HEARST POWER DISTRIBUTION COMPANY LTD.

2015 Cost of Service Application

Responses to interrogatories

EB-2014-0080

Submitted on: September 11, 2015

925 rue Alexandra Street, S.P./P.O. Bag 5000
Hearst, Ontario
P0L 1N0

September 11, 2015
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: EB-2014-0080 – Responses to interrogatories

Dear Ms. Walli,

Please find enclosed Hearst Power Distribution Company Ltd (HPDC)'s Evidence Update and its responses to the interrogatories and updated evidence filed in the above named matter. Updated live excel models and other relevant documents that are referenced throughout the interrogatory responses have being uploaded to the Board's WebDrawer.

This application is being filed pursuant to the Board's e-Filing Services. Two hard copies of the Application will be delivered to the Board over the next few business days.

We would be pleased to provide any further information or details that you may require relative to this application.

Jessy Richard
General Manager

Hearst Power Distribution Company Limited
925 rue Alexandra Street, S.P./P.O. Bag 5000
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Hearst Power Distribution Company Limited

Exhibit 1

Responses to Interrogatories

September 11, 2015

Staff-1

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

Response: A revised RRWF along with all relevant revised models are being filed along with these responses.

Staff-2

Chapter 2 Appendices, Sheet 8.3, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide updated bill impacts for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.), reflecting any changes made during the interrogatory process.

Response: A revised set of bill impacts can be found at the next pages. A revised set of OEB Appendices is also being filed in conjunction with these responses

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 800 **kWh** ◯ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
	Monthly Service Charge	Monthly	$ 9.19	1	$ 9.19	$ 13.00	1	$ 13.00	$ 3.81	41.46%
				1	$ -		1	$ -	$ -	
	Smart Meter Disposition Rider	Monthly		1	$ -	$ 3.28	1	$ 3.28	$ 3.28	
	Foregone Revenue Rate Rider	Monthly		1	$ -	-$ 1.91	1	-$ 1.91	-$ 1.91	
	Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.24	1	$ 0.24	$ 0.24	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kWh	$ 0.0160	800	$ 12.80	$ 0.0135	800	$ 10.80	-$ 2.00	-15.64%
	Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
	LRAM & SSM Rate Rider	per kWh		800	$ -		800	$ -	$ -	
	Foregone Revenue Rate Rider	per kWh		800	$ -	$ 0.0013	800	$ 1.00	$ 1.00	
				800	$ -		800	$ -	$ -	
				800	$ -		800	$ -	$ -	
				800	$ -		800	$ -	$ -	
				800	$ -		800	$ -	$ -	
				800	$ -		800	$ -	$ -	
				800	$ -		800	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 21.99			$ 26.41	**$ 4.42**	**20.11%**
	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kWh	-$ 0.0028	800	-$ 2.24		800	$ -	$ 2.24	-100.00%
N/A	Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2015	per kWh	$ 0.0007				800	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim basis until April 31, 2014	per kWh	-$ 0.0021				800	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Global Adjustment Sub-Account Disposition (2013) - effective on an interim basis until April 30, 2014	per kWh	$ 0.0018				800	$ -	$ -	
Expired in 2014	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kWh	-$ 0.0001				800	$ -	$ -	
Applicable	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kWh	$ -	800	$ -	-$ 0.0014	800	-$ 1.12	-$ 1.12	
N/A	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Applicable	Rate Rider Calculation for Accounts 1575 and 1576	per kWh	$ -	800	$ -	-$ 0.0005	800	-$ 0.39	-$ 0.39	
Applicable	Rate Rider Calculation for Accounts 1568	per kWh	$ -	800	$ -	$ 0.0001	800	$ 0.09	$ 0.09	
	Low Voltage Charges	per kWh	$ 0.0007	800	$ 0.56	$ 0.0007	800	$ 0.56	$ -	0.00%
	Line Losses on Cost of Power	per kWh	$ 0.1021	36.8	$ 3.76	$ 0.1021	8.33092	$ 0.85	-$ 2.91	-77.36%
	Smart Meter Entity Charge	per kWh	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.86**			**$ 27.19**	**$ 2.33**	**9.37%**
	RTSR - Network	per kWh	$ 0.0061	837	$ 5.10	$ 0.0063	808	$ 5.12	$ 0.02	0.40%
	RTSR - Line and Transformation Connection	per kWh	$ 0.0048	837	$ 4.02	$ 0.0051	808	$ 4.12	$ 0.11	2.64%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 33.98**			**$ 36.44**	**$ 2.46**	**7.23%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	808	$ 3.56	-$ 0.13	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	808	$ 0.97	-$ 0.03	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
	TOU - Off Peak	per kWh	$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
	TOU - Mid Peak	per kWh	$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%

TOU - On Peak	per kWh	$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	FALSE	$ -	$ 0.0940	FALSE	$ -	$ -	
Energy - RPP - Tier 2		$ 0.1100	FALSE	$ -	$ 0.1100	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 126.23**			**$ 128.52**	**$ 2.30**	**1.82%**
HST		13%		$ 16.41	13%		$ 16.71	$ 0.30	1.82%
Total Bill (including HST)				$ 142.64			$ 145.23	$ 2.59	1.82%
Ontario Clean Energy Benefit [1]				-$ 14.26			-$ 14.52	-$ 0.26	1.82%
Total Bill on TOU (including OCEB)				**$ 128.38**			**$ 130.71**	**$ 2.33**	**1.82%**
Total Bill on RPP (before Taxes)				**$ 44.52**			**$ 46.81**	**$ 2.30**	**5.16%**
HST		13%		$ 5.79	13%		$ 6.09	$ 0.30	5.16%
Total Bill (including HST)				$ 50.30			$ 52.90	$ 2.59	5.16%
Ontario Clean Energy Benefit [1]				-$ 5.03			-$ 5.29	-$ 0.26	5.17%
Total Bill on RPP (including OCEB)				**$ 45.27**			**$ 47.61**	**$ 2.33**	**5.16%**
Loss Factor (%)		4.60%			1.04%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: General Service less than 50 Kw

TOU / non-TOU: non-TOU

Consumption 2,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
	Monthly Service Charge	Monthly	$ 19.76	1	$ 19.76	$ 19.79	1	$ 19.79	$ 0.03	0.15%
				1	$ -		1	$ -	$ -	
	Smart Meter Disposition Rider	Monthly		1	$ -	$ 4.82	1	$ 4.82	$ 4.82	
	Foregone Revenue Rate Rider	Monthly		1	$ -	-$ 0.01	1	-$ 0.01	-$ 0.01	
	Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.62	1	$ 0.62	$ 0.62	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kWh	$ 0.0067	2000	$ 13.40	$ 0.0068	2000	$ 13.59	$ 0.19	1.41%
	Smart Meter Disposition Rider	per kWh		2000	$ -		2000	$ -	$ -	
	LRAM & SSM Rate Rider	per kWh		2000	$ -		2000	$ -	$ -	
	Foregone Revenue Rate Rider	per kWh		2000	$ -	-$ 0.0000	2000	-$ 0.09	-$ 0.09	
				2000	$ -		2000	$ -	$ -	
				2000	$ -		2000	$ -	$ -	
				2000	$ -		2000	$ -	$ -	
				2000	$ -		2000	$ -	$ -	
				2000	$ -		2000	$ -	$ -	
				2000	$ -		2000	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 33.16			$ 38.71	**$ 5.55**	**16.74%**
	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kWh	-$ 0.0028	2000	-$ 5.60		2000	$ -	$ 5.60	-100.00%
N/A	Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2015	per kWh	$ 0.0007				2000	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim basis until April 31, 2014	per kWh	-$ 0.0021				2000	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Global Adjustment Sub-Account Disposition (2013) - effective on an interim basis until April 30, 2014	per kWh	$ 0.0018				2000	$ -	$ -	
Expired in 2014	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kWh	-$ 0.0001				2000	$ -	$ -	
Applicable	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kWh	$ -	2000	$ -	-$ 0.0014	2000	-$ 2.81	-$ 2.81	
N/A	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Applicable	Rate Rider Calculation for Accounts 1575 and 1576	per kWh	$ -	2000	$ -	-$ 0.0005	2000	-$ 0.99	-$ 0.99	
Applicable	Rate Rider Calculation for Accounts 1568	per kWh	$ -	2000	$ -	$ 0.0001	2000	$ 0.15	$ 0.15	
	Low Voltage Charges	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0006	2000	$ 1.20	$ -	0.00%
	Line Losses on Cost of Power	per kWh	$ 0.1100	92	$ 10.12	$ -	20.8273	$ -	-$ 10.12	-100.00%
	Smart Meter Entity Charge	per kWh	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 39.67**			**$ 37.06**	**-$ 2.61**	**-6.58%**
	RTSR - Network	per kWh	$ 0.0056	2092	$ 11.72	$ 0.0058	2021	$ 11.76	$ 0.05	0.40%
	RTSR - Line and Transformation Connection	per kWh	$ 0.0042	2092	$ 8.79	$ 0.0045	2021	$ 9.09	$ 0.31	3.50%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 60.17**			**$ 57.92**	**-$ 2.26**	**-3.75%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2092	$ 9.20	$ 0.0044	2021	$ 8.89	-$ 0.31	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2092	$ 2.51	$ 0.0012	2021	$ 2.42	-$ 0.09	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
	TOU - Off Peak	per kWh		1280	$ -		1280	$ -	$ -	
	TOU - Mid Peak	per kWh		360	$ -		360	$ -	$ -	
	TOU - On Peak	per kWh		360	$ -		360	$ -	$ -	
	Energy - RPP - Tier 1	per kWh	$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
	Energy - RPP - Tier 2	per kWh	$ 0.1100	1400	$ 154.00	$ 0.1100	1400	$ 154.00	$ -	0.00%
	Total Bill on TOU (before Taxes)				**$ 86.14**			**$ 83.48**	**-$ 2.65**	**-3.08%**
	HST		13%		$ 11.20	13%		$ 10.85	-$ 0.35	-3.08%
	Total Bill (including HST)				$ 97.33			$ 94.34	-$ 3.00	-3.08%
	Ontario Clean Energy Benefit [1]				-$ 9.73			-$ 9.43	$ 0.30	-3.08%
	Total Bill on TOU (including OCEB)				**$ 87.60**			**$ 84.91**	**-$ 2.70**	**-3.08%**
	Total Bill on RPP (before Taxes)				**$ 296.54**			**$ 293.88**	**-$ 2.65**	**-0.90%**
	HST		13%		$ 38.55	13%		$ 38.20	-$ 0.35	-0.90%
	Total Bill (including HST)				$ 335.09			$ 332.09	-$ 3.00	-0.90%
	Ontario Clean Energy Benefit [1]				-$ 33.51			-$ 33.21	$ 0.30	-0.90%

Total Bill on RPP (including OCEB)			**$ 301.58**				**$ 298.88**		**-$ 2.70**	**-0.90%**
Loss Factor (%)	4.60%				1.04%					

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: General Service Over 50 kW

TOU / non-TOU: non-TOU

Consumption 60 kW ◯ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
	Monthly Service Charge	Monthly	$ 54.8200	1	$ 54.82	$ 46.3400	1	$ 46.34	-$ 8.48	-15.47%
				1	$ -		1	$ -	$ -	
	Smart Meter Disposition Rider	Monthly		1	$ -	$ 7.84	1	$ 7.84	$ 7.84	
	Foregone Revenue Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
	Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.55	1	$ 4.55	$ 4.55	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kW	$ 2.3213	60	$ 139.28	$ 1.9726	60	$ 118.36	-$ 20.92	-15.02%
	Smart Meter Disposition Rider	per kW		60	$ -		60	$ -	$ -	
	LRAM & SSM Rate Rider	per kWh		60	$ -		60	$ -	$ -	
	Foregone Revenue Rate Rider	per kWh		60	$ -	$ 0.1743	60	$ 10.46	$ 10.46	
				60	$ -		60	$ -	$ -	
				60	$ -		60	$ -	$ -	
				60	$ -		60	$ -	$ -	
				60	$ -		60	$ -	$ -	
				60	$ -		60	$ -	$ -	
				60	$ -		60	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 194.10			$ 191.79	**-$ 2.31**	**-1.19%**
N/A	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kW	-$ 1.0232				60	$ -	$ -	
Applicable	Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2015	per kW	$ 0.2351	60	$ 14.11		60	$ -	-$ 14.11	-100.00%
Expired in 2014	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim	per kW	-$ 0.7626				60	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Global Adjustment Sub-Account Disposition (2013) - effective on an interim basis until April 30, 2014	per kW	$ 0.6279				60	$ -	$ -	
Expired in 2014	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kW	-$ 0.0122				60	$ -	$ -	
N/A	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kW		60	$ -		60	$ -	$ -	
	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kW		60	$ -	$ 0.6109	60	$ 36.65	$ 36.65	
	Rate Rider Calculation for Accounts 1575 and 1576	per kW		60	$ -	-$ 0.1748	60	-$ 10.49	-$ 10.49	
	Rate Rider Calculation for Accounts 1568	per kW		60	$ -	$ 0.0114	60	$ 0.68	$ 0.68	
	Low Voltage Charges	per kW	$ 0.2270			$ 0.2329	60	$ 13.97	$ 13.97	
	Line Losses on Cost of Power	per kW	$ 0.0940	2.76	$ 0.26	$ -	0.62482	$ -	-$ 0.26	-100.00%
	Smart Meter Entity Charge	per kW	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 209.25**			**$ 233.40**	**$ 24.15**	**11.54%**
	RTSR - Network	per kW	$ 2.3025	63	$ 144.50	$ 2.3931	61	$ 145.08	$ 0.57	0.40%
	RTSR - Line and Transformation Connection	per kW	$ 1.7025	63	$ 106.85	$ 1.8182	61	$ 110.23	$ 3.38	3.16%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 460.61**			**$ 488.71**	**$ 28.11**	**6.10%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	63	$ 0.28	$ 0.0044	61	$ 0.27	-$ 0.01	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	63	$ 0.08	$ 0.0012	61	$ 0.07	-$ 0.00	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	60	$ 0.42	$ 0.0070	60	$ 0.42	$ -	0.00%
	TOU - Off Peak	per kWh		38	$ -		38	$ -	$ -	
	TOU - Mid Peak	per kWh		11	$ -		11	$ -	$ -	
	TOU - On Peak	per kWh		11	$ -		11	$ -	$ -	
	Energy - RPP - Tier 1	per kW	$ 0.0940	60	$ 5.64	$ 0.0940	60	$ 5.64	$ -	0.00%
	Energy - RPP - Tier 2	per kW	$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
	Total Bill on TOU (before Taxes)				**$ 461.63**			**$ 489.72**	**$ 28.09**	**6.09%**
	HST		13%		$ 60.01	13%		$ 63.66	$ 3.65	6.09%
	Total Bill (including HST)				$ 521.64			$ 553.39	$ 31.75	6.09%
	Ontario Clean Energy Benefit [1]				-$ 52.16			-$ 55.34	-$ 3.18	6.10%
	Total Bill on TOU (including OCEB)				**$ 469.48**			**$ 498.05**	**$ 28.57**	**6.08%**
	Total Bill on RPP (before Taxes)				**$ 467.27**			**$ 495.36**	**$ 28.09**	**6.01%**
	HST		13%		$ 60.74	13%		$ 64.40	$ 3.65	6.01%
	Total Bill (including HST)				$ 528.01			$ 559.76	$ 31.75	6.01%
	Ontario Clean Energy Benefit [1]				-$ 52.80			-$ 55.98	-$ 3.18	6.02%
	Total Bill on RPP (including OCEB)				**$ 475.21**			**$ 503.78**	**$ 28.57**	**6.01%**
	Loss Factor (%)		4.60%			1.04%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: **Intermediate**

TOU / non-TOU: non-TOU

Consumption 1,000 kW ◯ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
	Monthly Service Charge	Monthly	$ 223.01	1	$ 223.01	$ 223.01	1	$ 223.01	$ -	0.00%
				1	$ -		1	$ -	$ -	
	Smart Meter Disposition Rider	Monthly		1	$ -	$ 8.90	1	$ 8.90	$ 8.90	
	Foregone Revenue Rate Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
	Stranded Meter Rate Rider	Monthly		1	$ -	$ 71.36	1	$ 71.36	$ 71.36	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kW	$ 1.0215	1000	$ 1,021.50	$ 1.0228	1000	$ 1,022.82	$ 1.32	0.13%
	Smart Meter Disposition Rider	per kW		1000	$ -		1000	$ -	$ -	
	LRAM & SSM Rate Rider	per kW		1000	$ -		1000	$ -	$ -	
	Foregone Revenue Rate Rider	per kW		1000	$ -	-$ 0.0007	1000	-$ 0.66	-$ 0.66	
				1000	$ -		1000	$ -	$ -	
				1000	$ -		1000	$ -	$ -	
				1000	$ -		1000	$ -	$ -	
				1000	$ -		1000	$ -	$ -	
				1000	$ -		1000	$ -	$ -	
				1000	$ -		1000	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 1,244.51			$ 1,325.43	**$ 80.92**	**6.50%**
N/A	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kW	-$ 0.8739				1000	$ -	$ -	
Applicable	Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2015	per kW	$ 0.2005	1000	$ 200.50		1000	$ -	-$ 200.50	-100.00%
Expired in 2014	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim	per kW	-$ 0.6605				1000	$ -	$ -	
Expired in 2014	Rate Rider for the disposition of Global Adjustment Sub-Account Disposition (2013) - effective on an interim basis until April 30, 2014	per kW	$ 0.5438				1000	$ -	$ -	
Expired in 2014	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kW	-$ 0.0050				1000	$ -	$ -	
N/A	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kW					1000	$ -	$ -	
Applicable	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kW				$ 0.5079	1000	$ 507.91	$ 507.91	
Applicable	Rate Rider Calculation for Accounts 1575 and 1576	per kW				-$ 0.1824	1000	-$ 182.36	-$ 182.36	
Applicable	Rate Rider Calculation for Accounts 1568	per kW				$ 0.0025	1000	$ 2.46	$ 2.46	
	Low Voltage Charges	per kW	$ 0.2677	1000	$ 267.70	$ 0.2747	1000	$ 274.70	$ 7.00	2.61%
	Line Losses on Cost of Power	per kW	$ 0.1100	46	$ 5.06	$ -	10.4137	$ -	-$ 5.06	-100.00%
	Smart Meter Entity Charge	per kW	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,718.56**			**$ 1,928.93**	**$ 210.37**	**12.24%**
	RTSR - Network	per kW	$ 2.5753	1046	$ 2,693.76	$ 2.6766	1010	$ 2,704.45	$ 10.69	0.40%
	RTSR - Line and Transformation Connection	per kW	$ 2.0081	1046	$ 2,100.47	$ 2.1446	1010	$ 2,166.95	$ 66.48	3.16%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 6,512.80**			**$ 6,800.33**	**$ 287.54**	**4.41%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1046	$ 4.60	$ 0.0044	1010	$ 4.45	-$ 0.16	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1046	$ 1.26	$ 0.0012	1010	$ 1.21	-$ 0.04	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
	TOU - Off Peak	per kWh		640	$ -		640	$ -	$ -	
	TOU - Mid Peak	per kWh		180	$ -		180	$ -	$ -	
	TOU - On Peak	per kWh		180	$ -		180	$ -	$ -	
	Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
	Energy - RPP - Tier 2		$ 0.1100	400	$ 44.00	$ 0.1100	400	$ 44.00	$ -	0.00%
	Total Bill on TOU (before Taxes)				**$ 6,525.90**			**$ 6,813.24**	**$ 287.34**	**4.40%**
	HST		13%		$ 848.37	13%		$ 885.72	$ 37.35	4.40%
	Total Bill (including HST)				$ 7,374.27			$ 7,698.96	$ 324.69	4.40%
	Ontario Clean Energy Benefit [1]				-$ 737.43			-$ 769.90	-$ 32.47	4.40%
	Total Bill on TOU (including OCEB)				**$ 6,636.84**			**$ 6,929.06**	**$ 292.22**	**4.40%**
	Total Bill on RPP (before Taxes)				**$ 6,626.30**			**$ 6,913.64**	**$ 287.34**	**4.34%**
	HST		13%		$ 861.42	13%		$ 898.77	$ 37.35	4.34%
	Total Bill (including HST)				$ 7,487.72			$ 7,812.42	$ 324.69	4.34%
	Ontario Clean Energy Benefit [1]				-$ 748.77			-$ 781.24	-$ 32.47	4.34%
	Total Bill on RPP (including OCEB)				**$ 6,738.95**			**$ 7,031.18**	**$ 292.22**	**4.34%**

Loss Factor (%) 4.60% 1.04%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: Sentinel

TOU / non-TOU: non-TOU

Consumption 1 kW ◯ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
	Monthly Service Charge	Monthly	$ 7.09	1	$ 7.09	$ 9.00	1	$ 9.00	$ 1.91	26.94%
				1	$ -		1	$ -	$ -	
	Foregone Revenue Rate Rider	Monthly		1	$ -	-$ 0.9550	1	-$ 0.96	-$ 0.96	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kW	$ 3.1198	1	$ 3.12	$ 1.9025	1	$ 1.90	-$ 1.22	-39.02%
	Smart Meter Disposition Rider	per kW		1	$ -		1	$ -	$ -	
	LRAM & SSM Rate Rider	per kW		1	$ -		1	$ -	$ -	
	Foregone Revenue Rate Rider	per kW		1	$ -	$ 0.6086	1	$ 0.61	$ 0.61	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 10.21			$ 10.56	**$ 0.35**	**3.39%**
Applicable	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kW	-$ 0.9880	1	-$ 0.99		1	$ -	$ 0.99	-100.00%
Expired	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim basis until April 31, 2014	per kW	-$ 0.6971				1	$ -	$ -	
Expired	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kW	-$ 0.0653				1	$ -	$ -	
Applicable	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kW				-$ 0.4172	1	-$ 0.42	-$ 0.42	
N/A	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kW				$ -			$ -	
Applicable	Rate Rider Calculation for Accounts 1575 and 1576	per kW				-$ 0.1456	1	-$ 0.15	-$ 0.15	
Applicable	Rate Rider Calculation for Accounts 1568	per kW				$ 0.0470	1	$ 0.05	$ 0.05	
	Low Voltage Charges	per kW	$ 0.1791	1	$ 0.18	$ 0.1821	1	$ 0.18	$ 0.00	1.68%
	Line Losses on Cost of Power		$ 0.0940	0.046	$ 0.00	$ -	0.01041	$ -	-$ 0.00	-100.00%
	Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.20**			**$ 11.01**	**$ 0.82**	**8.02%**
	RTSR - Network	per kW	$ 1.7453	1	$ 1.83	$ 1.8139	1	$ 1.83	$ 0.01	0.40%
	RTSR - Line and Transformation Connection	per kW	$ 1.3314	1	$ 1.39	$ 1.4219	1	$ 1.44	$ 0.04	3.16%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 13.41**			**$ 14.28**	**$ 0.87**	**6.48%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.00	$ 0.0044	1	$ 0.00	-$ 0.00	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	-$ 0.00	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1	$ 0.01	$ 0.0070	1	$ 0.01	$ -	0.00%
	TOU - Off Peak	per kWh		1	$ -		1	$ -	$ -	
	TOU - Mid Peak	per kWh		0	$ -		0	$ -	$ -	
	TOU - On Peak	per kWh		0	$ -		0	$ -	$ -	
	Energy - RPP - Tier 1		$ 0.0940	1	$ 0.09	$ 0.0940	1	$ 0.09	$ -	0.00%
	Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
	Total Bill on TOU (before Taxes)				**$ 13.68**			**$ 14.54**	**$ 0.87**	**6.35%**
	HST		13%		$ 1.78	13%		$ 1.89	$ 0.11	6.35%
	Total Bill (including HST)				$ 15.45			$ 16.44	$ 0.98	6.35%
	Ontario Clean Energy Benefit [1]				-$ 1.55			-$ 1.64	-$ 0.09	5.81%
	Total Bill on TOU (including OCEB)				**$ 13.90**			**$ 14.80**	**$ 0.89**	**6.41%**
	Total Bill on RPP (before Taxes)				**$ 13.77**			**$ 14.64**	**$ 0.87**	**6.31%**
	HST		13%		$ 1.79	13%		$ 1.90	$ 0.11	6.31%
	Total Bill (including HST)				$ 15.56			$ 16.54	$ 0.98	6.31%
	Ontario Clean Energy Benefit [1]				-$ 1.56			-$ 1.65	-$ 0.09	5.77%
	Total Bill on RPP (including OCEB)				**$ 14.00**			**$ 14.89**	**$ 0.89**	**6.37%**
	Loss Factor (%)		4.60%			1.04%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: Street Lighting

