.4
2017	85,160.3	20,339.7
2018	81,427.7	20,658.9
2019	81,427.7	20,909.7
2020	81,427.7	21,115.0
2021	81,427.7	21,343.0
2022	81,427.7	21,479.8

TAB 5

Vulnerable Energy Consumers Coalition Interrogatory # 68

Issue:

Issue 43: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

Reference:

E1-02-01 Page: 4 (Lines 7-15)
E1-02-01 Pages 6-8
E1-02-01 Pages 37-38
E1-02-01-01

Interrogatory:

a) With respect to the Broad Annual Series set out at pages 1-2 of Attachment 1, please provide a schedule that sets out for each variable (excluding CDD, HDD, Ontario GDP and Ontario Housing Starts) the following:
   i. The source of the actual and forecast data
   ii. The date the forecast data was published
   iii. An indication as to which years are actual vs. forecast values.
   iv. The actual 2016 values for those variables where Attachment 1 was based on forecast values.
   v. An update to the forecast if a more recent forecast is now available.

b) With respect to Tables E.2 and E.3 please provide a schedule that sets out:
   i. The actual 2016 Ontario GDP growth rate and Housing Starts.
   ii. The most recent forecasts from each source and resulting average through to 2022.

c) With respect to the monthly values set out at pages 3-4 of Attachment 1, please provide schedules that set out for each variable:
   i. The source of the actual and forecast data
   ii. The data the forecast data was published
   iii. An indication as to which years are actual vs. forecast values.
   iv. An update to the forecast if a more recent forecast is now available.

Response:

a)

i. For the Ontario population, actual data is from Statistics Canada, and forecast data is based on average growth rate from IHS Global Insight and Centre for Spatial Economics. For Ontario disposable income, please see Exhibit E1, Tab 2, Schedule 1, Appendix B, lines 16-22. For Ontario commercial GDP, actual data is from IHS Global Insight and, for forecast data, please refer to Exhibit I-47-CME-80 a.ii). For Ontario industrial GDP, the actual is from IHS Global Insight, for forecast, please refer to Exhibit I-47-CME-80 a.iii). For Ontario number of households, the historical is based on cumulating housing starts net of demolitions and, for forecast please refer to Exhibit I-47-CME-80 a.iv).

ii. Please see Exhibit E1, Tab 2, Schedule 1, page 7, lines 1-6.

iii. Figures prior to 2017 are actual data, except for Ontario GDP which is partially actual and partially forecast. 2017 figures are partially actual and partially forecast.

iv. Please see Exhibit I-46-Staff-219 Table E.3 for 2016 actual GDP.

v. Please see the corresponding tables in Exhibit I-46-Staff-219.

b)

i. In 2016, GDP growth was 2.7% and housing starts was 75.3 thousand units.

ii. Please see Exhibit I-46-Staff-219, Tables E2 and E.3.

c)

i. Please see Exhibit E1, Tab 2, Schedule 1, Appendix A lines 14-22.

ii. Please see response to question a) ii.

iii. Please see response to question a) iii.

iv. Please see Exhibit I-46-Staff-219, Attachment 1.

TAB 6

OEB Staff Interrogatory # 219

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
E1-02-01 Page: 7

Interrogatory:
The load forecast was last updated June 7, 2017 using data available in January 2017. Since then, Hydro One prepared a partial update of the application in December 2017.

Please file an update of the load forecast using 2017 actual consumption information, or as much of 2017 as possible. Please also update for updates to explanatory variables including actual and normal weather, as well as historic and forecast economic data.

Response:
The following material is provided based on an update to the load forecast using 2017 actual information:

- Updated Forecast and CDM Tables 3, 4, 7, and 8 originally provided in Exhibit E1, Tab 2, Schedule 1;
- Updated Tables E2, E3, E4, E5, E6, E7, E8a, E8b, and E9 originally provided in Appendix E to that Exhibit; and
- Updated regression results for models in Appendix A and Appendix B to that Exhibit.

Updated explanatory variables including actual and normal weather, as well as historic and forecast economic data are provided in the MS Excel attachment to this response.

Table 3 (Updated) - Hydro One Distribution Load and Number of Customers

Year	GWh Delivery Forecast	Distribution Customer Count
2018	35,055	1,297,878
2019	34,619	1,305,398
2020	34,543	1,312,936
2021	35,381	1,380,394
2022	35,357	1,388,694

Table 4 (Updated) - CDM Impact on Hydro One Distribution Load (GWh)

	Retail	ST Customers		
Year	Customers	Direct	LDC	Total
2015	1,619	169	856	2,644
2016	1,810	195	929	2,935
2017	1,982	209	957	3,149
2018	2,171	229	1,056	3,456
2019	2,377	252	1,153	3,782
2020	2,504	267	1,219	3,990
2021*	2,639	283	1,208	4,130
2022*	2,695	289	1,225	4,210

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

Table 7 (Updated) - Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2015	21,822	17,241	39,063
2016	21,896	17,178	39,074
2017	21,646	17,322	38,969
2018	21,552	17,342	38,894
2019	21,483	17,296	38,779
2020	21,510	17,370	38,880
2021*	22,573	16,937	39,511
2022*	22,646	16,921	39,567
Load Impact of CDM			
2015	1,619	1,025	2,644
2016	1,810	1,124	2,935
2017	1,982	1,166	3,149
2018	2,171	1,286	3,456
2019	2,377	1,406	3,782
2020	2,504	1,486	3,990
2021*	2,639	1,491	4,130
2022*	2,695	1,514	4,210
Load Forecast After Deducting Impact of CDM			
2015	20,203	16,216	36,419
2016	20,085	16,054	36,139
2017	19,664	16,156	35,426
2018	19,382	16,056	35,055
2019	19,106	15,890	34,619
2020	19,006	15,885	34,543
2021*	19,934	15,446	35,381
2022*	19,951	15,406	35,357

Note. All figures are weather-normal.
* Includes Acquired Utilities.

Table 8 (Updated) - One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Bound	Forecast	Upper Bound
2016	36,139	36,139	36,139
2017	35,426	35,426	35,426
2018	34,447	35,055	35,646
2019	33,801	34,619	35,450
2020	33,578	34,543	35,512
2021*	34,149	35,381	36,600
2022*	33,892	35,357	36,874

* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

1 **APPENDIX E**

2

3 **Table E.2 (Updated) - Consensus Forecast for Ontario GDP and Housing Starts**

4

Survey of Ontario GDP Forecast (annual growth rate in %)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2017)	3.0	2.3	2.3	2.1	2.0	2.0
Conference Board (Nov 2017)	3.0	1.9	1.7	1.9	1.9	1.9
U of T (Oct 2017)	2.8	2.2	2.2	2.3	2.3	2.3
C4SE (Aug 2017)	2.8	2.0	2.5	2.2	1.7	2.0
CIBC (Dec 2017)	3.0	2.3	1.7			
BMO (Jan 2018)	2.8	2.4	2.0			
RBC (Sep 2017)	2.9	2.1	1.8			
Scotia (Jan 2018)	2.9	2.3	1.8			
TD (Dec 2017)	2.9	2.3	1.9			
Desjardins (Dec 2017)	3.0	2.3	1.8			
Central 1 (Dec 2017)	2.8	2.5	2.3			
National Bank (Jan 2018)	3.0	2.6	1.5			
Laurentian Bank (Aug 2017)	2.2	2.0				
Average	**2.9**	**2.2**	**2.0**	**2.1**	**2.0**	**2.1**

Survey of Ontario Housing Starts Forecast (in 000's)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2017)	81.0	71.2	63.5	62.9	61.3	59.8
Conference Board (Nov 2017)	81.7	74.7	69.3	70.4	71.3	70.8
U of T (Aug 2017)	80.6	68.1	69.3	71.2	72.4	73.3
C4SE (Jan 2017)	72.8	81.0	79.8	78.9	78.7	75.8
CIBC (Dec 2017)	78.0	70.0	63.0			
BMO (Jan 2018)	80.2	76.0	70.0			
RBC (Sep 2017)	80.1	68.8	70.0			
Scotia (Jan 2018)	79.0	75.0	71.0			
TD (Dec 2017)	81.1	73.1	69.4			
Desjardins (Dec 2017)	82.6	68.9	67.7			
Central 1 (Dec 2017)	80.7	76.6	78.4			
National Bank (Jan 2018)	80.4	69.0	65.0			
Laurentian Bank (Aug 2017)	72.0	71.0				
Average	**79.2**	**72.6**	**69.7**	**70.9**	**70.9**	**69.9**

5 **Forecast updated on January 20, 2018**

Table E.3 (Updated) - Economic Variables for Ontario

Year	GDP (2007 M$)	% change	Population (1,000's)	% change	Housing (1,000's)	% change
2005	586,000	3.2	12,528	1.1	77.8	-7.9
2006	596,942	1.9	12,662	1.1	74.4	-4.4
2007	601,735	0.8	12,764	0.8	68.0	-8.6
2008	601,717	0.0	12,883	0.9	75.6	11.2
2009	582,941	-3.1	12,998	0.9	49.5	-34.5
2010	600,135	2.9	13,135	1.1	61.2	23.7
2011	614,590	2.4	13,264	1.0	68.5	11.9
2012	622,725	1.3	13,414	1.1	63.2	-7.8
2013	631,882	1.5	13,556	1.1	59.3	-6.3
2014	648,763	2.7	13,680	0.9	58.3	-1.7
2015	667,659	2.9	13,790	0.8	69.9	20.0
2016	685,008	2.6	13,976	1.4	75.3	7.7
2017	704,570	2.9	14,193	1.6	79.2	5.2
2018	720,361	2.2	14,375	1.3	72.6	-8.4
2019	734,437	2.0	14,553	1.2	69.7	-4.0
2020	750,103	2.1	14,720	1.1	70.9	1.6
2021	764,857	2.0	14,879	1.1	70.9	0.1
2022	780,618	2.1	15,034	1.0	69.9	-1.4

Table E.4 (Updated) - Number of Customers History and Forecast

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	106	248	477	633	893	907	1,004	1,119	1,236	1,356	1,465	1,562
General Service - Demand Billed	7,183	6,550	6,669	6,504	6,098	5,323	5,231	5,239	5,276	5,320	5,365	5,412
General Service - Energy Billed	98,095	98,513	98,568	95,503	87,686	88,878	88,523	87,902	87,625	87,464	87,424	87,505
Residential - Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	447,647	447,029	450,545	454,013	457,450	460,812
Residential - Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,514	328,159	329,568	330,939	332,412	333,941
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	147,253	147,537	147,748	147,946	148,130	148,287
Sub-transmission *	794	795	800	882	838	804	805	807	810	813	824	827
Urban General Service - Demand Billed	1,272	1,185	1,184	1,167	1,893	1,715	1,711	1,735	1,739	1,746	1,755	1,766
Urban General Service - Energy Billed	11,650	12,308	12,307	10,807	17,703	17,780	17,747	18,000	18,050	18,123	18,220	18,342
Urban Residential	159,086	167,672	169,795	170,796	208,639	213,199	215,844	226,816	229,377	231,914	234,449	236,957
Street Light *	4,771	4,724	4,804	5,104	5,118	5,251	5,428	5,462	5,495	5,528	5,568	5,602
Sentinel Light *	31,447	30,504	30,380	26,670	25,689	24,364	22,761	22,582	22,407	22,220	22,270	22,150
Unmetered Scattered Load *	5,504	5,512	5,562	5,104	5,624	5,537	5,455	5,490	5,522	5,555	5,799	5,830
Acquired Residential	35,434	35,562	35,892	36,212	36,382	36,487	36,664	37,000	37,257	37,509	37,763	38,015
Acquired General Service - Energy Billed	4,361	4,357	4,340	4,349	4,350	4,348	4,282	4,280	4,278	4,276	4,274	4,272
Acquired General Service - Demand Billed	307	309	322	321	330	336	292	298	303	309	315	321
Acquired Urban Residential	13,709	13,862	14,020	14,175	14,353	14,515	14,703	14,887	15,058	15,227	15,397	15,565
Acquired Urban General Service - Energy Billed	1,180	1,207	1,222	1,243	1,246	1,263	1,257	1,271	1,284	1,297	1,310	1,323
Acquired Urban General Service - Demand Billed	193	185	182	189	193	193	201	205	205	205	205	205
Sum: Includes Newly Acquired for 2021-2022 only	1,247,577	1,255,963	1,267,680	1,267,171	1,274,369	1,283,351	1,289,922	1,297,878	1,305,398	1,312,936	1,380,394	1,388,694

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.5 (Updated) - Hydro One Distribution Load History and Forecast in GWh

Year	Actual/Forecast GWh	Growth	Normalized Weather GWh	Growth
2011	37,641	-0.8	38,062	3.2
2012	37,627	0.0	37,419	-1.7
2013	37,621	0.0	37,418	0.0
2014	37,798	0.5	37,091	-0.9
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	35,101	-2.1	35,426	-2.0
2018	35,055	-0.1	35,055	-1.0
2019	34,619	-1.2	34,619	-1.2
2020	34,543	-0.2	34,543	-0.2
2021*	35,381	2.4	35,381	2.4
2022*	35,357	-0.1	35,357	-0.1

Table E.6 (Updated) - Actual Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	26	27	28	29	30	31
General Service - Demand Billed	3,100	2,888	2,825	2,928	2,394	2,343	2,482	2,458	2,418	2,401	2,392	2,391
General Service - Energy Billed	2,306	2,518	2,398	2,358	2,189	2,132	2,239	2,207	2,154	2,120	2,096	2,081
Residential - Medium Density	4,402	4,396	4,553	4,499	4,930	4,851	4,596	4,592	4,560	4,569	4,589	4,620
Residential - Low Density	5,491	5,515	5,563	5,541	4,767	4,614	4,418	4,331	4,249	4,207	4,181	4,171
Seasonal	701	666	699	682	671	641	594	585	571	562	555	551
Sub-transmission *	16,787	17,082	16,395	16,599	15,806	15,468	15,143	15,158	15,003	15,026	14,918	14,878
Urban General Service - Demand Billed	686	677	607	628	1,064	1,036	1,020	1,037	1,022	1,016	1,014	1,016
Urban General Service - Energy Billed	397	415	400	382	600	589	597	604	595	591	589	589
Urban Residential	1,541	1,563	1,564	1,528	1,983	1,947	1,833	1,910	1,900	1,908	1,920	1,937
Street Light *	125	127	125	122	122	122	100	99	99	99	109	109
Sentinel Light *	19	19	20	20	21	21	14	14	13	13	14	14
Unmetered Scattered Load *	23	23	23	23	24	24	29	29	29	30	31	31
Acquired Residential	308	302	305	303	301	300	297	298	295	293	290	287
Acquired General Service - Energy Billed	114	111	110	111	110	109	111	111	109	108	107	106
Acquired General Service - Demand Billed	270	233	232	241	235	237	237	239	237	236	236	236
Acquired Urban Residential	105	106	107	106	102	100	100	99	98	97	95	94
Acquired Urban General Service - Energy Billed	41	43	44	43	43	43	41	42	41	41	41	42
Acquired Urban General Service - Demand Billed	164	128	129	136	136	138	111	147	145	145	146	146
Sum: Includes Acquired Utilities for 2021-2022 only	35,587	35,901	35,186	35,327	34,586	33,804	33,093	33,051	32,641	32,572	33,354	33,330

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.7 (Updated) - Weather Corrected Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	26	27	28	29	30	31
General Service - Demand Billed	3,150	2,959	2,803	2,769	2,373	2,368	2,515	2,480	2,445	2,432	2,428	2,431
General Service - Energy Billed	2,343	2,580	2,380	2,229	2,169	2,155	2,269	2,218	2,167	2,136	2,114	2,101
Residential - Medium Density	4,466	4,495	4,528	4,453	4,901	4,907	4,645	4,619	4,595	4,612	4,640	4,679
Residential - Low Density	5,571	5,640	5,532	5,485	4,738	4,668	4,464	4,379	4,298	4,256	4,230	4,220
Seasonal	711	681	695	675	667	648	600	585	571	562	555	551
Sub-transmission *	16,901	16,427	16,421	16,271	15,683	15,526	15,243	15,158	15,003	15,026	14,918	14,878
Urban General Service - Demand Billed	697	694	602	594	1,054	1,047	1,034	1,015	995	985	979	976
Urban General Service - Energy Billed	404	425	397	362	595	595	605	593	582	575	571	569
Urban Residential	1,563	1,599	1,555	1,513	1,971	1,969	1,852	1,834	1,817	1,816	1,820	1,829
Street Light *	125	127	125	122	122	122	100	99	99	99	109	109
Sentinel Light *	19	19	20	20	21	21	14	14	13	13	14	14
Unmetered Scattered Load *	23	23	23	23	24	24	29	29	29	30	31	31
Acquired Residential	312	309	303	300	299	300	300	298	295	293	290	287
Acquired General Service - Energy Billed	115	114	109	105	109	109	112	111	109	108	107	106
Acquired General Service - Demand Billed	274	239	230	228	233	237	240	239	237	236	236	236
Acquired Urban Residential	107	108	107	105	101	100	101	99	98	97	95	94
Acquired Urban General Service - Energy Billed	42	44	43	40	42	43	42	42	41	41	41	42
Acquired Urban General Service - Demand Billed	167	132	128	128	135	138	145	147	145	145	146	146
Sum: Includes Acquired Utilities for 2021-2022 only	35,982	35,680	35,094	34,531	34,334	34,068	33,397	33,051	32,641	32,572	33,354	33,330

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.8a (Updated) - Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,331,311	1,964,583	35,730,299	671,097	458,532	48,092,490
2012	80,371	10,060,780	1,914,575	36,409,471	587,036	374,718	48,465,197
2013	127,613	9,893,511	1,878,538	35,537,470	669,854	390,595	47,437,132
2014	161,733	9,883,885	1,872,751	35,781,683	675,645	395,502	47,700,052
2015	165,405	8,536,187	3,076,837	35,473,518	662,107	393,100	47,251,947
2016	171,973	8,118,010	2,846,792	33,699,203	665,454	397,953	44,835,978
2017	188,672	7,848,256	2,745,769	30,285,554	663,744	403,987	41,068,251
2018	197,039	7,860,142	2,698,633	30,587,100	670,226	415,528	41,342,914
2019	202,720	7,748,892	2,639,651	30,273,707	664,657	411,015	40,864,970
2020	209,833	7,709,334	2,605,735	30,321,166	662,985	410,313	40,846,068
2021	216,001	7,694,461	2,581,634	30,540,679	662,217	412,725	42,107,717
2022	222,751	7,704,261	2,567,244	30,461,169	662,705	414,543	42,032,673