TOU / non-TOU: non-TOU

Consumption 1 kW ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
	Monthly Service Charge	Monthly	$ 7.88	1	$ 7.88	$ 7.88	1	$ 7.88	$ -	0.00%
				1	$ -		1	$ -	$ -	
	Foregone Revenue Rate Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
	Distribution Volumetric Rate	per kW	$ 2.2937	1	$ 2.29	$ 2.6235	1	$ 2.62	$ 0.33	14.38%
	Smart Meter Disposition Rider	per kW		1	$ -		1	$ -	$ -	
	LRAM & SSM Rate Rider	per kW		1	$ -		1	$ -	$ -	
	Foregone Revenue Rate Rider	per kW		1	$ -	-$ 0.1649	1	-$ 0.16	-$ 0.16	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
				1	$ -		1	$ -	$ -	
	Sub-Total A (excluding pass through)				$ 10.17			$ 10.34	**$ 0.16**	**1.62%**
Applicable	Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2015	per kW	-$ 0.9151	1	-$ 0.92		1	$ -	$ 0.92	-100.00%
N/A	Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2015	per kW	$ 0.2127				1	$ -	$ -	
Expired	Rate Rider for the disposition of Deferral/Variance Account Disposition (2013) - effective on an interim basis until April 31, 2014	per kW	-$ 0.6954				1	$ -	$ -	
Expired	Rate Rider for the disposition of Global Adjustment Sub-Account Disposition (2013) - effective on an interim basis until April 30, 2014	per kW	$ 0.5726				1	$ -	$ -	
Expired	Rate Rider for Application of Tax Change - effective until April 30, 2014	per kW	-$ 0.1335				1	$ -	$ -	
Applicable	Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)	per kW				-$ 0.4618	1	-$ 0.46	-$ 0.46	
N/A	Rate Rider Calculation for RSVA - Power - Global Adjustment	per kW				$ 0.5079			$ -	
	Rate Rider Calculation for Accounts 1575 and 1576	per kW				-$ 0.1608	1	-$ 0.16	-$ 0.16	
	Rate Rider Calculation for Accounts 1568	per kW				$ 0.1742	1	$ 0.17	$ 0.17	
	Low Voltage Charges	per kW	$ 0.1755	1	$ 0.18	$ 0.1784	1	$ 0.18	$ 0.00	1.65%
	Line Losses on Cost of Power		$ 0.0940	0.046	$ 0.00	$ -	0.01041	$ -	-$ 0.00	-100.00%
	Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
	Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.23**			**$ 10.86**	**$ 0.63**	**6.16%**
	RTSR - Network	per kW	$ 1.7364	1	$ 1.82	$ 1.8047	1	$ 1.82	$ 0.01	0.40%
	RTSR - Line and Transformation Connection	per kW	$ 1.3043	1	$ 1.36	$ 1.3930	1	$ 1.41	$ 0.04	3.16%
	Sub-Total C - Delivery (including Sub-Total B)				**$ 13.41**			**$ 14.09**	**$ 0.68**	**5.08%**
	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.00	$ 0.0044	1	$ 0.00	-$ 0.00	-3.40%
	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	-$ 0.00	-3.40%
	Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1	$ 0.01	$ 0.0070	1	$ 0.01	$ -	0.00%
	TOU - Off Peak	per kWh		1	$ -		1	$ -	$ -	
	TOU - Mid Peak	per kWh		0	$ -		0	$ -	$ -	
	TOU - On Peak	per kWh		0	$ -		0	$ -	$ -	
	Energy - RPP - Tier 1		$ 0.0940	1	$ 0.09	$ 0.0940	1	$ 0.09	$ -	0.00%
	Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
	Total Bill on TOU (before Taxes)				**$ 13.67**			**$ 14.35**	**$ 0.68**	**4.98%**
	HST		13%		$ 1.78	13%		$ 1.87	$ 0.09	4.98%
	Total Bill (including HST)				$ 15.45			$ 16.22	$ 0.77	4.98%
	Ontario Clean Energy Benefit [1]				-$ 1.54			-$ 1.62	-$ 0.08	5.19%
	Total Bill on TOU (including OCEB)				**$ 13.91**			**$ 14.60**	**$ 0.69**	**4.95%**

Total Bill on RPP (before Taxes)			**$ 13.77**				**$ 14.45**	**$ 0.68**	**4.94%**
HST	13%		$ 1.79		13%		$ 1.88	$ 0.09	4.94%
Total Bill (including HST)			$ 15.56				$ 16.32	$ 0.77	4.94%
Ontario Clean Energy Benefit [1]			-$ 1.56				-$ 1.63	-$ 0.07	4.49%
Total Bill on RPP (including OCEB)			**$ 14.00**				**$ 14.69**	**$ 0.70**	**4.99%**
Loss Factor (%)	4.60%				1.04%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010*.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

1-Staff-3

Ref: Exhibit 1, Tab 2, Schedule 1

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”.

a) What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.
b) Please explain how feedback received from customers was incorporated into the application.

Response:

a) An ad was published in local newspapers. The ad explained that the last rate adjustment was done in 2010 and that the cost of smart meters for the installation of the smart meters in previous years needed to be disposed. The ad also mentioned the OEB rate design change for variable/fix charges in the residential class.

b) Only one customer telephoned our office over concerns that the small consumers will be paying more while the big consumers would be paying less. We explained that the fixed distribution charge would be equal for all residential customers by 2020 but the electricity cost would still be less if you use less electricity. The customer was satisfied with the explanation provided

1-Staff-4

Ref: Exhibit 1, Tab 5, Schedule 1 – Legal Application

Hearst Power filed its original application for 2015 rates on March 5, 2015, and a complete application on June 8, 2015. Hearst Power has requested rates to be effective November 1, 2015.

a) Please provide Hearst Power's expectations regarding filing its application for 2016 rates.
b) Considering the possibility that a final rate order may not be in place for a November 1, 2015 effective date, what would be the implications to Hearst Power of maintaining the final approved 2015 rates from this proceeding throughout the 2016 rate year?

Response:

a) Please refer to answer b) below
b) Hearst Power Distribution hopes to have rates ready for November 2015. HPDC would agree not submit an IRM for 2016 and keep the 2015 approved rates throughout the year. An IRM would be submitted for 2017 due to inflation and the rate design change in the residential class.

1-Staff-5

Ref: Exhibit 1, Tab 5, Schedule 1 – Legal Application

Ref: EB-2014-0080 Interim Rate Order

Hearst Power has applied for 2015 rates to be effective November 1, 2015. Hearst Power's current rates were declared interim as of January 1, 2015 until such time as a Final Rate Order is issued by the OEB through an Interim Rate Order dated December 15, 2014.

a) Please provide a calculation of net income earned in excess of 300 basis points above the Board approved return on equity from January 1, 2015 to June 30, 2015.
b) Please provide a forecast of net income earned in excess of 300 basis points above the Board approved return on equity from July 1, 2015 to October 31, 2015.
c) Please explain whether Hearst Power would find it reasonable for the OEB to require Hearst Power to return the excess earnings calculated in parts a) and b) above, to its ratepayers and if not, why not.

Response:

a) Refer to document "OEB – 1 Staff 5a"

b) Refer to document "OEB – 1 Staff 5b"

c) Yes, Hearst Power would find it reasonable to return the excess earnings for the period of January 1st to December 31st, 2015 to its ratepayers as per its actual excess earnings.

1-Staff-6

Ref: Exhibit 1, Tab 2, Schedule 1

Ref: Filing Requirements for Electricity Distribution Rate Applications, Ch. 2, p. 8

Chapter 2 of the Filing Requirements states,

> *"The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)*

a) Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

b) Hearst Power indicates that it has conducted a customer satisfaction survey with its residential class.

   i. Please describe any customer engagement initiatives undertaken with other rate classes.

   ii. Please provide the results of any studies conducted, or any available documentation of these initiatives

Response:

a) Of the customer engagement activities listed at table 1.10 of Exhibit 1, the following were in place prior to the issuance of the RRFE, Scorecards and the cost of service.

   - E-billing
   - CDM and Save on Energy programs
   - Christmas lights and Canada Day festivities
   - LEAP

   The following activities are new

   - Bi-annual customer survey
   - Educational Publications

b) The utility has not conducted any customer engagement activities in classes other than Residential. The utility is considering including other classes in the next survey in 2016.

1-Staff-7

Ref: Exhibit 1, Tab 5, Schedule 11

Ref: Hearst Power Conditions of Service

Board staff notes that s. 2.3.7.3 refers to charges for ongoing maintenance and verification of interval meters. Hearst Power has not indicated whether charges are contained in its Conditions of Service which do not appear on its Tariff of Rates and Charges.

a) Please confirm that Hearst Power's Conditions of Service contains rates or charges that do not appear on its current or proposed Tariff of Rates and Charges. If confirmed, please list all such charges.
b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2010 to 2013 inclusive, and the revenue forecasted for the 2014 bridge and 2015 test years.
c) Please explain whether, in Hearst Power's view, these rates and charges should be included on the tariff sheet of approved rates and charges.

Response:

a) No actual charges or rates are stated in dollars in our Condition of Service. The document refers to many variable charges, for example: repairs of damaged equipment by the customer, costs associated with re-design and inspection services due to changes or deviation initiated by the Customer, etc. These costs are based on actual costs and are re-examined and approved yearly by the HPDC board of Directors.

   Please refer to document "OEB – 1 Staff 7a" for list of our current charge out rates.

b)

Year	Reporting	Account	Revenues
2010	actuals	4025	$ 62,036
2011	actuals	4025	$ 62,164
2012	actuals	4025	$ 102,824
2013	actuals	4025	$ 95,252
2014	actuals	4025	$ 122,375
2015	budgeted	4025	$ 100,000

c) Hearst Power strongly believes that, since the revenues generated from these charges out rates are not included in the rate base, they should not be controlled by the OEB. Hearst Power uses these rates to charge for equipment rental, material sold, customer initiated work request as well as local contractors' assistance. HPDC reviews these rates annually and updates the costs as needed (ex: fuel costs, collective agreements, etc), and the updates are done quickly by the HPDC board and management so that the related expenses do not become bigger than its revenues.

   HPDC is also currently in negotiation with Hydro One for a mutual work sharing agreement since we believe it would benefit H1 customers that are nearby our geographical area as well as benefit customers within our service area by providing quicker response time to power outages or other emergencies (ex: house fire). These rates will be separate and reviewed as required with H1. HPDC does not wish to complicate these negotiations even more by adding a third party (OEB) to the table.

1-Staff-8

Ref: Exhibit 1, Tab 1, Schedule 3

Ref: Exhibit 2, Tab 6, Schedule 1, page 16

Hearst Power has described the budget process, through which the capital and OM&A budgets are reviewed and approved by the Board of Directors.

a) Please indicate when the described budget process was put in place and for what year the first budget was prepared under this process?

b) Please describe the budget review process that was in place prior to the introduction of the process described in Hearst Power's evidence.

c) Please indicate which parties were responsible to review and approve the capital plans for 2010 to 2013 as shown at Exhibit 2, Tab 6, Schedule 1, page 16.

d) Please describe the process by which the variances from the capital plans from 2010 to 2013 were reviewed, and how these variances were considered in establishing subsequent capital budgets.

e) Please provide a schedule of OM&A Variances, actual vs. budget for the years 2010 to 2014, similar to the schedule provided for capital budget variances at Exhibit 2, Tab 6, Schedule 1, page 16.

f) Please describe the process and frequency by which variances from both capital and OM&A budgets are reviewed under the current budget process.

g) Please explain how variances from budget will be considered in subsequent budgets under the current process.

Response:

a) The budget process has been put in place in 2010 prior to the 2010 rate application. This process was implemented in 2010.

b) To the best of the current GM's knowledge and findings, although budgets were done every year since the existence of Hearst Power, the budgeting process was undocumented.

c) The Board of Directors was responsible to review and approve the capital plans.

d) The previous General Manager which was in place from early 2011 to early 2014, for a number of reasons, did not follow his actual planned capital budget. The Board was aware of the variables as they were easily identifiable. Also, our certified accountant firm discussed these issues with HPDC's board. At that time, the Board believed it would take more time for the G.M. to master his responsibilities due to the complexity and heavy workload involved in that position. In December 2013, the search for a new general manager began and on May 2014, the new manager started. The new manager needed to re-align the company operations so that budgeted capital items become actuals by year end. The company could not have continued to function safely and effectively if the distribution assets were not addressed. A Distribution System Plan was built in 2014 with the assistance of Archie Bax of A.E.S.I consulting and the budgeting of capital items is based on this report.

e) Refer to "OEB – 1 Staff 8e".

f) HPDC board of directors requires quarterly reporting of the income statement, the balance sheet as well as capital project status.

g) No change, HPDC board of directors requires quarterly reporting of the income statement, the balance sheet as well as capital project status.

1-Staff-9

Ref: Exhibit 1, Tab 3, Schedule 1, Attachment 4, pages 3 and 16

Hearst Power's balance sheet for December 31, 2014 shows accounts payable and accrued liabilities of $1,915,775. This amount is broken down at page 9, but continues to show accounts payable of $1.7 million. Board staff notes that total expenses for the year are approximately $10.5 million and that estimated monthly expenses would appear to be approximately $880 thousand.

a) Please provide a breakdown of the accounts payable of $1.7 million.
b) Please describe Hearst Power's policy for managing its accounts payable.

Response:

a) Please refer to "OEB – 1 Staff 9a" for breakdown of the $1.7 million payable.

The major reason why the payable was higher at December 31st, 2014 was that the invoice for the electricity purchased from Hydro One in November was late coming in and was only payable early in February 2015. Here below is a table showing the invoice for the power purchases at year end 2014:

Name of Provider	Power Purchased for the month of	Invoice amount	Invoice Received on	Invoice Payable due date
IESO	Nov-14	$ 177,443	15/12/2014	17-Dec-14
Hydro One	Nov-14	$ 668,187	19/01/2015	07-Feb-15
IESO	Dec-14	$ 246,124	15/01/2015	17-Jan-15
Hydro One	Dec-14	$ 771,190	20/01/2015	08-Feb-15
	Due at Dec 31	$ 1,685,502		

b) HPDC pays it account payables before the due date.

1-Staff-10

Ref: Exhibit 1, Tab 5, Schedule 6

Ref: Exhibit 1, Tab 5, Schedule 6, Shareholder Declaration

Hearst Power's evidence indicates that its Board of Directors does not have a separate audit committee. Board staff notes that Article 4.5 of the Shareholder Declaration, dated November 22, 2000, states that the "Shareholder anticipates that the Board will establish an Audit and Finance Committee to review financial results".

a) Please explain why Hearst Power's Board of Directors has not yet established an Audit and Finance Committee.
b) Please explain the process by which the Board of Directors reviews the audited financial statements of the Corporation.

Response:

a) HPDC is a very small LDC (4th smallest LDC in Ontario – by customer count) and is located in Hearst, a far Northeastern Ontario Town with a population of 5,000. The current board members oversee all activities, including financials. Please note all of HPDCs Directors are financially literate, additionally one of the Directors is a Certified General Accountant.

b) A representative of our accounting firm, Collins Barrow, presents to the board, annually, the financial statements and does a review of their findings. The board then approved the year-end financial statements and identifies potential concerns that need to be addressed at the next board meeting.

1.0-VECC-1

Reference: E1/T2/S2

a) Please provide details as to who carried out the customer satisfaction survey (the cooperative of Utilities or Tandem Energy Services).
b) What was the cost of the survey?
c) Hearst sent the survey out to all 2,274 customers. How many customers responded?
d) Were any of the survey questions asked unique to Hearst Power? If so please identify these questions.
e) In responding to questions of system reliability, were customers made aware of the distinction between outages due to the loss of supply and outages within the Hearst service territory? If so how was this information conveyed?
f) Please explain who and how the Section 11 Recommendations were compiled (e.g. were these comments of customers, or conclusions derived by Hearst from the study results)?

Response:

a) HPDC with the help of Tandem Energy Services and in cooperation with a group of Utilities develop a customer survey that we believed was able to meet OEB expectations.

   HPDC printed and mailed the survey (in the same envelope as their monthly bill) to all residential clients. The survey was also available on e-billing for registered customers, on our website and additionally, paper copies were made available at HPDC reception area.

   The survey was to be signed and returned to HPDC's office and the Customer Service and Billing Clerk compiled the survey data. Each survey received was entered for a draw for a Samsung computer tablet.

b) There was no cost for constructing the survey itself, just additional work for HPDC's General Manager and Tandem Energy Services.

   The estimated cost for printing the survey was 120$ (2,000 survey x 3 pages x 0.02$ per page) and the Samsung tablet expense was 269.99$. There were no costs for envelopes or for shipping since the surveys were included with the monthly invoices, nor any costs to add it to e-billing or our website.

   The data was compiled by HPDC Customer Service and Billing Clerk therefore, no additional cost incurred.

   Total cost of survey = 390$

c) HPDC received 340 responses to its survey which represents 15%

d) HPDC developed its survey with the help of Tandem Energy Service and a group of LDCs including Hydro Hawkesbury, Hydro 2000 Inc., Cooperative Hydro Embrun, Renfrew Hydro and Ottawa River Corp. All questions were similar in nature but all surveys were made unique in its presentation by each LDC. HPDC is not aware if a question was uniquely used by any LDC.

e) No, the customers were not advised. HPDC believes that it is impossible for a customer to differ between outages due to a loss of supply or outages within HPDC service area. An outage is an outage, whatsoever the reason, the customer will view it as an outage.

HPDC customers are aware of the longer response time required for power outages with Hydro One as almost all, if not all, of the major or long duration outages are due to Hydro One. When a prolonged outage occurs, it is common practice for HPDC customers to refer to Hydro One's Storm Center for updates. Evidence of such common practice was recognized in recent times as the HPDC area was out of power for 27 hours, from July 18 to 19, 2015, due to loss of supply from Hydro One

f) The recommendations were derived by HPDC from the survey results. Some of the recommendations in Section 11 were already implemented or in process of being implemented prior to receiving the customer's comments as the new HPDC General Manager was required to do a complete review of the company prior to filing this rate application.

Hearst Power Distribution Company Limited

Exhibit 2

Responses to Interrogatories

September 11, 2015

2-Staff-11

Ref: Exhibit 2, Chapter 2 Appendix 2-EC and Appendices 2-BA Fixed Asset Continuity Schedules for 2012, 2013 and 2014 under former CGAAP and Revised CGAAP

According to Appendix 2-EC, Hearst Power has shown the following amounts for Account 1576:

Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	($38,956)
Return on rate base associated with Account 1576 balance	($2,524)
Amount included in Deferral and Variance Account Rate Rider calc.	**($41,480)**

OEB staff notes that the opening net PP&E for 2013 per Appendix 2-EC is $818,172 which does not match the Closing net PP&E for 2012 per Appendix 2-BA of $876,244.

After adjusting for the above-noted discrepancy, OEB staff has calculated the following amount for Account 1576:

Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	($97,028)
Return on rate base associated with Account 1576 balance	($6,287)
Amount that should be included in Deferral and Variance Account Rate Rider calc.	**($103,315)**

a) Please adjust the appropriate schedules or explain the discrepancy, and provide supporting evidence as necessary.
b) Please adjust the appropriate schedules or explain the discrepancy, and provide supporting evidence as necessary.

Response: Please find below the revised schedule. Note that in view of the increase in balance, Hearst is now asking for a 2 year disposition period.

Account 1576 - Accounting Changes under CGAAP

2013 Changes in Accounting Policies under CGAAP

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

	2010	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				818,172	760,100	
Net Additions - Note 4				58,962	144,266	
Net Depreciation (amounts should be negative) - Note 4				-117,034	-119,556	
Closing net PP&E (1)				760,100	784,810	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				818,172	799,056	
Net Additions - Note 4				58,962	144,266	
Net Depreciation (amounts should be negative) - Note 4				-78,078	-84,332	
Closing net PP&E (2)				799,056	858,990	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-38,956	-74,180	

Effect on Deferral and Variance Account Rate Riders		
Closing balance in Account 1576	-	74,180
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	9,610
Amount included in Deferral and Variance Account Rate Rider Calculation	-	83,790

WACC	6.48%
# of years of rate rider disposition period	2

2-Staff-12

Ref: Exhibit 2, Tab 3, Schedule 1

Ref: Board Letter- Allowance for Working Capital for Electricity Distribution Rate Applications, June 3, 2015

Hearst Power has calculated its allowance for working capital using the 13% default value applicable for 2015 applications. On June 3, 2015, the OEB issued a letter indicating that "effective immediately" the OEB would adopt a default value of 7.5% of the sum of the cost of power and OM&A expenses to calculate working capital allowance. Hearst Power states that the policy does not apply to this application, which is for 2015 rates. Hearst Power filed its complete 2015 rate application on June 8, 2015.

a) Please provide any other explanations as to why Hearst Power's 2015 application, filed simultaneously with 2016 applications, should not be subject to the OEB's 7.5% default value, which is effective immediately.
b) Please provide a calculation of Working Capital Allowance and Rate Base using the 7.5% default value in the event the OEB decides to apply the updated rate.

Response:

a) Hearst Power application was due on August 31st, 2014. A request to extend this deadline was sent to the OEB earlier in 2014 but was rejected. The basis of that request was that HPDC was subject to an OEB variance accounts audit which was only completed in April 2014. The previous HPDC GM was reluctant to start the Cost of Service application prior to the completion of the OEB Audit. Additionally, a new manager was hired in May 2014 and since the previous manager did not start the rate application before leaving, the new GM had a lot of learning, studying, and calculating prior to filling an accurate rate application. With the significant amount of work required for filing a complete rate application, it was impossible to be done in 4 months by the new GM, therefore HPDC advised the board that it would file as soon as the application was completed. Please note that, at the time, there were only two HPDC staff employed at the office, a GM and an administrative assistant. The 3rd employee, a Customer Service and Billing Clerk, was only hired in October 2014.

   HPDC wasn't able to submit the application prior to August 2014; consequently, an interim rate order was received by the OEB in December 2014.

   Finally, the rate application was filed March 5, 2015. An "incompletion letter" was sent by the OEB on April 2nd, 2015 requesting that the application be updated to shown actual financial data for 2014. The actual and audited financial data was only available to HPDC in late April and the revised rate application was submitted Monday June 8, five days after the OEB announced the reduction to 7.5% working capital.

   HPDC has one of the lowest delivery rates in all of Ontario (top 5) even with its small sized customer base. HPDC also wants to point out that it currently has an "Efficiency Assessment" of "1" (most efficient), classified by the OEB. Lowering the 2015 working capital from 13% to 7.5% will make HPDC even more vulnerable to negative economical drivers as the company is operating very lean. A lower rate of 7.5% would not be beneficial to HPDC's customers as they are looking for better service and HPDC will have difficulties when facing future unexpected expenses or market variances.

b) Please refer to document "OEB – 2 Staff 12b"

2-Staff 13

Ref: Exhibit 2, Tab 6, Schedule 1, page 32-33

Hearst Power's capital plan includes the planned expenditure of $85,000, out of a total capital budget of $184,000 in the test year for its pole replacement program.

a) Please explain how the project reflects customer preferences identified through customer engagement.
b) Please describe and quantify where possible the benefits that the applicant's customers will realize from this investment.
c) Please describe any alternatives to capital investment that were assessed and rejected in favour of the proposed capital investment.

Response:

a) In the test year the total budget is $164,000 and the pole replacement program is budgeted for $75,000.

   The customers indicated concerns with the price of power and were happy with reliability. The age of the pole assets and the condition leads one to predict that pole failures will occur if no action is taken to replace the asset. In order to minimize the cost of power it is prudent to replace the pole assets on a gradual planned basis before failure. This is more cost effective (pole failures frequently require overtime work to complete the installation and restore power) and less disruptive that being reactive and running the poles to failure. Running poles to failure negatively impacts system reliability. The customers do not want more outages.

b) Page 34 states

   "The main driver for the pole replacement program is the risk of plant failing in service and creating long outages for customers and added O&M costs for the utility. This is intensified if there are simultaneous failures if the failures are the result of weather stressors such as high winds. HPDC only has one line crew to respond to these situations."

   And as well;

   "There are some safety benefits to doing the pole replacement project. First is the reduction of the possibility of poles falling in adverse weather and causing accidents or damage to property. Second is the safety related to the potential loss of power during extreme cold weather and the loss of heat for an extended period of time."

   HPDC has not quantified the benefits at this time.

c) On page 70 of the DSP it states

"The pole replacement is needed because of the condition of the poles. Maintenance will not restore strength to these poles and any maintenance treatment to slow the deterioration would be costly and ineffective when compared to the replacement option."

The replacement of an overhead system with new poles is the lowest cost method to proceed. While not costed out it is obvious that the replacement of the overhead system with an underground system would be a considerably more expensive project and would require a complete rebuild as opposed to only replacing those poles that were inadequate. These considerations were not included in the DSP but they were the basis for the presented plan.

2-Staff-14

Ref: Exhibit 2, Tab 6, Schedule 1, page 5

Hearst Power indicates that it gathers "relevant information" to assess the condition of its assets.

a) Please provide examples of the "relevant information" gathered.

Response:

a) HPDC gathers pole height; date installed, location, pole class and pole condition information. It also gathers transformer location, size, date manufactured, voltage – primary and secondary information. In addition it performs DSC required inspections and performs follow-up as required.

   HPDC used a pole condition assessment process that is described in document "OEB 2-Staff-14a"

2-Staff-15

Ref: Exhibit 2, Tab 6, Schedule 1, page 5

Ref: Exhibit 2, Tab 6, Schedule 1, page 16

Hearst Power states that, under its previous General Manager, "budgets were approved but the work was not completed nor was the money spent".

a) Please identify the projects that were approved from 2010 to 2013 but not completed.
b) Please quantify the backlog of projects that has arisen through this period.
c) Please indicate how the backlog of uncompleted projects from 2010 to 2013 has been reflected in the current distribution system plan.
d) If these projects have not been included in the current plan, how does Hearst Power plan to eliminate this backlog?

Response:

a) There were no documented "projects" that could be found. The only information was an annual budget that was approved. Nor was there a record of what work was completed of a project nature. So there was a budget with a dollar estimate and there were actual expenditures for plant capital work.

b) As described in a) above there is no backlog project list. What was done for the DSP and for the test year and the forecast period was assess the plant condition, primarily through condition assessment of the poles and the reliability performance of the system. Other capital drivers were reviewed as well but as indicated in the DSP with economic growth virtually zero and no externally driven projects these drivers had no impact on the capital program.

c) See answer to b) above.

d) There was no list of projects. However HPDC plans to continue to monitor system performance, the condition of its assets and the external drivers to address the community and system requirements.

2-Staff-16

Ref: Exhibit 2, Tab 6, Schedule 1, page 18

Hearst Power has provided its Asset Management Process diagram at page 18. Board staff notes that the process does not include the categories of General Plant or O&M.

a) Please describe Hearst Power's basis for forecasting investment requirements under these categories.

General Plant	
1908 - Building & Fixtures -	Warehouse expenses including desks and cabinets
1915 - Office Furniture Equipment -	Head Office furniture, phone system, bill folding equipment etc.
1920 - Computer Equipment Hardware -	All PC's, laptops, printers, billing printers etc.
1925 - Computer Software -	All software and software upgrades. PC office software, billing software, GIS software. Etc.
1930 - Transportation -	All new vehicles and refurbishments
1940 - Tools & Equipment -	All tools and equipment to support line operations including u/g plant location.

For account 1908 - Building & Fixtures:
In Appendix "C" on pages 62 and 63, the age and the past work on the warehouse is detailed. HPDC is planning to do some additional refurbishing to the warehouse. This is detailed in the 2015 to 2019 budgets also in Appendix "C" pages 64 to 68 of the DSP. The installation of a natural gas furnace for the warehouse in the 2015 budget will convert this facility from an electrically heated facility and result in heating cost savings. The proposed work for 2016 is to renovate the internal floor, walls and doors, for 2017 is to provide new desks and cabinets and 2019 is to repair the perimeter safety / security fence.
These activities reflect a desire by HPDC to provide its staff with a more usable, cost effective workplace that also incorporated the energy efficiency improvements it was advocating to its customers. These improvements achieve this at a modest pace with modest impact on the annual cost.

For account 1915 - Office Furniture Equipment
In 2015 the office and warehouse phone equipment is scheduled to be replaced. The phone system is very old and parts to service the system are no longer available per the company servicing the system. Expected cost $2500.

In 2018 the bill folding machine is scheduled for replacement. This is on the basis that the existing unit was purchased in 2005 and the company servicing the unit has indicated that a replacement should be anticipated in this timeframe.

For account 1920 –Computer hardware
In 2015 one desktop [$3000] is being purchased to replace a unit was purchased in 2005. Also the laser bill printer is being replaced [$7000]. The unit is 6 years old and prints 4000-5000 pages per month.

For account 1930 – Transportation

In 2015 HPDC plans to purchase a new pickup truck to replace an old rusted unit in need of repair. For the remaining years 2015 to 2019 provisions are being made for miscellaneous repairs. Actual expenditures will be based on the real needs at the time.

For account 1940 – Tools and Equipment
In 2015 $7000 is budgeted to purchase an underground cable locator and miscellaneous tools. A new apprentice was hired and tools needed to be provided. In 2016 an amount of $2500 is budgeted for miscellaneous tools and this amount is budgeted through 2019 with provision for inflation.

In summary for General Plant expenditures for account 1908, there is a paced upgrade to a building constructed in 1958 that takes into account energy efficiency and the effectiveness of the facility. The upgrading is expected to be completed by the end of the DSP planning horizon. For account 1920 the strategy is to replace computer hardware as it approaches the end of its useful life typically after 8 to 10 years in service for PC's. For account 1925 the strategy is to keep the mission critical software current. This specifically includes the billing software and GIS software. Office productivity software is also included as necessary. For Account 1930 there is a specific purchase of a new pickup truck to replace an existing unit that is need of extensive repairs. Future year forecast expenditures are provision for replacement of fleet units or major refurbishment or replacement of components such as a boom or aerial device. For account 1940 the current year has a specific equipment purchase identified. Future year forecast expenditures are provision for the replacement of smaller tools that break or wear out with use.

O&M

The forecast costs reflect the retirement of a lead hand and the filling of a vacancy. The previous costs were for a lead hand and two Journeyman Line persons and an apprentice. The forecast is for a lead hand one Journeyman Lineman and two apprentices. The apprentice costs are budgeted including wage increases as they progress through their training program. The remaining costs reflect inflation.

2-Staff-17

Ref: Exhibit 2, Tab 6, Schedule 1, page 19

Ref: Exhibit 2, Tab 6, Schedule 1, page 25-26

Hearst Power has provided a high level justification of projects on page 19, as well as selection criteria on pages 25-26.

a) Does Hearst Power plan to put in place a quantifiable projects prioritization methodology?
b) If so, when will this methodology be put in place?

Response:

a) HPDC does plan to put a quantifiable projects prioritization process in place. For this DSP submission this was not done because there were a lot of other more pressing issues to deal with. Also considering the fact that there is only one material project in the whole forecast period it seemed a bit academic to develop more than was done at this time.

b) Realistically, this will be developed when time permits. In practice there is a process that is followed already. The pole replacement and the surge arrestor replacement are both started in 2015 because they are urgent. But the surge arrestor project is completed sooner because of the higher safety impact. However the surge arrestor program was below the materiality threshold and thus was not discussed in the prioritization of material projects.

2-Staff-18

Ref: Exhibit 2, Tab 6, Schedule 1, Appendix B

Hearst Power has provided detailed system outage information at Appendix B. Board staff notes that defective equipment appears to be the single biggest contributing cause of interruptions other than loss of supply. According to Appendix B, none of the outages were caused by pole failures while several, in addition to blown fuses and failed lightning arrestors, were due to broken switches and blown transformers.

a) Please explain how the pole replacement program will improve reliability?
b) In addition to replacing lightning arrestors, does Hearst Power have a plan to address failures of transformers and switches (excluding those included within the System Service Investment budget category for improving SAIDI)?

Response:

a) The pole replacement program will not improve reliability but maintain it. Without this program, the reliability will deteriorate.

b) HPDC currently uses a run to failure approach on transformers. The transformers are generally small with a small number of customers connected. Hence this approach is not causing a large reliability impact.

   HPDC does spot scanning of transformers with thermographic equipment and replaces units with tank temperatures that are considered too high.

   HPDC is continuing to monitor the equipment failure category to determine trends that it can address. HPDC has a very small number of “line Switches”, the switches mentioned in the outage reports are fused disconnect switches or cutouts. HPDC is making efforts going forward to use consistent terminology to prevent confusion in interpretation on the outage descriptions.

2-Staff-19

Ref: Exhibit 2, Tab 6, Schedule 1, page 13

Ref: Exhibit 2, Tab 6, Schedule 1, page 33

On page 13 of the DSP, Hearst Power indicates that it "will review its system's ability to restore customers through switching and add additional switches at strategic points to make this achievable".

a) When is the system ability review expected to be completed?
b) If it has not yet been completed, how was the need of adding one solid blade switch per year under the System Service Investment Category for improving SAIDI determined?

Response:

a) The review should be completed in 2016 once the rate application is completed.

b) It was clear that given the existing network topography one switch per year could be placed to improve reliability. What was not clear is where exactly the switch should be placed to provide the function desired and yet minimize installation cost – in other words a detailed design. It was felt that the detailed design could be addressed when the project was going to proceed. However the budget dollars and the objective to be achieved need to be in the plan in order to order to proceed.

2-Staff-20

Ref: Exhibit 2, Tab 6, Schedule 1, page 21-22

Hearst Power has not provided asset counts for pad mounted switchgear or overhead line switches.

a) What is the number of units in each of the asset categories?

Response:

b) HPDC has no padmounted switchgear. It currently has 9 Load Break Switches as well as one set of solid blade switches installed in 2015 as part of the system plan.

2-Staff-21

Ref: Exhibit 2, Tab 6, Schedule 1, page 14

Ref: Exhibit 2, Tab 6, Schedule 1, page 25

On page 14 of the DSP, Hearst Power indicates that it inspected poles that were over 35 years old. Three paragraphs below and on page 25, Hearst Power states that it surveyed the condition of poles more than 30 years in service.

a) What was the minimum age for assessing the poles?

Response:

a) All pole installed before 1980 were inspected, therefore all poles over 35 years. Pole inspection was limited to these older poles due to the fact that the new manager started in May 2015 and no work was started by the previous manager on this rate application due for August 31st, 2015. Timing was an issue so HPDC, with the help of an AESI consultant, decided to inspect older poles only.

2-Staff-22

Ref: Exhibit 2, Tab 6, Schedule 1, page 27

Hearst Power states that in 2019 a new survey of the condition of the poles will be carried out for poles that have been in service for 30 years or more.

a) Is Hearst Power considering a more precise method of pole testing in addition to visual inspections and hammer testing?

Response:

a) No, HPDC is not considering other alternatives at this time but can look into this and decide how to proceed.

2-Staff-23

Ref: Exhibit 2, Tab 6, Schedule 1, Appendix D, page 70

Ref: Exhibit 2, Tab 6, Schedule 1, Appendix E, page 81

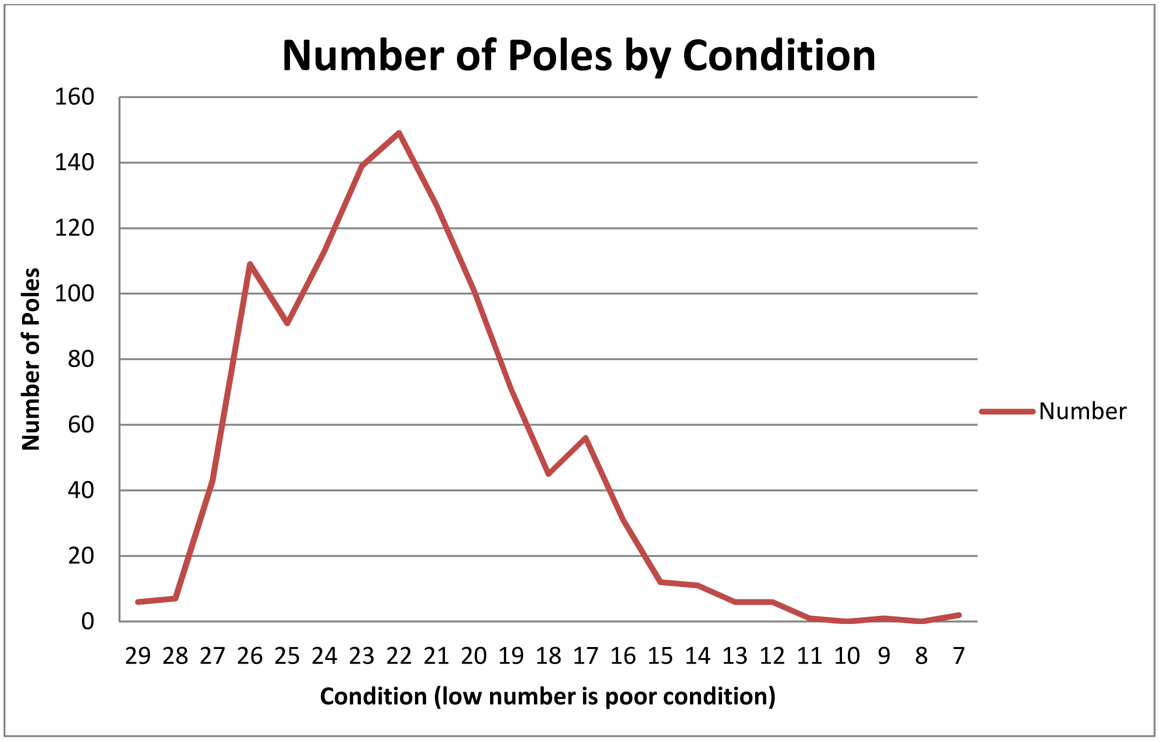
Appendices D and E of the DSP describe the justification of the pole replacement program and the rating system for pole condition. Hearst has determined that 126 poles or approximately 11% of the poles examined have a rating of 17 or lower.

a) What was the basis for selecting 17 as the threshold for replacement?
b) Please provide a distribution chart of the scores of all poles examined.
c) Please explain the escalation rate of 5% per year for annual cost projections.

Response:

a) During the survey, the poles were classified in 5 categories: Poor, Below Average, Fair, Good and New. There were 10 poles identified as Poor and 116 poles were identified as Below Average, therefore a total of 126 poles were in bad condition (below fair). It was estimated that the HPDC crew could replace around 20 to 25 poles per year without requiring assistance by a third party. Thus, on a 5 year plan, this equals to 100-125 poles. HPDC choose to replace a minimum of 100 poles starting with the pole with the lowest rating up to the 100th worst pole, which ended with "17" as the highest pole rating that would be replaced.

b) Chart of number of poles by condition is below:



c) 5% increase includes salary rates increases, poles and supplies increases as well as fuel and equipment cost increases.

2-Staff-24

Ref: Exhibit 2, Tab 6, Schedule 1, page 33

Hearst Power has provided a table in section 4.6.1 which includes the pole replacement program and one other of several non-material projects in this investment category.

a) Please explain the inclusion of the costs of Overhead Conduits in this table.

Response:

a) Account #1835 should not have indicated “Overhead Conduits” but rather “Overhead Conductors and Devices”. This is a typo probably resulting from the extensive use of French in Hearst. HPDC projected that since this account has a direct relation with the pole replacement plan, provisions should be accounted and this was shown in System Renewal.

2-Staff-25

Ref: Exhibit 2, Tab 6, Schedule 1, page 32-33

Board staff notes the significant impact of one bucket truck on General Plant expenditures in 2012. Hearst Power indicates that there are no material General Plant expenditures planned for 2015-2019.

a) Does Hearst Power have a contingency plan in place should a new truck or boom be required between 2015 and 2019?

Response:

a) HPDC currently have two buckets trucks and one digger derrick truck in good working condition; no problems are expected within the planning horizon of the DSP. HPDC rarely use all equipment at the same time therefore, if one is unavailable, two other are still available. No contingency plan is required as local contractors have buckets or digger derrick trucks available if needed. HPDC plans to replace its digger derrick truck (year 2000) in its next rate application (2020-2025). The digger derrick truck will be over 20 years old by that time.

2-Staff-26

Ref: Exhibit 2, Tab 7, Schedule 1

Ref: Appendix 2-G

Hearst Power has included a table of Service Reliability Indicators in Exhibit 2, Tab 7, Schedule 1 which is inconsistent with the Exhibit filed at Appendix 2-G in the revised Chapter 2 Appendices filed June 8, 2015.

a) Please confirm that the revised Appendix 2-G is based on 2014 actual SAIDI and SAIFI as at December 31, 2014. If this is not the case, please provide an updated Appendix 2-G.
b) Please provide the most current 5 year historical average SAIDI and SAIFI, based on full year 2014 actual information.
c) Please complete the table of Service Quality Indicators in Appendix 2-G for all categories listed.

Response:

a) Yes, the data for the SAIDI and SAIFI ratios in table 2-G in Service Reliability Indicators in Exhibit 2, Tab 7, Schedule 1 is correct (updated to Dec 31, 2014). The data in the Chapter 2 Appendices was not updated (data was for up to Oct 31, 2014)

b) 5 year averages:
SAIDI (Includes outages caused by loss of supply) = 3.66
SAIDI (Excludes outages caused by loss of supply) = 1.19
SAIFI (Includes outages caused by loss of supply) = 1.96
SAIFI (Excludes outages caused by loss of supply) = 0.64

c) The Service Quality Indicators on the bottom table shown on page 50 of Exhibit 2, Appendix 2-G, were as of October 31st, 2014. Here below is the revised for the 2014 actuals, as of December 31st, 2014:

Indicator	OEB Mininum Standard	2010	2011	2012	2013	2014
Low Voltage Connections	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%
High Voltage Connections	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65.00%	96.70%	95.00%	92.50%	100.00%	96.70%
Appointments Met	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Written Response to Enquiries	80.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emergency Urban Response	80.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emergency Rural Response	80.00%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appointment Scheduling	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standard	85.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2.0 – VECC -2
Reference: E2/T2/S1

a) Please clarify whether Tables 2-8 through 2-11 show additions to rate base or capital expenditures (or whether both are the same).

Response:

a) Tables 2-8 through 2-11 show the year end gross fixed assets.

2.0 – VECC - 3
Reference: E2/T1/S3

a) In explaining the 2010 actual/ to Board approved rate base variances Hearst explains that "*HPDC, like many others, tend to put capital investments on hold until the cost of service application is approved. This caused delays in HPDC investing time in maintaining and upgrading its system*." Please explain whether Hearst Power is deferring 2015 capital expenditures until it receives Board approval of this application.
b) Please provide the 2015 capital expenditures (by Board category) to date.

Response:

a) No, in 2010 HPDC delayed it capital expense, even if it did plan for replacing asset, as HPDC did not know what to expect from the OEB (if the capital plan would be approved or not). The General Manager in place at that time decided it would be better to wait for approval.

   In 2015, HPDC has new General Manager equipped with a Distribution System Plan which he intends to follow very closely and expects the OEB to approve this DSP. Although HPDC has delayed the purchase of a new vehicle (pickup truck, valued at 28,000$) until it receives OEB approval, it did not want to delay any further the capital work required to remove all dangerous poles and devices in its territory.

b) Please refer to "VECC – 2-VECC-3b"

2.0 – VECC - 4
Reference: E2/T2/S3/Continuity Schedule 2015 / E2/T4/S1Table 2.20

a) It appears from the 2015 Continuity Schedule that $146,999 (net book value of $28,913) related to the mechanical meters that were removed as part of the smart meter initiative (i.e. stranded meters) remain in rate base in 2015. Please confirm that Hearst's 2015 rate base does not include any assets/costs related to stranded meters.
b) Please explain the difference between the net book value shown in 2015 for meters of $28,913 (Account 1860) and the amount shown in Table 2.20 of $45,081 and Table# of $6,006 ($51,087).

Response:

a) VECC is correct in that it would appear as though Hearst inadvertently omitted removing the stranded meters from the continuity schedules
b) The revised table below shows the correction. The RRWF and other models field along with these responses also reflect the correct removal of the stranded meters.

Fixed Asset Continuity Schedule

Accounting Standard: MIFRS
Year: 2015

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 130,427	$ 5,000		$ 135,427	-$ 120,301	-$ 3,394		-$ 123,695	$ 11,732
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 4,232			-$ 4,232	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 707,005	$ 70,000		$ 777,005	-$ 564,672	-$ 4,858		-$ 569,530	$ 207,475
47	1835	Overhead Conductors & Devices	$ 981,153	$ 21,000		$ 1,002,153	-$ 817,997	-$ 19,317		-$ 837,314	$ 164,839
47	1840	Underground Conduit	$ 7,681			$ 7,681	-$ 2,588	-$ 285		-$ 2,873	$ 4,808
47	1845	Underground Conductors & Devices	$ 438,181	$ 5,431		$ 443,612	-$ 386,138	-$ 2,337		-$ 388,475	$ 55,138
47	1850	Line Transformers	$ 571,797	$ 6,017		$ 577,814	-$ 489,595	-$ 2,938		-$ 492,533	$ 85,281
47	1855	Services (Overhead & Underground)	$ 25,416	$ 11,000		$ 36,416	-$ 4,600	-$ 1,235		-$ 5,835	$ 30,581
47	1860	Meters	$ 146,989		-$ 96,809	$ 50,180	-$ 108,608	-$ 9,467	$ 90,803	-$ 27,272	$ 22,907
47	1860	Meters (Smart Meters)	$ 661,252	$ 2,625		$ 663,877	-$ 215,373	-$ 44,183		-$ 259,556	$ 404,321
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 268,434	$ 7,500		$ 275,934	-$ 102,564	-$ 6,212		-$ 108,776	$ 167,158
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 45,274	$ 2,500		$ 47,774	-$ 41,014	-$ 755		-$ 41,770	$ 6,004
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220			-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 39,387	$ 10,000		$ 49,387	-$ 26,101	-$ 4,564		-$ 30,665	$ 18,722
10	1930	Transportation Equipment	$ 732,201	$ 28,000		$ 760,201	-$ 548,600	-$ 33,468		-$ 582,068	$ 178,132
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 102,729	$ 7,000		$ 109,729	-$ 95,225	-$ 1,414		-$ 96,639	$ 13,090
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 3,546			-$ 3,546	$ -
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 4,954,680**	**$ 176,073**	**-$ 96,809**	**$ 5,033,944**	**-$ 3,612,531**	**-$ 134,427**	**$ 90,803**	**-$ 3,656,155**	**$ 1,377,789**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,954,680**	**$ 176,073**	**-$ 96,809**	**$ 5,033,944**	**-$ 3,612,531**	**-$ 134,427**	**$ 90,803**	**-$ 3,656,155**	**$ 1,377,789**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 134,427**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 134,427

2.0-VECC-5

Reference: E2/T4/S1

a) Please explain the difference between the $669,539 shown for 2015 closing balance smart meter additions and the $663,877 shown in Table 2.16 Summary of Cost Claim.
b) Please show the derivation (calculation) of the rate riders shown in Table 2.17.

Response:

a) The 2015 opening balance for account 1860 inadvertently included the additions for the year. The opening balance in the revised OEB Appendices has been corrected. Both numbers now show 663,877.
b) The rate riders at table 2.17 originate from the Smart Meter Model. (A revised model is filed with these responses which will change the values of the rate riders)

2.0-VECC-6

Reference: E2/T6/S1/DSP

a) Is the author of the DSP (J. Richard) an employee of Hearst Power or an outside consultant?
b) Please provide the qualifications of Mr. Richard.

Response:

a) No, the author of the DSP is A.J. (Archie) Bax of Acumen Engineered Solutions International Inc. (AESI). Archie Bax is a Professional Engineer (P.Eng., B.A. Sc., M.A. Sc.) with extensive experience in the Electrical Distribution sector.
b) Please refer to answer above.