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.8b (Updated) - Weather Corrected Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,030,850	1,907,448	34,691,170	651,580	445,197	46,695,764
2012	80,371	9,909,510	1,885,788	35,862,030	578,209	369,084	47,737,698
2013	127,613	9,807,861	1,862,275	35,229,815	664,055	387,214	47,027,563
2014	161,733	9,849,440	1,866,224	35,656,983	673,290	394,123	47,534,380
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	191,621	7,970,925	2,788,685	30,758,917	674,118	410,301	41,710,148
2018	197,039	7,860,142	2,698,633	30,587,100	670,226	415,528	41,342,914
2019	202,720	7,748,892	2,639,651	30,273,707	664,657	411,015	40,864,970
2020	209,833	7,709,334	2,605,735	30,321,166	662,985	410,313	40,846,068
2021	216,001	7,694,461	2,581,634	30,540,679	662,217	412,725	42,107,717
2022	222,751	7,704,261	2,567,244	30,461,169	662,705	414,543	42,032,673

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.9 (Updated): Hydro One Distribution CDM Impacts (GWh) by Rate Class

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Service - Demand Billed	191.0	225.3	271.8	329.5	295.3	328.5	368.1	405.4	445.9	472.0	479.3	491.1
General Service - Energy Billed	193.8	270.1	317.3	367.1	373.6	418.1	461.6	503.4	549.0	575.9	582.3	592.1
Residential - Medium Density	116.6	115.2	114.2	176.6	238.6	269.9	294.3	324.6	358.1	380.0	388.2	398.3
Residential - Low Density	145.4	144.5	139.6	217.5	230.7	256.7	282.9	307.8	334.9	350.6	353.9	359.2
Seasonal	18.6	17.5	17.5	26.8	32.5	35.7	38.0	41.1	44.5	46.3	46.5	46.9
Sub-transmission *	551.2	667.1	731.7	922.0	991.8	1,087.5	1,128.1	1,243.5	1,359.4	1,436.9	1,442.0	1,464.6
Urban General Service - Demand Billed	42.2	52.8	58.3	70.6	131.2	145.2	151.3	165.9	181.6	191.2	193.3	197.3
Urban General Service - Energy Billed	33.4	44.5	52.9	59.5	102.4	115.5	123.1	134.7	147.4	155.1	157.4	160.4
Urban Residential	40.8	41.0	39.2	60.0	96.0	108.3	117.4	128.9	141.6	149.6	152.2	155.7
Acquired Residential	0.9	1.6	2.5	4.2	5.7	6.5	9.1	12.0	14.2	16.6	19.5	20.4
Acquired General Service - Energy Billed	0.7	1.7	2.6	3.9	4.8	5.9	8.5	11.2	13.2	15.6	18.2	19.2
Acquired General Service - Demand Billed	1.0	2.1	3.7	4.8	5.6	7.6	10.6	13.9	16.5	19.3	22.7	23.8
Acquired Urban Residential	0.4	0.7	1.0	1.6	2.1	1.8	2.3	2.8	3.3	3.7	4.2	4.4
Acquired Urban General Service - Energy Billed	0.5	1.0	1.4	2.3	2.9	2.5	3.0	3.6	4.2	4.7	5.4	5.6
Acquired Urban General Service - Demand Billed	4.0	4.3	5.8	7.6	10.9	10.8	10.7	17.0	19.4	22.1	25.2	26.2
Sum: Includes Acquired Utilities for 2021-2022 only	1,333	1,578	1,743	2,230	2,492	2,765	2,965	3,255	3,562	3,758	3,890	3,965

* Includes Acquired Utilities corresponding figure in 2021 and 2022 only.

APPENDIX A
MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses the State-Space approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LRTLT = f (LGDPONT, LBPONT, D98Jan)

where:
LRTLT = logarithm of retail load,
LGDPONT = logarithm of Ontario GDP in constant 1997 dollars,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix E

LBPONT = logarithm of Ontario residential building permits in constant dollar,

- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.110997
K[1]	-0.522702

<u>Non-Seasonal</u>

Factors	SS parameters:
A[1]	0.480758
K[1]	-0.39066
GDPONT[-4]	0.0570301
BPONT[-8]	0.0064509
D98JAN	-0.0152325

R-squared = 0.987, R-squared corrected for mean = 0.987, Durbin-Watson Statistics = 2.24.

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. In fact, the results show that in this case the fit is very good, and therefore there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described on the previous page to generate the forecast for Hydro One Distribution load.

APPENDIX B
ANNUAL ECONOMETRIC MODELS

<u>Retail Load</u>

Annual econometric model for retail load uses personal disposable income per household, relative energy price, and heating degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))+C(4)
*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD(-1)+C(6)*D99A+C(7)*TR
+C(8)*TR2+C(9)*D08ON

where:

LRTLT = logarithm of retail load,

LYPDPHH = logarithm of Ontario personal disposable income per household / house in constant dollar,

- History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on IHS Global Insight housing starts
- Forecast is based on forecasts of disposable income from C4SE, University of Toronto (PEAP) and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016 Outlook
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,
TR2 = TR to power 2,
D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.
C(1) – C(9) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	5.455606	1.417433	3.848934
C(2)	0.501070	0.117024	4.281767
C(3)	-0.018521	0.011507	-1.609597
C(4)	0.059849	0.039567	1.512599
C(5)	0.286743	0.125373	2.287128
C(6)	-0.024341	0.009153	-2.659188
C(7)	-0.095632	0.030017	-3.185970
C(8)	0.002488	0.000682	3.649962
C(9)	-0.013932	0.008698	-1.601852

R-squared = 0.989, Adjusted R-squared = 0.976, Durbin-Watson Statistic = 1.56.

Similar to the regression analysis in the case of the Monthly Econometric model above, the goodness of fit, measured by (Adjusted) R-square for the Annual Econometric Model for retail load, is also found to be close to 1. Therefore the assessment on an annual basis also leads to a forecast outcome which provides consistent results, thus giving confidence to the econometric method.

The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for personal disposable income per household / house, energy prices, and heating degree days and dummy variables, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Distribution load.

Embedded LDC Load

Annual econometric model for embedded LDC load uses number of houses / households, relative energy price, and heating and cooling degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)-LPGASRES(-1))
+C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)-C(4)*C(6)
*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*TR

where:

LEMBLDCS = logarithm of Embedded LDC load,

LHHOLD = logarithm of Ontario number of households / houses,

- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016 Outlook
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

C(1) – C(7) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	1.688480	0.599547	2.816260
C(2)	1.658200	0.898035	1.846476
C(3)	-0.049467	0.016226	-3.048694

C(4)	0.008636	0.009463	0.912634
C(5)	0.013980	0.057537	0.242965
C(6)	0.790897	0.073593	10.74685
C(7)	0.010313	0.004125	2.499980

R-squared = 0.981, Adjusted R-squared = 0.977, Durbin-Watson Statistic = 1.85.

Similar to the regression analysis in the case of the other econometric models noted above, the goodness of fit, measured by (Adjusted) R-square for the Embedded LDC Model, is also found to be close to 1 leading to a forecast outcome which provides consistent results, thus giving confidence to the econometric method. The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for Ontario number of households / houses, energy prices, and cooling and heating degree days and dummy variable, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Embedded LDC load.

TAB 7

Table E.3: Economic Variables for Ontario

Year	GDP (2007 M$)	% change	Population (1,000's)	% change	Housing (1,000's)	% change
2005	585,843	3.2	12,528	1.1	77.8	-7.9
2006	596,797	1.9	12,662	1.1	74.4	-4.4
2007	601,735	0.8	12,764	0.8	68.0	-8.6
2008	601,723	0.0	12,883	0.9	75.6	11.2
2009	582,904	-3.1	12,998	0.9	49.5	-34.5
2010	600,131	3.0	13,135	1.1	61.2	23.7
2011	614,606	2.4	13,264	1.0	68.5	11.9
2012	622,717	1.3	13,414	1.1	63.2	-7.8
2013	631,871	1.5	13,556	1.1	59.3	-6.3
2014	648,890	2.7	13,685	1.0	58.3	-1.7
2015	665,034	2.5	13,797	0.8	69.9	20.0
2016	682,213	2.6	13,983	1.3	74.7	6.8
2017	697,790	2.3	14,144	1.2	70.4	-5.8
2018	712,665	2.1	14,305	1.1	67.3	-4.4
2019	727,128	2.0	14,452	1.0	72.7	8.1
2020	741,175	1.9	14,584	0.9	71.3	-2.0
2021	756,002	2.0	14,709	0.9	71.4	0.2
2022	770,631	1.9	14,847	0.9	69.9	-2.2

Table E.4: Number of Customers History and Forecast

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	106	248	477	633	893	907	1,034	1,152	1,272	1,396	1,508	1,608
General Service - Demand Billed	7,183	6,550	6,669	6,504	6,098	5,323	5,379	5,406	5,457	5,511	5,563	5,612
General Service - Energy Billed	98,095	98,513	98,568	95,503	87,686	88,878	88,817	88,484	88,423	88,405	88,435	88,515
Residential - Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	446,636	446,102	449,958	453,821	457,608	461,272
Residential - Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,695	328,410	330,076	331,741	333,473	335,223
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	149,166	149,485	149,813	150,145	150,445	150,701
Sub-transmission *	794	795	800	882	838	804	806	808	811	814	825	828
Urban General Service - Demand Billed	1,272	1,185	1,184	1,167	1,893	1,715	1,715	1,744	1,753	1,762	1,772	1,783
Urban General Service - Energy Billed	11,650	12,308	12,307	10,807	17,703	17,780	17,763	18,074	18,166	18,268	18,380	18,501
Urban Residential	159,086	167,672	169,795	170,796	208,639	213,199	214,934	225,944	228,666	231,390	234,088	236,737
Street Light *	4,771	4,724	4,804	5,104	5,118	5,251	5,286	5,323	5,364	5,401	5,445	5,481
Sentinel Light *	31,447	30,504	30,380	26,670	25,689	24,364	24,166	23,987	23,822	23,645	23,719	23,605
Unmetered Scattered Load *	5,504	5,512	5,562	5,104	5,624	5,537	5,567	5,597	5,633	5,667	5,944	5,975
Acquired Residential	35,434	35,562	35,892	36,212	36,382	36,487	36,745	37,000	37,257	37,514	37,769	38,018
Acquired General Service - Energy Billed	4,361	4,357	4,340	4,349	4,350	4,348	4,347	4,345	4,343	4,341	4,339	4,337
Acquired General Service - Demand Billed	307	309	322	321	330	336	342	348	353	359	365	371
Acquired Urban Residential	13,709	13,862	14,020	14,175	14,353	14,515	14,676	14,834	14,994	15,153	15,312	15,467
Acquired Urban General Service - Energy Billed	1,180	1,207	1,222	1,243	1,246	1,263	1,280	1,295	1,310	1,324	1,339	1,352
Acquired Urban General Service - Demand Billed	193	185	182	189	193	193	193	193	193	194	194	194
Sum: Includes Newly Acquired for 2021-2022 only	1,247,577	1,255,963	1,267,680	1,267,171	1,274,369	1,283,351	1,291,963	1,300,516	1,309,216	1,317,967	1,386,522	1,395,578

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.5: Hydro One Distribution Load History and Forecast in GWh

Year	Actual/Forecast GWh	Growth	Normalized Weather GWh	Growth
2011	37,641	-0.8	38,062	3.2
2012	37,627	0.0	37,419	-1.7
2013	37,621	0.0	37,418	0.0
2014	37,798	0.5	37,091	-0.9
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	36,244	1.1	36,244	0.3
2018	36,019	-0.6	36,019	-0.6
2019	35,680	-0.9	35,680	-0.9
2020	35,673	0.0	35,673	0.0
2021*	36,363	1.9	36,363	1.9
2022*	36,373	0.0	36,373	0.0

* Includes Acquired Utilities.

TAB 8

Table 1: Summary of Rate Class Review Results

Reclassification	# of Customers
R1 to UR	8,250
R2 to UR	46
R2 to R1	3,887
GSe to UGe	227
GSd to UGd	22

In its Decision on Hydro One's last distribution rate application (EB-2013-0416), the Board agreed that a five-year cycle of review and reclassification may be appropriate for the company in the future. As such, Hydro One proposes to update the rate class review on a province-wide basis every five years to coincide with the resetting of rates as part of a rates application. Individual density zones will be updated in the interim period between rates applications in response to customer inquiries or if material changes within or adjacent to a density zone would impact the rate classification of affected customers.

2. REVIEW OF SEASONAL RATE CLASS

In its Decision dated March 12, 2015 in proceeding EB-2013-0146, the Board directed Hydro One to bring forward a plan for elimination of the Seasonal rate class. Hydro One prepared a "Report on Elimination of the Seasonal Class", which was filed with the Board on August 4, 2015. The report assessed the impact of eliminating the Seasonal class and included consideration of the Board's policy to move residential classes to all-fixed rates starting in 2016, which was issued after the March 12, 2015, Decision. On September 30, 2015, the Board issued an Order requiring Hydro One to apply the OEB's policy on distribution rate design (i.e., move to all-fixed rates) for residential customers to its Seasonal class. In the Board's view, such a change constituted the initial step in the execution of the Board's direction to eliminate the Seasonal class.

TAB 9

JT 3.18-6, Attachment 1, Cells A19-G43

Allocation of the Residential Customers Forecast into Different Rate Classes, Before Reclassification						
Rate Class	2017	2018	2019	2020	2021	2022
R1	446636	451445	456281	461124	465891	470535
R2	330695	332343	334009	335674	337406	339156
Seasonal	149166	149485	149813	150145	150445	150701
UR	214934	216668	218410	220154	221872	223541
Sum	1141431	1149941	1158514	1167097	1175614	1183932
Sum Check	0	0	0	0	0	0
Impact of Reclassification on Retail Residential Rate Classes, Starting in 2018						
Rate Class	2017	2018	2019	2020	2021	2022
R1	0	-5343	-6323	-7303	-8283	-9263
R2	0	-3933	-3933	-3933	-3933	-3933
Seasonal	0	0	0	0	0	0
UR	0	9276	10256	11236	12216	13196
Sum	0	0	0	0	0	0
Allocation of the Residential Customers Forecast into Different Rate Classes, After Reclassification						
Rate Class	2017	2018	2019	2020	2021	2022
R1	446,636	446,102	449,958	453,821	457,608	461,272
R2	330,695	328,410	330,076	331,741	333,473	335,223
Seasonal	149,166	149,485	149,813	150,145	150,445	150,701
UR	214,934	225,944	228,666	231,390	234,088	236,737
Sum	1,141,431	1,149,941	1,158,514	1,167,097	1,175,614	1,183,932
Sum Check	0	0	0	0	0	0

TAB 10

Exhibit I, Tab 43, VECC-71, Attach 1, Rows 49-61

Forecasting Retail Total Number of General Service Customers:						
	2017	2018	2019	2020	2021	2022
Retail Total Number of General Service Customers (Gse + GSd + Uge + UGd)						
Change (1)	-23	34	91	148	204	261
Level (2)	113,673	113,708	113,799	113,946	114,150	114,411

(1) Given the information available at the time of forecast (including residential developments), change in the total number of retail general service customers in 2017 was forecast to be -23, which is significantly more than the 3-year average, -1,766 per year. Based on the economic outlook, the latter figure was considered to be too low. Thus, it was assumed that the average annual change over 3 years before 2014, 261, is a better measure of annual change in long run. Thus, the annual change was assumed to converge towards this value between 2018 and 2022.

(2) Forecast for each year equals change in the total number of customer in that year plus forecast in the prior year.

TAB 11

UNDERTAKING – JT 3.18-1

Topic: Historical CDM Included in Load Forecast Model

Reference
43-VECC-75
43-VECC-65
2016 Ontario Planning Outlook (OPO)
http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Preamble:
The load forecast models use actual load data up to and including 2016 (E1/T2/S1, page 7).

VECC 75, Attachment 1 indicates that the historical CDM savings attributable to Hydro One's service area were derived from CDM savings reported in the OPO.

VECC-65 confirms that the CDM savings shown in in Exhibit E1/Tab 2/Schedule 1, page 42 – Table E.9 are end-use values.

Undertaking

a) VECC 75 indicates that the historical CDM savings were taken from the 2016 Ontario Planning Outlook (OPO). However, the OPO only provides historical CDM savings up to 2015. Please indicate where the 2016 actual savings came from and provide a reference to/copy of the source.

b) Attachment 1 indicates that 16.56% of historical provincial CDM savings due Codes and Standards (C&S) was assumed to be attributable to Hydro One' service area. It also indicated that the 16.56% represents Hydro's One's share of the targeted CDM savings for 2015-2020. Please explain how the use of this percentage appropriately reflects Hydro One's share of historical C&S savings.

c) Also, Attachment 1 shows Hydro One total end use CDM savings for 2016 of 1,866.7 GWh whereas Exhibit E1/Tab 2/Schedule 1, page 42 – Table E.2 shows total end use savings for the same year of 2,765 GWh. Similar differences exist for all historical years. Please reconcile the differences and/or correct the data/forecast as required.

d) Please clarify whether historical savings set out in the OPO are: i) based on the annualized savings from EE programs assuming all savings from a year's programs come into play on January 1st or ii) based on actual savings for the year which would recognize that EE programs are implemented throughout the year?

Response

a) The 2016 CDM assumptions are not actual savings but rather a forecast based on the OPO 2016 information.

b) The verified historical C&S savings are not available from the IESO. Hydro One uses the same Hydro One share of targeted CDM savings for the C&S category to yield a consistent data set over time for modeling purposes.

c) 1866 GWH savings at the end use level is only for Hydro One retail customers, while 2765 GWH includes savings from the embedded LDCs. This same reason applies to data for other historical years

d) Hydro One assumes that the reported results from the IESO are annualized impacts and that savings are in effect on January 1st.