2.0-VECC-7

Reference: E2/T6/S1/DSP/pg. 8 /Table 1

a) Please clarify the units of measurement used in Table 1: Customer – Hours by Cause (which appears to show for 2010 outages as large as 16,689 hours).

Response:

a) The units are customer-hours [customers interrupted times the duration of the interruption in hours]. Table 1 shows that in 2010, 14937.00 customer-hours were attributable to the Loss of Supply category and Table 2 shows that there were 3 “Loss of Supply” incidents and Table 3 shows that 6455 customers were affected.

   Please note that for most “Loss of Supply” interruption, all HPDC customers are affected (HPDC is located at the end of Hydro One’s transmission line).

2.0-VECC-8

Reference: E2/T6/S1/DSP/pg. 32

a) Please clarify what is meant by the following statement made in the DSP "*As noted in section 2.1.3 [5.3.3] the historical period was overseen by a previous General Manager. These expenditures do not represent the real needs of the HPDC power system nor are these expenditures consistent with a long term, sustainable, economical, well-functioning distribution system*." Please note we are unable to locate any material at section 2.1.3 or 5.3.3 that would be material to this statement.

Response:

a) In section 2.1.3 page 17 the following is stated :

"As can be seen, the plant capital plan-to-actual figures have a large variance. In early 2014 the previous General Manager left and a new General Manager was hired. The planning and rationale for the capital work that was completed prior to 2014 were undocumented decisions made by the previous GM for which we have no explanation. Going forward the activities that generate the budget dollar requirements will be planned and documented and completed as budgeted."

Without information about what was included in the budget and no recorded information about what was completed and why, it is not possible to conclude that system needs were identified or addressed. Hence, the conclusion that was stated as quoted in your question. The best information that HPDC could find anecdotally was that the Lead Hand and the line crew with little or no direction did what they felt was the minimum that was necessary to do to the power system in the absence of direction from the General Manager and in the absence of any shared plan. Any direction that was given apparently was to spend as little as possible.

2.0-VECC-9

Reference: E2/T6/S1/DSP/pg.16

a) Table 9 demonstrates that in the past Hearst Power has struggled to meet its planned expenditures. The Utility also notes it employs only one 2-Person line crew. Based on these facts what comfort can Hearst provide the Board that it will be able to complete its proposed 2015-2017 pole replacement program?

Response:

a) In 2015, HPDC hired a new General Manager. He addressed to regulatory submission and the plan communicated to the Board. HPDCL is focused on the execution of the plan and as of August 31 has completed the majority of its planned Capital projects for 2015 (Please refer to "VECC 2-VECC-9a").

When the DSP was being prepared there was only a single line crew. Since then the Lead Hand has retired and two line apprentices have been hired to fill the previous vacancy as well as the Lead Hand vacancy. One of the Journeymen has been promoted to Lead Hand. It should be noted that the Lead Hand is a working journeyman so HPDC has two "two person" crews and has two bucket trucks and a radial boom derrick with the ability to mount an insulated bucket.

2.0-VECC-10

Reference: E2/T6/S1/DSP/pg.64

a) Is the entire 2015 System Renewal budget of $86,448 related to the 20 pole replacements? If not please provide the entire budget for each of the 20 poles to be replaced (including any pole dressing).
b) Please explain if the replacement of the porcelain surge arrestors of $13k is related to the pole replacement program.
c) What is the unit cost for each pole replacement? Please clarify if this is includes just the pole or a fully dressed pole.

Response:

b) The pole replacement costs for 2015 are $70,000 as detailed on page 64 of the DSP section 5.3 Appendix C System Renewal. In addition a $5000 amount is budgeted to upgrade any open wire bus or open wire service to triplex for services from the pole being replaced to the customer service point.

c) No it is not. On page 14 the surge or lightning arrestor problem is identified and is discovered as part of the system reliability analysis. Also when considering the failure mechanism a public safety concern is raised as well.

d) For 2015, 20 poles are estimated to cost $70,000 so the average estimated cost is $3500. This includes the disconnection, removal and disposal of the old pole as well as the installation, dressing of the new pole and tying in the primary and secondary circuits as well as removal and reinstallation of distribution transformers that are mounted on the poles.

Hearst Power Distribution Company Limited

Exhibit 3

Responses to Interrogatories

September 11, 2015

3-Staff-27

Ref: Exhibit 1, Executive Summary, page 5

Ref: Exhibit 1, Tab 5, Schedule 4

Ref: Exhibit 3, Tab 1, Schedule 4, Economic Overview

At Exhibit 1, page 5, Hearst Power explains its increased return on equity in 2013 by an economic increase in the wood industry sector. In the Economic Overview to its load forecast, Hearst Power states that the forestry industry was "challenged", adversely affecting employment. Hearst also indicates that it expects the status quo over the planning horizon.

a) Please reconcile these conflicting statements regarding economic growth in the region and explain how it will impact the load forecast.

Response:

a) From 2006 to 2009, the lumber industry "was challenged" with a declining demands (sales) every year. It wasn't until 2010 that the local lumber industry reached its lowest point and started trending upward. By 2011, the lumber demand continued its trend upward but the local mills had lost many employees due to having sent them home in the recession of 2008 to 2009 so the industries were feeling the effects. It wasn't until late 2012 and early 2013 that the mills that survived the recession got back to full operation. In 2014, the lumber industry demand trend was stable (same as 2013) and the mills continue to operate in full. HPDC expects the same for 2015 ("status quo" - no change compared for 2014, except for CDM projects).

3-Staff-28

Ref: Exhibit 3, Tab 1, Schedule 6

Hearst Power has provided a list of the variables tested as inputs, and those which have been excluded. Board staff notes that several economic indicators were tested and all have been excluded from the equation, as well as customer count.

a) Please explain why economic indicators would not be an appropriate explanatory variable for the forecast equation.
b) Please provide the results in a table similar to Table 3.16 for the excluded variables.

Response:

(response to VECC 3.0 –VECC -17)

The utility notes that the model was built with an automatic selection feature. The feature selection automatically identifies the combination of input variables that provide the best fit predictive regression equation without multicollinearity. The minimum R-Square (which in this case was selected to be 0%) is first applied to each independent variable against the dependent and those under the R-square are flagged as OFF. A value of zero ignores this feature.

The variance inflation factor (VIF) is used to test the adjusted R-Square relationship of each independent variables.

Variance inflation factors (VIF) measure how much the variance of the estimated regression coefficients are inflated as compared to when the predictor variables are not linearly related.

The following guidelines are used to interpret the VIF

VIF	Status of predictors
VIF = 1	Not correlated
1 < VIF < 5	Moderately correlated
VIF > 5 to 10	Highly correlated

The iterative process is undertaken to disable variables where the maximum VIF, calculated as 1/(1-RSQ) is over this threshold. The utility selected 10 as a value.

With these parameters, the model kept both the “Winter Flag” and “Shutdown flag”.

All that said, the utility did run independent scenarios to analyze each results but found that there were little differences in the results. Ultimately, the utility used the automatic selection feature to determine the variables where were to be included in the regression analysis. The results of various regression scenarios are shown in the tables at the next page.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.928058472
R Square	0.861292528
Adjusted R Square	0.852623311
Standard Error	448677.1856
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	7	1.40003E+14	2.00004E+13	99.35067094	4.7948E-45
Residual	112	2.25469E+13	2.01311E+11		
Total	119	1.6255E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-9194911.924	13530511.42	-0.67956869	0.498179712	-36003885.9	17614062.05	-36003885.9	17614062.05
HDD	2147.014297	707.9307503	3.032802709	0.003011355	744.3402617	3549.688333	744.3402617	3549.688333
CDD	5414.47381	3893.426682	1.390670546	0.167082359	-2299.852082	13128.7997	-2299.852082	13128.7997
WinterFlag	18589.93252	182670.7407	0.101767434	0.919123247	-343348.7244	380528.5895	-343348.7244	380528.5895
Employment	14741.35688	20849.73734	0.707028422	0.481017282	-26569.72502	56052.43879	-26569.72502	56052.43879
Cust Count	2975.909465	2282.177388	1.303978157	0.19491469	-1545.932488	7497.751419	-1545.932488	7497.751419
AvgTemp	-27213.7357	20709.52322	-1.314068673	0.191508138	-68247.0013	13819.52991	-68247.0013	13819.52991
ShutDWN	80007.73404	157979.516	0.506443722	0.613540702	-233008.4262	393023.8943	-233008.4262	393023.8943

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.925358375
R Square	0.856288123
Adjusted R Square	0.853831509
Standard Error	446834.266
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.39189E+14	6.95947E+13	348.5644754	5.16798E-50
Residual	117	2.33603E+13	1.99661E+11		
Total	119	1.6255E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	5423317.967	101746.8996	53.30204645	6.45778E-84	5221813.564	5624822.369	5221813.564	5624822.369
HDD	3061.291231	144.8795794	21.12990143	9.53487E-42	2774.364816	3348.217646	2774.364816	3348.217646
CDD	3455.453758	3126.143833	1.105340619	0.271279813	-2735.710289	9646.617804	-2735.710289	9646.617804

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.926629854
R Square	0.858642887
Adjusted R Square	0.853726117
Standard Error	446995.3274
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	4	1.39572E+14	3.4893E+13	174.6355907	7.00575E-48
Residual	115	2.29776E+13	1.99805E+11		
Total	119	1.6255E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-7206250.899	13391285.81	-0.538129871	0.591527376	-33731810.82	19319309.02	-33731810.82	19319309.02
HDD	3059.85751	145.0176451	21.09989793	2.39734E-41	2772.605465	3347.109555	2772.605465	3347.109555
CDD	3078.020299	3139.156462	0.980524653	0.328885502	-3140.044493	9296.08509	-3140.044493	9296.08509
Employment	8836.477599	20238.91707	0.436608222	0.663214148	-31252.92195	48925.87715	-31252.92195	48925.87715
Cust Count	3094.226269	2262.366113	1.367694756	0.174074516	-1387.085588	7575.538126	-1387.085588	7575.538126

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.926503411
R Square	0.85840857
Adjusted R Square	0.854746722
Standard Error	445433.175
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.39534E+14	4.65113E+13	234.4195405	4.61911E-49
Residual	116	2.30156E+13	1.98411E+11		
Total	119	1.6255E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-1888924.916	5548798.321	-0.340420539	0.734155562	-12879019.15	9101169.32	-12879019.15	9101169.32
HDD	3057.978186	144.4471683	21.17021899	1.1864E-41	2771.882369	3344.074004	2771.882369	3344.074004
CDD	3111.054386	3127.277044	0.994812529	0.321898094	-3082.911844	9305.020617	-3082.911844	9305.020617
Cust Count	2642.489097	2004.882698	1.318026785	0.190091543	-1328.433706	6613.4119	-1328.433706	6613.4119

3-Staff-29

Ref: Exhibit 3, Tab 1, Schedule 6, Wholesale Purchases

In explaining its adjustments to wholesale purchases, Hearst Power states that it has removed 4.3 million kWh in Fit and Microfit generation.

a) Please explain why these amounts have been removed in the adjustment to wholesale purchases.
b) Please provide a recalculation of the load forecast including the Fit and Microfit kWh in wholesale purchases.
c) Please provide revised Tables 3.9 and 3.10 to include totals for each year.

Response:

a) The rational behind removing Fit/MicroFit was to normalize the wholesale purchases by removing the “known” factors such as loss of customer and Fit/MicroFit forecast as much as possible prior to running the regression. Removing the Fit/MicroFit only makes sense if the utility then uses a “Fit/Micro Fit” variable to explain the shift in monthly load.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.927129
R Square	0.859568
Adjusted R Square	0.854683
Standard Error	452231
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	1.44E+14	3.6E+13	175.9749	4.81E-48
Residual	115	2.35E+13	2.05E+11		
Total	119	1.67E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	5273935	174933.1	30.14831	1.98E-56	4927427	5620444	4927427	5620444
HDD	3106.189	286.0033	10.86068	2.44E-19	2539.672	3672.707	2539.672	3672.707
CDD	5737.17	3815.595	1.503611	0.135423	-1820.79	13295.13	-1820.79	13295.13
WinterFlag	25196.39	183012.1	0.137676	0.890737	-337315	387708.2	-337315	387708.2
ShutDWN	71485.79	158135.6	0.452054	0.652082	-241750	384722	-241750	384722

		Excluding MicroFit	Including MicroFit	
		(As proposed by the utility)	(As proposed by Board Staff)	
Date	**Actual WS**	**Predicted WS**	**Predicted WS**	**Difference**
2005-January	9197784	8,972,172	8,983,737	- 11,565
2005-February	7774648	8,069,489	8,053,433	16,056
2005-March	8036639	8,041,760	8,024,856	16,904
2005-April	6502163.5	6,702,643	6,645,983	56,661
2005-May	6331361	6,221,484	6,152,606	68,878
2005-June	5959868.5	5,814,945	5,790,582	24,364
2005-July	5175336.5	5,843,553	5,871,024	- 27,471
2005-August	5779475	5,653,184	5,620,610	32,574
2005-September	5783367	5,987,894	5,932,258	55,636
2005-October	6483513.5	6,568,308	6,511,637	56,671
2005-November	7676467.5	7,533,304	7,500,842	32,462
2005-December	8896336	8,403,135	8,397,288	5,847
2006-January	8679087	8,270,521	8,260,616	9,905
2006-February	8214062	8,337,129	8,329,263	7,866
2006-March	7943311	7,573,089	7,541,844	31,245
2006-April	6342750	6,709,274	6,652,816	56,458
2006-May	6369655.5	6,139,639	6,085,912	53,726
2006-June	5967231.5	5,862,159	5,812,358	49,801
2006-July	5525209.5	5,749,998	5,742,257	7,741
2006-August	5948963.5	5,754,617	5,704,644	49,973
2006-September	5877685	6,121,347	6,047,924	73,423
2006-October	6420299.5	6,782,514	6,728,297	54,217
2006-November	7402269.5	7,234,018	7,192,397	41,620
2006-December	8310910.5	7,813,302	7,789,407	23,895
2007-January	8384634	8,466,127	8,462,208	3,919
2007-February	8800029	8,661,130	8,663,178	- 2,048
2007-March	7759037.5	7,805,465	7,781,331	24,135
2007-April	7258825.5	6,967,270	6,918,706	48,564
2007-May	6474482.5	6,194,064	6,132,890	61,174
2007-June	6127499.5	5,954,302	5,923,382	30,921
2007-July	5932199.5	5,653,919	5,621,710	32,209
2007-August	6105556.5	5,710,371	5,672,371	38,000
2007-September	6194744.5	6,025,640	5,955,326	70,314
2007-October	6541924	6,484,131	6,420,784	63,347
2007-November	8254635	7,529,989	7,497,425	32,564
2007-December	9574588	8,442,919	8,438,290	4,629
2008-January	9079341	8,418,506	8,413,130	5,376
2008-February	8837021	8,401,929	8,396,046	5,884
2008-March	9024592	8,194,267	8,182,029	12,238
2008-April	7191861	6,816,270	6,763,086	53,184
2008-May	6991462	6,469,664	6,405,874	63,790

2008-June	6168427	5,835,717	5,766,198	69,519
2008-July	5381918	5,572,173	5,512,744	59,429
2008-August	6313812	5,622,770	5,562,725	60,045
2008-September	6081323	6,115,159	6,053,280	61,879
2008-October	6749178	6,654,035	6,597,482	56,554
2008-November	7771702	7,312,381	7,273,158	39,222
2008-December	9255481	8,748,234	8,752,947	- 4,713
2009-January	9687027	9,055,056	9,069,157	- 14,101
2009-February	8395038	8,305,784	8,296,958	8,826
2009-March	7068217	7,954,054	7,934,466	19,588
2009-April	6414184	6,999,519	6,951,942	47,577
2009-May	6469952	6,483,829	6,420,473	63,356
2009-June	6260939	5,958,862	5,915,779	43,083
2009-July	4648945	5,623,380	5,557,431	65,949
2009-August	5697613	5,772,150	5,727,498	44,653
2009-September	6237383	5,927,423	5,856,267	71,155
2009-October	7124815	6,879,262	6,828,005	51,257
2009-November	6010367	6,930,511	6,879,604	50,907
2009-December	7389479	8,354,309	8,346,968	7,341
2010-January	7877934	8,418,506	8,413,130	5,376
2010-February	6923499	8,019,457	8,001,870	17,587
2010-March	6126461	7,273,199	7,232,778	40,421
2010-April	6975021	6,560,083	6,499,060	61,023
2010-May	6192325	6,252,823	6,222,607	30,215
2010-June	5966146	5,883,986	5,812,185	71,801
2010-July	5877652	5,697,111	5,690,485	6,625
2010-August	5838235	5,744,463	5,735,756	8,708
2010-September	5299732	6,174,898	6,102,089	72,809
2010-October	6525309	6,725,248	6,669,279	55,969
2010-November	7304633	7,302,435	7,262,908	39,527
2010-December	8576299	8,065,571	8,049,395	16,176
2011-January	8946669	8,917,318	8,927,204	- 9,887
2011-February	7921364	8,224,708	8,213,402	11,306
2011-March	6808616	8,105,657	8,090,707	14,949
2011-April	7136876	7,027,549	6,980,830	46,719
2011-May	5732243	6,256,291	6,191,440	64,851
2011-June	5876887	5,796,533	5,722,968	73,565
2011-July	5555950	5,720,313	5,723,169	- 2,855
2011-August	5798395	5,645,604	5,602,091	43,513
2011-September	5918461	5,998,415	5,923,395	75,020
2011-October	6234104	6,513,406	6,455,967	57,439
2011-November	7019349	7,196,343	7,153,570	42,773
2011-December	7445070	8,235,257	8,224,274	10,984
2012-January	8385129	8,458,592	8,454,442	4,150
2012-February	7845578	7,996,852	7,978,574	18,278
2012-March	7503491	7,262,047	7,221,285	40,762
2012-April	6539070	6,966,365	6,917,774	48,591
2012-May	6100225	6,190,727	6,132,754	57,972
2012-June	5011748	5,737,492	5,687,521	49,971

2012-July	5461517	5,679,098	5,670,555	8,544
2012-August	6002405	5,706,280	5,662,801	43,479
2012-September	5933883	6,130,120	6,067,901	62,219
2012-October	6685854	6,631,815	6,572,987	58,828
2012-November	7408803	7,393,456	7,356,715	36,741
2012-December	8178514	8,210,844	8,199,113	11,731
2013-January	8938428	8,697,599	8,700,763	- 3,163
2013-February	8209750	8,363,049	8,355,976	7,073
2013-March	8094362	7,856,100	7,833,515	22,585
2013-April	6171276	7,227,375	7,186,770	40,605
2013-May	5970163	6,379,546	6,312,999	66,547
2013-June	5636891	5,917,312	5,851,885	65,427
2013-July	5598405	5,742,646	5,722,492	20,154
2013-August	5844163	5,709,796	5,677,019	32,778
2013-September	5891223	6,018,775	5,941,188	77,586
2013-October	6851089	6,613,731	6,554,350	59,381
2013-November	7530000	7,479,957	7,445,862	34,095
2013-December	9066138	8,954,992	8,966,031	- 11,039
2014-January	8698192	8,971,569	8,983,115	- 11,547
2014-February	8777587	8,409,163	8,403,501	5,662
2014-March	8067658	8,427,849	8,422,759	5,090
2014-April	7355167	7,191,810	7,150,117	41,693
2014-May	6303616	6,244,945	6,177,697	67,249
2014-June	6386105	5,821,371	5,766,449	54,922
2014-July	5431065	5,684,549	5,632,318	52,231
2014-August	5417147	5,677,507	5,624,263	53,244
2014-September	5326981	5,453,139	5,359,497	93,641
2014-October	6541069	7,390,480	7,356,803	33,678
2014-November	6870430	7,815,713	7,791,892	23,821
2014-December	8395195	8,210,241	8,198,492	11,749
2015-January		8,664,596	8,666,750	- 2,154
2015-February		8,278,869	8,269,220	9,649
2015-March		7,849,349	7,826,557	22,792
2015-April		6,916,816	6,866,708	50,107
2015-May		6,283,301	6,223,525	59,776
2015-June		5,858,268	5,804,931	53,337
2015-July		5,696,674	5,674,418	22,256
2015-August		5,699,674	5,658,978	40,696
2015-September		5,995,281	5,923,913	71,368
2015-October		6,724,293	6,669,559	54,734
2015-November		7,372,811	7,335,437	37,373
2015-December		8,343,880	8,336,221	7,660

3-Staff-30

Ref: Exhibit 3, Tab 1, Schedule 8, page 28

Hearst Power states that it was unable to run the regression analysis without having 20 years of history for all variables, which was not available.

a) Please explain why the required history was not available, and for which variables.

Response: see 3.0 –VECC -15

3-Staff-31

Ref: Exhibit 3, Tab 2, Schedule 1

Ref: Chapter 2 Appendices, Appendix 2-I, CDM Workform

Board staff notes that there appear to be some anomalies in Hearst Power's calculation of the CDM adjustment.

a) Please complete the "net to gross" conversion by entering the required information in Columns C and D at Rows 83 to 86 in Appendix 2-I.
b) Please confirm that no CDM adjustment was incorporated into Hearst Power's last approved load forecast for 2010 rates. If this is the case, please remove the entry in Cell B 166 of the Appendix.
c) Please adjust the loss factor at Cell B122 to correspond with the loss factor calculated at Appendix 2-R.
d) Please recalculate the CDM adjustment and Final Weather-Adjusted Load Forecast based on these corrections.

Response:

a) The revised set of Appendices shows the net to gross table completed
b) Hearst confirms that no CDM adjustment was incorporated into Hearst Power's last approved load forecast for 2010 rates. (please note that cell B166 does not contain any data, Hearst assumes that the Board meant B116)
c) B122 has been revised to show the correct loss factor (note that Hearst has updated it loss factor during these interrogatories.
d) The utility has made the requested correction in both the Load Forecast model and OEB Appendices and notes that the Final Load Forecast did not change as a result of these changes. The reason being that those inputs were never included in the calculations.

3-Staff-32

Ref: Exhibit 3, Tab 4, Schedule 3, Other Revenue Variance Analysis

Hearst Power appears to use the same variance explanation regarding accounting anomalies for Revenues From Merchandise Jobbing in 2012, 2013 and 2014.

a) Please confirm that the practice of netting revenues and expenses in this category was corrected in 2012.
b) Please explain why the problem appears to have occurred again in 2013 and 2014.

Response:

a) Only a portion of the netted revenues and expenses were corrected by our financial auditors at year end in 2012, 2013 and 2014.

   Not all revenues in Merchandise Jobbing were netted but only specific revenues were recorded as credit in expense instead of revenue (revenues for water activities, revenues from Hearst Power Sales, etc.).

   The netting of revenues was always of concerns for our auditors as Collins Barrow had advised of their divergence in previous years. In 2012, monthly netting entries continued to be made by HPDC staff, but the Collins Barrow accountant (auditor) decided to make annual year-end entries to reverse parts of the netting. The auditor was not able to reverse all entries due to the fact that some of the amounts were immaterial and sometimes not easily identifiable.
   The netting of revenue did not affect the overall financials end results of the company but instead, it painted a distorted overall picture of the actual expenses and revenues.

b) Monthly netting entries continued to be made in 2013 and some were reversed by the Collins Barrow auditor at year-end. In 2014, monthly netting entries continued but when the new General Manager started in May, he did not approved such accounting method and working with the auditor, started to identify and establish the correct way to record all revenue and expense. Since the first 6 months of 2014 were already recorded with revenue netting, it was decided that a full change was to be completed only on January 1st 2015 and the 2014 year was to be treated same as 2013.

HPDC confirms that, starting January 1st 2015, each revenue entry has been recorded in its proper related account and there is no more netting.

3.0 –VECC -11
Reference: E3, pg. 3

a) It is noted that HPDCL has no Unmetered & Scattered Load (USL) class. Does HPDCL have any unmetered customers (e.g., cable companies, billboard owners, etc.) other than Street Lights and Sentinel Lights that are not metered?
    - If yes, in what customer classes are they included and how are their volumetric billing determinants established?
    - If no, are all customers such as cable companies (who are typically unmetered in other utilities) metered in HPDCL's case?

Response

a) HPDC does not have any Unmetered & Scattered customers. All customers are metered except for the Street Lights and Sentinel Lights customers.
    - If yes, in what customer classes are they included and how are their volumetric billing determinants established?
    - If no, are all customers such as cable companies (who are typically unmetered in other utilities) metered in HPDCL's case?
        a. Yes, they are metered.