TAB 12

Table E.8b: Weather Corrected Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,030,850	1,907,448	34,691,170	651,580	445,197	46,695,764
2012	80,371	9,909,510	1,885,788	35,862,030	578,209	369,084	47,737,698
2013	127,613	9,807,861	1,862,275	35,229,815	664,055	387,214	47,027,563
2014	161,733	9,849,440	1,866,224	35,656,983	673,290	394,123	47,534,380
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	178,213	8,149,966	2,842,412	33,699,242	677,233	409,686	44,869,833
2018	184,739	8,025,918	2,832,322	33,491,228	672,386	414,168	44,534,208
2019	191,107	7,940,259	2,797,926	33,144,837	667,563	410,184	44,074,129
2020	198,809	7,924,744	2,787,731	33,133,111	664,084	408,125	44,044,395
2021	204,487	7,887,971	2,771,740	33,111,381	663,644	410,749	45,049,972
2022	210,569	7,871,666	2,764,065	33,152,081	662,981	411,710	45,073,072

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.9: Hydro One Distribution CDM Impacts (GWh) by Rate Class

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Service - Demand Billed	191.0	225.3	271.8	329.5	295.3	328.5	364.5	397.3	436.5	461.5	469.6	480.2
General Service - Energy Billed	193.8	270.1	317.3	367.1	373.6	418.1	454.9	493.5	537.6	563.2	568.8	577.6
Residential - Medium Density	116.6	115.2	114.2	176.6	238.6	269.9	296.7	325.4	358.4	379.6	387.2	396.7
Residential - Low Density	145.4	144.5	139.6	217.5	230.7	256.7	278.7	300.0	326.4	341.6	344.7	349.9
Seasonal	18.6	17.5	17.5	26.8	32.5	35.7	38.6	41.8	45.2	47.0	47.2	47.6
Sub-transmission *	551.2	667.1	731.7	922.0	991.8	1,087.5	1,218.2	1,336.7	1,464.4	1,546.4	1,546.5	1,582.0
Urban General Service - Demand Billed	42.2	52.8	58.3	70.6	131.2	145.2	160.4	179.4	197.4	208.9	213.0	218.2
Urban General Service - Energy Billed	33.4	44.5	52.9	59.5	102.4	115.5	126.0	140.3	154.2	163.0	166.1	170.0
Urban Residential	40.8	41.0	39.2	60.0	96.0	108.3	118.6	135.3	149.2	158.2	161.7	165.9
Acquired Residential	0.9	1.6	2.5	4.2	5.7	6.5	9.2	11.9	14.1	16.5	19.3	20.2
Acquired General Service - Energy Billed	0.7	1.7	2.6	3.9	4.8	5.9	8.4	10.9	12.9	15.1	17.7	18.5
Acquired General Service - Demand Billed	1.0	2.1	3.7	4.8	5.6	7.6	10.8	13.9	16.5	19.3	22.7	23.7
Acquired Urban Residential	0.4	0.7	1.0	1.6	2.1	1.8	2.3	2.8	3.1	3.6	4.1	4.2
Acquired Urban General Service - Energy Billed	0.5	1.0	1.4	2.3	2.9	2.5	3.1	3.8	4.3	4.9	5.6	5.9
Acquired Urban General Service - Demand Billed	4.0	4.3	5.8	7.6	10.9	10.8	13.7	16.6	19.0	21.5	24.6	25.6
Sum: Includes Acquired Utilities for 2021-2022 only	1,333	1,578	1,743	2,230	2,492	2,765	3,056	3,350	3,669	3,870	3,999	4,086

* Includes Acquired Utilities corresponding figure in 2021 and 2022 only.

Note: All savings are at end-use level

TAB 13

Exhibit I, Tab 43, VECC-75, Attachment 1, Cells A33-N56

All LDCs savings at end use level by category

			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
15	(15)=(8)/(9)	EE saving %	100.0%	97.1%	97.5%	93.9%	92.6%	85.1%	79.7%	79.8%	71.7%	67.2%	63.6%
16	(16)=1-(15)	C&S saving %	0.0%	2.9%	2.5%	6.1%	7.4%	14.9%	20.3%	20.2%	28.3%	32.8%	36.4%
17	(17)=(14)*(15)	EE program Saving	1,462,523	3,105,412	3,562,442	4,202,387	4,568,050	5,217,504	5,666,402	6,337,185	7,215,814	7,634,870	8,056,714
18	(18)=(14)*(16))	C&S saving	-	91,336	91,345	274,069	365,444	915,352	1,439,086	1,606,610	2,850,692	3,728,658	4,603,837
19	(19)=(17)+(18)	Total	1,462,523	3,196,748	3,653,786	4,476,455	4,933,494	6,132,856	7,105,489	7,943,796	10,066,506	11,363,528	12,660,550
			-	-	-	-	-	-	-	-	-	-	-

HONI EE share

2006-2014: use achieved target % 13.71%
2015-2022: HONI 2015-2020 target share if 16.56 %, to be conservative, use share of 13.71%

HONI C&S share
2006-2020 use share of 16.56%

	2011-2014 Target	2011-2014 Verified Energy savings	2015-2020 Target
HONI target/actual	1,130,210,000	898,318,000	1,159
All LDCs	6,000,000,000	6,552,993,397	7,000
HONI Share	18.84%	13.71%	16.56%

HONI energy savings

			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
20	(20)=(18)*16.56%	C&S	-	15,123	15,124	45,379	60,508	151,559	238,276	266,013	472,001	617,370	762,277
21	(21)=(17)*13.71%	EE program	200,490	425,706	488,358	576,085	626,212	715,242	776,780	868,734	989,181	1,046,627	1,104,456
22	(22)=(18)+(19)	Total	200,490	440,829	503,482	621,463	686,720	866,801	1,015,055	1,134,747	1,461,182	1,663,997	1,866,733

TAB 14

Vulnerable Energy Consumers Coalition Interrogatory # 73

Issue:

Issue 43: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

Reference:

E1-02-01 Page: 9, 20 and 39-42

Interrogatory:

a) Please provide versions of Tables 4, 7, E.5, E.6, E.7 and E.9 that also include the years back to 2005.

b) Please provide a schedule that for the years 2015 and 2022 reconciles the CDM savings as reported in Table 4 with those reported in Table E.9.

Response:

a) In 2008, new rate classes were introduced and the change was implemented over a four-year period. Thus, the data for the new rate classes, total retail, and embedded load only stabilized in 2011. Consequently, consistent data for the tables noted above prior to 2011 are not available.

b) The CDM figures in Table 4 are at the wholesale level and, as such, include distribution losses. In contrast, CDM figures in Table E.9 are at the sales level, so they do not include distribution losses as presented in the following table in GWh.

	At Wolesale Level (From Table 4)					At End Use Level (From Table E.9)		
	Retail	ST Customers				Retail	ST	
Year	Customers	Direct	LDC	Total	Total	Customers	Customers	Total
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=(1)+(4)	(6)=(8)-(7) **	(7)	(8)
2015	1,619	169	856	1,025	2,644	1,500	992	2,492
2016	1,810	195	929	1,124	2,935	1,678	1,088	2,765
2017	1,983	208	1,052	1,260	3,243	1,838	1,218	3,056
2018	2,171	228	1,154	1,382	3,553	2,013	1,337	3,350
2019	2,378	251	1,264	1,514	3,892	2,205	1,464	3,669
2020	2,505	265	1,334	1,599	4,104	2,323	1,546	3,870
2021*	2,642	277	1,322	1,599	4,241	2,452	1,547	3,999
2022*	2,698	284	1,352	1,636	4,334	2,504	1,582	4,086

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.
** Thus retail CDM is calculated as total in table E.9 less ST in Table E.9.

TAB 15

Vulnerable Energy Consumers Coalition Interrogatory # 75

Issue:

Issue 43: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

Reference:

E1-02-01 Page: 9 (Table 4), 11 and 20 (Table 7)
IESO Ontario Planning Outlook (OPO)
EB-2013-0416, Exhibit A, Tab 16, Schedule 3, page 4, Table 1

Preamble: The Application states that the load forecast takes into account CDM detailed information consistent with the IESO Ontario Planning Outlook.

Interrogatory:

a) Please complete the following schedule showing the impact of each year's CDM activity on Retail load consistent with Exhibit E1, Tab 2, Schedule 1, Table 4 and EB-2013-0416, Exhibit A, Tab 16, Schedule 3, Table 1

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

b) Please complete the following schedule showing the impact of each year's CDM activity on ST-Direct customer load consistent with Table 4.

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

c) Please complete the following schedule showing the impact of each year's CDM activity on ST-LDC customer load consistent with Table 4.

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

d) Please explain how the actual savings reported in the parts (a)-(c) for programs implemented in each of the years 2006-2016 were determined and provide the sources used.

e) Please provide a schedule that compares the CDM savings assumed in EB-2013-0416 from CDM initiatives implemented in each of the years 2013-2016 with the actual values used in the current Application.

f) Please provide a breakdown of the 2006-2016 savings from CDM initiatives (per parts (a) to (c)) into the various CDM categories utilized by the IESO (per OPO, page 21). If not possible, please explain how the historical results are consistent with the OPO.

g) Please provide a copy of IESO 2011-2014 verified CDM results (including persistence for the post 2014 period) report for Hydro One Networks. Please reconcile the values reported by the IESO with those attributed to 2011-2014 program savings per part (f).

h) Please provide a copy of the IESO's 2016 verified CDM results report for Hydro One Networks. Please reconcile the values reported by the IESO with those attributed to 2015 and 2016 program savings per part (f).

i) Please provide a copy of Hydro One Networks current 2015-2020 CDM Plan as approved by the IESO. Please reconcile the CDM Plan values for 2017-2020 with those attributed to 2017-2020 program savings per part (f).

j) Please explain how the total CDM savings assumed savings from initiatives undertaken in 2017-2022 were determined and reconcile with IESO's OPO (page 21). Provide copies of any reports/analyses relied upon.

Response:

a) Hydro One cannot complete the above schedule to show the impact of each year's CDM activity by implementation year using the 2016 OPO and other available information, which do not provide CDM savings by implementation year.

b) Please see response to question a) above.

c) Please see response to question a) above.

d) Hydro One incorporates cumulative CDM impacts in the load forecast. Due to data availability issues from IESO, the historical CDM impact can only be "estimated" but not "verified". The detailed calculations of CDM assumptions are provided in the response to question (f) below.

The following table demonstrates what historical CDM impact was added to the actual load. For example, the actual CDM impact in 2015 is the block 1 (C&S)+ block 4 (2006-2011 historical program persistence)+ block 6 (2012-2014 program persistence) + block 7 (2015 program impact). Currently, only the block 7 (2015 target programs' saving) result is verified by the IESO. The impact due to codes and standards (C&S) (block 1), 2006-2014 historical energy efficiency (EE) program persistence savings are not available.

<table>
<tr><th rowspan="2">Category</th><th rowspan="2">Initial activity year</th><th colspan="11">Results by Year</th></tr>
<tr><th>2006</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th></tr>
<tr><td>C&S</td><td>2006-2016</td><td colspan="5">1</td><td colspan="4">1</td><td colspan="2">1</td></tr>
<tr><td rowspan="11">Energy Efficienty Programs</td><td>2006</td><td colspan="5" rowspan="5">2</td><td colspan="4" rowspan="5">3</td><td colspan="2" rowspan="5">4</td></tr>
<tr><td>2007</td></tr>
<tr><td>2008</td></tr>
<tr><td>2009</td></tr>
<tr><td>2010</td></tr>
<tr><td>2011</td><td colspan="5" rowspan="6"></td><td colspan="4" rowspan="4">5 - (2011-2014 verfied results)</td><td colspan="2" rowspan="4">6</td></tr>
<tr><td>2012</td></tr>
<tr><td>2013</td></tr>
<tr><td>2014</td></tr>
<tr><td>2015</td><td colspan="4" rowspan="2"></td><td colspan="2" rowspan="2">7 (2015-2016 verified results)</td></tr>
<tr><td>2016</td></tr>
<tr><td colspan="13">8- TOTAL OF CDM IMPACT</td></tr>
</table>

e) The requested information is provided below:

Energy Saving in MWh

Year	EB-2013-0416	EB-2017-0049
2013	1,593	1,135
2014	1,645	1,461
2015	1,681	1,664
2016	1,723	1,867

f) The table below provides the 2006-2016 CDM savings by category used in our load forecast:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
EE progranms (2006-2016)	200,490	425,706	488,358	576,085	626,212	715,242	776,780	868,734	989,181	1,046,627	1,104,456
Code and Standards	-	15,123	15,124	45,379	60,508	151,559	238,276	266,013	472,001	617,370	762,277

Exhibit I-43-VECC-075 Attachment 1 (MS Excel format) provides the detailed calculation used to determine the savings attributed to "savings from the historical programs" for Hydro One broken down into various OPA categories.

g) The IESO 2011-2014 Verified CDM results are provided in Exhibit I-43-VECC-075 Attachment 2 in MS Excel format.

The 2011-2014 target program actual savings is part of the all historical EE program impact. They cannot be reconciled with OPO savings because OPO categories are different.

h) The IESO 2016 Verified CDM result is provided in Exhibit I-43-VECC-075 Attachment 3 in MS Excel format.

The 2015 and 2016 target program saving assumptions implicit in the total of CDM forecast is as follows:

6 Year (2015-2020) GWh Target:						
Implementation year	2015	2016	2017	2018	2019	2020
2015	193	193	193	193	193	193
2016	-	193	193	193	193	193
2017	-	-	193	193	193	193
2018	-	-	-	193	193	193
2019	-	-	-	-	193	193
2020	-	-	-	-	-	193
Total in Year	193	386	580	773	966	1,159

The verified CDM energy savings for these two years are:

Implementation year	2015-2020 program verified result and persistence (GWh)					
	2015	2016	2017	2018	2019	2020
2015	336	316	313	313	312	310
2016	-	212	210	210	209	208
Total	336	528	523	522	521	519

The actual verified CDM savings in 2015 and 2016 is 134 GWh and 142 GWh higher than our assumptions for year 2015 and 2016, respectively.

i) Hydro One's CDM plan approved by the IESO is provided in Exhibit I-43-VECC-075 Attachment 4 in MS Excel format.

The 2017-2020 target program savings assumptions implicit in the total of CDM forecast is as follows:

6 Year (2015-2020) GWh Target:						
Implementation year	2015	2016	2017	2018	2019	2020
2015	193	193	193	193	193	193
2016	-	193	193	193	193	193
2017	-	-	193	193	193	193
2018	-	-	-	193	193	193
2019	-	-	-	-	193	193
2020	-	-	-	-	-	193
Total in Year	193	386	580	773	966	1,159

The 2017-2020 CDM savings in the most current 2015-2020 CDM plan approved by the IESO is as follows:

Impelenation Year	2015	2016	2017	2018	2019	2020
2015	220	220	220	220	220	220
2016		243	243	243	243	243
2017			199	199	199	199
2018				265	265	265
2019					158	158
2020						170
Total	220	463	662	927	1,085	1,255

The CDM plan for the 2017-2020 is higher than the assumptions we used in the forecast.

j) The detail calculation to determine the savings in 2017-2022 is provided as an MS Excel I-43-VECC-075-05. Reconciliation could not be performed as explained in response to (a).

TAB 16

UNDERTAKING – JT 3.18-2

Reference

43-VECC-75

2016 Ontario Planning Outlook (OPO)

Preamble:

VECC 75 requested detailed data on historical savings by implementation year which, according to the responses to parts (a) – (c), Hydro One is unable to provide.

VECC 75 requested (parts (g) and (h)) copies of Hydro One's verified CDM results reports

Undertaking

a) Attachment 2 only provides the impact of 2011-2014 programs for the period 2011-2014. Please provide the IESO report that indicates the persisting impact of these programs though to 2020 as originally requested.

b) Please complete parts (a) and (b) of VECC 75 based on the verified results for Hydro One's historical EE programs.

c) With respect to the response to part (g), please explain the "definitional" difference between historic EE program savings as reported by Hydro One and the historic EE savings reported in the OPO (Data Tables, Figure 11) for the period 2006-2020.

Response

a) The requested information is provided in the MS Excel attachment to this response.

b) Verified results for Hydro One are not available for 2005-2010. The 2011-2016 EE program savings are provided below based on the available verified results from the IESO. The information is the combined savings for retail and ST-direct customers as the information is not broken out by the IESO for Retail and ST-Direct customers.

Witness: ALAGHEBAND Bijan

Hydro One Historical Verified EE Programs for 2011-2016 (GWh)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2011	86	85	85	79	76	69	61	60	62	54	51	37
2012	1	61	59	59	55	52	41	38	38	37	30	28
2013	0	2	80	77	74	66	57	54	54	54	51	45
2014	1	2	11	212	200	194	186	182	180	177	176	171
2015	-	-	-	-	336	316	313	313	312	310	306	305
2016	-	-	-	-	-	212	210	210	209	208	206	206

c) The definition of the EE programs savings reported by Hydro One is same as the historical EE savings reported in the OPO.

For 2006-2010, the EE programs includes non-target CDM programs initiated by both LDCs and the OPA, as well as the CDM programs funded by other organizations, such as federal, provincial and/or municipal government, natural gas companies, and other non-government organizations.

For 2011-2014 period, the EE programs includes incremental LDCs 2011-2014 target programs and the persistence of 2006-2010 programs.

For 2015-2020 period, the EE programs include incremental LDCs 2015-2020 target programs and the persistence of 2006-2014 programs.

TAB 17

Residual HON EE Program Savings – 2006-2016 Programs vs. 2011-2016 Programs

HONI Energy Savings (MWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2006-2016 EE Programs (per VECC 75-1)	200,490	425,706	488,358	576,085	626,212	715,242	776,780	868,734	989,181	1,046,627	1,104,456
2011-2016 EE Programs (per JT 3.18-2)						88,000	150,000	235,000	427,000	741,000	909,000
Residual EE Program Saving	200,490	425,706	488,358	576,085	626,212	627,242	626,780	633,734	562,181	305,627	195,456

TAB 18

Vulnerable Energy Consumers Coalition Interrogatory # 76

Issue:

Issue 43: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

Reference:

E1-02-01 Page: 20 and 22-31

Interrogatory:

a) Please provide a schedule that sets out:

   i. The actual weather normalized Retail Load for 2016 (before deducting impact of CDM)
   ii. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the Monthly Econometric Model.
   iii. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the Annual Econometric Model.
   iv. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the End Use Model.
   v. The forecast Retail load for 2017-2022 per the Application (before deducting impact of CDM).

b) Please explain how each of the models and resulting forecasts accounted for the fact that the forecast for 2017-2020 excluded the load for the acquired utilities but the forecast for 2021-2022 included this load.

c) Please provide the detail calculations setting out how the proposed Retail load forecast (before deducting CDM) for each of the years 2017 to 2022 was determined using the results of these three models.

Response:

a)

   i. The actual weather normalized Retail Load for 2016 (before deducting impact of CDM) is 21,896 GWh. Retail load is based on its current definition so that it does not include general service customers moved to ST rate class due to the reclassification of customers.

Witness: ALAGHEBAND Bijan

ii. Based on the monthly econometric model, the predicted retail load for 2016 actual value is 24,145 GWh and the requested forecast is presented in Table 1 below. It includes retail general service customer load that was moved to ST rate class due to reclassification of customers. The monthly econometric model is used to forecast up to and including 2018 load due to its short-term nature.

iii. Based on the annual econometric model, the predicted retail load for 2016 actual value is 23,529 GWh and the 2017-2022 forecast is presented in Table 1 below. It includes retail general service customer load that was moved to ST rate class due to the reclassification of customers.

iv. The end-use model is not used to predict retail load for 2016 actual load. The 2017-2022 forecast is presented in Table 1 below. It includes non-LDC ST load, and the gross forecast only includes incremental CDM relative to 2016.

v. The forecast of retail load per the Application is provided in Table 1. It is consistent with the current definition of retail so that it does not include retail general service customer load that was moved to ST rate class due to the reclassification of customers. Consequently, the forecast is lower compared to the other forecasts in Table 1 below. The forecast includes load of the Acquired Utilities for the years 2021 and 2022.

Table 1: Retail Gross Load Forecasts in GWh

Year	Annual Econometric (1)	Monthly Econometric (1)	End-Use (2)	Forecast in the Application (3)
2017	23629	23643	24881	22071
2018	23770	23935	24711	22134
2019	23956	n.a.	24483	22168
2020	24152	n.a.	24463	22294
2021	24091	n.a.	24394	23344
2022	24195	n.a.	24387	23391

Note. The forecasts presented in this table are not comparable for the reasons noted above. For comparable forecasts, please see Table 2 below.

(1) Includes part of retail general service customers that were reclassified as ST and does not include the load of Acquired Utilities.

(2) It includes non-LDC ST customers and incremental CDM relative to 2016. the other gross forecast shown in table include to total CDM.

(3) based on current definition of retail and includes the load of Acquired Utilities in the years 2021 and 2022.

b) The models noted above are used to forecast Hydro One's load excluding Acquired Utilities. Forecast load for the Acquired Utilities for the years 2021 and 2022 was added to the retail forecast.

c) First, different forecasts were adjusted to reflect the current definition of retail load. Such differences were discussed in response to part (b). Next, growth rates for each forecast were calculated. The average of the forecasts was applied to 2016 gross load, resulting in a preliminary forecast. In Table 2, to make the results comparable with the forecast used in this Application, the gross load of the Acquired Utilities is added to the preliminary forecast for 2021 and 2022. The preliminary forecast was considered to be low compared to the economic outlook at the time of forecast, so it was adjusted upward to arrive at the forecast used in this Application.

Table 2: Calculation of Forecast Based on Different Models in GWh

	Forecast in GWh			Growth Rates (%)				
Year	Annual Econometric (1)	Monthly Econometric (1)	End-Use (2)	Annual Econometric	Monthly Econometric	End-Use	Average of Growth Rate	Preliminary Forecast (3)
2016	21,896	21,896	21,896					21,896
2017	21,757	21,771	21,784	-0.6	-0.6	-0.5	-0.6	21,771
2018	21,906	22,071	21,636	0.7	1.4	-0.7	0.5	21,871
2019	22,103		21,437	0.9		-0.9	0.0	21,869
2020	22,301		21,421	0.9		-0.1	0.4	21,959
2021	22,240		21,247	-0.3		-0.8	-0.5	22,931
2022	22,344		21,233	0.5		-0.1	0.2	22,971

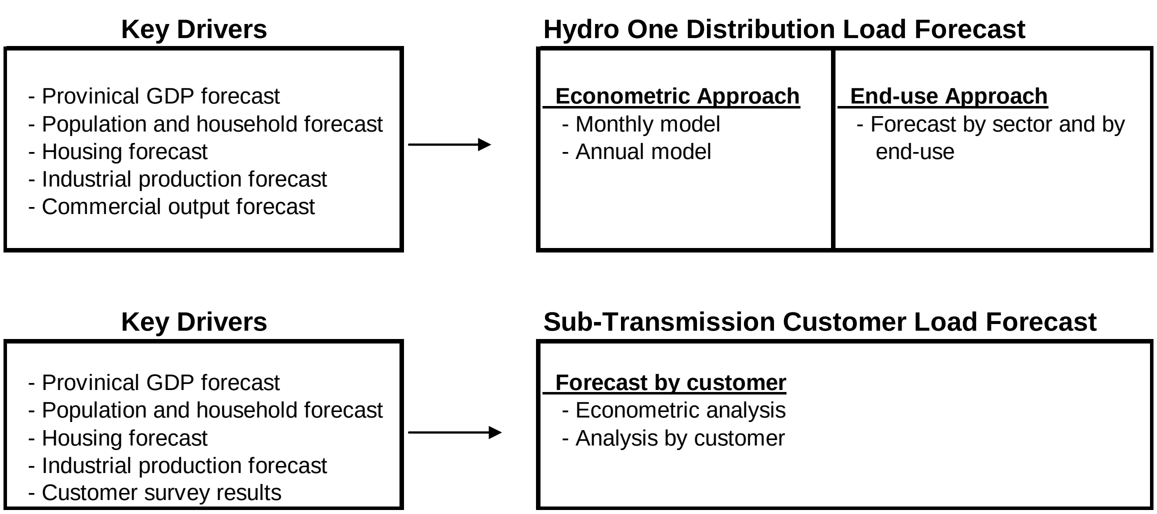
(1) Equals corresponding value in response to (a) less retail general service that was moved to ST rate class.
(2) Equals corresponding value in response to (a) less Direct ST plus CDM value in 2016 so that the gross forecast would be consistent with the other forecasts, which include total CDM and not incremental CDM relative to 2016.
(3) Calculated using the average growth rate applied to 2016 gross base-load. Next, for the years 2021 and 2022 the Acquired Utilities load was added to the implied forecast. The latter step is performed to make it comparable with the forecast used in this application.

TAB 19

2. DISCUSSION OF THE ECONOMIC CONSIDERATIONS THAT INFLUENCE HYDRO ONE DISTRIBUTION'S LOAD FORECASTS

This section discusses some of the key economic considerations in developing load forecasts and the application of forecasting methodologies. The elements of the forecasting process used by Hydro One Distribution are, for the most part, based on the relationship between major economic drivers and electricity demand over the forecast period 2017 to 2022. Consequently, the load forecast will reflect the impact of such drivers on load. The major economic drivers used in the analysis are summarized in Figure 1.

Figure 1
Hydro One Distribution Load Forecast Methodology



Key information used in the analysis includes the Ontario GDP, provincial demographic, industrial production and commercial output forecasts and regional analysis included in the economic forecast. Also taken into consideration are Hydro One Distribution CDM plans, which have a direct impact on distribution system electricity demand.

TAB 20

UNDERTAKING – JT 3.18-7

Topic: Use of Multiple Models

Reference

43-VECC-76

46-CME-70

Preamble:

VECC 76 c) provides the load forecasts from the different models and resulting preliminary forecast. It notes in part c) that this forecast was adjusted upwards to arrive at the forecast used in the application.

CME-70 also describes how the results from the three models were used to establish the load forecast.

Undertaking

a) How was the upward adjustment referred to in VECC 76 c) determined?

b) Table 2 of VECC-75 indicates that the results of the models were averaged and adjusted before adjusting the forecast for CDM? (Note the value for 2016 actual is equivalent to E1, Tab 2, Schedule 1, Table 7 – for the Retail Class before deducting CDM). However, CME 70 c) states the forecast was based on an average of the forecasts after adjusting for CDM. Please clarify whether the averaging was done before or after adjusting for CDM?

c) The response to VECC-75 indicates that it was the growth rates (over 2016 actuals) that were “averaged”. However, CME-70 c) suggests it was the average of the forecast values that was averaged. Please clarify the approach used.

Response

a) At the time the forecast was being finalized, the economic outlook seemed to be improving over time. This was more in terms of improvement in expectations (e.g., rising consumer confidence and stock market prices) rather than rising economic forecast as Hydro One was already using the latest economic forecast available. Thus, it was not clear how much of that improvement was already factored into the economic forecast underlying the load forecast. Consequently, the upward adjustment to the forecast was based on expert judgment.

b) As noted in part c) of Exhibit I-46-CME-70, the averaging was done after deducting CDM. However, since the same CDM amount is deducted from different forecasts, averaging after deducting CDM yields nearly same result as averaging before deducting CDM and then deducting CDM from the result. In Exhibit I-43-VECC-75, Hydro One was asked to provide a comparison of gross forecasts (i.e., before deducting CDM) from different models and the gross forecast used in the Application. The response provided was the most direct way of performing such a comparison.

c) The approach used was averaging the growth rates of the three forecast methodologies.

TAB 21

by rate class are provided in Appendix E, Tables E.5 to E.9. Results by rate class in Appendix E reflect changes due to customer classification in 2015 (see Exhibit G1, Tab 2, Schedule 1 of Hydro One's last distribution application EB-2013-0416) and continuation of these changes over the years 2018 to 2022 as discussed in Exhibit G1, Tab 2, Schedule 1 of the current Application.

Table 7: Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2015	21,822	17,241	39,063
2016	21,896	17,178	39,074
2017	22,071	17,416	39,487
2018	22,134	17,438	39,572
2019	22,168	17,405	39,573
2020	22,294	17,484	39,778
2021*	23,344	17,260	40,604
2022*	23,391	17,315	40,706
Load Impact of CDM			
2015	1,619	1,025	2,644
2016	1,810	1,124	2,935
2017	1,983	1,260	3,243
2018	2,171	1,382	3,553
2019	2,378	1,514	3,892
2020	2,505	1,599	4,104
2021*	2,642	1,599	4,241
2022*	2,698	1,636	4,334
Load Forecast After Deducting Impact of CDM			
2015	20,203	16,216	36,419
2016	20,085	16,054	36,139
2017	20,088	16,156	36,244
2018	19,963	16,056	36,019
2019	19,790	15,890	35,680
2020	19,789	15,885	35,673
2021*	20,702	15,661	36,363
2022*	20,693	15,679	36,373

Note. All figures are weather-normal.
* Includes Acquired Utilities.

TAB 22

Exhibit I, Tab 43, VECC-75, Attachment 5

	Formula	2016 OPO						
		TWh	2017	2018	2019	2020	2021	2022
1		Codes and standards (Implemented by 2015)	6.3	6.9	7.3	7.4	7.4	7.4
2		Codes and standards (Implemented 2016 and beyond)	0.0	0.2	0.3	0.4	0.6	0.9
3		Historical program persistence (2006-2015)	6.4	5.7	5.5	4.9	4.4	3.6
4		Forecast savings from planned programs (2016-2020)	3.3	5.0	6.4	7.9	8.0	7.8
5		Planned savings from future programs & Codes and Standards	0.0	0.0	0.0	0.0	0.6	1.3
6		Total TWh	15.9	17.8	19.5	20.7	20.9	21.1

		2016 OPO						
		TWh	2017	2018	2019	2020	2021	2022
7	(7)=(1)+(2)	Codes and standards	6.3	7.1	7.6	7.8	7.8	7.8
8	(8)=(3)+(4)	EE programs	9.7	10.7	11.9	12.8	13.1	13.3
9		Total	16	17.8	19.5	20.6	20.9	21.1

		Transmission direct connected customers (non-LDC)						
		MWh	2017	2018	2019	2020	2021	2022
10	From the IESO	Transmission direct customer	900,000	1,400,000	1,500,000	1,700,000	1,700,000	1,700,000

		OPA Loss Factor Assumption						
			2017	2018	2019	2020	2021	2022
11	From the IESO	distribution	0.065	0.065	0.065	0.065	0.065	0.065
12	From the IESO	transmission	0.025	0.025	0.025	0.025	0.025	0.025
13	(13)=(11)+(12)	DX+TX	0.09	0.09	0.09	0.09	0.09	0.090

		All LDCs savings at end use level						
			2017	2018	2019	2020	2021	2022
14	(14)=((6)-(10)/(1+(13))	All LDCs savings (MWh)	13,761,467.9	15,045,871.6	16,513,761.5	17,431,192.7	17,614,678.9	17,798,165.1

		All LDCs savings at end use level by category						
			2017	2018	2019	2020	2021	2022
15	(15)=(8)/(9)	EE saving %	61.0%	60.1%	61.0%	61.8%	62.7%	63.0%
16	(16)=1-(15)	C&S saving %	39.0%	39.9%	39.0%	38.2%	37.3%	37.0%
17	(17)=(14)*(15)	EE program Saving	8,395,361	9,044,428	10,077,629	10,778,709	11,040,780	11,218,749
18	(18)=(14)*(16))	C&S saving	5,366,107	6,001,443	6,436,133	6,652,484	6,573,899	6,579,416
19	(19)=(17)+(18)	Total	13,761,468	15,045,872	16,513,761	17,431,193	17,614,679	17,798,165
			-	-	-	-	-	-

HONI EE share

2015-2022: HONI 2015-2020 target share if 16.56 %, to be conservative, use share of 13.71%

HONI C&S share

2006-2020 use share of 16.56%

	2011-2014 Verified Energy savings	2015-2020 Target
HONI target/actual	898,318,000	1,159
All LDCs	6,552,993,397	7,000
HONI Share	13.71%	16.56%

		HONI energy savings						
			2017	2018	2019	2020	2021	2022
20	(20)=(18)*16.56%	C&S	888,489	993,685	1,065,658	1,101,480	1,088,469	1,089,382
21	(21)=(17)*13.71%	EE program	1,150,879	1,239,857	1,381,493	1,477,601	1,513,527	1,537,924
22	(22)=(18)+(19)	Total	2,039,369	2,233,541	2,447,151	2,579,081	2,601,995	2,627,306

TAB 23

Table 4: CDM Impact on Hydro One Distribution Load (GWh)

Year	Retail Customers	ST Customers Direct	ST Customers LDC	Total
2015	1,619	169	856	2,644
2016	1,810	195	929	2,935
2017	1,983	208	1,052	3,243
2018	2,171	228	1,154	3,553
2019	2,378	251	1,264	3,892
2020	2,505	265	1,334	4,104
2021*	2,642	277	1,322	4,241
2022*	2,698	284	1,352	4,334

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

The CDM figures for all years are consistent with IESO Ontario Planning Outlook ("OPO"), including the load impact of LDC energy efficiency programs for the years 2015-2020. The methodology for incorporating CDM into the load forecast is described in Section 3 of this Exhibit.

2.7 CUSTOMER FORECAST

Through its distribution system, Hydro One is expected to serve about 1.283 million customers in 2016 and 1.292 million customers in 2017. These totals reflect the impact of amendments to the Distribution System Code on Hydro One, related to the elimination of load transfer arrangements between electricity distributors (EB-2015-0006). The customer base is forecast to reach 1.301, 1.309, and 1.318 million, respectively, over the 2018 to 2020 period. With the integration of the Acquired Utilities, the customer base is forecast to

TAB 24

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**
VOLUME:	**Volume 3**	
DATE:	**June 14, 2018**	
BEFORE:	**Ken Quesnelle**	**Presiding Member and Vice-Chair**
	Lynne Anderson	**Member**
	Emad Elsayed	**Member**

looking at the -- so perhaps I can just ask the question directly. So what years are being captured in the lost revenue adjustment mechanism variance account? Is it 2017 to 2020 or is it 2015 to 2020?

MR. CHHELAVDA: If you look at page 26 of the compendium, I believe the response to question A details the years that are covered. So for 2018 programs, it is implemented in '17, '18, 2019 programs implemented in '17 to '19, and for 2020 programs it would be for programs implemented in 2017 to 2020.

MR. SEGEL-BROWN: Okay. So the table set out -- so if we go back to tab 9, which is page 23, in this response to the interrogatory it seems to be showing an account tracking back to 2015, so you're confirming that the proposed account is only for the 2017 on with cumulative results?

MR. CHHELAVDA: So I will go back to page 26 of the compendium, where it states that, you know, the lost revenue is due to the incremental savings in each of 2018, '19, and '20. It gives you the -- it gives you the years -- it covers for each one. So again for 2018 it would be for programs implemented in '17 and '18, for 2019 from programs implemented in 2017 to 2019, and for 2020 savings for programs implemented in 2017 to 2020.

MR. SEGEL-BROWN: Okay. If we could turn to tab 11, which is page 29. So this undertaking response indicates that the impact on the current rate base of maintaining the current depreciation rate rather than using the updated

TAB 25

UNDERTAKING – JT 3.18-4

Topic: LRAMVA Threshold

Reference

55-CCC-75

46-Staff-233

Preamble:

In response to 55-CCC-75 HON confirmed it was establishing an LRAM Variance Account.

Staff-233, Table 3 sets out Hydro One's proposed LRAMVA thresholds (i.e., CDM amounts assumed in the load forecast)

Undertaking

a) Please confirm that Hydro One will be seeking recovery of:
   i. Lost revenues in 2018 from programs implemented in 2015-2018.
   ii. Lost revenue in 2019 from programs implemented in 2015-2019, and
   iii. Lost revenues in 2020 from programs implemented in 2015-2020?

   If not, please clarify Hydro One's proposals for lost revenue recovery.

b) Are the CDM savings values set out in CCC-75, Table 3 annualized values (i.e., assuming all CDM programs are implemented January 1st) or do the values represent the expected forecast savings in each year?

c) Are the values set out in CCC-75, Table 3 the base CDM savings against which Hydro One plans to calculate the LRAMVA amounts?
   i. If yes and the values are not "annualized" please provide the annualized equivalents.
   ii. If no, please provide Hydro One's proposed "annualized" LRAMVA thresholds for each year for which it will be seeking a lost revenue recovery.

d) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why aren't the 2015 and 2016 implementation year values in Table 3 based on the actual verified Hydro One savings for 2015 and 2016?

e) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why is it necessary to seek recovery for lost revenue from programs implemented in 2015 and 2016?

f) For the program years 2017-2020, why use the values in CCC-75 as opposed to those set out in HON's approved CDM plan – provided in response to OSEA #6?

g) Since the LRAM calculations are class specific – please provide a breakdown of the proposed LRMVA kWh threshold for each year (2018-2020) by customer class and indicate how the values were derived.

h) Staff-233 makes reference (page 2, line 14) to an attached MS Excel file. However, there does not appear to be a corresponding attachment on the OEB web-site. Please provide.