3.0 –VECC -12
Reference: E3, pg. 6 and 31-32

Response:

a) The wholesale purchases in both the model and the tables in Exhibit 3 were in fact update to reflect 2014 year end actual data. Hearst should have updated the statements at pages 6, 31 and 32 to reflect the fact that the data is up to year end 2014.

a) Given that actual purchase data was available up to December 2014 (per pages 31-232), why wasn't 2014 actual data also used in the multiple regression model?

3.0 –VECC -13

Reference: E3, pg. 10

a) Are the customer counts set out in Table 3.2 year end or average annual values?
b) Please provide a schedule that set out the 2015 count by customer class as of June 30, 2014 and June 30, 2015.

Response:

a) Year end values
b)

Date	Residential	GS<50 kW	GS>50 kW	Intermediate	Sentinel Lights	Street Lights
June-30-14	2268	454	40	2	17	943
June-30-15	2259	454	42	2	13	945

3.0 –VECC -14
Reference: E3, pg. 16

a) The last paragraph states that HPDCL "removed" the kWh associated with Fit and MicroFit generation. Please clarify whether these kWhs were removed or "added" to the power purchases from the IESO and Hydro One.
b) The second last paragraph states that the customer eventually shut down in early 2011 but then goes on to state that usage data was only removed for the period up to October 2008. Please reconcile these two statements.

Response:

a) The kWh were removed from the wholesale purchases prior to running the regression
b) In other words: In 2008, the customer significantly reduced it consumption by stopping production in order to try and survive the recession, hoping it could resumed its operation once the recession is over. In 2011, the customer completely shut down in 2011.

Here is the timeline of event for this customer:

- Prior to October 2008: Mill in production of wood products including press wood and laminate
- From November 2008 to 2011: mill was not in production but lights and minimum heat were kept on
- After 2011 and up to date, the operations at the mill were officially suspended and some equipment was sold. The mill area is used for lumber storage, therefore lights and minimum heat is required.

The consumption after the equipment "power-off" in October 2008 was not significant, and remains stable since that time. Consequently, in order to achieve a better forecast, it was better to removed only the consumption of this customer up to October 2008.

3.0 –VECC -15

Reference: E3, pg. 17 and 28
OEB's Chapter 2 Cost of Service Rate Application Filing Guidelines, July 19, 2014, page 28

a) Please explain why it is necessary to have 20 years of data for all the variables used in the regression model in order to base "weather normal" on 20 years of HDD and CDD values (per page 28, lines 1-3).
b) It is noted that the Filing Guidelines for 2015 Cost of Service Based Rate Applications require that the Applicant provide "the load forecasts based on a) 10-year average and b) 20-year trends in HDD and CDD". Please provide a schedule that compares the purchase power forecast (as produced using the regression model based on: a) a definition of weather normal using a 10 year average, as proposed by HPDCL, and b) a 20-year trend in the HDD and CDD values.

Response:

a) The applicant mistakenly thought that the 20 years of data was required for all variables.

b) The table below shows the results of the 10 year average and 20 year average, the second table show the results of the Load Forecast using a 10 year average in comparison to the 20 Year average.

Comparison of 10/20 year average HDD/CDD

HDD	CDD
10 Year Avg	20 Year Avg
1061.2	1097.3
933.2	922.2
790.7	794.1
489.8	509.4
266.9	275.7
100.7	103.5
48.1	51.6
73.1	77.3
175.0	184.5
424.2	420.4
632.6	642.5
954.7	929.6

HDD	CDD
10 Year Avg	20 Year Avg
0	0
0	0
0	0
0	0
9	6
26	26
44	41
28	28
6	8
1	1
0	0
0	0

Load Forecast using 10/20 year average HDD/CDD

		Using 20 year Avg HDD/CDD	Using 10 year Avg HDD/CDD
	Year	**2015**	**2015**
Residential	Cust/Conn	2,272	2,272
	kWh	24,917,641	24,872,947
	kW		
General Service < 50 kW	Cust/Conn	464	464
	kWh	11,416,287	11,395,810
	kW		
General Service > 50 to 4999 kW	Cust/Conn	41	41
	kWh	23,147,250	23,105,732
	kW	66,383	66,264
Intermediate	Cust/Conn	2	2
	kWh	21,793,907	21,793,907
	kW	62,295	62,295
Sentinel Lights	Cust/Conn	15	15
	kWh	19,559	19,559
	kW	71	71
Street Lighting	Cust/Conn	947	947
	kWh	1,029,688	1,029,688
	kW	11,303	11,303

3.0 –VECC -16
Reference: E3, pg. 18 - 20 and 24

a) Please explain why a Winter Flag is required when the regression model already in includes the HDD variable to account for the winter heating requirements.
b) Please confirm that:
   - The winter flag variable is set at zero in the winter months and 1 in the non-winter months.
   - The fact that the coefficient resulting from the regression analysis is positive (per page 24), means that the flag will increase forecasted purchases in the summer months relative to the winter months.
   - Please discuss whether or not this result is counter intuitive to HPDCL's claim that the variable is meant to reflect the heavy dependence on electric heat in the winter..
c) Did HPDCL test whether a Spring/Fall flag would improve the regression model? If so, please provide the results.
d) What do the revised Wholesale numbers set out in Table 3.12 b) represent?

Response:

a) The use of the Winter Flag is no different than the Spring/Fall Flag which has been used and approved as an acceptable variable in countless applications. The Spring/Fall flag was tested but found to be unreliable due to the fact that the utility's weather is much different than utilities in southern Ontario. As explained in the application, the utility's "seasonal variable" was modified to reflect Hearst's actual seasonal usage.
b) Hearst somewhat disagrees with VECC in that a Dummy Variable or Indicator Variable is an artificial variable created to represent an attribute with two or more distinct categories/levels. Dummy variables assign the numbers '0' and '1' to indicate membership in any mutually exclusive and exhaustive category.

   Many new studies, including a study published by Princeton University states the following;
   "Regression analysis is used with numerical variables. Results only have a valid interpretation if it makes sense to assume that having a value of 2 on some variable is does indeed mean having twice as much of something as a 1, and having a 50 means 50 times as much as 1. <u>However social scientists often need to work with categorical variables in which the different values have no real numerical relationship with each other. Examples include variables for race,</u>

political affiliation, or marital status".

The utility changed the winter dummy flags (Nov-Mar) to "1" and the summer flags (Apr-Oct) to "0" and the results were the same.

Without changing winter flag from "0" to "1"

R Squared	**0.8567**
Adjusted R Squared	**0.8517**
Standard Error	**450132.8750**
F - Statistic	**171.8102**

	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept
Intercept	5,356,480.402	174,121.451	30.763	0.00%			
HDD	3,013.966	284.676	10.587	0.00%	85.48%	2959.98	5505984.50
CDD	4,461.577	3,797.893	1.175	24.25%	30.79%	-38331.42	7333455.50
WinterFlag	25,630.668	182,163.020	0.141	88.84%	67.12%	1934142.95	6167758.00
ShutDWN	84,215.454	157,401.928	0.535	59.37%	24.02%	1530572.31	5698174.00

Changing winter flag from "0" to "1"

R Squared	**0.8567**
Adjusted R Squared	**0.8517**
Standard Error	**450132.8750**
F - Statistic	**171.8102**

	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept
Intercept	5,382,111.070	274,429.443	19.612	0.00%			
HDD	3,013.966	284.676	10.587	0.00%	85.48%	2959.98	5505984.50
CDD	4,461.577	3,797.893	1.175	24.25%	30.79%	-38331.42	7333455.50
WinterFlag	25,630.668	182,163.020	0.141	88.84%	67.12%	-1934142.95	8101901.00
ShutDWN	84,215.454	157,401.928	0.535	59.37%	24.02%	1530572.31	5698174.00

c) The table was copied from the tab "Adjustments and Variables" from the model. The revised wholesale purchases represents the wholesale variables adjusted for microfit and the loss of the intermediate user.

d) Note that Hearst should have used the unadjusted wholesale purchases to emphasize the seasonal consumption. A corrected table is shown below. The idea of the table is to show that unlike other utilities where the summer and winter months have the highest consumption and spring and fall have the lowest consumption, the tables below shows that the lowest consumption months are the summer months.

Unadjusted Wholesale Purchases kWh	
2005-January	12040115
2005-December	11748201
2006-January	11403923
2007-February	11396537
2006-March	11177732
2006-February	11174429
2007-January	11144240
2006-December	10860583
2005-November	10834098
2005-March	10822381
2007-March	10459243
2005-February	10319632
2006-November	10297709
2007-April	9692973
2009-January	9687027
2005-October	9633073
2007-December	9574588
2006-October	9518805
2006-April	9457861
2006-May	9455389
2008-December	9255481
2005-May	9168836
2005-April	9168123
2008-January	9079341
2013-December	9066138
2008-March	9024592
2011-January	8946669
2013-January	8938428
2006-June	8931355
2006-August	8930085
2008-February	8837021
2007-May	8815221
2006-September	8786642
2014-February	8777587
2007-October	8702807
2014-January	8698192
2005-September	8579568
2010-December	8576299
2005-August	8542170
2007-September	8441906
2007-June	8406333
2014-December	8395195

2009-February	8395038
2005-June	8391313
2012-January	8385129
2007-November	8254635
2013-February	8209750
2012-December	8178514
2007-July	8166977
2013-March	8094362
2014-March	8067658
2007-August	8056499
2011-February	7921364
2010-January	7877934
2012-February	7845578
2006-July	7844343
2008-November	7771702
2005-July	7715191
2013-November	7530000
2012-March	7503491
2011-December	7445070
2012-November	7408803
2009-December	7389479
2014-April	7355167
2010-November	7304633
2008-April	7191861
2011-April	7136876
2009-October	7124815
2009-March	7068217
2011-November	7019349
2008-May	6991462
2010-April	6975021
2010-February	6923499
2014-November	6870430
2013-October	6851089
2011-March	6808616
2008-October	6749178
2012-October	6685854
2014-October	6541069
2012-April	6539070
2010-October	6525309
2009-May	6469952
2009-April	6414184
2014-June	6386105
2008-August	6313812
2014-May	6303616
2009-June	6260939
2009-September	6237383
2011-October	6234104
2010-May	6192325
2013-April	6171276
2008-June	6168427
2010-March	6126461
2012-May	6100225
2008-September	6081323

2009-November	6010367
2012-August	6002405
2013-May	5970163
2010-June	5966146
2012-September	5933883
2011-September	5918461
2013-September	5891223
2010-July	5877652
2011-June	5876887
2013-August	5844163
2010-August	5838235
2011-August	5798395
2011-May	5732243
2009-August	5697613
2013-June	5636891
2013-July	5598405
2011-July	5555950
2012-July	5461517
2014-July	5431065
2014-August	5417147
2008-July	5381918
2014-September	5326981
2010-September	5299732
2012-June	5011748
2009-July	4648945

3.0 –VECC -17
Reference: E3, pg. 24

a) Please confirm whether the R-Squared values set out in Table 3.17 are: i) R Squared values or b) Adjusted R-Squared values. If the former, please provide the later for each variable tested.
b) It is noted that the Winter Flag and ShutDWN variables are not statistically significant. Please explain why they were retained in the regression model.
c) Please provide an alternative regression analysis just using HDD and CDD and provide tables equivalent to Table 3.14 and Table 3.15 based on the results.
d) Please provide a schedule that compares the purchase power forecast that results from the model as proposed by HPDCL with the 2015 forecast using the equation developed in part c).

Response:

a) Under the independent analysis at table 3.17, the R-Square represents the R-Square values and not the Adjusted R-Square. The model cannot be updated and tested to calculate the independent Adjusted R-Square. The change in models would take more time and add more costs to the application however, the model will be update to reflect this recommendation for future applications.
b) The utility's view is that any variable which improves results, even if marginally, should be included in the regression study.

The utility notes that the model was built with an automatic selection feature. The feature selection automatically identifies the combination of input variables that provide the best fit predictive regression equation without multicollinearity. The minimum R-Square (which in this case was selected to be 0%) is first applied to each independent variable against the dependent and those under the R-square are flagged as OFF. A value of zero ignores this feature.

The variance inflation factor (VIF) is used to test the adjusted R-Square relationship of each independent variables.
Variance inflation factors (VIF) measure how much the variance of the estimated regression coefficients are inflated as compared to when the predictor variables are not linearly related.

The following guidelines are used to interpret the VIF

VIF	Status of predictors

VIF = 1	Not correlated
1 < VIF < 5	Moderately correlated
VIF > 5 to 10	Highly correlated

The iterative process is undertaken to disable variables where the maximum VIF, calculated as 1/(1-RSQ) is over this threshold. The utility selected 10 as a value.
With these parameters, the model kept both the “Winter Flag” and “Shutdown flag”.

c) The following table shows the results of the regression with the HDD and CDD only along with a table showing the Adjusted Wholesale using the proposed variables compared to using HDD and CDD only.

R Squared	**0.8563**
Adjusted R Squared	**0.8538**
Standard Error	**446834.2813**
F - Statistic	**348.5645**

	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept
Intercept	5,423,317.967	101,746.900	53.302	0.00%			
HDD	3,061.291	144.880	21.130	0.00%	85.48%	2959.98	5505984.50
CDD	3,455.454	3,126.144	1.105	27.13%	30.79%	-38331.42	7333455.50

d) The following table shows the results of the regression with the HDD and CDD only along with a table showing the Adjusted Wholesale using the proposed variables compared to using HDD and CDD only.

Year	Adjusted Wholesale		
	Variables as proposed	Variables HDD CDD	Diff
2005	83,811,871	83,722,557	- 89,314
2006	82,347,604	82,318,487	- 29,117
2007	83,895,328	83,885,993	- 9,335
2008	84,161,106	84,234,182	73,077
2009	84,244,138	84,299,363	55,225
2010	82,117,780	82,046,634	- 71,145
2011	83,637,394	83,636,063	- 1,332
2012	82,363,689	82,317,713	- 45,976
2013	84,960,880	85,003,145	42,265
2014	85,298,336	85,373,988	75,652
2015	83,683,813	83,585,312	- 98,501

3.0 –VECC -18
Reference: E3, pg. 33

a) Please clarify for which years the data is based on forecast vs. actual values.
b) Please confirm that third customer class shown in the table is GS>50-1499 and not GS>50-4999.
c) Please confirm that for the years where actual values are involved:
   - The values for the Street Lighting, Sentinel Lights and Intermediate classes are based on actual sales.
   - The values for Residential, GS<50, and GS 50>50-1499 are were derived multiplying i) the average historical ratio of the actual class' sales to the actual (adjusted) purchases by ii) the <u>predicted</u> purchases for the year using the actual value for all the independent variables (including HDD and CDD)..

   If this is not the case, please explain how the values for each customer class were derived.
d) If the basis for the determination of the predicted wholesale purchase values did not use weather normal values for HDD and CDD, how can the resulting calculation of the customer class sales result in weather adjusted "actual" values as the title to Table 3-24 states?
e) Please confirm that the forecast 2015 kWh sales for Street Lighting, Sentinel Lights and Intermediate are not linked in any way to the 2015 forecast for purchases power.

a) 2010 to 2014 are based on actuals while 2016 is forecasted
b) The applicant confirms that the General Service Class is in fact GS>50-1499
c) For non-weather sensitive classes, the utility calculates a yearly ratio between the class's kWh and demand. The utility then takes an average of the ratio to determine the 2015 forecasted demand.
d) For weather sensitive customer classes, the applicant calculates a ratio (column c) between the Wholesale Purchases and the Retail Consumption. The applicant then applies this ratio (column c) to the adjusted wholesale (column d) in order to come up with the Residential Weather normalized load. (column e)

Residential						
			a) / b)			
	a)	b)	c)	d)	e)	f)
Year	Residential Actual kWh	Total Actual Wholesale	Ratio%	Adjusted Wholesale	Residential Weather Normal	Per customer
2005	27517850	83596959	32.92%	83811871	27588593	11755
2006	26697050	83001434	32.16%	82347604	26486748	11365
2007	26674248	87408154	30.52%	83895328	25602243	10976
2008	26529865	88846118	29.86%	84161106	25130898	10851
2009	27160625	81403959	33.37%	84244138	28108258	12158
2010	24736853	79509530	31.11%	82117780	25548327	11132
2011	24621320	80704953	30.51%	83637394	25515944	11120
2012	23813833	81742651	29.13%	82363689	23994758	10476
2013	25300382	84500806	29.94%	84960880	25438133	11133
2014	25241629	86123559	29.31%	85298336	24999768	10970
2015		Avg	29.72%	83683813	24872947	10914

x =

The adjusted wholesale (columnd d) is based on the regression results. For example, had the utility only used the HDD and CDD as variables, the column d) would have shown the following balances

Year	Adjusted Wholesale
	Variables as proposed
2005	83,811,871
2006	82,347,604
2007	83,895,328

2008	84,161,106
2009	84,244,138
2010	82,117,780
2011	83,637,394
2012	82,363,689
2013	84,960,880
2014	85,298,336
2015	83,683,813

To answer the specific question at e). Hearst contemplated putting the adjusted figures for historical years 2010-2014 but thought that showing “actuals” instead of “weather adjusted” would be more insightful. Hearst admits that the title of the table is misleading

A more complete and descriptive table is shown at the next page.

	Final Load Forecast Results								
			2010	2011	2012	2013	2014	2015 Weather Adj	2015 Final Adjusted (adjusted for CDM)
		Cust/Conn	2,295	2,295	2,291	2,285	2,279	2,279	2,272
Residential	**Actual**	kWh	24,736,853	24,621,320	23,813,833	25,300,382	25,241,629	24,872,947	24,347,981
	Weather Adjusted	kWh	25,548,327	25,515,944	23,994,758	25,438,133	24,999,768		
General Service < 50 kW		Cust/Conn	391	422	444	453	457	457	464
	Actual	kWh	11,499,854	11,814,687	11,024,461	11,359,856	11,110,938	11,395,810	11,155,291
	Weather Adjusted	kWh	11,877,098	12,243,978	11,108,219	11,421,706	11,004,475		
General Service > 50 to 4999 kW		Cust/Conn	40	39	40	40	41	41	41
	Actual	kWh	17,450,896	21,470,204	23,664,082	23,218,142	23,609,369	23,105,732	22,618,065
	Weather Adjusted	kWh	18,023,359	22,250,331	23,843,869	23,344,556	23,383,148		

e) Hearst confirms that the forecast 2015 kWh sales for Street Lighting, Sentinel Lights and Intermediate are not linked to the 2015 forecast for purchases power as they are not weather sensitive classes

Hearst notes that the identical methodology was used in both case EB-2013-0122 and EB-2013-0139 and was deemed by VECC to be “fairly robust” and to be an “appropriate model to use for purposes of forecasting purchases”.

3.0 –VECC -19
Reference: E3, pg. 34-35

a) The tables on pages 34 and 35 set out different CDM savings by year for the 2011-2014 period. Please confirm that it is the savings profile on page 35 that HPDCL is relying on for purposes of its load forecast and indicate if the schedule on page 34 has any relevance or role in the application.
b) Are there any reports (preliminary or final) from the OPA/IESO on 2014 full year CDM results? If so, please provide
c) With respect to page 35, please reconcile the reported savings in 2014 from just 2014 CDM programs (1,287,131 kWh) with results reported in the OPA's 2014 Q3 Report which shows the CDM savings in 2014 from 2011, 2012, 2014 and 2014 programs as 1,300,000 kWh.
d) Please explain how the 566,363 kWh/6,500 kW manual adjustment for Street Lighting CDM was determined.
e) Base on any corrections or revisions to the Application arising from the preceding responses please revise Table 3.25 as required.

Response:

a) Hearst confirms that the table at page 35 shows the correct savings for 2011-2014.

2011-2014 CDM Program - 2014, last year of the current CDM plan					
4 Year (2011-2014) kWh Target: 3,310,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	4.21%	4.21%	4.21%	4.21%	16.84%
2012 CDM Programs		6.61%	6.61%	6.61%	19.84%
2013 CDM Programs			10.97%	10.97%	21.93%
2014 CDM Programs				38.89%	38.89%
Total in Year	**4.21%**	**10.82%**	**21.79%**	**60.67%**	**97.49%**
kWh					
2011 CDM Programs	139,344.00	139,344.00	139,344.00	139,344.00	557,376.00
2012 CDM Programs	- 16,000.00	218,857.00	218,857.00	218,857.00	640,571.00
2013 CDM Programs		99,000.00	362,961.00	362,961.00	824,922.00
2014 CDM Programs				1,287,131.00	1,287,131.00
Total in Year	**123,344.00**	**457,201.00**	**721,162.00**	**2,008,293.00**	**3,310,000.00**

b) Please refer to document "VECC 3-VECC-19b"
c) 2014 CDM programs (1,287,131 kWh) is a calculated cell from the OEB appendices App.2-LF_CDM_WF. It appears as though the target shortfall are added to the 2015-2020 targets
d) Ask Jessy
e) Table 3.25 does not require any adjustment.

3.0 –VECC -20
Reference: E3, pg. 36-37

a) Please provide copies of any plans HPDCL has submitted to the OPA/IESO regarding how it intends to achieve its 2015-2020 CDM Target.
b) Please confirm that for future purposes of the calculating the LRAMVA for 2015 HPDCL is proposing that the amount of CDM deemed to be included in the load forecast is 533,333.33 kWh? If not, what is the amount and how was it determined.
c) Please provide a breakdown, by customer class, of this amount, including related kW values for demand billed classes.
d) The proposed LRAMVA amount for 2015 as discussed in part (b) does not appear to include either i) the impact of 2014 CDM programs in 2015 or ii) the impact of the Street Lighting CDM adjustment. Please explain why.

Response:

a) The 2015-2020 CDM strategy plan is presented at the next page.
b) In compliance with the filing requirements, Hearst has populated Appendix 2-I which calculates the "Amount used for CDM threshold for LRAMVA (2015)" to be 533,333,33. Whether this amount is reasonable is a question for the OEB rather than Hearst.
c) Again, this is an amount calculated in the OEB's worksheet.
d) same answer as part b) and c).

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	29-Apr-2015
CDM Plan Version	Initial Submission

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Chapleau Public Utilities Corporation	Hearst Power Distribution Company Limited	Grimsby Power Incorporated							
Company Representative:										
Name:	Marita Morin	Jessy Richard	Doug Curtiss							
Title:	Secretary-Treasurer	General Manager	Chief Executive Officer							
Email Address:	chec@onlink.net	jrichard@hearstpower.com	dougc@grimsbypower.com							
Phone Number (XXX-XXX-XXXX):	(705) 864-0111	705-372-2820	905-945-5437							

3.