Response

a) No. Hydro One will be seeking recovery of:
   i. lost revenues due to the incremental savings in 2018 from programs implemented in 2017-2018;
   ii. lost revenues due to the incremental savings in 2019 from programs implemented in 2017-2019; and
   iii. lost revenues due to the incremental savings in 2020 from programs implemented in 2017-2020.

b) The CDM saving values set out in Exhibit I-55-CCC-75 are the annualized forecast savings in each year.

c) Yes.
   i. The values are forecasted annualized savings due to EE programs.
   ii. Not applicable.

d) Hydro One incorporates cumulative CDM impacts (including EE and C&S) in the load forecast based on the OPO information. The 2015 and 2016 actual CDM savings from the EE target programs are implicitly included in the *total* CDM assumption. When the load forecast for this Application was prepared, Hydro One did not have the 2016 verified result report and 2011-2015 persistence report from the IESO. As such, Hydro One applied Hydro One's share of the OPO EE savings for the forecast years (2017-2022).

e) Hydro One will be only seeking recovery for lost revenue due to incremental savings from programs implemented in 2017 and beyond, as indicated in the response to part a).

f) Hydro One applied its share of Ontario energy savings based on the OPO information for 2017-2022. The proposed CDM programs in the CDM plan can be updated by LDCs as often as needed to reflect actual program performance. In addition, the expected energy savings are very close to the target of 1,159 GWh by the end of 2020. Therefore, Hydro One simply used the target CDM assumptions per the OPO in preparing its load forecast.

g) The proposed 2018-2020 LRAMVA threshold by rate class is as follows:

Implementation Year	Service - Demand Billed	General Service - Energy Billed	Residential - Medium Density	Residential - Low Density	Seasonal	transmission Direct customers	General Service - Demand	General Service - Energy Billed	Urban Residential
	kW	KWH	KWH	KWH	KWH	KW	KW	KWH	KWH
2018	6,497	87,066,805	56,144,302	53,234,536	7,115,397	47,520	1,002	23,296,048	22,291,454
2019	14,410	130,006,286	84,798,946	79,316,486	10,537,861	64,340	3,953	34,902,484	33,525,240
2020	17,850	172,532,973	113,839,336	105,044,163	13,870,876	77,381	5,449	46,478,919	44,817,001

The threshold is the incremental savings in 2018-2020 compared to the savings in 2016. For the energy billed customers, the share of CDM savings by rate class was applied to the incremental six year target program CDM savings in 2018-2020 vs 2016. For the demand billed customers, the share of six year target program savings of total EE savings was applied to peak savings.

h) Please see MS Excel attachment to this reponse, which is based on OEB's template. The threshold and CDM adjustment savings for 2018 calculated in the attached file are different from the number Hydro One used in its load forecast and represent a different methodology for incorporating CDM into the load forecast.

TAB 26

Consumers Council of Canada Interrogatory # 75

Issue:

Issue 55: Are the proposed line losses over the 2018 – 2022 period appropriate?

Reference:

F1-03-01 Page 4

Interrogatory:

HON is proposing to establish a Lost Revenue Adjustment Mechanism Variance Account. Please describe how this account will operate. For 2018 what is the proposed Board-approved CDM adjustment? How was that amount derived?

Response:

Per the Board's Filing Requirements for Electricity Distribution Rate Applications, Chapter 2, Section 3.2.6 the OEB has established Account 1568 as the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) to capture the variance between the OEB-approved Conservation and Demand Management (CDM) forecast and the actual results at the customer rate class level. Distributors are expected to compare the OEB-approved CDM adjustment to the load forecast with the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

Hydro One's proposed CDM target program savings included in the 2018 load forecast is 842.6 GWH which is based on the OEB's Appendix 2-I, Load Forecast CDM Adjustment Work Form, as shown below and provided in Exhibit E1, Tab 2, Schedule 1, Attachment 2.

The forecast CDM adjustment accounts only for the 2015-2018 target programs but not the persistent savings of historical EE programs and C&S.

6 Year (2015-2020) kWh Target:						
Implementation yar	**2,015**	**2,016**	**2,017**	**2,018**	**2,019**	**2,020**
2,015	193,170,000	193,170,000	193,170,000	193,170,000	193,170,000	193,170,000
2,016		193,170,000	193,170,000	193,170,000	193,170,000	193,170,000
2,017			193,170,000	193,170,000	193,170,000	193,170,000
2,018				193,170,000	193,170,000	193,170,000
2,019					193,170,000	193,170,000
2,020						193,170,000
Total in Year	**335,528,398**	**528,017,133**	**683,208,870**	**842,605,433**	**1,001,184,662**	**1,159,020,000**

TAB 27

2018 Cost Allocation Model

EB-2017-0049

Sheet O1 Revenue to Cost Summary Worksheet -

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets			1	2	3	4	5	6	7	8	9	10	11	12	13
		Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST
crev	Distribution Revenue at Existing Rates	$1,372,743,246	$86,431,034	$294,031,748	$486,346,781	$105,206,634	$147,418,514	$133,513,581	$20,730,664	$27,698,803	$11,485,873	$3,181,473	$3,059,399	$3,349,603	$50,289,137
mi	Miscellaneous Revenue (mi)	$53,630,485	$5,113,873	$13,762,853	$16,978,792	$3,251,750	$5,143,910	$2,799,207	$884,648	$630,884	$400,910	$3,095,690	$128,914	$175,550	$1,263,504
		Miscellaneous Revenue Input equals Output													
	Total Revenue at Existing Rates	$1,426,373,731	$91,544,907	$307,794,601	$503,325,573	$108,458,384	$152,562,424	$136,312,787	$21,615,312	$28,329,688	$11,886,784	$6,277,163	$3,188,313	$3,525,152	$51,552,642
	Factor required to recover deficiency (1 + D)	1.0535													
	Distribution Revenue at Status Quo Rates	$1,446,251,442	$91,059,278	$309,776,676	$512,389,870	$110,840,280	$155,312,539	$140,663,018	$21,840,758	$29,182,030	$12,100,924	$3,351,836	$3,223,225	$3,528,969	$52,982,040
	Miscellaneous Revenue (mi)	$53,630,485	$5,113,873	$13,762,853	$16,978,792	$3,251,750	$5,143,910	$2,799,207	$884,648	$630,884	$400,910	$3,095,690	$128,914	$175,550	$1,263,504
	Total Revenue at Status Quo Rates	$1,499,881,927	$96,173,150	$323,539,529	$529,368,662	$114,092,030	$160,456,449	$143,462,225	$22,725,406	$29,812,914	$12,501,834	$6,447,526	$3,352,139	$3,704,518	$54,245,544
	Expenses														
di	Distribution Costs (di)	$296,043,624	$13,880,251	$56,811,229	$123,632,500	$22,442,750	$30,566,173	$24,066,976	$3,639,014	$4,913,696	$3,249,036	$1,276,804	$623,713	$129,298	$10,812,183
cu	Customer Related Costs (cu)	$112,914,202	$17,342,130	$35,880,922	$29,884,640	$7,396,371	$11,750,651	$3,669,940	$2,389,657	$942,101	$782,311	$307,921	$453,381	$615,006	$1,499,170
ad	General and Administration (ad)	$165,812,442	$12,272,123	$36,787,914	$61,635,070	$11,930,641	$17,016,378	$12,062,489	$2,418,638	$2,587,786	$1,606,652	$629,519	$422,161	$994,016	$5,449,055
dep	Depreciation and Amortization (dep)	$392,554,546	$22,041,757	$74,859,159	$143,680,290	$27,159,381	$42,143,309	$45,932,205	$6,051,795	$9,735,237	$3,175,609	$1,565,488	$563,812	$780,121	$14,866,382
INPUT	PILs (INPUT)	$61,450,658	$3,089,741	$11,412,410	$23,389,292	$4,208,265	$6,660,515	$7,053,841	$914,232	$1,461,570	$539,992	$198,348	$98,756	$67,904	$2,355,792
INT	Interest	$191,624,551	$9,634,887	$35,587,869	$72,935,958	$13,122,835	$20,769,805	$21,996,332	$2,850,895	$4,557,684	$1,683,882	$618,519	$307,955	$211,749	$7,346,179
	Total Expenses	$1,220,400,023	$78,260,888	$251,339,504	$455,157,751	$86,260,243	$128,906,830	$114,781,782	$18,264,233	$24,198,075	$11,037,483	$4,596,599	$2,469,778	$2,798,095	$42,328,762
	Direct Allocation	$10,056,427	$0	$0	$0	$0	$0	$2,433,638	$0	$742,547	$0	$792,388	$0	$3,349,392	$2,738,463
NI	Allocated Net Income (NI)	$269,425,477	$13,546,720	$50,036,797	$102,548,474	$18,450,799	$29,202,493	$30,926,999	$4,008,379	$6,408,136	$2,367,551	$869,642	$432,987	$297,721	$10,328,780
	Revenue Requirement (includes NI)	$1,499,881,927	$91,807,608	$301,376,300	$557,706,225	$104,711,041	$158,109,324	$148,142,418	$22,272,612	$31,348,758	$13,405,033	$6,258,629	$2,902,765	$6,445,207	$55,396,005
		Revenue Requirement Input equals Output													
	Rate Base Calculation														
	Net Assets														
dp	Distribution Plant - Gross	$11,237,405,954	$579,713,089	$2,115,962,140	$4,283,058,771	$786,930,558	$1,189,677,239	$1,268,742,598	$163,522,270	$263,447,311	$96,412,087	$35,454,190	$17,636,787	$13,324,945	$423,523,969
gp	General Plant - Gross	$1,177,857,488	$58,457,160	$216,512,174	$443,684,292	$80,762,598	$124,689,466	$133,196,119	$17,071,972	$27,610,485	$10,197,283	$18,812,133	$1,876,989	$1,370,755	$43,616,062
accum dep	Accumulated Depreciation	($4,334,809,525)	($232,298,166)	($829,215,397)	($1,646,212,508)	($306,952,885)	($448,639,165)	($477,148,904)	($62,062,368)	($99,356,301)	($35,808,932)	($21,144,024)	($6,481,711)	($5,178,453)	($164,310,710)
co	Capital Contribution	($896,478,209)	($44,988,122)	($170,042,045)	($348,174,064)	($68,750,362)	($88,309,790)	($101,001,376)	($11,839,720)	($21,006,039)	($7,736,768)	($3,528,163)	($1,493,867)	($1,551,257)	($28,056,636)
	Total Net Plant	$7,183,975,709	$360,883,961	$1,333,216,872	$2,732,356,490	$491,989,910	$777,417,750	$823,788,436	$106,692,154	$170,695,456	$63,063,671	$29,594,135	$11,538,199	$7,965,990	$274,772,685
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$3,578,426,392	$314,343,871	$756,058,590	$696,990,259	$97,027,383	$323,060,856	$359,595,615	$91,875,316	$162,376,228	$18,635,242	$3,130,073	$3,752,171	$2,820,297	$748,760,491
	OM&A Expenses	$574,770,268	$43,494,504	$129,480,065	$215,152,211	$41,769,762	$59,333,201	$39,799,404	$8,447,310	$8,443,584	$5,637,999	$2,214,244	$1,499,256	$1,738,320	$17,760,409
	Directly Allocated Expenses	$10,056,427	$0	$0	$0	$0	$0	$2,433,638	$0	$742,547	$0	$792,388	$0	$3,349,392	$2,738,463
	Subtotal	$4,163,253,087	$357,838,375	$885,538,655	$912,142,470	$138,797,145	$382,394,057	$401,828,657	$100,322,626	$171,562,359	$24,273,241	$6,136,704	$5,251,427	$7,908,009	$769,259,363
	Working Capital	$325,326,021	$27,962,301	$69,197,995	$71,276,877	$10,845,923	$29,881,137	$31,399,801	$7,839,437	$13,406,271	$1,896,766	$479,536	$410,358	$617,950	$60,111,668
	Total Rate Base	$7,509,301,730	$388,846,261	$1,402,414,867	$2,803,633,368	$502,835,833	$807,298,888	$855,188,237	$114,531,591	$184,101,727	$64,960,437	$30,073,671	$11,948,558	$8,583,940	$334,884,353
		Rate Base Input Does Not Equal Output													
	Equity Component of Rate Base	$3,003,720,692	$155,538,504	$560,965,947	$1,121,453,347	$201,134,333	$322,919,555	$342,075,295	$45,812,636	$73,640,691	$25,984,175	$12,029,469	$4,779,423	$3,433,576	$133,953,741
	Net Income on Allocated Assets	$269,425,477	$17,912,262	$72,200,025	$74,210,911	$27,831,788	$31,549,618	$26,246,806	$4,461,173	$4,872,292	$1,464,351	$1,058,539	$882,360	($2,442,968)	$9,178,319
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$269,425,477	$17,912,262	$72,200,025	$74,210,911	$27,831,788	$31,549,618	$26,246,806	$4,461,173	$4,872,292	$1,464,351	$1,058,539	$882,360	($2,442,968)	$9,178,319
	RATIOS ANALYSIS														
	REVENUE TO EXPENSES STATUS QUO%	100.00%	1.05	1.07	0.95	1.09	1.01	0.97	1.02	0.95	0.93	1.03	1.15	0.57	0.98
	EXISTING REVENUE MINUS ALLOCATED COSTS	($73,508,196)	($262,700)	$6,418,301	($54,380,652)	$3,747,343	($5,546,900)	($11,829,631)	($657,300)	($3,019,071)	($1,518,250)	$18,534	$285,548	($2,920,055)	($3,843,363)
		Deficiency Input equals Output													
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$4,365,543	$22,163,229	($28,337,563)	$9,380,989	$2,347,125	($4,680,193)	$452,794	($1,535,844)	($903,200)	$188,896	$449,373	($2,740,689)	($1,150,461)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.97%	11.52%	12.87%	6.62%	13.84%	9.77%	7.67%	9.74%	6.62%	5.64%	8.80%	18.46%	-71.15%	6.85%

TAB 28

the total bill impact for a typical DGen customer to no more than 10%. This is the same approach proposed, and approved by the Board, in Hydro One's 2016 and 2017 Draft Rate Orders (EB-2015-0079 and EB-2016-0081). The increase in revenue collected from the DGen class is offset by decreasing the revenue collected from USL and Seasonal classes, which have the highest R/C ratios above 1.

Table 5: Revenue-to-Cost Ratios and Class Revenue Recovery – 2017 to 2018

Rate Class	2017		2018				Board Range
	R/C	Revenue Requirement ($ M)	R/C		Revenue Requirement ($ M)		R/C (%)
			CAM	After Rate Design	CAM	After Rate Design	
UR	1.10	87.6	1.05	1.05	96.2	96.2	85 - 115
R1	1.10	310.9	1.07	1.07	323.5	323.5	85 - 115
R2	0.95	519.4	0.95	0.95	529.4	529.4	85 - 115
Seasonal	1.04	113.4	1.09	1.09	114.1	113.9	85 - 115
GSe	0.99	160.6	1.01	1.01	160.5	160.5	80 - 120
UGe	0.95	21.8	1.02	1.02	22.7	22.7	80 - 120
GSd	0.95	145.5	0.97	0.97	143.5	143.5	80 - 120
UGd	0.95	30.3	0.95	0.95	29.8	29.8	80 - 120
St Lgt	0.95	12.1	0.93	0.93	12.5	12.5	80 - 120
Sen Lgt	0.95	7.3	1.03	1.03	6.4	6.4	80 - 120
USL	1.10	3.2	1.15	1.09	3.4	3.2	80 - 120
DGen	0.61	4.6	0.57	0.63	3.7	4.1	80 - 120*
ST	0.95	51.0	0.98	0.98	54.2	54.2	85 - 115
TOTAL		1,467.6			1,499.9	1,499.9	

** Assume same as for GS, as previously approved in EB-2013-0416*

<u>R/C Ratio from 2018 to 2020</u>

Table 6 and Table 7 show how the R/C ratio and revenue requirement by class are adjusted by the 2019 and 2020 rate design process. Hydro One proposes to continue increasing the DGen class R/C ratio from 0.63 in 2018 to 0.76 in 2019, which limits the total bill impact for a typical DGen customer to no more than 10% per year. The increase in revenue from the DGen class is made up by decreasing the revenue collected from the

USL, Seasonal and R1 classes, which had the highest R/C ratios above 1. By 2020, the DGen rate class R/C ratio will be within the Board-approved range and no further adjustments will be required to any of the R/C ratios.

Table 6: Revenue-to-Cost Ratios and Class Revenue Recovery – 2018 to 2019

Rate Class	2018		2019			
	R/C	Revenue Requirement ($ M)	R/C		Revenue Requirement ($ M)	
			Before Rate Design	After Rate Design	Before Rate Design	After Rate Design
UR	1.05	96.2	1.06	1.06	100.6	100.6
R1	1.07	323.5	1.08	1.08	336.9	336.8
R2	0.95	529.4	0.95	0.95	547.9	547.9
Seasonal	1.09	113.9	1.08	1.08	117.4	117.0
GSe	1.01	160.5	1.00	1.00	163.8	163.8
UGe	1.02	22.7	1.02	1.02	23.4	23.4
GSd	0.97	143.5	0.96	0.96	147.2	147.2
UGd	0.95	29.8	0.94	0.94	30.5	30.5
St Lgt	0.93	12.5	0.94	0.94	13.0	13.0
Sen Lgt	1.03	6.4	1.04	1.04	6.7	6.7
USL	1.09	3.2	1.10	1.08	3.3	3.2
DGen	0.63	4.1	0.68	0.76	4.5	5.0
ST	0.98	54.2	0.97	0.97	55.7	55.7
TOTAL		1,499.9			1,551.0	1,551.0

TAB 29

Table 3: Meter Reading Weighted Average Costs in 2018 and 2021 CAMs (Sheet I7.2)

Meter Reading Weighted Average Costs

2018 CAM	From I7.2																			
UR	R1	R2	Seasonal	GSe	GSd	UGe	Ugd	St Lgt	Sen Lgt	USL	DGEN	ST							TOTAL
0.5%	3.9%	53.0%	13.2%	13.0%	12.0%	1.4%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%							100.0%
2021 CAM	From I7.2																		
UR	R1	R2	Seasonal	GSe	GSd	UGe	Ugd	St Lgt	Sen Lgt	USL	DGEN	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	TOTAL
0.5%	3.8%	52.6%	13.1%	12.9%	11.9%	1.3%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.1%	0.0%	100.0%

2.2.2 Density Factors (CAM Sheet E2)

No density adjustment is required for the six new acquired rate classes, as these classes are not distinguished based on density. The value "1" has been input in the 2021 CAM sheet E2 for the six acquired rate classes. These factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2017 model.

Table 4: Density Factors in 2021 CAM (CAM Sheet E2)

UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd
1.000	1.900	4.800	3.600	2.400	2.200	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

2.2.3 New Acquired Rate Class Allocator Adjustments

All costs associated with serving the customers of the Acquired Utilities in 2021 have been added to the 2021 CAM. Six new rate classes have also been added to the 2021 CAM to accommodate the rate harmonization of the acquired utilities in 2021. All inputs to the 2021 CAM have been reviewed to ensure that the model is appropriately assigning costs to the Hydro One existing and the new acquired rate classes. In addition, three adjustment factors were developed and included in the 2021 CAM to ensure that the costs allocated to the six new acquired rate classes appropriately reflect the cost of serving the customers in these rate classes. These adjustment factors are described below.

Witness: Henry Andre

Fixed Assets Adjustment

An adjustment factor has been applied to the amount of gross fixed assets ("GFA") in USofA accounts 1830 to 1860 to align the costs allocated by the CAM to these USofA accounts with the amount of GFA specifically required to serve the new acquired rate classes. The amount of GFA that should appropriately be allocated to the new acquired rate classes is estimated from the GFA in these USofA accounts for the acquired utilities prior to acquisition plus the in-service additions to these accounts up to 2021. The total GFA that should appropriately be assigned to the new acquired rate classes also takes into consideration that a portion of Hydro One's bulk distribution assets associated with serving customers in each of the new acquired rate classes should also be allocated to these classes. The amount of bulk distribution assets assigned to the new acquired classes was determined using the same proportion of bulk assets assigned to Hydro One's other customer classes not directly served by the bulk system.

Assets in all other USofA fixed asset accounts (e.g. distribution station assets, land, buildings, general plant, etc.) are considered to be commonly shared among all classes served by Hydro One. The amount of these common assets normally allocated to all rate classes using the cost allocation principles underlying the CAM are not adjusted.

The GFA adjustment factors are shown in Table 5. The adjustment factors are applied to the GFA in USofAs 1830 to 1860 as shown in rows 437-507 of the 2021 CAM's "E2 Allocators" tab. Hydro One proposes to apply these same factors in future runs of the CAM.

Table 5: GFA Adjustment Factor

GFA (USofA 1830-1860)	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.515	0.381	0.197	0.670	0.701	0.383

The amount of GFA not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Given the Board's CAM methodology, the appropriate allocation of GFA to the new acquired rate classes is critical for driving the allocation of the majority of distribution O&M costs, other than customer-related costs (e.g. billing, collections, meter-related expenses). The allocation of O&M costs, in turn, is a key driver of most administration and general costs.

Net Fixed Asset ("NFA") Allocator Adjustment

The NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab are also adjusted to reflect the GFA adjustment for USofA's 1830-1860 as described above. GFA values assigned to the new acquired rate classes are translated to NFA values based on the relationship between total GFA and NFA determined from rows 112 to 116 in the CAM's "O6 Source Data for E2" tab. The NFA adjustment factors that have been applied are shown in Table 6 below.

Table 6: NFA and NFA ECC Adjustment Factor

NFA and NFA ECC	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.549	0.461	0.354	0.697	0.740	0.498

The amount of NFA and NFA ECC not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Depreciation Cost Adjustment

A depreciation adjustment factor is applied to the depreciation assigned by the CAM to USofA accounts 1830 to 1860 for the new acquired rate classes. The depreciation amounts assigned to the new acquired rate classes as shown in "Sheet 7 Amortization" of the CAM are reduced by the same GFA adjustment factors discussed above in order to reduce the depreciation amount assigned to the new acquired rate classes consistent with the reduction in the GFA for those USofA accounts.

The depreciation amount not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Table 7 shows the unadjusted depreciation amounts compared to the adjusted amounts for each rate class shown in row 2016 of the "O4 Summary by Class & Accounts" tab of the CAM.

Table 7: Adjusted Depreciation Amounts to Reflect New Acquired Rate Classes

Deprecation USofA 5705	UR	R1	R2	Seas	GSe	GSd	UGe	UGd	St.L	Sen.L	USL	Dgen	ST	AUR	AUGSe	AUGSd	AR	AGSd	AGSe
Unadjusted	22.1	74.5	138.3	27.1	40.5	45.4	6.0	9.6	3.3	1.5	0.6	1.0	14.8	2.5	0.9	1.8	7.0	1.7	3.1
Adjusted	22.4	75.5	140.3	27.5	41.1	46.0	6.1	9.8	3.4	1.6	0.6	1.0	15.0	1.6	0.5	0.9	5.3	1.4	1.8

TAB 30

UNDERTAKING – JT 3.26-3

Reference
I-49-Staff-242 and 243

Undertaking
With respect to the Gross Fixed Assets (GFA) and Net Fixed Assets (NFA) adjustments:

a) Why did Hydro One think it was necessary to adjust the starting balances for the capital assets of the acquired utilities?

b) Why does Hydro One believe that the allocation of the capital assets using the cost allocation methodology is too high? Is this an error in the cost allocation model or as a result of something else?

c) Please confirm that Hydro One will not be updating the adjustment factors even as more capital is invested into the acquired utilities' service territories.

d) How will any new capital spending in the acquired utilities' service territories be allocated if Hydro One will no longer separately track the costs associated with the acquired utilities?

Response
a) Hydro One believes that it is necessary to adjust the 2021 capital assets allocated to the six acquired rate classes in the Cost Allocation Model ("CAM") because in its Decisions in the MADD proceedings for the acquisition of Haldimand County Hydro, Norfolk Power Distribution and Woodstock Hydro Services the OEB stated that it expected Hydro One to propose rates at the time of rate rebasing that reflect the costs to serve these acquired utilities.

   As discussed in the evidence at Exhibit G1, Tab 3, Schedule 1, section 2, the allocation of costs are largely driven by the amount of capital assets allocated to the rate classes per the principles underlying the CAM. As illustrated in Tab 5 of the spreadsheet provided in Exhibit I, Tab 49, Schedule Staff-242 part (c), there is a material difference between the Gross Book Value ("GBV") that the 2021 CAM would normally assign to the six acquired rate classes and the forecast 2021 GBV for the acquired utilities (which is based on actual GBVs at the time of acquisition with forecast in-service additions up to 2021). As such, in order to set rates that appropriately reflect the costs to serve these acquired utilities, the amount of capital assets allocated to these acquired rate classes have to be adjusted.

b) Hydro One does not believe that there is an error in the OEB Cost Allocation model. However, simply allocating a share of Hydro One's total assets based on the relative peak loads of the acquired classes, consistent with the CAM principles, results in the allocation of costs to the acquired classes that are not consistent with the direction from the Board as discussed in part (a) above.

c) Hydro One does not anticipate needing to update the proposed adjustment factors in the near term. However, recognizing that the adjustment factors capture cost differences related to both the installed capital costs and the unique characteristics of the acquired utilities' distribution systems (e.g. customer density), in the long term, as more of the original assets are replaced at Hydro One's installed capital costs, Hydro One will assess the need to update the currently proposed adjustment factors.

d) Hydro One's <u>total</u> new capital spending, both within and outside the acquired utilities' service territories, will be shared by all Hydro One customer classes. This includes the acquired rate classes who will attract a share of all new capital spending as a result of the CAM's underlying allocation methodology and the use of the proposed GFA Adjustment Factors. Therefore there is no need to separately track the costs associated with the acquired utilities.

TAB 31

Exhibit I, Tab 49-, taff 242 – Attachment 1, Tab 1, Columns A-C and R-V

		2020	2021	2021	2022	2022
Woodstock						
Distribution Plant		YE GBV	I/S Adds	YE GBV	I/S Adds	YE GBV
1815	Transformer station equip - above 50kV	$ 51,135	$ 21,056	$ 72,191	$ 21,056	$ 93,246
1820	Distribution station equip - below 50kV	$ 2,036,006	$ 225,517	$ 2,261,523	$ 225,517	$ 2,487,040
1830	Poles, towers and fixtures	$ 12,011,679	$ 524,905	$ 12,536,584	$ 524,905	$ 13,061,489
1835	Overhead conductors and devices	$ 8,429,104	$ 605,423	$ 9,034,527	$ 605,423	$ 9,639,951
1840	Underground conduit	$ 5,794,906	$ -	$ 5,794,906	$ -	$ 5,794,906
1845	Underground conductors and devices	$ 9,134,950	$ 204,714	$ 9,339,664	$ 204,714	$ 9,544,377
1850	Line transformers	$ 10,064,636	$ 379,744	$ 10,444,380	$ 380,744	$ 10,825,125
1855	Services					
1860	Meters (existing)	$ 7,328,793	$ 524,905	$ 7,853,698	$ 47,746	$ 7,901,444
	TOTAL	$ 54,851,210	$ 2,486,264	$ 57,337,473	$ 2,010,105	$ 59,347,578

		2020	2021	2021	2022	2022
Haldimand						
Distribution Plant		YE GBV	I/S Adds	YE GBV	I/S Adds	YE GBV
1815	Transformer station equip - above 50kV	$ 164,836	$ 39,103	$ 203,939	$ 39,103	$ 243,042
1820	Distribution station equip - below 50kV	$ 1,509,932	$ 271,738	$ 1,781,670	$ 271,738	$ 2,053,408
1830	Poles, towers and fixtures	$ 30,185,446	$ 1,302,706	$ 31,488,152	$ 1,343,206	$ 32,831,358
1835	Overhead conductors and devices	$ 22,673,099	$ 1,001,750	$ 23,674,849	$ 1,009,250	$ 24,684,099
1840	Underground conduit	$ 1,723,786	$ -	$ 1,723,786	$ -	$ 1,723,786
1845	Underground conductors and devices	$ 9,173,114	$ 276,260	$ 9,449,373	$ 277,760	$ 9,727,133
1850	Line transformers	$ 18,690,683	$ 833,529	$ 19,524,211	$ 833,529	$ 20,357,740
1855	Services	$ 3,564,629		$ 3,564,629		$ 3,564,629
1860	Meters (existing)	$ 3,666,117	$ 50,744	$ 3,716,861	$ 50,744	$ 3,767,605
	TOTAL	$ 91,351,641	$ 3,775,830	$ 95,127,471	$ 3,825,330	$ 98,952,801

		2020	2021	2021	2022	2022
Norfolk						
Distribution Plant		YE GBV	I/S Adds	YE GBV	I/S Adds	YE GBV
1815	Transformer station equip - above 50kV	$ 9,028,904	$ 10,432	$ 9,039,336	$ 10,640	$ 9,049,976
1820	Distribution station equip - below 50kV	$ 4,244,386	$ 486,468	$ 4,730,854	$ 490,197	$ 5,221,051
1830	Poles, towers and fixtures	$ 22,268,220	$ 815,249	$ 23,083,469	$ 826,914	$ 23,910,383
1835	Overhead conductors and devices	$ 14,036,935	$ 737,282	$ 14,774,218	$ 745,948	$ 15,520,166
1840	Underground conduit	$ 5,142,242	$ -	$ 5,142,242	$ -	$ 5,142,242
1845	Underground conductors and devices	$ 7,956,681	$ 307,192	$ 8,263,873	$ 310,136	$ 8,574,009
1850	Line transformers	$ 18,347,923	$ 475,802	$ 18,823,725	$ 483,878	$ 19,307,603
1855	Services	$ 2,781,477		$ 2,781,477		$ 2,781,477
1860	Meters (existing)	$ 2,937,650	$ 39,824	$ 2,977,474	$ 40,620	$ 3,018,094
	TOTAL	$ 86,744,419	$ 2,872,249	$ 89,616,667	$ 2,908,334	$ 92,525,001

TAB 32

Consumers Council of Canada Interrogatory # 71

Issue:

Issue 53: Are the proposed Retail Transmission Service Rates appropriate?

Reference:

A-07-01 Page 11

Interrogatory:

Please explain how the $150.9 million increase in the opening balance of net fixed was derived.

Please explain how the $14.9 million of working capital related to the Acquired Utilities was derived.

Response:

For each of the Acquired utilities, Hydro One started with the December 31, 2016 net book value of their assets and increased plant by the forecast capital additions (Exhibit A-3-1, Attachment 1, Page 25) less accumulated depreciation to reach the net fixed asset amounts as shown in Exhibit B1-1-1, Appendix A, Tables 1-6.

$ Million	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NORFOLK						
Utility Plant		59.0	61.6	63.7	65.7	67.8
Plus Additions		2.6	2.1	2.1	2.1	3.2
Gross Plant	**59.0**	**61.6**	**63.7**	**65.7**	**67.8**	**70.9**
Less Accumulated Depreciation	(4.3)	(5.7)	(7.1)	(8.5)	(10.0)	(11.5)
Net Plant Year End	**54.7**	**55.9**	**56.5**	**57.2**	**57.8**	**59.5**
HALDIMAND						
Utility Plant		56.1	59.5	62.9	66.8	70.8
Plus Additions		3.4	3.4	3.9	4.0	4.0
Gross Plant	**56.1**	**59.5**	**62.9**	**66.8**	**70.8**	**74.8**
Less: Accumulated Depreciation	(2.8)	(4.2)	(5.7)	(7.3)	(8.9)	(10.5)
Net Plant Year End	**53.3**	**55.3**	**57.2**	**59.5**	**61.9**	**64.2**
WOODSTOCK						
Utility Plant		28.6	30.8	33.1	34.9	37.0
Plus Additions		2.2	2.3	1.8	2.1	2.2
Gross Plant	**28.6**	**30.8**	**33.1**	**34.9**	**37.0**	**39.2**
Less Accumulated Depreciation	(1.4)	(2.5)	(3.6)	(4.7)	(5.8)	(6.9)
Net Plant at Year End	**27.2**	**28.3**	**29.6**	**30.3**	**31.2**	**32.3**

Working Capital

A breakdown of working capital for each acquired utility service area is included in the table below.

2021 Working Capital ($million)	
Norfolk	4.3
Haldimand	5.6
Woodstock	5.0
Total	14.9

Please refer to Exhibit D1, Tab 1, Schedule 1, for details regarding Hydro One's calculation of, and assumptions behind, the cash working capital forecast.

TAB 33

Vulnerable Energy Consumers Coalition Interrogatory # 92

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 6-7
A-07-01 Page 11 Lines 5-14
2021 CAM
B1-01-01 Appendix A Pages 6-11

Interrogatory:

a) Please provide a schedule that sets out the gross fixed assets, accumulated depreciation and net fixed assets for each acquired utility as of January 1, 2021 that was added to the opening balances per page 11?

b) Please reconcile the values reported in part (a) with the Net Plant for each acquired utility reported in Appendix A.

c) Please provide a schedule that sets out the Net Plant allocated to each of the six acquired utility rate classes per the 2021 CAM.

d) Please provide schedules that contrast:
   i. The Net Plant allocated to the Acq. UR, Acq. UGSe, and Acq. UGSd classes per the 2021 CAM with the total Net Plant attributable to Woodstock in 2021 (per Appendix A)
   ii. The Net Plant allocated to the Acq. Res, Acq. GSe, and Acq. GSd classes per the 2021 CAM with the total Net Plant attributable to Haldimand and Norfolk in 2021 (per Appendix A)

Response:

a) Please see Exhibit I-53-CCC-71

b) Please see Exhibit I-53-CCC-71

c) The Table below provides the Net Plant allocated to each of the six acquired rate classes in 2021:

	AUR	AUGe	AUGd	AR	AGSe	AGSd
Net Plant Allocated to Acquired Rate Classes in 2021 ($M)	$26.5	$7.1	$8.3	$95.1	$24.0	$26.6

d) i. & ii. The Table below compares the total Net Plant allocated to the acquired customers in the 2021 CAM and that provided in B1-01-01 Appendix A:

	Net Plant Allocated per CAM 2021 ($M)	Average Net Plant per B1-01-01, Appendix A
Woodstock	$41.9	$31.7
Norfolk+Haldimand	$145.7	$121.7

TAB 34

Vulnerable Energy Consumers Coalition Interrogatory # 95

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

Previous Proceeding
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model
EB-2010-0145 (Woodstock) Cost Allocation Model
EB-2016-0276, Hydro One Networks Final Argument, page 4

Interrogatory:

a) Please provide schedules that for each of Haldimand, Woodstock and Norfolk sets out the values and the percentage of total OM&A attributed their Residential GS<50 and GS>50 customer classes in the last Cost Allocation used for rate setting prior to acquisition.

b) Please provide a schedule setting out the total OM&A attributed to each of the acquired customer classes per the 2021 CAM.

c) Please provide a schedule that sets out, for each of the three acquired utilities, the total OM&A added to the Hydro One Networks' 2021 revenue requirement/2021 CAM.

Response:

a) Table below provides the requested information:

	OM&A	Residential	GS < 50 kW	GS 50-4,999 kW*	Total OM&A for all Rate Classes
Woodstock (EB-2010-0145)	**($)**	$2,627,287	$560,751	$572,009	$4,169,207
	(%)	63.0%	13.4%	13.7%	
Norfolk (EB-2011-0272)	**($)**	$3,817,789	$865,723	$821,213	$5,651,555
	(%)	67.6%	15.3%	14.5%	
Haldimand (EB-2013-0134)	**($)**	$5,758,497	$1,032,520	$747,013	$8,217,075
	(%)	70.1%	12.6%	9.1%	

* For Woodstock, this columns shows data for the GS 50-999kW.

b) The Table below provides the requested information:

HONI - 2021 OMA ($)	AUR	AUGe	AUGd	AR	AGSe	AGSd
	$2,871,657	$512,840	$935,312	$8,811,860	$1,847,606	$1,428,178

c) The schedule below shows incremental OM&A for each of the acquired utilities that will be added to Hydro One's revenue requirement in 2021. See part a) above the the OM&A allocated to each acquired utility.

Acquired Utilities OM&A	**2021**
Haldimand	5.3
Norfolk	3.2
Woodstock	2.2
Total	**10.7**

TAB 35

UNDERTAKING – JT 3.18-19

Reference

56-SEC-96

Preamble:

Part (c) iii) of the response states: "The combined Hydro One and Acquired Utilities' revenue requirement is $9 M less than would have been in the absence of the transaction".

Undertaking

a) Please clarify whether the referenced quote was referring to the difference in revenue requirement, as stated in the response, or to the difference in OM&A costs.

b) If the reference was to the overall revenue requirement, please provide the 2021 forecast values for: i) Hydro One's distribution revenue requirement and ii) the Acquired Utilities' revenue requirement, in the absence of the transaction underpinning the response.

c) If the reference was actually to the difference in 2021 OM&A costs then, based on the forecasts of status quo OM&A and capital expenditures provided in the relevant acquisition proceedings, please provide a forecast of the 2021 revenue requirement for the Acquired Utilities, in the absence of the transaction.

Response

a) Hydro One confirms that the incremental OM&A cost to serve the three acquired utility's customers is $10.7M, as compared to the status quo OM&A of $19.7M.

The response also indicated that "The combined Hydro One and Acquired Utilities' revenue requirement is $9M less than it would have been in absence of the transaction." This was incorrect, the revenue requirement savings should have said $11.3 million.

b) Not Applicable

Witness: JODOIN Joel

c) The equivalent calculation for total revenue requirement is $11.3 million, where $9.0 million represents OM&A.