Primary Contact for CDM Plan	
Name:	Marita Morin
LDC Name:	Chapleau PUC
Title:	Secretary-Treasurer
Email Address:	chec@onlink.net
Phone Number (XXX-XXX-XXXX):	(705) 864-0111

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Jan-2016

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Monthly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		
Other (Please specify reason)		

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Chapleau Public Utilities Corporation
Company Representative:	Marita Morin
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	29-Apr-2015

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**15,080**	1,050.0	3,180.0	10,850.0							
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**15,105**	1,058	3,184	10,864	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$4,037,280**	$298,764.00	$843,903.00	$2,894,613.00							
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$4,037,280**	$298,765	843,903	2,894,612	0	0	0	0	0	0	0

			Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
f.	**CDM Plan Cost Effectiveness** *Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool*	**Program Year**	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
		2015	2,016,727	939,336	2.1	1,719,449	0	17194487466.0	0.000
		2016	1,978,468	956,995	2.1	1,677,123	797,637	2.1	0.034
		2017	2,061,773	961,959	2.1	1,749,562	747,329	2.3	0.033
		2018	2,245,305	954,380	2.4	1,909,155	781,026	2.4	0.032
		2019	2,206,181	917,910	2.4	1,875,134	725,009	2.6	0.031
		2020	2,418,520	1,004,708	2.4	2,050,997	754,080	2.7	0.030
		CDM Plan Total	**$12,926,974**	**$5,735,288**	2.3	**$10,981,419**	**$3,805,080**	2.9	0.026

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Chapleau Public Utilities Corporation

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes	Yes								$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$5,869	1.35
	Coupon Program			1-Jan-2016	Yes	Yes								$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$25,313	97.24
																									0.00
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes	Yes					72.04		72.04		72.04		36.02		36.02		288.15
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 13,793.35	43.23	$ 14,947.21	47.33	$ 14,947.21	47.33	$ 33,322.51	69.12	$ 40,218.83	90.73	$117,229	297.74
FCR TOTAL												$0	0.0		135.0		139.1		139.1		124.9		146.5		684.5
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												0.27												0.27
	Conservation Instant Coupon Booklet												19.45												19.45
	Direct Install Lighting												36.02												36.02
	Retrofit Initiative												317.48												317.48
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	373.2											0.0	373.2
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	373.2		135.0		139.1		139.1		124.9		146.5		1,057.7
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Hearst Power Distribution Company Limited

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes									$ 4,121.75	0.97	$ 4,121.75	0.97	$ 4,121.75	0.97	$ 2,056.75	0.38	$ 4,121.75	0.97	$18,544	4.26
	Coupon Program			1-Jan-2016	Yes	Yes								$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$71,719	277.26
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes						72.04		72.04		72.04		72.04		72.04		360.19
			Unassigned Target	1-Jan-2016			Yes	Yes	Yes	Yes	Yes				0.00		0.00		245.43		245.43		240.21		731.06
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 65,321.35	241.20	$ 69,672.06	249.10	$ 62,681.64	218.80	$ 62,681.64	218.80	$ 62,681.64	218.80	$323,038	1,146.70
FCR TOTAL												$0	0.0	$122,762	369.7	$127,113	377.6	$199,209	592.7	$197,144	592.1	$197,675	587.5	$843,903	2,519.5
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												0.97												0.97
	Conservation Instant Coupon Booklet												55.45												55.45
	Direct Install Lighting												72.04												72.04
	Retrofit Initiative												535.66												535.66
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	664.1											0.0	664.1
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	664.1	$122,762	369.7	$127,113	377.6	$199,209	592.7	$197,144	592.1	$197,675	587.5	$843,903	3,183.6
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 3:	Grimsby Power Incorporated

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes									$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$444,737	97.0
	Coupon Program			1-Jan-2016	Yes	Yes								$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$306,000	1,109.1
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes	Yes					360		288		252		180		180		1,260.7
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 275,195.45	1,269	$ 275,195.45	1,269	$ 275,195.45	1,269	$ 275,195.45	1,269	$ 315,560.30	1,520	$1,416,342	6,597.3
FCR TOTAL												$0	0.0		1,870.6		1,798.6		1,762.6		1,690.6		1,941.6		9,064.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												19												19.4
	Conservation Instant Coupon Booklet												222												221.8
	Retrofit Initiative												1,379												1,378.7
	Direct Install Lighting												180												180.1
																									0.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	1,800.0											0.0	1,800.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	1,800.0		1,870.6		1,798.6		1,762.6		1,690.6		1,941.6		10,864.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Enhanced Direct Install (DIL)	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***	Q4 2015		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs *(if applicable)***	Chapleau Public Utilities Corporation	Hearst Power Distribution Company Limited	Grimsby Power Incorporated
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The 2011-2014 Small Business Lighting (SBL) is currently being considered for provincial program enhancements. Therefore, this is neither a CPUC/HEARST/GPI proposed local or regional program. CPUC/HEARST/GPI anticipates that the new province-wide program replacing Direct Install Lighting will be available by January 1, 2016. The program is assume to be offered to Small Business, a direct install type, and will include lighting, refrigeration, hvac, agriculture and other measures. Duration 2016-2020.		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Chapleau PUC and Hearst Power expect to collaborate with other Northern LDCs in order to provide cost efficiencies. Collaboration activities may include co-marketing of programs, program design and implementation of pilot programs specific to Northern Ontario. Grimsby Power will look to collaborate with other Niagara Region LDCs.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Chapleau, Hearst and Grimsby will look to collaborate with local gas utility companies to deliver programs in their respective service areas. Specific collaboration efforts have yet to be determined.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Chapleau PUC - East Lake Superior region is scheduled for the next planning cycle. Chapleau PUC will work to gain alignment between the CDM plan and commitments required as part of the IRRP. Hearst Power - North/East of Sudbury region is scheduled for future planning activity. Hearst Power will work to gain alignment between the CDM plan and commitments required as part of the IRRP. Grimsby Power - Niagara region is scheduled for future planning activity. GPI will work to gain alignment between the CDM Plan and commitments required as part of the IRRP.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Budgets were generally aligned to be consistent with 80% incentives and 20% administration fees.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	Chapleau PUC, Hearst Power and Grimsby Power expect to run the new DIL and residential program(s) once released.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Chapleau PUC has a major exterior LED project which will complete in 2015, taking advantage of legacy framework incentive funding. This project contributes over 30% of the overall MWh target. Hearst Power has a approx. 20 RETROFIT projects with expected completion dates in 2015. These projects represent 535.66 MWh towards the 2015-2020 framework without impacting the new budget.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	
Other *Additional assumptions used in the CDM Plan*	The Home Assistance Program was very successful in Chapleau and Hearst and is considered to be saturated. In Grimsby, the Social Housings buildings did not meet the eligibility criteria. For these reasons, the Home Assistance Program was not identify to provide savings towards the overall target. Should changes be made to the existing program, the LDCs will consider revising the plan to include the revised program. The LDCs will ensure that the Low Income sector is specifically targeted for the Heating and Cooling Program as well as the Coupon Program through bill inserts and other marketing efforts to be determined.

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		O. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.

3.0 –VECC -21
Reference: E3, pg. 39

a) The two columns reporting the 2015 load forecast before and after CDM have different customer counts for some of the classes. Please explain.

Response:

a) An error was made while transposing numbers in table 3.26. The correct information is presented below. As can be seen, The 2015 Weather Adjusted and 2015 Final (further adjusted for CDM) show the same customer count.

	Year	2010	2011	2012	2013	2014	2015 Weather Adj	2015 Final Adjusted (kWh)
Residential	Cust/Conn	2,295	2,295	2,291	2,285	2,279	2,272	2,272
	kWh	24,736,853	24,621,320	23,813,833	25,300,382	25,241,629	24,872,947	24,347,981
	kW							
General Service < 50 kW	Cust/Conn	391	422	444	453	457	464	464
	kWh	11,499,854	11,814,687	11,024,461	11,359,856	11,110,938	11,395,810	11,155,291
	kW							
General Service > 50 to 4999 kW	Cust/Conn	40	39	40	40	41	41	41
	kWh	17,450,896	21,470,204	23,664,082	23,218,142	23,609,369	23,105,732	22,618,065
	kW	64,939	65,160	66,539	65,160	66,539	66,264	64,865
Intermediate	Cust/Conn	3	3	2	2	2	2	2
	kWh	18,965,408	19,113,182	20,375,091	21,805,339	23,201,291	21,793,907	21,333,927
	kW	61,632	60,417	62,501	61,716	62,667	62,295	60,980
Sentinel Lights	Cust/Conn	22	18	17	17	17	15	15
	kWh	21,979	21,276	21,276	21,276	21,288	19,559	19,146
	kW	72	72	72	72	72	71	70
Street Lighting	Cust/Conn	922	926	932	941	943	947	947
	kWh	1,008,500	1,008,758	1,021,182	1,026,377	1,030,212	1,029,688	441,593
	kW	11,064	11,093	11,167	11,288	11,311	11,303	4,565

3.0 –VECC -22
Reference: E3, pg. 46-47

a) Please add two more rows to the table showing:
- The actual purchases for each year including purchases of embedded generation.
- The losses for each year in kWh and as a ratio of total sales.

Response:

a) Note that the table at page 46/47 is an OEB Appendix. The utility has replicated the table below with the added lines. While responding to the IRs, Hearst found that the inputs to Appendix 2-R Loss Factor were incorrect. Table b) shows the correct Loss Factor. The revised rates and appendices were updated to reflect this revised Loss Factor

Appendix 2-R
Loss Factors

		Historical Years						6-Year Average
		2009	2010	2011	2012	2013	2014	
	Losses Within Distributor's System							
A(1)	"Wholesale" kWh delivered to distributor (higher value)	80,601,482	79,509,530	80,704,953	81,742,651	85,473,147	86,123,559	81,606,353
A(2)	"Wholesale" kWh delivered to distributor (lower value)	78,291,808	77,598,404	78,808,832	80,148,426	83,591,984	84,294,612	79,687,891
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)							
C	Net "Wholesale" kWh delivered to distributor = A(2) - B	78,291,808	77,598,404	78,808,832	80,148,426	83,591,984	84,294,612	79,687,891
D	"Retail" kWh delivered by distributor	77,457,009	73,683,490	78,049,427	79,919,925	82,731,372	84,214,727	78,368,245
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-			-
F	Net "Retail" kWh delivered by distributor = D - E	77,457,009	73,683,490	78,049,427	79,919,925	82,731,372	84,214,727	78,368,245
G	Loss Factor in Distributor's system = C / F	1.0108	1.053	1.010	1.003	1.010	1.001	1.017
	Losses Upstream of Distributor's System							
H	Supply Facilities Loss Factor (From H1 and IESO)	1.0295	1.0246	1.0241	1.0199	1.0225	1.0217	1.0241
	Total Losses							
I	Total Loss Factor = G x H	1.0406	1.0791	1.0340	1.0228	1.0331	1.0227	1.0414

b) The billing cycle has not changed since the last cost of service

3.0 –VECC -23
Reference: E3, pg. 53

a) Please explain why there are no values for USOA #4330 (Expenses for Merchandise Jobbing, etc.) to compliment USOA #4325.
b) Please provide a schedule similar to Appendix 2-F that sets out the Other Operating Revenues for the first six months of 2014 and the first six months of 2015.

Response:

a) Prior to 2015, expenses were recorded in Acc. #5025. As of January 1st 2015, expenses in relation to account #4325 or recorded in #4330.

b) Below is a table showing the first six months of 2014 and 2015 for Other Operating Revenues:

Account #	Account Name	First six month of Year	
		2014	2015
4082	Retail Services Revenues	-$ 1,859.85	-$ 2,550.08
4084	Service Transaction Requests	-$ 20.50	-$ 46.00
4086	SSS Admin. Revenue	-$ 5,477.00	-$ 5,431.25
4210	Rent from Electric Property	$ 44.70	$ -
4225	Late Payment Charges	-$ 7,659.36	-$ 7,818.19
4235	Misc. Services Revenues	-$ 11,220.00	-$ 8,070.00
4324	Special Purpose Charges Rec.	$ -	$ -
4325	Rev. from Merchandise Jobbing	-$ 38,040.33	-$ 11,466.38
4330	Cost & Expense of Merchandise	$ -	$ 6,766.19
4375	Rev from Non-Utility Operations	$ -	-$ 53,370.50
4380	Exp of Non-Utility Operations	$ -	$ 28,464.50
4390	Misc. Non-Operating Income	$ -	$ -
4405	Interest and Dividend Income	-$ 27,243.16	-$ 19,522.05
TOTAL		-$ 91,475.50	-$ 73,043.76

3.0 –VECC -24

Reference: E3, pg. 56-59

a) Page 56 explains that there was an accounting change as of 2012 to record full expenses and revenues for Merchandise Jobbing. However, there is no account for the years 2012 and after showing the expenses side. Please reconcile.

Response:

- Prior to 2012, the inter-corporate expenses were recorded in "Accounts Receivables". When this amount was received, it was removed from the book. If any additional revenue was generated in an intercorporate transaction, it was recorded as a credit to our expense account.
- From 2012 to 2014, some "netting" of Merchandise and Jobbing revenues and expenses were identified at year end by our financial auditors and reallocated. Revenues were allocated to Merchandise Jobbing (Acc#4325) and expenses were allocated to Overhead Distribution Lines and Feeders - Operation Supplies and Expenses (Acc. #5025)
- Starting January 1st, 2015, HPDC records all expenses in relations to revenue account #4325 are in #4330 and all expenses in relations to revenue account #4375 are in #4380

Hearst Power Distribution Company Limited

Exhibit 4

Responses to Interrogatories

September 11, 2015

4-Staff-33

a) Please confirm that Hearst Power is planning to implement monthly billing by December 31, 2016 for all customer classes. If not, please explain why not.
b) Please provide the number of Residential and GS <50 kW customers that are currently billed on a monthly and on a bi-monthly basis.
c) Please identify any impacts that the implementation of monthly billing has had, or is forecasted to have in the 2015 test year on billing and collection expenses or any other OM&A category.
d) Please provide a breakdown of the costs associated with the implementation of monthly billing.
e) Please quantify any offsetting costs (benefits) associated with the implementation of monthly billing.
f) Please identify the percentage of customers on e-billing as of December 31, 2014. If Hearst Power does not provide e-billing to its customers please explain the reasons.
g) Please describe Hearst Power's efforts to promote e-billing to its customers.
h) Please describe other initiatives that Hearst Power has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

Response

a) HPDC is currently billing its customers on a monthly basis and will continue to do so unless the OEB instructs otherwise.

b) 100% of both Residential and GS<50 kW customers are billed on monthly basis. As per the 2014 Yearbook, that is 2,264 Residential customers and 410 GS<50 kW.

c) No change, no impacts, no costs.

d) Same as above

e) Same as above

f) E-billing was made available to clients in July 2014 and it was promoted at the same time with inserts in the customer's monthly invoice. In December 2014, all e-billing registered customer were credited 5.00$ to their account. A total of 233 credits were administered, therefore representing 8.6% of HPDC total customers (all classes).

g) E-billing was promoted via insert and our website. HPDC promoted e-billing by crediting all e-billing registered customer 5.00$ to their account if they were registered as of December 2014. HPDC agreed to continue with a 5.00$ credit to all registered customers on December 2015.

h) Hearst Power has currently undertaken the following activities to assists it's customers:
   - E-billing (offers immediate delivery once invoices are ready)
   - Promote CDM and SaveOnEnergy programs through newspaper and radio adds
   - Bi-annual customer survey to identify customer needs
   - Bi-monthly educational publication in local newspaper

4-Staff-34

Ref: Exhibit 4, Tab 3, Schedule 1, page 20

Hearst Power shows a variance of $74,572 between Board approved and 2015 proposed expense for Overhead Lines. The variance is explained to be the result of adjustments to employee vacations in 2012 and graduation of one apprentice to journeyman (and subsequent loss of this employee) during 2013. Board staff notes that these program costs have increased by approximately 37% from 2010 Board approved levels.

a) Please explain how vacations were calculated from 2002 to 2012.
b) Did this adjustment apply to vacation for all employees?
c) How was the adjustment applied to other programs?
d) What was the total amount of the adjustment?
e) Please confirm that this was a one-time adjustment with no impact on subsequent years' costs. If not, please explain how subsequent years are impacted.
f) What level of employee was hired to replace the journeyman who left in 2013?
g) Have there been any other changes in salary levels, other than contracted increases?
h) What were the contracted wage increases in 2010, 2011 and 2012?

Response

a) Because of the uniqueness of HPDC collective agreement procedure for its employee vacation pay, each employee's vacation accrued amount from 2002 to 2012 was compounded incorrectly. In our collective agreement Article 15 – "Vacation With Pay" states that the employee shall receive XX weeks paid vacation at XX percent of total earnings of previous calendar year including vacation pay (Please refer to document "OEB – 4 Staff 34a"). This means that employees are getting paid vacation amounts on the vacation amounts they received in the prior year (vacation on vacation).

   Employees were actually paid by % of vacation instead of what was written in the collective agreement and when a payroll error was identified in 2012, it trigged the investigation which identified significant amounts that were not accrued to employees. The error affected the years 2002 up to 2012.

The vacation amounts were corrected and all paid out in 2012.

b) The adjustment was applied to all active employees except the General Manager.

c) Of the total adjustment paid out, 24,044.63$ was entered in account 5125 – "Maintenance of Overhead Conductors and Devices", 793.33$ was entered in 5315 – "Customer Billing" and 250.53$ was entered in Account Receivables. (Total of vacation adjustment = 25,088.49$)

d) The total amount was 25,088.49$

e) It was a one-time adjustment that affected that year, however, in order to prevent the same error, the vacation accrual has been calculated according to the collective agreement in future years (vacation on vacation). Thus, since vacations on vacation were being calculated on wages, this resulted in a small increase in wages payable.

f) An electrician was hired as a journeyman apprentice in June 2014.

g) Prior to October 2014, HPDC has always had two employees in the office to do all the administrative work, a General Manager and a Billing Clerk. With the regulatory work increasing at a fast pace and the problems caused by the previous General Manager from 2011 to 2013, the Billing Clerk salary was reviewed and adjusted according with the review of her tasks. In 2014, the Billing Clerk was promoted to Administrative Assistant and consequently, her salary was adjusted once again. A Customer Service and Billing Clerk (1 person) was hired in October 2014. HPDC now has 3 office employees.

h) The Collective agreement increased wages as per the following:
April 1st, 2010 = 4.2% increase
April 1st, 2011 = 2.5% increase
April 1st, 2012 = 2.5% increase

4-Staff-35

Ref: Exhibit 4, Tab 3, Schedule 1, page 21

Hearst Power states that the increase in total compensation for non-union employees is attributable to a cost of living increase and a provision for benefit coverage.

a) To which positions does this category refer?
b) Please provide the salary inflation applied for 2013, 2014 and 2015.

Response

a) It is applicable for the 3 HPDC staff employees, such the General Manager, the "Administrative Assistant" and the newly employed "Customer Service and Billing Clerk".

- In the General Manager's case for year 2013 to 2015, the salary inflation is not applicable as there was a change of manager in early 2014 and the current Manager was hired under a performance contracts with set targets and attached wages.
- The Billing clerk had her salary adjusted in 2013 which increase her hourly rate by 11.75%, from 22.19$ on Jan 2012 to 24.80$ in Jan 2013. As of January 2014, her salary increased 1% from 24.80$ to 25.05$. In late 2014, the Billing clerk was promoted to Administrative Assistant and saw her salary increased again. Thus, as of January 2015, it was up 10% from 25.05$ (January 2014) to 27.61$ (January 2015).
- The newly hired Customer Service and Billing Clerk at 21.28$ per hour. As of January 2015, her salary increased by 2% for inflation. Once her probationary period was successfully completed, her salary was increased to 23.41$ as of April 6th, 2015.

4-Staff-36

Ref: Exhibit 4, Tab 3, Schedule 1, page 24

Ref: Appendix 2-K

Hearst Power has provided headcount at page 24 of Exhibit 4, Tab 3, Schedule 1, page 24 and also at Appendix 2-K. Board staff notes that the position of Field Superintendent is shown for 12 months in 2015 in the written evidence, but for only 9 months in the excel version.

a) Please clarify the number of months applicable to this position for 2015.
b) If this position will be vacant for part of the year, please provide the impact to 2015 compensation.

Response

a) The Field Superintendent or Leadhand position will be assigned to an HPDC employee for 12 months in 2015. The current Field Superintendent or Leadhand is to retire shortly, and as early as in September 2015. The Leadhand position will be transferred to the next employee with the most seniority and a new journeyman will be hired at the same time.

   Therefore, both tables are right. Veikko is working 9 months in 2015 but HPDC will pay a Leadhand for 12 months since he will be replaced immediately.

   In 2015, HPDC will hire:
   - 1 General Manager
   - 1 Administrative Assistant
   - 1 Customer Service and billing clerk
   - 1 Leadhand (there will be a change of employee but total cost will remain the same)
   - 3 journeyman (One journeyman will be hired immediately once the Leadhand retires)

b) No position will be vacant for part of the year.

4-Staff-37

Ref: Exhibit 4, Tab 3, Schedule 1, page 24

Ref: Exhibit 3, Tab 4, Schedule 1, page 53

Hearst Power states that it has created other interest revenues with a change in its investment savings account to compensate for the additional employee expense. Board staff notes that the short term investment interest shown at Exhibit 3 appears to remain constant from 2011 to 2015.

a) Please describe the change to the investment savings account and quantify the impact.
b) If applicable, please update Other Revenues to reflect this change.

Response

a) From 2011 to 2014, HPDC had approximately 2.4M$ invested in a savings account which generated around 55k$ revenues of interest. Of that amount, in 2014 HPDC repaid 450k$ on its note payable to the Town of Hearst and invested 1.5M$ with different brokers to potentially gain the same amount or more interest than the 0.85% interest rate it was generating at the bank.

   HPDC anticipates to generate as much interest revenues (55k$) with the remaining 1.95M$ savings then it did with its previous 2.4M$ invested at the bank.

   Therefore, HPDC forecasts to offset some, or possibly most, of the additional employee cost due to the fact that its interest revenues will be the same but it has reduced its interest expense with the 450k$ that paid on the note payable to the Town of Hearst. The Town of Hearst note payable current is 12%, thus 12% of 450k$ is 54k$ which is basically the cost of the employee.

b) No change.

4-Staff-38

Ref: Exhibit 4, Tab 3, Schedule 4, page 26-27

Ref: Exhibit 4, Tab 3, Schedule 4, Inter-Corporate Services Agreement

Hearst Power has provided its Corporate Cost Allocation and Shared Service information at Exhibit 4, page 27, as well as the accompanying intercorporate agreement. Board staff notes that the intercorprate agreement does not appear to address time spent by Hearst Power staff and appears to be inconsistent with the information shown in Appendix 2-N.

a) How were the shared service costs determined?
b) Please provide any cost allocation study performed to support the figures shown in Appendix 2-N.
c) Has Hearst Power included the costs of services provided to Hearst Power from the Town of Hearst in its evidence?
d) Please update Appendix 2-N to include services provided to Hearst Power from the Town of Hearst, such as insurance, office space, etc.
e) Please reconcile the annual lump sum payment of $31,000 for Shared Services shown at Schedule A to the agreement with the information included in Appendix 2-N.

Response

a) The shared services identified in Appendix 2-N are when both Hearst Power and the Town of Hearst use a specific service, material or equipment.

   For example, since Hearst Power is billing the water charges for the Town of Hearst, the cost for the billing software, billing clerk, postage, paper, printing supplies, folding machine, etc are invoiced accordingly to the Town of Hearst. Since Hearst Power has 2,772 hydro meters in operation and the Town of Hearst has 1,822 water meters, the split of the invoice is based on this ratio, which is 60% Hearst Power, 40% Town of Hearst.

b) Please refer to "OEB-Staff-38b" for cost allocation study

c) Yes, the cost of the service is shown in account 4380. There should not be any actual profit on each transaction itself, but in reality, since expenses are shared, there is cost savings for HPDC.

d) Please refer to "OEB - 4 Staff 38c"

e) Appendix 2-N should have shown an amount of 11,000$ in both boxes (Price and Cost for Service) and not 10,000$ (typo error). The 31,000$ in Schedule A represents the following costs:

- General Manager – 5,000$
- Billing Clerk – 15,000$
- Town Receptionist / Cashier – 11,000$

The above amounts total 31,000$ and are also shown in document "OEB – 4 Staff 38b"

4-Staff-39

Ref: Exhibit 4, Tab 3, Schedule 6, page 36

Hearst Power has provided its 2014 vendor list and states that there is only one material purchase. Board staff notes that there are other material purchases, other than the one described.

a) Please provide an explanation for the material payments made to ERTH Holdings Inc. and Strategik Builders.

Response

- ERTH Holdings Inc. is the owner of our billing software, "NorthStar". They invoice monthly for support, license fees and software upgrades or modifications.
- Strategik Builders was the construction company hired to complete the renovation project at HPDC's warehouse. Please refer to the DSP (Ex.2, tab 6), page 62, for additional details on the renovation project at the warehouse (exterior siding, insulation, replacement of windows and doors, etc.)

4-Staff-40

Ref: Exhibit 4, Tab 3, Schedule 6, page 41

Ref: Appendix 2-M

Board staff requests further clarity regarding the costs related to the preparation of this application to be amortized over the 5-year IRM period.

a) Please provide an itemized list of one-time costs related to the preparation of this application including:
   - Consultant costs to prepare DSP;
   - Consultant costs to prepare this application (allocated amount to exclude any ongoing regulatory work)
   - Intervenor costs
   - Publication costs
   - OEB costs (assume $25k for consultant)
   - Legal costs

b) Please describe any further costs which you feel should be included among one-time costs.

c) Please update OM&A costs to reflect this revision to the one-time costs to be amortized.