Acquired Utilities 2021 Revenue Requirement			
$million	Status Quo	Post-Integration	Savings
OM&A	19.7	10.7	9.0
Depreciation	5.0	4.3	0.8
Return on Debt	4.9	4.3	0.6
Return on Equity	6.8	5.9	1.0
Income Tax	0.4	0.5	0.0
Revenue Requirement	36.9	25.6	11.3

TAB 36

School Energy Coalition Interrogatory # 96

Issue:

Issue 56: Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?

Reference:

G1-03-01

Attached to these interrogatories as Schedule 2 is a breakdown of the costs and rate base allocated to the six new Acquired classes in the cost allocation model filed in December (the "December CAM"), plus additional comparisons as set forth below. With respect to the allocations to the customers of the Acquired Utilities:

Interrogatory:

a. Please confirm that the figures in lines 1-4, 9-11, 13, and 16-19 accurately reflect the amounts in the December CAM allocated to these rate classes.
b. Please confirm that the figures in line 23 are a reasonable estimate of the costs allocated to the Combined Classes for 2021, or alternatively replace those estimates with the Hydro One's estimates.
c. With respect to the OM&A allocations:
    i. Please explain why the estimated OM&A costs to serve the Woodstock customers in 2021 are $2.2 million, but the allocated costs are $3.9 million.
    ii. Please explain why the estimated OM&A costs to serve the Norfolk and Haldimand customers in 2021 are $8.5 million, but the allocated costs are $11.9 million.
    iii. Please confirm that the 2021 OM&A savings of $9.0 million claimed in EB-2016-0276 were in fact not correct, and that the correct figure should be $3.9 million less the OM&A amounts allocated to the Combined Classes. Please estimate that figure.
d. With respect to the rate base allocations:
    i. Please advise the correct allocation in line 12 of the $166.0 million in transferred ate base from A/7/1, p. 11 as between the Woodstock classes and the Norfolk/Haldimand classes. Please advise the amount of that $166.0 of rate base that is reasonably allocable to the Combined Classes.
    ii. Please advise the amount of depreciation in 2021 reasonably attributable to the $151.1 million of net fixed assets transferred on January 1, 2021, and provide a breakdown by rate class. Please compare these amounts to the amounts allocated, and provide an explanation of the higher allocation.

iii. Please advise the amount of interest in 2021 reasonably attributable to the $166.0 million of rate base transferred on January 1, 2021, and provide a breakdown by rate class. Please compare these amounts to the amounts allocated, and provide an explanation of the higher allocation.

iv. Please advise the amount of ROE/net income in 2021 reasonably attributable to the $166.0 million of rate base transferred on January 1, 2021, and provide a breakdown by rate class. Please compare these amounts to the amounts allocated, and provide an explanation of the higher allocation.

v. Please advise the amount of PILs in 2021 reasonably attributable to the $166.0 million of rate base transferred on January 1, 2021, and provide a breakdown by rate class. Please compare these amounts to the amounts allocated, and provide an explanation of the higher allocation.

e. With respect to the cost savings claimed:

i. Please confirm that the actual revenues of the three Acquired Utilities in 2014, prior to the transfer to the Hydro One, totalled $33.7 million.

ii. Please confirm that, to get to the total cost to serve these customers in 2021, $41.9 million, the Acquired revenue requirement would have had to increase by 24.6%, a compound annual growth rate of 3.2% per year. Please confirm that, had those utilities kept their increases to an amount equal to or less than that, no cost savings would have occurred.

Response:

a) It is confirmed that the figures in lines 1-3, 10, 13 and 16-19 in SEC's Schedule 2 accurately reflect the amounts in the Cost Allocation Model filed on December 21, 2017 ("December CAM") allocated to the acquired rate classes.

Line 4: The total OM&A should include the costs that are being directly allocated to the acquired rate classes. Below are the updated OM&A costs for the acquired rate classes:

Table 1

	AUR	AUGe	AUGd	Woodstock	AR	AGe	AGd	Norfolk/ Haldimand	Total Acquired
OM&A									
Distribution Costs	$1,113,873	$217,669	$231,905	$1,563,446	$3,914,134	$860,710	$760,909	$5,535,752	$7,099,199
Customer Related Costs	$990,150	$155,982	$49,672	$1,195,805	$2,529,476	$486,762	$109,147	$3,125,384	$4,321,189
General and Administration	$767,634	$139,189	$197,548	$1,104,370	$2,368,250	$500,134	$372,797	$3,241,182	$4,345,552
Directly Allocated Costs	$0	$0	$456,187	$456,187	$0	$0	$185,326	$185,326	$641,513
Totals	$2,871,657	$512,840	$935,312	$4,319,809	$8,811,860	$1,847,606	$1,428,178	$12,087,644	$16,407,453

The information on Lines 9 & 11 is not correct. Below is the updated rate base for the acquired rate classes, as discussed in the response to Exhibit I-56-SEC-90 part f).

Table 2

	AUR	AUGe	AUGd	Woodstock	AR	AGe	AGd	Norfolk/ Haldimand	Total Acquired
Rate Base									
Net Plant	$26,507,933	$7,053,375	$8,329,435	$41,890,744	$95,097,168	$23,989,153	$26,565,144	$145,651,465	$187,542,209
Working Capital	$1,536,699	$651,895	$2,083,880	$4,272,474	$4,750,287	$1,607,713	$3,446,235	$9,804,236	$14,076,710
Total Rate Base	$28,044,632	$7,705,270	$10,413,315	$46,163,218	$99,847,455	$25,596,867	$30,011,379	$155,455,701	$201,618,919

b) Hydro One does not confirm the figures in line 23 in SEC's Schedule 2. Table below provides Hydro One's estimates of the total costs allocated to the Combined Classes:

Table 3

	Woodstock	Norfolk/ Haldimand	Total Acquired
Total Allocated Costs to the Combined Classes	$431,727	$1,109,316	$1,541,043

c)

i) The $2.2M estimated cost to serve Woodstock customers represents the incremental cost added to revenue requirement as a result of the acquisition. The $4.3M allocated cost, includes an allocated share of common corporate costs (asset management, finance and information technology) and a share of customer service related costs.

ii) The allocated OM&A costs to serve Norfolk and Haldimand are $12.1M. These costs are higher than the estimated $8.5M in incremental for the same reasons as detailed in the response to part i) above.

iii) This is not confirmed. The incremental OM&A cost to serve the three acquired utility's customers is $10.7M, as compared to the $19.7M provided in Schedule 1. As shown in Exhibit A, Tab 3, Schedule 1, Table 2, Hydro One's legacy 2020 OM&A cost of $601.9M has only been increased in 2021 and 2022 by the inflation less productivity factor (1.45%). Added to that is the $10.7 million incremental cost to serve the three acquired utilities in 2021, with that amount inflated by 1.45% in 2022. Therefore, the OM&A cost savings claimed in EB-2016-0276 are correct and are in fact $9M. The combined Hydro One and Acquired Utilities' revenue requirement is $9M less than it would have been in absence of the transaction.

d)

i) The allocation of the $166 million in transferred rate base between the three acquired utilities is as follows.

Table 4

$/M	Net Plant	Working Capital	Rate Base
Norfolk	57.8	4.3	62.1
Haldimand	61.9	5.6	67.5
Woodstock	31.2	5	36.2
TOTAL	$150.9	$14.9	$165.8

For the purposes of financial reporting, there is no information by rate class and so a "combined classes" share of the rate base is not identified, however, in the response to I-56-SEC-94 Hydro One has provided an estimate of the amount of rate base allocated to the combined classes for the purposes of cost allocation.

ii) The amount of depreciation attributed to the acquired customers, included in Hydro One's total revenue requirement in 2021 is $4.3 million. It is not possible to break down this amount by class.

The amount of depreciation allocated to the acquired classes is $11.5M plus an estimated $0.4M of "combined" classes depreciation. This is higher than the value noted above because it includes the deprecation associated with non-local distribution assets and common general plant used to serve the Acquired Utilities' customers, and it also includes a share of Hydro One's total deprecation based on the Acquired Utilities' calculated GBV as a share of Hydro One's total GBV. This approach to allocating depreciation is different than the basis for the depreciation amount included in Hydro One's revenue requirement, which calculates depreciation based on GBV of assets for the Acquired Utilities *that was reset* to their NBV of assets at the time the acquisition was completed.

iii) The amount of interest attributable to the acquired customers, included in Hydro One's total revenue requirement in 2021 is $4.3M. It is not possible to break down this amount by class.

The amount of interest allocated to the acquired classes is $4.9M plus an estimated $0.2M of "combined" classes interest. This is higher than the amount above because it includes the interest associated with non-local distribution assets and common general plant used to serve the Acquired Utilities' customers.

iv) The ROE attributable to the acquired customers, included in Hydro One's total revenue requirement in 2021 is $5.9M.

The amount of ROE/Net Income allocated to the acquired classes is $6.9M plus an estimated $0.3M of "combined" classes Net Income. This is higher than the amount above because it includes the Net Income associated with non-local distribution assets and common general plant used to serve the Acquired Utilities' customers.

v) The amount of PILS attributed to the acquired customers, included in Hydro One Distribution's total revenue requirement in 2021 is $0.5 million. The amount of PILS allocated to the acquired classes is $1.6M plus an estimated $0.1M of "combined" classes PILS. This is higher than the amount above because it includes the PILS associated with non-local distribution assets and common general plant used to serve the Acquired Utilities' customers.

e)

i) Per the 2014 Yearbook of Electricity Distributors, the total distribution revenue of the three acquired utilities was $33.7 million in 2014.

ii) The impact on Hydro One Distribution's 2021 revenue requirement that relates to the integration of the Acquired customers is $25.6 million. This is the equivalent to a compound annual growth decrease of 3.85% per year from 2014 to 2021.

iii) The total allocated cost to serve the acquired utility customers is $41.2M (plus an estimated $1.5M for the "combined" classes costs). Note that this exceeds the $34.9M in costs that Hydro One is proposing to collect from the new acquired rate classes in 2021.

iv) Hydro One discussed the cost savings achieved in the response to c) iii.

TAB 37

To provide a more meaningful assessment of the impact of Hydro One's application on acquired customers, Hydro One has compared its proposed 2021 and 2022 rates against what the Acquired Utilities' rates would have been had they ***not*** been acquired by Hydro One ("No Acquisition" scenario).

Under the "No Acquisition" scenario, the three Acquired Utilities are assumed to have filed either a Price Cap IR or Cost of Service/Rebasing rate application with the OEB annually from when their rates were last approved. Each utility is assumed to have filed a Cost of Service/Rebasing application consistent with the RRF (i.e. four years after their last rebasing under 3rd generation IRM and then every five years thereafter). For rebasing years, the distribution rates are assumed to increase by 6.3% which represents the average OEB-approved increase in base distribution rates for the residential and general service < 50kW rate classes of all distributors whose rates were rebased in 2015, 2016 and 2017[2]. For the remaining years, the Price Cap IR adjustment is applied based on the actual OEB-approved inflation, productivity and stretch factors until 2018, at which point they are held constant. Details of the distributors and rebasing increases used to establish the 6.3% value, as well as the annual inflation, stretch and Price Cap IR adjustment factors assumed for each Acquired Utility, are provided in Attachment 6.

<u>Bill Impact Assessment</u>

Table 12 shows the Hydro One proposed 2021 charges compared against the 2021 escalated Acquired Utility charges under the "No Acquisition" scenario. For reference purposes, the Acquired Utilities' charges at the time of acquisition are also included in Table 12.

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[2] This is consistent with the approach used by the OEB to assess the appropriate increase to apply in the setting of base distribution rates for Algoma Power Inc. and Hydro One Remote Communities Inc. as part of their distribution rates applications.

TAB 38

Average increase for a rebasing year

2015/2014 Average Increase for Residential class	7.5%
2015/2014 Average Increase for GS<50kW class	6.9%
2016/2015 Average Increase for Residential class	8.1%
2016/2015 Average Increase for GS<50kW class	6.6%
2017/2016 Average Increase for Residential class	4.1%
2017/2016 Average Increase for GS<50kW class	4.8%
Average Increase	**6.3%**

Growth assumptions used for each year

Year	Norfolk (2012 Rebasing)				Haldimand (2014 Rebasing)				Woodstock (2011 Rebasing)			
	Price Cap IR			CoS	Price Cap IR			CoS	Price Cap IR			CoS
	Inflation Factor	Stretch Factor	Final Adjustment Factor		Inflation Factor	Stretch Factor	Final Adjustment Factor		Inflation Factor	Stretch Factor	Final Adjustment Factor	
2014	1.70%	0.30%	1.40%		N/A				N/A			
2015	1.60%	0.30%	1.30%		1.60%	0.15%	1.45%					6.30%
2016				6.30%	2.10%	0.15%	1.95%		2.10%	0.60%	1.50%	
2017	1.90%	0.30%	1.60%		1.90%	0.15%	1.75%		1.90%	0.45%	1.45%	
2018	1.20%	0.30%	0.90%					6.30%	1.20%	0.45%	0.75%	
2019	1.20%	0.30%	0.90%		1.20%	0.15%	1.05%		1.20%	0.45%	0.75%	
2020	1.20%	0.30%	0.90%		1.20%	0.15%	1.05%					6.30%
2021				6.30%	1.20%	0.15%	1.05%		1.20%	0.45%	0.75%	

2015/2014 Average Increase for Residential Class

Residential	MFC 2015	VC 2015	MFC 2014	VC 2014	TB 2015	TB 2014	$ Change	% Change
Festival Hydro Inc.	16.27	12.30	15.18	12.68	28.57	27.86	0.72	2.57%
Hearst Power Distribution Company Limited	11.93	9.45	9.19	12.00	21.38	21.19	0.19	0.90%
Horizon Utilities Corporation	15.72	11.63	14.92	11.03	27.35	25.95	1.41	5.42%
Hydro One Brampton Networks Inc.	11.07	11.63	10.10	11.03	22.70	21.13	1.58	7.46%
Niagara Peninsula Energy Inc.	18.43	13.88	16.06	12.08	32.31	28.14	4.18	14.84%
North Bay Hydro Distribution Limited	15.71	10.58	14.64	9.83	26.29	24.47	1.82	7.44%
St. Thomas Energy Inc.	14.21	12.60	11.53	12.00	26.81	23.53	3.28	13.94%

Source of data: 2014 and 2015 Rates Database published by the OEB

2015/2014 Average Increase for Residential Class (excluding Algoma) **7.5%**

2015/2014 Average Increase for General Service<50 kW Class

General Service < 50kW	**MFC 2015**	**VC 2015**	**MFC 2014**	**VC 2014**	**TB 2015**	**TB 2014**	**$ Change**	**% Change**
Festival Hydro Inc.	30.66	30.40	29.44	29.80	61.06	59.24	1.82	3.07%
Hearst Power Distribution Company Limited	18.30	12.40	19.76	13.40	30.70	33.16	-2.46	-7.42%
Horizon Utilities Corporation	39.14	20.20	33.21	17.20	59.34	50.41	8.93	17.71%
Hydro One Brampton Networks Inc.	24.39	32.20	18.23	32.00	56.59	50.23	6.36	12.66%
Niagara Peninsula Energy Inc.	37.76	27.60	37.79	27.60	65.36	65.39	-0.03	-0.05%
North Bay Hydro Distribution Limited	23.27	35.80	21.69	33.40	59.07	55.09	3.98	7.22%
St. Thomas Energy Inc.	23.20	31.60	17.47	30.20	54.80	47.67	7.13	14.96%

Source of data: 2014 and 2015 Rates Database published by the OEB

2015/2014 Average Increase for GS<50 kW Class (excluding Algoma) **6.9%**

2016/2015 Average Increase for Residential Class

Residential	MFC 2016	VC 2016	MFC 2015	VC 2015	TB 2016	TB 2015	$ Change	% Change
Entegrus Powerlines Inc. - Chatham-Kent	18.98	5.78	18.98	6.60	24.76	25.58	-0.82	-3.00%
Grimsby Power Inc.	19.55	7.43	15.69	9.08	26.98	24.77	2.21	9.00%
Guelph Hydro Electric Systems Inc.	18.93	10.80	14.49	13.20	29.73	27.69	2.04	7.00%
Halton Hills Hydro Inc.	17.04	7.50	12.72	9.00	24.54	21.72	2.82	13.00%
Horizon Utilities Corporation	18.8	9.08	15.72	11.63	27.88	27.35	0.53	2.00%
Hydro Ottawa Limited	12.96	14.48	9.67	17.55	27.44	27.22	0.22	1.00%
Kingston Hydro Corporation	13.98	10.43	12.56	11.55	24.41	24.11	0.30	1.00%
Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkhill	18.98	5.78	14.43	10.95	24.76	25.38	-0.62	-2.00%
Entegrus Powerlines Inc. - Dutton	18.98	5.78	13.44	9.53	24.76	22.97	1.79	8.00%
Entegrus Powerlines Inc. - Newbury	18.98	5.78	12.52	9.45	24.76	21.97	2.79	13.00%
Milton Hydro Distribution inc.	18.61	8.25	15.43	10.80	26.86	26.23	0.63	2.00%
Oshawa PUC Networks Inc.	11.21	10.65	8.47	9.00	21.86	17.47	4.39	25.00%
Ottawa River Power Corporation	14.02	9.68	10.99	11.25	23.70	22.24	1.46	7.00%
PowerStream Inc. - Barrie	12.9	10.73	12.67	10.50	23.63	23.17	0.45	2.00%
Toronto Hydro-Electric System Limited	22.78	14.10	18.63	11.54	36.88	30.17	6.72	22.00%
Wasaga Distribution Inc.	14.91	8.85	11.57	10.80	23.76	22.37	1.39	6.00%
Waterloo North Hydro Inc.	19.71	11.55	15.2	14.40	31.26	29.60	1.66	6.00%
Wellington North Power Inc.	23.97	11.48	18.49	13.88	35.45	32.37	3.08	10.00%

Source of data: EB-2016-0055 (Algoma Power Inc. 2017 Rates Application). Hydro One received the detailed table above from Algoma Power Inc. (Algoma Power Inc. received this table from OEB staff). The table was compiled by OEB Staff and was used to determine the 2017 Algoma Power Inc. RRRP adjustment factor (see OEB Decision and Rate Order, issued on December 8, 2016, page 1).