Response:

a) Please see details below
   - Consultant costs to prepare DSP; $35,000
   - Consultant costs to prepare this application (allocated amount to exclude any ongoing regulatory work) $0
   - Intervenor costs $20,000
   - Publication costs $1000
   - OEB costs $25,000
   - Accounting costs $5000

b) All costs are listed above

c) The OM&A has been update to reflect $86,000/5 = $17,200 in one-time costs.

4-Staff-41

Ref: Exhibit 4, Tab 5, Schedule 2, 2014 Tax Return

Hearst Power's 2014 tax return indicates taxable income was $79,667 but that no taxes were payable.

a) Please explain why no taxes were payable.

Response

a) The income tax return included in the report was the Federal version. Every year, HPDC files a tax exempt report to the Federal government, since only the PIL's are payable to the Provincial government. Included is the report sent to the Provincial government which indicates the amount payable. HPDC income tax rate is 15.5%. (please refer to "OEB – 4 Staff 41")

4-Staff-42

Ref: Exhibit 4, Tab 6, Schedule 2

Ref: Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications, 2.7.6.2

Ref: Exhibit 9, Tab 4, Schedule 1

Chapter 2 of the Filing Requirements states that distributors who have rebased in 2010 are not eligible for lost revenue associated with the persistence of legacy programs in 2010 and beyond. Hearst Power states that it is not requesting recovery of revenue from any pre-2011 CDM activities. Board staff notes that the first line in Table 4.9 refers to “Pre-2011 Programs Completed in 2011”.

a) Please confirm that this entry refers to pre-2011 CDM activities.
b) Please adjust the requested LRAM amounts to remove all pre-2011 CDM activities.
c) Please reconcile the amount requested with the balance for recovery in Account 1568 shown at Exhibit 9, Tab 4, Schedule 1.
d) Please make any necessary corrections to the continuity schedule and rate rider calculations for the LRAMVA.

Response:

a) Confirmed

b) Is presented at the next page

c) The table below shows the revised DVA balances

LV Variance Account	1550	24,306
Smart Metering Entity Charge Variance Account	1551	1,300
RSVA - Wholesale Market Service Charge	1580	(157,918)
RSVA - Retail Transmission Network Charge	1584	161,341
RSVA - Retail Transmission Connection Charge	1586	62,283
RSVA - Power (excluding Global Adjustment)	1588	(71,923)
RSVA - Global Adjustment	1589	134,529
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(233,640)
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	(65,290)
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0
Total of Group 1 Accounts (excluding 1589)		**(279,540)**

Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	36,458
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	2,288
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0
Other Regulatory Assets - Sub-Account - Other [4]	1508	(0)
Retail Cost Variance Account - Retail	1518	(96)
Misc. Deferred Debits	1525	4,234
Renewable Generation Connection Capital Deferral Account	1531	0
Renewable Generation Connection OM&A Deferral Account	1532	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0
Smart Grid Capital Deferral Account	1534	0
Smart Grid OM&A Deferral Account	1535	0
Smart Grid Funding Adder Deferral Account	1536	0
Retail Cost Variance Account - STR	1548	0
Board-Approved CDM Variance Account	1567	0
Extra-Ordinary Event Costs	1572	0
Deferred Rate Impact Amounts	1574	0
RSVA - One-time	1582	0
Other Deferred Credits	2425	0
Total of Group 2 Accounts		**42,884**

Deferred Payments in Lieu of Taxes	1562	(0)
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	19
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0
Total of Account 1562 and Account 1592		**19**

LRAM Variance Account **(Enter dollar amount for each class)**	1568	15,921
	(Account 1568 - total amount allocated to classes)	15,920
	Variance	1

Total Balance Allocated to each class (excluding 1589 and 1586)	**(236,637)**
Total Balance Allocated to each class from Account 1589	**134,529**
Total Balance Allocated to each class (including 1589 and excluding 1586)	**(102,109)**

IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0
Accounting Changes Under CGAAP Balance + Return Component	1576	(83,790)
Total Balance Allocated to each class for Accounts 1575 and 1576		**(83,790)**

d) The EDDVAR model has been updated to reflect the new LRAMVA balance

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HEARST POWER DISTRIBUTION COMPANY LIMITED

LRAMVA SUPPORT

JANUARY 14, 2015

UPDATED: SEPTEMBER 10, 2015

PREPARED BY: ANGELA MATTHEWS, PMP

UPDATED BY: JARRETT URECH, CET

REVIEWED BY: BART BURMAN, MBA, BA.SC. P.ENG., PRESIDENT

1. LRAMVA

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The variance calculated from this comparison results in a credit or debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Hearst Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Initiative Name	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULT	$ 1,323.08	$ 1,283.07	$ 1,292.90	
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS		$ 1,670.71	$ 1,681.11	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS			$ 3,368.36	
Total LRAMVA	$ 1,323.08	$ 2,953.78	$ 6,342.36	$ 10,619.22

The following OPA documents were used to prepare the LRAMVA calculations:

- Final Verified Annual 2013 CDM Report_HCHearst Power Distribution Company Limited.xls
- Hearst Power Distribution Company Limited - 2013 Results R1 List.xls
- 2011-2013 Hearst Power Program Savings and Persistence.xls

SUPPORTING ATTACHMENTS

Hearst Power LRAMVA CALCULATIONS

OPA Conservation & Demand Management Programs

Initiative Results at End-User Level

Initiative Name	Program Year	Results Status	2011				2012				2013											
			Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	2010 Rate (effective Januray 1)	2011 Rate (effective May 1)	2012 Rate (effective May 1)	2013 Rate (effective May 1)	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA	
2011 OPA PROGRAM RESULTS																						
Residential Service															kWh	kWh	kWh					
Appliance Retirement	2011	Final	0.83	6,300	1.61	12,211	0.83	6,300			0.83	6,300			0.0102	0.0156	0.0159	0.0160	$ 86.95	$ 99.55	$ 100.60	
Appliance Exchange	2011	Final	0.08	90	0.15	174	0.08	90			0.08	90			0.0102	0.0156	0.0159	0.0160	$ 1.24	$ 1.42	$ 1.43	
HVAC Incentives	2011	Final	0.28	515	0.46	862	0.27	515			0.27	515			0.0102	0.0156	0.0159	0.0160	$ 7.10	$ 8.13	$ 8.22	
2011 Adjustments				*-116*		*-194*									0.0102	0.0156	0.0159	0.0160	*-$ 1.60*	*$ -*	*$ -*	
Conservation Instant Coupon Booklet	2011	Final	0.77	12,421	0.68	11,276	0.77	12,421			0.77	12,421			0.0102	0.0156	0.0159	0.0160	$ 171.42	$ 196.26	$ 198.33	
2011 Adjustments				*184*		*171*									0.0102	0.0156	0.0159	0.0160	*$ 2.54*	*$ -*	*$ -*	
Bi-Annual Retailer Event	2011	Final	1.12	19,612	1.00	17,951	1.12	19,612			1.12	19,612			0.0102	0.0156	0.0159	0.0160	$ 270.64	$ 309.87	$ 313.13	
2011 Adjustments				*1,457*		*1,584*									0.0102	0.0156	0.0159	0.0160	*$ 20.11*	*$ -*	*$ -*	
RESIDENTIAL TOTAL			**3.07**	**40,463**	**3.90**	**44,035**	**3.07**	**38,938**	**0.00**	**0**	**3.07**	**38,938**	**0.00**	**0**					**$ 558.39**	**$ 615.22**	**$ 621.71**	
General Service <50kW															kWh	kWh	kWh					
Direct Install Lighting	2011	Final	41.14	100,177	38.42	107,887	41.14	100,177			41.14	100177.13			0.0097	0.0066	0.0067	0.0067	$ 764.69	$ 667.85	$ 671.19	
GENERAL SERVICE <50kW TOTAL			**41.14**	**100,177**	**38.42**	**107,887**	**41.14**	**100,177**	**0.00**	**0**	**41.14**	**100,177**	**0.00**	**0**					**$ 764.69**	**$ 667.85**	**$ 671.19**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**44.22**	**140,641**	**42.33**	**151,922**	**44.22**	**139,115**	**0.00**	**0**	**44.22**	**139,115**	**0.00**	**0**					**$ 1,323.08**	**$ 1,283.07**	**$ 1,292.90**	
2012 OPA PROGRAM RESULTS																						
Residential Service															kWh	kWh	kWh					
Appliance Retirement	2012	Final					0.55	4,124	0.55	4,124	0.55	4,124				0.0156	0.0159	0.0160		$ 65.15	$ 65.84	
Appliance Exchange	2012	Final					0.04	65	0.04	65	0.04	65				0.0156	0.0159	0.0160		$ 1.02	$ 1.03	
HVAC Incentives	2012	Final					0.71	1,337	1.45	2,757	0.71	1,337				0.0156	0.0159	0.0160		$ 21.13	$ 21.35	
2012 Adjustments								*6*		*11*						0.0156	*0.0159*	*0.0160*		*$ 0.09*	*$ -*	
Conservation Instant Coupon Booklet	2012	Final					0.15	933	0.15	885	0.15	933				0.0156	0.0159	0.0160		$ 14.74	$ 14.90	
Bi-Annual Retailer Event	2012	Final					0.99	17,873	1.08	19,501	0.99	17,873				0.0156	0.0159	0.0160		$ 282.39	$ 285.37	
RESIDENTIAL TOTAL							**2.43**	**24,337**	**3.28**	**27,343**	**2.43**	**24,332**	**0.00**	**0**						**$ 384.53**	**$ 388.49**	
General Service <50kW															kWh	kWh	kWh					
Direct Install Lighting	2012	Final					51.48	192,927	69.11	231,868	51.48	192,927				0.0066	0.0067	0.0067		$ 1,286.18	$ 1,292.61	
GENERAL SERVICE <50kW TOTAL							**51.48**	**192,927**	**69.11**	**231,868**	**51.48**	**192,927**	**0.00**	**0**						**$ 1,286.18**	**$ 1,292.61**	
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**53.91**	**217,264**	**72.38**	**259,211**	**53.91**	**217,259**	**0.00**	**0**						**$ 1,670.71**	**$ 1,681.11**	
2013 OPA PROGRAM RESULTS																						
Residential Service															kWh	kWh	kWh	kWh				
Appliance Retirement	2013	Final									0.06	417	0.13	896			0.0159	0.0160			$ 6.66	
Appliance Exchange	2013	Final									0.21	369	0.39	702			0.0159	0.0160			$ 5.90	
HVAC Incentives	2013	Final									3.50	6,713	7.46	14,311			0.0159	0.0160			$ 107.18	
Conservation Instant Coupon Booklet	2013	Final									0.35	5,144	0.31	4,566			0.0159	0.0160			$ 82.13	
Bi-Annual Retailer Event	2013	Final									0.79	11,465	0.76	10,972			0.0159	0.0160			$ 183.06	
Home Assistance	2013	Final									3.07	75,888	3.07	75,888			0.0159	0.0160			$ 1,211.68	
RESIDENTIAL TOTAL											**7.98**	**99,996**	**12.13**	**107,335**							**$ 1,596.60**	
General Service <50kW															kWh	kWh	kWh	kWh				
Efficiency: Equipment Replacement	2013	Final									3.38	16,707	4.72	23,271			0.0067	0.0067			$ 111.93	
Direct Install Lighting	2013	Final									73.73	243,305	78.06	257,773			0.0067	0.0067			$ 1,630.14	
GENERAL SERVICE <50kW TOTAL											**77.11**	**260,011**	**82.78**	**281,045**							**$ 1,742.08**	
General Service 50 to 4,999 kW															kW	kW	kW	kW				
Efficiency: Equipment Replacement (Industrial)	2013	Final									1.07	2,948	1.49	4,107			2.3102	2.3213			$ 29.68	
GENERAL SERVICE 50 to 4,999 kW											**1.07**	**2,948**	**1.49**	**4,107**							**$ 29.68**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**86.15**	**362,956**	**96.39**	**392,487**							**$ 3,368.36**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**44.22**	**140,641**	**42.33**	**151,922**	**44.22**	**139,115**	**0.00**	**0**	**44.22**	**139,115**	**0.00**	**0**					**$ 1,323.08**	**$ 1,283.07**	**$ 1,292.90**	
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**53.91**	**217,264**	**72.38**	**259,211**	**53.91**	**217,259**	**0.00**	**0**						**$ 1,670.71**	**$ 1,681.11**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**86.15**	**362,956**	**96.39**	**392,487**							**$ 3,368.36**	
Total LRAMVA			**44.22**	**140,641**	**42.33**	**151,922**	**98.13**	**356,379**	**72.38**	**259,211**	**184.28**	**719,329**	**96.39**	**392,487**					**$ 1,323.08**	**$ 2,953.78**	**$ 6,342.36**	**$ 10,619.22**

Table 1: Hearst Power Distribution Company Limited Initiative and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	14	10	1		1	1	0		6,300	4,124	417		1	38,406
Appliance Exchange	Appliances	1	0	1		0	0	0		90	65	369		0	1,240
HVAC Incentives	Equipment	1	3	14		0	1	4		515	1,337	6,713		4	19,497
Conservation Instant Coupon Booklet	Items	338	21	232		1	0	0		12,421	933	5,144		1	62,772
Bi-Annual Retailer Event	Items	635	708	630		1	1	1		19,612	17,873	11,465		3	154,995
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**3**	**2**	**5**		**38,938**	**24,332**	**24,108**		**10**	**276,911**
Business Program															
Retrofit	Projects	0	0	5		0	0	4		0	0	19,655		4	39,310
Direct Install Lighting	Projects	32	48	56		41	51	74		100,177	192,927	243,305		162	1,456,014
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	0	0		0	0	0		0	0	0		0	0
Energy Audit	Audits	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**41**	**51**	**78**		**100,177**	**192,927**	**262,959**		**167**	**1,495,324**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	0	0		0	0	0		0	0	0		0	0
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0	0	92		0	0	3		0	0	75,888		3	142,716
Home Assistance Program Total						**0**	**0**	**3**		**0**	**0**	**75,888**		**3**	**142,716**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	0	0	0		0	0	0		229	73	0		0	1,135
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**	**0**		**229**	**73**	**0**		**0**	**1,135**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results							**0**	**0**			**1,525**	**0**		**0**	**6,101**
Adjustments to 2012 Verified Results								**0**				**6**		**0**	**17**
Energy Efficiency Total						**44**	**54**	**86**		**139,344**	**217,332**	**362,956**		**180**	**1,916,086**
Demand Response Total (Scenario 1)						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to Previous Years' Verified Results Total						**0**	**0**	**0**		**0**	**1,525**	**6**		**0**	**6,118**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**44**	**54**	**86**		**139,344**	**218,857**	**362,961**		**180**	**1,922,204**
													Full OEB Target:	**680**	**3,910,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**26.5%**	**49.2%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 2: Adjustments to Hearst Power Distribution Company Limited Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	0	0			0	0			-116	6		
Conservation Instant Coupon Booklet	Items	5	0			0	0			184	0		
Bi-Annual Retailer Event	Items	55	0			0	0			1,457	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	0	0			0	0			0	0		
Consumer Program Total						**0**	**0**			**1,525**	**6**		
Business Program													
Retrofit	Projects	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	0	0			0	0			0	0		
Energy Audit	Audits	0	0			0	0			0	0		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**0**	**0**			**0**	**0**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	0			0	0			0	0		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**0**			**0**	**0**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0		
High Performance New Construction	Projects	0	0			0	0			0	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**0**	**0**			**0**	**0**		
Other													
Program Enabled Savings	Projects	0	0			0	0			0	0		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**0**	**0**			**0**	**0**		
Adjustments to 2011 Verified Results						**0**				**1,525**			
Adjustments to 2012 Verified Results							**0**				**6**		
Total Adjustments to Previous Years' Verified Results						**0**	**0**			**1,525**	**6**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 11: Hearst Power Distribution Company Limited Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	2	1	0		12,211	4,124	896	
Appliance Exchange**	Appliances	0	0	0		174	65	702	
HVAC Incentives	Equipment	0	1	7		862	2,757	14,311	
Conservation Instant Coupon Booklet	Items	1	0	0		11,276	885	4,566	
Bi-Annual Retailer Event	Items	1	1	1		17,951	19,501	10,972	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**4**	**3**	**9**		**42,474**	**27,331**	**31,447**	
Business Program									
Retrofit	Projects	0	0	6		0	0	27,378	
Direct Install Lighting	Projects	38	69	78		107,887	231,868	257,773	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	0	0	
Energy Audit	Audits	0	0	0		0	0	0	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**38**	**69**	**84**		**107,887**	**231,868**	**285,151**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	0	0	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	3		0	0	75,888	
Home Assistance Program Total		**0**	**0**	**3**		**0**	**0**	**75,888**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	0	0	0		458	146	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**0**	**0**	**0**		**458**	**146**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**0**	**0**	**0**		**0**	**1,561**	**0**	
Adjustments to 2012 Verified Results		**0**	**0**	**0**		**0**	**0**	**11**	
Energy Efficiency Total		**42**	**73**	**96**		**150,819**	**259,345**	**392,487**	
Demand Response Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to Previous Years' Verified Results Total		**0**	**0**	**0**		**0**	**1,561**	**11**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**42**	**73**	**96**		**150,819**	**260,906**	**392,498**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Hearst Power Distribution Company Limited Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	0	0			-194	11		
Conservation Instant Coupon Booklet	Items	0	0			171	0		
Bi-Annual Retailer Event	Items	0	0			1,584	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			0	0		
Consumer Program Total		**0**	**0**			**1,561**	**11**		
Business Program									
Retrofit	Projects	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	0	0			0	0		
Energy Audit	Audits	0	0			0	0		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**0**	**0**			**0**	**0**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	0			0	0		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**0**			**0**	**0**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total									
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0			0	0		
High Performance New Construction	Projects	0	0			0	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**0**	**0**			**0**	**0**		
Other									
Program Enabled Savings	Projects	0	0			0	0		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**0**	**0**			**0**	**0**		
Adjustments to 2011 Verified Results		**0**				**1,561**			
Adjustments to 2012 Verified Results			**0**				**11**		
Total Adjustments to Previous Years' Verified Results		**0**	**0**			**1,561**	**11**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

Table is at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	(Implementation) Year	Status	Notes:	Activity Unit Name	Activity/Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (kW) 2011	2012	2013	2014	Net Annual Energy Savings (kWh) 2011	2012	2013	2014
Tier 1	Consumer	Appliance Exchange	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012		Appliances	1	0.00	0	0.0790825	0.0790825	0.0790825	0.00	89.66231	89.66231	89.66231	38.000979
Tier 1	Consumer	Appliance Retirement	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012		Appliances	14	0.00	12	0.8322176	0.8322176	0.8322176	0.00	6300.4453	6300.4453	6300.4453	6300.3107
Tier 1	Consumer	Bi-Annual Retailer Event	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012		Products	581	0.00	18	1.1221359	1.1221359	1.1221359	0.00	19611.754	19611.754	19611.754	19611.754
Tier 1	Consumer	Conservation Instant Coupon Booklet	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012		Products	333	0.00	11	0.7654435	0.7654435	0.7654435	0.00	12421.445	12421.445	12421.445	12421.445
Tier 1	Consumer	HVAC Incentives	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012		Installations	1	0.00	1	0.2749094	0.2749094	0.2749094	0.00	514.73504	514.73504	514.73504	514.73504
Tier 1	Consumer	Retailer Co-op	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Released August 31, 2012	Custom reta	Products	0	0.00	0	0	0	0	0.00	0	0	0	0
Tier 1	Business	Direct Install Lighting	Hearst Power Distribution Company Limited	Commercial & Institutional	EE	2011	Final; Released August 31, 2012		Projects	32	0.04	108	41.14234	41.14234	41.14234	0.04	100177.13	100177.13	100177.13	90092
Tier 1	Pre-2011 Pr	High Performance New Construction	Hearst Power Distribution Company Limited	Commercial & Institutional	EE	2011	Final; Released August 31, 2012	Not evaluat	Projects	0	0.00	0	0.0445992	0.0445992	0.0445992	0.00	229.06169	229.06169	229.06169	229.06169

Table is at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	(Implementation) Year	Status	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (kW)				Net Annual Energy Savings (kWh)			
												2011	2012	2013	2014	2011	2012	2013	2014
Tier 1	Business	Direct Install Lighting	Hearst Power Distribution Company Limited	C&I	EE	2012	Final; Releas	Projects	48	0.11478768	191.66024	0	51.47940535	51.47940535	51.47940535	0	192927.09	192927.09	192927.09
Tier 1	Consumer	Appliance Exchange	Hearst Power Distribution Company Limited	Residential	EE	2012	Final; Releas	Appliances	0.2562627	4.92168E-05	0.1255838	0	0.037005147	0.037005147	0.037005147	0	64.721494	64.721494	64.721494
Tier 1	Consumer	Appliance Retirement	Hearst Power Distribution Company Limited	Residential	EE	2012	Final; Releas	Appliances	10.220893	0.000728821	8.7480467	0	0.547985829	0.547985829	0.547985829	0	4123.5694	4123.5694	4123.5694
Tier 1	Consumer	Bi-Annual Retailer Event	Hearst Power Distribution Company Limited	Residential	EE	2012	Final; Releas	Products	707.99308	0.001313599	19.501376	0	0.987668245	0.987668245	0.987668245	0	17872.775	17872.775	17872.775
Tier 1	Consumer	Conservation Instant Coupon Booklet	Hearst Power Distribution Company Limited	Residential	EE	2012	Final; Releas	Products	20.615046	0.000204511	0.9330913	0	0.153768036	0.153768036	0.153768036	0	933.09127	933.09127	933.09127
Tier 1	Consumer	HVAC Incentives	Hearst Power Distribution Company Limited	Residential	EE	2012	Final; Releas	Installations	2.606622	0.000940713	3.2107854	0	0.707303341	0.707303341	0.707303341	0	1337.4431	1337.4431	1337.4431
Tier 1	Pre-2011 Pr	High Performance New Construction	Hearst Power Distribution Company Limited	C&I	EE	2012	Final; Releas	Projects	0.0006674	0.000100296	0.1461212	0	0.075410652	0.075410652	0.075410652	0	73.060576	73.060576	73.060576
Tier 1 - 2011	Pre-2011 Pr	High Performance New Construction	Hearst Power Distribution Company Limited	C&I	EE	2011	Final; Releas	Buildings	0	0.001154868	0	0	0	0	0	0	0	0	0
Tier 1 - 2011	Consumer	HVAC Incentives	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Releas	Installations	-0.222895	-0.000149944	-0.277804	-0.062458855	-0.062458855	-0.062458855	-0.062458855	-115.7184	-115.7184	-115.7184	-115.7184
Tier 1 - 2011	Consumer	Bi-Annual Retailer Event	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Releas	Products	54.600649	7.78194E-05	1.5840351	0.071983186	0.071983186	0.071983186	0.071983186	1457.0878	1457.0878	1457.0878	1457.0878
Tier 1 - 2011	Consumer	Conservation Instant Coupon Booklet	Hearst Power Distribution Company Limited	Residential	EE	2011	Final; Releas	Products	5.482955	1.07437E-05	0.1708254	0.010743677	0.010743677	0.010743677	0.010743677	183.9587	183.9587	183.9587	183.9587

All Savings at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	Tx (Transmission) or Dx (Distribution) connected	(Implementation) Year	Notes	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (kW) 2011	2012	2013	2014		Net Annual Energy Savings (kWh) 2011	2012	2013	2014
LDC	Business	Retrofit	Hearst Power Distribution Company Limited	Commercial & Institutional	EE	Dx	2013	N/A	Projects	5	0.006	27.378			0.004	0.004		0.000	0.000	19.655	19.655
LDC	Business	Small Business Lighting	Hearst Power Distribution Company Limited	Commercial & Institutional	EE	Dx	2013	N/A	Projects	56	0.078	257.773			0.074	0.074				243.305	243.305
LDC	Consumer	Annual Coupons	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	Custom loac	measures	232	0.000	4.566	0.000	0.000	0.000	0.000		0.000	0.000	5.144	5.144
LDC	Consumer	Appliance Exchange	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	Dehumidifie	Appliances	1	0.000	0.702			0.000	0.000				0.369	0.369
LDC	Consumer	Appliance Retirement	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	N/A	Appliances	1	0.000	0.887			0.000	0.000				0.413	0.413
LDC	Consumer	Bi-Annual Retailer Events	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	Custom loac	measures	630	0.001	10.972	0.000	0.000	0.001	0.001		0.000	0.000	11.465	11.465
LDC	Consumer	Home Assistance Program	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	N/A	Projects Cor	92	0.003	75.888	0.000	0.000	0.003	0.003		0.000	0.000	75.888	66.827
LDC	Consumer	HVAC	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	Blended Loa	Equipment	14	0.007	14.311			0.004	0.004				6.713	6.713
LDC	Consumer	Appliance Retirement	Hearst Power Distribution Company Limited	Residential	EE	Dx	2013	N/A	Appliances	0	0	0	0	0	0	0		0	0	0	0
LDC	Consumer	HVAC	Hearst Power Distribution Company Limited	Residential	EE	Dx	2012	Blended Loa	Equipment	0	0	0	0	0	0	0		0	0	0	0

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

4.0 -VECC -25
Reference: E4/T3

a) Is Hearst Power a member of the EDA? If yes, please provide the annual dues paid for each of 2010 through 2014 and the forecast 2015 amounts.