2016/2015 Average Increase for Residential Class (Entegrus was excluded because rate increases are distorted by the impact of harmonization) 8.1%

2016/2015 Average Increase for General Service<50 kW Class

General Service < 50kW	MFC 2016	VC 2016	MFC 2015	VC 2015	TB 2016	TB 2015	$ Change	% Change
Entegrus Powerlines Inc. - Chatham-Kent	30	19.80	34.84	23.6	49.80	58.44	-8.64	-14.78%
Grimsby Power Inc.	24.32	37.40	26.67	26.2	61.72	52.87	8.85	16.74%
Guelph Hydro Electric Systems Inc.	16.33	27.40	15.57	26.2	43.73	41.77	1.96	4.69%
Halton Hills Hydro Inc.	27.51	19.80	27.51	17	47.31	44.51	2.80	6.29%
Horizon Utilities Corporation	41.21	21.20	39.14	20.2	62.41	59.34	3.07	5.17%
Hydro Ottawa Limited	17.23	43.20	16.72	42	60.43	58.72	1.71	2.91%
Kingston Hydro Corporation	14.27	29.20	25.85	21.2	43.47	47.05	-3.58	-7.61%
Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkhill	30	19.80	19.06	10.2	49.80	29.26	20.54	70.20%
Entegrus Powerlines Inc. - Dutton	30	19.80	27.45	12.2	49.80	39.65	10.15	25.60%
Entegrus Powerlines Inc. - Newbury	30	19.80	22.91	22.8	49.80	45.71	4.09	8.95%
Milton Hydro Distribution inc.	16.51	34.80	16.42	34.8	51.31	51.22	0.09	0.18%
Oshawa PUC Networks Inc.	16.02	31.40	8.38	34	47.42	42.38	5.04	11.89%
Ottawa River Power Corporation	22.02	25.00	22.97	21	47.02	43.97	3.05	6.94%
PowerStream Inc.	26.55	28.40	26.08	27.8	54.95	53.88	1.07	1.99%
Toronto Hydro-Electric System Limited	30.47	56.36	24.8	45.86	86.83	70.66	16.17	22.88%
Wasaga Distribution Inc.	14.76	29.80	13.54	27.4	44.56	40.94	3.62	8.84%
Waterloo North Hydro Inc.	31.96	31.80	31.96	28.6	63.76	60.56	3.20	5.28%
Wellington North Power Inc.	41.71	35.80	39.25	33.6	77.51	72.85	4.66	6.40%

Source of data: EB-2016-0055 (Algoma Power Inc. 2017 Rates Application). Hydro One received the detailed table above from Algoma Power Inc. (Algoma Power Inc. received this table from OEB staff). The table was compiled by OEB Staff and was used to determine the 2017 Algoma Power Inc. RRRP adjustment factor (see OEB Decision and Rate Order, issued on December 8, 2016, page 1).

2016/2015 Average Increase for GS<50 kW Class (Entegrus was excluded because rate increases were distorted by the impact of harmonization) 6.6%

2017/2016 Average Increase for Residential Class

Residential	2017 MFC	2017 VC	2016 MFC	2016 VC	TB 2017	TB 2016	$ change	% Change
Atikokan Hydro Inc.	42.31	6.00	36.95	8.32	48.31	45.27	3.04	6.72%
Brantford Power Inc.	17.80	6.08	14.64	8.80	23.88	23.44	0.44	1.88%
Canadian Niagara Power Inc. - Eastern Ontario Power	27.72	9.76		12.16	37.48	35.60	1.88	5.28%
Canadian Niagara Power Inc. - Fort Erie	27.72	9.76		12.16	37.48	35.60	1.88	5.28%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	27.72	9.76		12.16	37.48	2018.00	1.88	5.28%
Horizon Utilities Corporation	21.34	6.48	18.80	9.68	27.82	28.48	-0.66	-2.32%
Hydro Ottawa Limited	16.60	12.08	12.96	15.44	28.68	28.40	0.28	0.99%
Kingston Hydro Corporation	18.54	6.56	13.98	11.12	25.10	25.10	0.00	0.00%
Lakefront Utilities Inc.	16.00	6.08	13.14	9.04	22.08	22.18	-0.10	-0.50%
London Hydro Inc.	19.34	6.56	16.42	9.68	25.90	26.10	-0.20	-0.77%
Northern Ontario Wires Inc.	30.30	7.36	24.25	9.84	37.66	34.09	3.57	10.47%
Oshawa PUC Networks Inc.	14.22	8.72	11.21	11.36	22.94	22.57	0.37	1.64%
PowerStream Inc.	18.51	10.40	12.90	11.44	28.91	24.34	4.57	18.78%
Renfrew Hydro Inc.	17.30	9.20	13.97	11.60	26.50	25.57	0.93	3.64%
Toronto Hydro-Electric System Limited	27.69	12.10	22.78	15.04	39.79	37.82	1.97	5.20%
Welland Hydro-Electric System Corp.	22.26	5.92	18.76	8.40	28.18	27.16	1.02	3.76%

Source of data: EB-2017-0051 (Hydro One Remote Communities Inc. 2018 Rates Application), Exhibit G1, Schedule 2, Tab 1, Attachment 1. This information was compiled by Board Staff and was used to determine 2018 Hydro One Remotes Communities Inc. rate increases.

2017/2016 Average Increase for Residential Class **4.1%**

2017/2016 Average Increase for General Service<50 kW Class

General Service < 50kW	2017 MFC	2017 VC	2016 MFC	2016 VC	TB 2017	TB 2016	$ change	% Change
Atikokan Hydro Inc.	76.23	9.40	76.23	19.20	85.63	95.43	-9.80	-10.27%
Brantford Power Inc.	30.14	15.80	26.46	13.80	45.94	40.26	5.68	14.11%
Canadian Niagara Power Inc. - Eastern Ontario Power	30.02	48.80		46.00	78.82	74.26	4.56	6.14%
Canadian Niagara Power Inc. - Fort Erie	30.02	48.80		46.00	78.82	74.26	4.56	6.14%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	30.02	48.80		46.00	78.82	2018.00	4.56	6.14%
Horizon Utilities Corporation	41.42	21.40	41.21	21.20	62.82	62.41	0.41	0.66%
Hydro Ottawa Limited	17.89	45.40	17.23	43.20	63.29	60.43	2.86	4.73%
Kingston Hydro Corporation	14.59	30.20	14.27	29.20	44.79	43.47	1.32	3.04%
Lakefront Utilities Inc.	23.96	16.40	23.96	17.20	40.36	41.16	-0.80	-1.94%
London Hydro Inc.	32.25	21.60	32.25	20.80	53.85	53.05	0.80	1.51%
Northern Ontario Wires Inc.	31.76	35.40	28.27	31.60	67.16	59.87	7.29	12.18%
Oshawa PUC Networks Inc.	16.24	32.20	16.02	31.40	48.44	47.42	1.02	2.15%
PowerStream Inc.	28.74	36.60	26.55	28.40	65.34	54.95	10.39	18.91%
Renfrew Hydro Inc.	31.25	30.60	31.25	30.60	61.85	61.85	0.00	0.00%
Toronto Hydro-Electric System Limited	32.68	60.46	30.47	56.36	93.14	86.83	6.31	7.27%
Welland Hydro-Electric System Corp.	30.91	18.20	29.23	17.20	49.11	46.43	2.68	5.77%

Source of data: EB-2017-0051 (Hydro One Remote Communities Inc. 2018 Rates Application), Exhibit G1, Schedule 2, Tab 1, Attachment 1. This information was compiled by Board Staff and was used to determine 2018 Hydro One Remotes Communities Inc. rate increases.

2017/2016 Average Increase for GS<50 kW Class	**4.8%**

TAB 39

Vulnerable Energy Consumers Coalition Interrogatory # 98

Issue:

Issue 49: Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

Reference:

H1-01-01 Page: 15-16
EB-2012-0410, Board Report, page 26

Interrogatory:

a) For each customer class that is transitioning to a 100% fixed charge, please provide a schedule that for each year of transition demonstrates whether the change in the fixed charge meets the Board's $4 criterion.

Response:

a) The Table below provides the requested information:

Rate Class		2015	2016	2017	2018	2019	2020	2021	2022
UR	Fixed Charge ($/Month)	$ 19.07	$ 22.29	$ 24.78	$ 27.71	$ 31.23	$ 35.85		
	Yr-Over-Yr Difference ($)		$ 3.22	$ 2.49	$ 2.93	$ 3.52	$ 4.62		
R1	Fixed Charge ($/Month)	$ 26.03	$ 30.11	$ 33.77	$ 37.79	$ 42.19	$ 47.06	$ 52.39	$ 58.53
	Yr-Over-Yr Difference ($)		$ 4.08	$ 3.66	$ 4.02	$ 4.40	$ 4.87	$ 5.33	$ 6.14
R2	Fixed Charge ($/Month)	$ 65.52	$ 72.86	$ 80.33	$ 88.61	$ 97.68	$ 107.71	$ 118.85	$ 131.71
	Yr-Over-Yr Difference ($)		$ 7.34	$ 7.47	$ 8.28	$ 9.07	$ 10.02	$ 11.15	$ 12.86
Seasonal	Fixed Charge ($/Month)	$ 28.62	$ 32.47	$ 36.28	$ 40.52	$ 45.07	$ 50.05	$ 55.44	$ 61.63
	Yr-Over-Yr Difference ($)		$ 3.85	$ 3.80	$ 4.24	$ 4.55	$ 4.98	$ 5.39	$ 6.18

Hydro One acknowledges the fact that the fixed charge increases in some cases do not meet the $4 limit set by the OEB. However, Hydro One has followed the direction provided by the OEB in its December 22, 2015 Decision and Order in EB-2015-0079 to transtion the UR rate class to fully-fixed rates over 5 years and R1, R2 and Seasonal classes over 8 years.

TAB 40

UNDERTAKING – JT 3.18-16

Topic: Transition to 100% Residential Fixed Rate

Reference

49-VECC-98

Preamble:

VECC 98 requested that Hydro One provide a table demonstrating whether its proposed transition to a fully fixed charge for its Residential and Seasonal classes met the Board's $4 impact criterion.

Undertaking

a) Please confirm that the table provided shows the total change in the monthly fixed charge for each affected class over the CIR period (i.e., the change shown is the result of both the move to a fully fixed charge plus the annual increase in rates for each class).

b) Please confirm that Appendix 12 of the Board's Revenue Requirement Work Form calculates the change in monthly fixed charge – excluding the impact of the overall rate increase.

c) Please re-do the response to VECC 98 using the same approach as the RRWF.

Response

a) Confirmed. The table provided in response to I-49-VECC-098 part a is the resulting monthly fixed charge of both the move to a fully fixed charge plus the annual increase in rates for each class.

b) Confirmed. The change in fixed rate that is calculated as a part of the Checks table in the Board's Revenue Requirement Work Form Tab 12 "New Rate Design Policy For Residential Customers" (cell B48) excludes the impact of the overall rate increase due to changes in revenue requirement.

c) The Excel attachment Hydro One provided in response to I-49-Staff-245 provides detailed calculations of the transition to all-fixed residential distribution rates for UR, R1, R2 and seasonal rate classes using the OEB's RRWF approach.

In I-49-Staff-245 Attachment 1, the year-over-year difference (cell B48) shows the impact of the move to a fully fixed charge only (excluding the impact of the overall rate increase due to changes in revenue requirement). The monthly fixed charges presented in that Attachment are the result of using the OEB's RRWF approach. Hydro One is not proposing the adoption of these fixed charges.

TAB 41

OEB Staff Interrogatory # 245

Issue:
Issue 49: Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

Reference:
E1-01-01 Page: 4
H1-01-02
EB-2013-0416, dated 2014-05-30
G1-04-01 Page: 16

Interrogatory:
At the first reference, referring to the revenue requirement workform (RRWF), Hydro One states "Tabs 10 through 13 of the workform have not been completed as the template does not allow for the necessary flexibility required for Hydro One's cost allocation and rate design requirements." Tab 12 of the RRWF provides the expected methodology for the implementation of the new rate design policy for residential customers.

a) Please explain why Hydro One could not have used one instance of Tab 12 for each transition year in each rate residential rate class. What flexibility was missing?

b) Please provide a derivation of proposed fixed charges for each residential class in each year using either Tab 12 of the RRWF, or an alternative worksheet which replicates the functionality to the extent possible.

Response:
a) Hydro One could have used one instance of Tab 12 for each transition year in each residential rate class to implement the Board's move to all-fixed residential distribution rates policy. However, using this approach would involve creating and managing 18 instances of Tab 12 (3 for UR class, 5 for R1 class, 5 for R2 class and 5 for seasonal class). Hydro One's approach is easier to manage as it integrates the rate design for all rate classes and the calculations for the move to all-fixed residential distribution rates in one worksheet for each year from 2018 to 2022. Using Hydro One's approach also results in a smoother transition to all-fixed rates for customers as its calculations consider the impact of both the proposed overall year-over-year revenue requirement change and the transition to all-fixed residential distribution rates.

As illustrated in the table below for the R1 class in 2018, Hydro One's approach will result in a smaller increase in the fixed charge as compared to the RRWF Workform, which helps mitigate the impact on low volume customers during rebasing.

	RRWF Tab 12 Approach 2018 R1 Rate Class	Hydro One 2018 Rate Design Sheet
2017 Fixed Charge	33.77	33.77
Impact of Increasing Revenue Requirement on Fixed Charge	35.58	
Proposed 2018 Fixed Charge based on 6 years remaining for transition	39.29	37.79
Indicated Increase in Fixed Charge	=39.29-35.58=3.71	
Actual Increase in Fixed Charge over 2017	=39.29-33.77=5.52	=37.79-33.77=4.02

b) A derivation of the proposed fixed charges for each residential class in each year using Tab 12 of the RRWF is provided in live Excel form as I-49-Staff-245-01.

TAB 42

Vulnerable Energy Consumers Coalition Interrogatory # 110

Issue:

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

H1-02-03 Page: 37-39

Interrogatory:

a) Why is the time required for an after regular hours reconnect (Table 13) significantly more than for a reconnect during regular hours (Table 12)?

Response:

a) The time required for an after regular hours reconnect (Table 13) is higher than the time required for a regular hours reconnect (Table 12), because after hours, the employee requires time to travel to and from the site, whereas during regular hours, the employee will already be in the vicinity of the work. As shown in Exhinit H1, Tab 2, Schedule 3, Attachment 1, Appendix B, the average driving time in Table B-9 on page 99 is 0.4 hours. Comparatively, in Table B-11 on page 101, the average driving time is 0.91 hours (to travel to the site), and that time is doubled to return after the reconnection is completed.

Witness: BOLDT John

TAB 43

Vulnerable Energy Consumers Coalition Interrogatory # 116

Issue:

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

H1-02-03 Page: 79

Interrogatory:

a) For net metering projects that have a capacity of less than 10 kW what work must Hydro One perform and are there any charges assessed against the customer?

Response:

a) For a standard micro net-metered connection (10 kW and under) customers are billed a standard fee. This fee covers the costs associated with the installation of a bi-directional meter, labour and equipment charges, in order to connect the generation facility.

   For a non-standard micro net-metered project such as those that require a transformer upgrade, or pole changes etc., an assessment is required in order to determine the costs specific to the project. Customers will be billed any applicable upgrade charges, as well as the costs associated with the installation of a bi-directional meter, labour and equipment charges, in order to connect the generation facility.

   Customers are responsible to pay for the costs related to the connection of a generation facility.

TAB 44

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2017-0049** **Hydro One Networks Inc.**

VOLUME: **Technical Conference**

DATE: **March 2, 2018**

and then you -- the policy is trying to follow through those principles... all those principles. I understand what your principle going -- going and looking at this is.

MR. MERALI: That the customer would be charged a fee for that connection.

MR. HARPER: Okay. Fine. No, thank you. I understand your point. That's all I was trying to do at this point in time.

The next one I have is trying -- and actually, it -- unfortunately, it has to do with two IRs. One was authored by Mr. Boldt, one was authored by yourself. So again, if I'm in the wrong spot, let me know.

It has to do at issue 54, CME 93. This was the one that was authored by Mr. Boldt, and then that response referred us to 51-VECC-103, which was authored by yourself, actually, and it has to do with -- the original question from CME had to do with why some specific service charges weren't changing over time while other ones were increasing over time.

And from the response to -- I guess from the combination of the two responses -- and maybe you can look at VECC 51 and VECC 103 -- am I correct that the decision as to whether charges will be increased as opposed where they remain fixed over time was really based on what was going to be the annual cost of -- if we had to -- if you did change these rates every year, what was going to be the annual cost to the company? Was it going to be complex? Did we have to retrain a whole bunch of customer-service staff on these new costs and therefore we're incurring a lot of costs to make the change? And really we would keep the rates fixed in areas where we'd be incurring a lot of costs to make the change and changing them probably in areas where we weren't going to be incurring a lot of costs.

Am I -- do I understand your philosophy correctly there?

MR. MERALI: Correct. And my finance folks might take issue with my response here, but the way the charges are laid out in terms of actual costs and increasing year over year, one, it's enormously costly to administer, and candidly, it's really customer unfriendly, right? This year it's $13.72 for a letter, and next year it's 13.96, and it's just, it's complex, it's not customer-friendly, it's difficult to train all your agents. It's difficult to update all your written collateral and all your digital collateral.

So we felt it most appropriate to have a single flat fee that was implemented for the entire period of the rate application.

MR. HARPER: That was only for some of the charges. When I looked through it, it caught my mind that it was the low-volume charges tended to be the ones where you were increasing every year and it was the ones where there was a high level of activity that they actually -- you were generally maintaining a fixed charge over the course of the year.

Am I fair in my interpretation of understanding of generally how the application of that principle applied out?

MR. MERALI: I'm saying this a little bit tongue in cheek, but I think any charges that I'm responsible for could remain flat. Anything John is responsible for varied year to year, but anything that was high-volume --

I mean, your point is correct. Anything that was high-volume and had a lot of customer impact, if it was something that was more back-office kind of easement charge or something that wasn't really customer-facing, I think they increased the charge on an annual basis.

MR. HARPER: Okay. Fine. No, I was just trying to clarify the principle and understand it. I think -- I think that's actually -- that's all my questions for Mr. Merali. I believe Mr. Garner has one.

FOLLOW-UP QUESTIONS BY MR. GARNER:

MR. GARNER: Yes, I'm going to jump in with two, and one I just need to confer with Mr. Harper on. The first one was something -- to follow up to your earlier discussion. The first was that you had said earlier that you did a study that looked at whether there was going to be an increase in bad debt if you removed the security deposit policy. Did I hear that right?

MR. MERALI: I said we did not do a study. Our evidence, our -- sorry, our historical experience had led us to believe that there would not be an increase in bad debt associated with that.