Response

a) Yes, HPDC is a member of the EDA.

Year	EDA dues	
2010	$ 7,150.00	(actual)
2011	$ 7,380.00	(actual)
2012	$ 7,800.00	(actual)
2013	$ 8,200.00	(actual)
2014	$ 8,600.00	(actual)
2015	$ 8,900.00	(actual)

4.0 -VECC -26
Reference: E4/T3

a) Does Hearst Power bill all customers monthly?
b) What was the billing practice (cycle) for customers in 2010.
c) If the billing cycle has changed since the last cost of service application please provide a table showing the incremental costs for monthly billing.

Response

a) Yes
b) Customers were billed monthly.
c) No change in billing cycle.

4.0 -VECC -27
Reference: E4/T3/S2

a) Please restate Appendix 2-JC on a consistent accounting basis (CGAAP) and show the any accounting adjustments (for NewCGAAP and IFRS separately).
b) Please identify an changes to 2015 OM&A which are due solely to accounting changes (e.g. capitalization/IFRS changes).

Response

a) No changes. Only difference with CGAAP, NewCGAAP and IFRS is the Property, Plant and Equipment (PPE) amortization which decreased with the new accounting systems. The accounting changes affect the amortization expense but not OM&A expenses

b) No changes. Refer to answer above.

4.0 -VECC -28
Reference: E4/T3/S3 Employee Compensation Appendix 2-K

a) Please amend Appendix 2-K to show Total Compensation capitalized in each of 2010 through 2015.

Response

a) The Total Employee compensation in Appendix 2-K includes the following capitalized compensation shown below, for the referenced year:

Year	Total Compensation Capitalized	Reporting basis
2010	$ 2,151	(actual)
2011	$ 4,260	(actual)
2012	$ 8,672	(actual)
2013	$ 1,760	(actual)
2014	$ 23,590	(actual)
2015	$ 33,685	(actual, as of June 30th, 2015)

4.0-VECC-29

Reference: E4/

a) Please provide the vegetation management budget for each of 2010 through 2015.

Response

a) There is no specific budget for “vegetation management”. This type of expense is budgeted and recorded in 3 different accounts for different related expenses:

- Account #5020 - “Overhead Distribution Lines and Feeders – Operation Labour”: **Labor cost to patrol lines**
- Account #5025 – “Overhead Distribution Lines and Feeders – Operation Supplies and Expenses”: **Vehicle cost**
- Account #5125 – “Maintenance of Overhead Conductors and Devices”: **Brushcutting and/or removal of trees**

4-VECC-30

Reference: E4/

a) Since its last rebasing in 2010 Hearst Power has implemented smart meters for all its customers. This interrogatory is seeking to find the **net** incremental costs in delivering this service. Please identify all incremental costs (2010 as compared to 2015) related to this new requirement. Please also show the savings from meter reading reduction costs

Response:

In 2010, HPDC had already started to install smart meters and during that year, there were both types of meter reading costs; for conventional meter and smart meters. Since the meter reading cost for 2010 are skewed, it would not justify showing 2010 meter reading cost compared to 2015. Instead, HPDC prepared the table below to show the 2015 smart meter reading costs vs the fictive 2015 conventional meters (meters that were used prior to the Smart meters) using current employee and vehicles rates.

Monthly meter ready costs

	2015 Residential and GS<50 - Conventionnal (Outside) - (Fictive)	2015 Smart Meter	Savings per month
# of meters	2,740	2,740	
Admin. Assist time	$ 44.00	$ 165.00	
Crew time	$ 5,376.00		
Vehicle	$ 800.00		
Erth holding		$ 3,216.23	
Cleo		$ 64.65	
Iron Mountain		$ 65.65	
Sensus		$ 1,672.44	
	$ 6,220.00	$ 5,183.97	$ 1,036.03
Cost per meter	$ 2.27	$ 1.89	$ 0.38

	2015 Conventionnal meter w/demand (Fictive)	2015 Smart Meter w/demand	Savings per month
# of meters	42	42	
Admin. Assist time	$ 22.00	$ 88.00	
Crew time	$ 672.00		
Vehicle	$ 150.00		
Erth holding		$ 49.30	
Cleo		$ 0.99	
Iron Mountain		$ 1.02	
Sensus		$ 25.65	
	$ 844.00	$ 164.96	$ 679.04
Cost per meter	$ 20.10	$ 3.93	$ 16.17

4-VECC-31

Reference: E4/T3/S5/Table 4.5 and 4.6

a) Please clarify whether Hearst Power does any meter reading for the Town and if so what the total 2015 fees for this service are.
b) Please provide the total amount of revenues received for water billing services from the Town in 2015
c) Please provide the amount that annual postal costs have increased in 2015 as compared to 2010.

Response

a) Yes, HPDC does water meter reading for the Town of Hearst through smart water meters. The meters are read exactly the same way via the billing clerk and using the same equipment and software as with electrical smart meters.

Since water and electrical billing is done as the same time as water and electrical reading, and that there is overlapping use of HR, software and equipment for these two tasks, HPDC invoices the Town of Hearst 15,000$ per year for the Billing clerk and 40% of the billing and meter readings expense.

If a software upgrade or specific equipment is required for the sole purpose of water meter reading or billing, it is understood that it is 100% the responsibility of the Town of Hearst.

Starting in 2015, the transactions in relation to water meter reading and billing is accounted in account #4375 (revenues) and #4380 (expenses).

b) The 2015 charges to the Town of Hearst for water meter reading and billing are forecasted at **60,000$,** as per the following:

- Salary for Billing Clerk – **15,000$**
- Meter reading and billing software, licenses, equipment rental (tower), etc – **40% of the actual expense.** HPDC has approximately 60% (2,772 meters) and the Town of Hearst has 40% (1,822 meters), the expenses are split accordingly. It is forecast that the Town of Hearst will pay HPDC **45,000$** in 2015 for water billing and meter reading software, licenses, equipment rental, postage, billing supplies, etc.

c) Please refer to "VECC – 4-VECC-31c"

4-VECC-32

Reference: E4/T3/S9

a) Please provide the annual amount of LEAP funding utilized by customers in each year since 2010.

Response

Year	Funding utilized by HPDC customers
2010	$0.00
2011	$0.00
2012	$0.00
2013	$1,428.13
2014	$0.00

4-VECC-33

Reference: E4/T5/S1

a) Please provide a table showing the actual amount of taxes (PILS) paid in each year since 2010 and forecast for 2015.

Response

a) Please refer to document “VECC 4-VECC-33”

Hearst Power Distribution Company Limited

Exhibit 5

Responses to Interrogatories

September 11, 2015

5-Staff-43

Ref: Exhibit 5, Tab 1, Schedule 3

Hearst Power states that its sole long term debt instrument is to the Town of Hearst issued at $1.8M in 2001. Hearst Power has provided a promissory note supporting this instrument, dated June 1, 2001.

a) Please confirm that this is the most recent promissory note related to this long term debt. If not, please provide all updated promissory notes.

Response

a) Yes, the promissory note has never been revised since it was issued, not even once payments were applied to the loan amount. An updated note has been requested and should be drafted for September or October 2015 showing the actual amount due. Also, the updated promissory note will carry a lower interest rate as HPDC and the Town of Hearst are currently in final stages of negotiations for a revised interest rate on this loan.

5-Staff-44

Ref: Exhibit 1, Tab 3, Schedule 1 – Historical Financial Statements

Ref: Exhibit 5, Tab 1, Schedule 3

The terms of the June 1, 2001 Promissory Note state that interest cannot exceed net income. Board staff notes that for 2011 to 2014, interest on long-term debt exceeds the net income, as shown below:

Year	Interest Expense	Net Income
2011	135,000	3,663
2012	300,000	175,058
2013	177,000	125,603
2014	175,000	96,265

a) Please explain how the long term debt payments in 2011, 2012, 2013 and 2014 were calculated and determined.
b) Please indicate which parties must authorize the amount of long term debt repayments in any given year.
c) Please provide an explanation for overpayments as shown in the above table.

Response

a) As identified in the attached document "OEB – 5 Staff 4a", there was no payment on the long term debt in 2007, 2008 and 2010. Since the HPDC's financial results were positive for the period of 2011 to 2014, the HPDC board agreed that is was justifiable to make additional payments which would cover those previous years.

   The HPDC board is "seized" by the original intent of the promissory note, which is to honor interest repayment, when circumstances are possible, and appropriate, so as not to jeopardize future operations or financial indebtness of the HPDC.

b) The interest repayment is based on the note payable but ultimately the HPDC board of directors has the authority to approve and make adjustments on the actual amount paid out.
c) Refer to question a) above

5-Staff-45

Ref: Exhibit 5, Tab 1, Schedule 3

Question for:

Jessy Richard

Review by:

Board staff notes that the 12% interest rate charged on the promissory note to the Town of Hearst is well in excess of the maximum long term debt rate that Hearst Power is allowed to recover from its customers through rates.

d) Has Hearst Power considered renegotiating the promissory note with the Town of Hearst? If not, why not?

e) Has Hearst Power considered replacing this promissory note with third party debt at a lower rate? If not, why not?

Response

a) Yes, the loan is pending a revise rate and the promissory note should be updated prior to the 2015 year-end, retroactive to January 1st 2015. The new interest rate should be around half of what it currently stands. The revised note would still give HPDC the chance to defer interest payments if the yearly income is insufficient.

b) Yes, in 2015 HPDC has contacted its bank manager for a possible rate on this loan. HPDC prefers the current loan structure with the Town of Hearst which allows the board and management to defer interest payment when the gross yearly income is poor or negative. The promissory note with the Town of Hearst offers greater control and less risk over a third party debt.

5.0-VECC-34

Reference: E5

a) Please provide the principal repayment schedule for the $1.8 million affiliated debt. Please reconcile (if necessary) this schedule with the principal amounts shown in Appendix 2-OB for years 2013 through 2015.

Response

a) Please refer to document "VECC 4-VECC-33"

Hearst Power Distribution Company Limited

Exhibit 7

Responses to Interrogatories

September 11, 2015

7-Staff-47

Ref: Exhibit 7, Tab 3, Schedule 1, page 19

Hearst Power proposes to reduce the revenue to cost ratio for its GS > 50kWh class over two years to bring it to the ceiling of the target range.

a) Please provide the resulting bill impacts of adjustments to the revenue to cost ratios over one year; three years; and four years.

Response:

a) Please note that Hearst used the revised revenue requirement to calculi the bill impacts under these scenarios. Bill impacts are presented as part of the response to Staff-2. The tables below show the revised Cost Allocation Results and proposed fixed and variable split for these scenarios.

Revised Cost Allocation Results.

Customer Class Name	**Service Rev Req (row40)**		**Misc. Revenue (mi) (row19)**		**Base Rev Req**		**Rev2Cost Expenses % (row 75)**
Residential	888,249	64.08%	146,678	63.91%	741,571	64.11%	90.08%
General Service < 50 kW	207,330	14.96%	33,077	14.41%	174,253	15.06%	105.82%
General Service > 50 to 4999 kW	85,662	6.18%	17,489	7.62%	68,173	5.89%	223.22%
Intermediate	62,048	4.48%	12,809	5.58%	49,239	4.26%	85.41%
Sentinel Lights	2,822	0.20%	516	0.22%	2,306	0.20%	66.15%
Street Lighting	140,093	10.11%	18,934	8.25%	121,159	10.47%	86.07%
TOTAL	**1,386,204**	**100.00%**	**229,503**	**100.00%**	**1,156,701**	**100.00%**	

Proposed Fixed to Variable Split

Customer Class Name	Fixed Rate	**Rate (i)**	**per**
Residential	**$13.00**	**$0.0135**	kWh
General Service < 50 kW	**$19.79**	**$0.0068**	kWh
General Service > 50 to 4999 kW	**$46.34**	**$1.9726**	kW
Intermediate	**$223.01**	**$1.0228**	kW
Sentinel Lights	**$9.00**	**$1.9025**	kW
Street Lighting	**$7.88**	**$2.6235**	kW
TOTAL			

Revenue to Cost Adjustment as proposed

Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement %						Revenue Offsets		Service Revenue Requirement $		
	Existing Rates		Cost Allocation Results		Proposed Allocation		%	$	Existing Rates	Cost Allocation Results	Rate Application
Residential	56.35%	651,783	64.11%	741,572	59.05%	683,009	63.91%	146,678	798,461	888,250	829,687
General Service < 50 kW	16.27%	188,214	15.06%	174,253	16.08%	186,051	14.41%	33,077	221,291	207,330	219,128
General Service > 50 to 4999 kW	14.93%	172,735	5.89%	68,173	12.48%	144,413	7.62%	17,489	190,224	85,662	161,902
Intermediate	3.51%	40,580	4.26%	49,239	3.45%	39,932	5.58%	12,809	53,389	62,048	52,741
Sentinel Lights	0.13%	1,520	0.20%	2,306	0.15%	1,752	0.22%	516	2,036	2,822	2,268
Street Lighting	8.81%	101,870	10.47%	121,159	8.78%	101,546	8.25%	18,934	120,804	140,093	120,480
TOTAL	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**	**100.00%**	**229,503**	**1,386,206**	**1,386,206**	**1,386,206**

Revenue to Cost Ratio Allocation

Customer Class Name	Ratio Allocation			Target Range		3 Year Revenue to Cost Allignment			Bill Impacts
	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Floor	Ceiling	2016	2017	2018	
Residential	0.90	0.93	-0.03	0.85	1.15				5.16%
General Service < 50 kW	1.06	1.06	0.00	0.80	1.20				-0.90%
General Service > 50 to 4999 kW	2.23	1.89	0.34	0.80	1.20	1.55	1.20		6.01%
Intermediate	0.85	0.85	0.00	0.80	1.20				4.34%
Sentinel Lights	0.66	0.80	-0.14	0.80	1.20				6.37%
Street Lighting	0.86	0.86	0.00	0.80	1.20				4.99%

Revenue to Cost Adjustment over 1 year

Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement %					
	Existing Rates		Cost Allocation Results		Proposed Allocation	
Residential	56.35%	651,783	64.11%	741,572	64.16%	742,115
General Service < 50 kW	16.27%	188,214	15.06%	174,253	16.08%	186,051
General Service > 50 to 4999 kW	14.93%	172,735	5.89%	68,173	7.37%	85,306
Intermediate	3.51%	40,580	4.26%	49,239	3.45%	39,932
Sentinel Lights	0.13%	1,520	0.20%	2,306	0.15%	1,752
Street Lighting	8.81%	101,870	10.47%	121,159	8.78%	101,546
TOTAL	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**

Revenue Offsets	
%	$
63.91%	146,678
14.41%	33,077
7.62%	17,489
5.58%	12,809
0.22%	516
8.25%	18,934
100.00%	**229,503**

Service Revenue Requirement $		
Existing Rates	Cost Allocation Results	Rate Application
798,461	888,250	888,793
221,291	207,330	219,128
190,224	85,662	102,795
53,389	62,048	52,741
2,036	2,822	2,268
120,804	140,093	120,480
1,386,206	**1,386,206**	**1,386,206**

Revenue to Cost Ratio Allocation

Customer Class Name	Ratio Allocation		
	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential	0.90	1.00	-0.10
General Service < 50 kW	1.06	1.06	0.00
General Service > 50 to 4999 kW	2.23	1.20	1.03
Intermediate	0.85	0.85	0.00
Sentinel Lights	0.66	0.80	-0.14
Street Lighting	0.86	0.86	0.00

Target Range	
Floor	Ceiling
0.85	1.15
0.80	1.20
0.80	1.20
0.80	1.20
0.80	1.20
0.80	1.20

3 Year Revenue to Cost Allignment		
2016	2017	2018

Bill Impacts
7.34%
-0.90%
0.16%
4.34%
6.37%
4.99%

Revenue to Cost Adjustment Over 4 years

Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement %						Revenue Offsets		Service Revenue Requirement $		
	Existing Rates		Cost Allocation Results		Proposed Allocation		%	$	Existing Rates	Cost Allocation Results	Rate Application
Residential	56.35%	651,783	64.11%	741,572	58.38%	675,299	63.91%	146,678	798,461	888,250	821,977
General Service < 50 kW	16.27%	188,214	15.06%	174,253	16.08%	186,051	14.41%	33,077	221,291	207,330	219,128
General Service > 50 to 4999 kW	14.93%	172,735	5.89%	68,173	13.15%	152,122	7.62%	17,489	190,224	85,662	169,611
Intermediate	3.51%	40,580	4.26%	49,239	3.45%	39,932	5.58%	12,809	53,389	62,048	52,741
Sentinel Lights	0.13%	1,520	0.20%	2,306	0.15%	1,752	0.22%	516	2,036	2,822	2,268
Street Lighting	8.81%	101,870	10.47%	121,159	8.78%	101,546	8.25%	18,934	120,804	140,093	120,480
TOTAL	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**	**100.00%**	**1,156,703**	**100.00%**	**229,503**	**1,386,206**	**1,386,206**	**1,386,206**

Revenue to Cost Ratio Allocation

Customer Class Name	Ratio Allocation			Target Range		3 Year Revenue to Cost Allignment			Bill Impacts
	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Floor	Celiling	2016	2017	2018	
Residential	0.90	0.93	-0.02	0.85	1.15				4.86%
General Service < 50 kW	1.06	1.06	0.00	0.80	1.20				-0.90%
General Service > 50 to 4999 kW	2.23	1.98	0.25	0.80	1.20	1.73	1.48	1.20	6.77%
Intermediate	0.85	0.85	0.00	0.80	1.20				4.34%
Sentinel Lights	0.66	0.80	-0.14	0.80	1.20				6.37%
Street Lighting	0.86	0.86	0.00	0.80	1.20				4.99%

7.0 – VECC –35
Reference: E7, pg. 2-4 / HPDCL's Cost Allocation model

a) Please explain why the 2015 customer count numbers in the Cost Allocation model (see Tabs I6.2, I7.1 and I7.2) do not match those in the Load Forecast (E3, Table 3-24).
b) Please explain why the 2015 revenue at current rates by customer class (and in total) as set out in the Cost Allocation model (Tab I6.1) does not equal the 2015 revenue at current rates as shown in E3, page 3.
c) With respect to page 3 (lines 19-21), are all Sentinel connections owned by the City of Hearst? If not, are the owners of the other connections also responsible for providing their own "services"?
d) With respect to billing and collecting weighting factors, the low weightings assigned to Intermediate Street Lighting and Sentinel Lighting is explained in part by the low volume of bills issued in each case. However, the purpose of this factor is to determine a relative cost per bill (which is then multiplied by the number of bills). As a result, please explain why volume of bills is a relevant factor in determining the weights.
e) With respect to Tab I6.2 of the Cost Allocation model, HPDCL has only input the number of Street Light connections and not provided a value for the number of Street Light devices. What is the number of Street Light devices that corresponds with the 943 connections?

Response:

a) The Cost Allocation shows outdated customer count which should have been updated. The model filed along with these responses shows the correct customer count.
b) The main reason why the number don't match is because of the incorrect number of customers in the CA model. (fixed rates are calculated based on the number of customers). There was also a small difference due to rounding which as also corrected.
c) HPDC has 13 sentinel lights connections (13 devices) in its territory as of January 2015. Of those 13 connections, 2 sentinel lights devices are the property of the Town of Hearst, the 11 remaining are owned and paid by private parties.
d) The Intermediate class has two (2) customers which are billed monthly; therefore there is 24 invoices per year for this class (2 customers x 12 months). The Street Light class has one (1) customer with 943 connections, therefore 12 invoices per

year (1 customer x 12 months). The Sentinel light has 13 device/connection but has 9 customers since some have 2 lights, this represents 108 invoices per year (9 customers x 12 months)

- ➔ For each invoice, there is a cost for the billing clerk, printing supplies, envelope and postage; therefore, HPDC views the volume of bills as a weighing factor.

e) 943 connections represent 943 street light devices. All of the Street Lighting devices in the Street Lighting class are owned by the Town of Hearst.

7.0 – VECC –36
Reference: E7, Appendix 2-P

a) With respect to Table B, please confirm that column 7B is meant to be 2015 revenues as current rates and, if so, why it does not equal the values set out at E3, page 3.
b) With respect to Table B, please explain why the revenues at proposed rates set out in column 7D do not equal the revenue by customer class as set out in the revenue reconciliation schedule at E8, page 25.
c) With respect to Table B, Column 7C, please explain why the values show for each customer class do not equal those from the Cost Allocation Model, Tab O1, Row 23.
d) With respect to Table C, please correct to show the status quo ratios per the Cost Allocation model (Note: The values currently shown are all 100%).

Response:

a) The two reasons for the discrepancies pointed above are that the rate design model was inadvertently linked to an outdated Cost Allocation model and the second reason is that Appendix 2-P was misinterpreted and therefore incorrectly populated. The revised table is shown below and was also factored into the revised rates.

b) c) d)

Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential			$888,249.27	64.08%
GS < 50 kW			$207,329.90	14.96%
GS > 50 kW			$85,662.18	6.18%
Intermediate			$62,047.77	4.48%
Sentinel Lighting			$2,821.99	0.20%
Street Lighting			$140,093.08	10.11%
				0.00%

				0.00%
Total	$ -	0.00%	$1,386,204.20	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$640,076.12	$653,481.29	$683,008.50	$146,678.00
GS < 50 kW	$184,833.40	$186,312.59	$186,051.30	$33,077.00
GS > 50 kW	$169,632.29	$173,722.94	$144,412.67	$17,489.00
Intermediate	$39,851.34	$40,184.51	$39,931.66	$12,809.00
Sentinel Lighting	$1,493.03	$1,351.13	$1,752.23	$516.00
Street Lighting	$100,040.58	$101,649.17	$101,546.17	$18,934.00
Total	$1,135,926.76	$1,156,701.64	$1,156,702.52	$229,503.00

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2010	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	0.98	90.08	93.41	85 - 115
GS < 50 kW	1.00	105.82	105.69	80 - 120
GS > 50 kW	1.00	223.22	189.00	80 - 120
Intermediate	0.80	85.41	85.00	80 - 120
Sentinel Lighting	0.70	66.16	80.38	85 - 115
Street Lighting	0.70	86.07	86.00	70 - 120

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	93.41			85 - 115
GS < 50 kW	105.69			80 - 120
GS > 50 kW	189.00	1.55	1.20	80 - 120
Intermediate	85.00			80 - 120
Sentinel Lighting	80.38			85 - 115
Street Lighting	86.00			70 - 120
0				80 - 120
0				80 - 120
0				0

				0
0				

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2013 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2014 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

7.0 – VECC –37
Reference: E7, pg. 19

a) Please explain why HPDCL is proposing to move the ratios for the Intermediate and Street Lighting classes further away from 1.0.
b) Please explain why HPDCL is increasing the ratio for Residential from 91% to 93%, as opposed to increasing further the ratios for the Intermediate ad Sentinel classes, both of which are only at 80% (as proposed).
c) Under HPDCL's proposal for 2016, which customer classes' ratios will be increased to offset the revenue loss of moving the GS>50-1,499 class ratio from 1.40 to 1.20?
d) Please calculate what the (common) 2015 revenue to cost ratio for the Intermediate and Sentinel classes would be if:
    - The ratios for Residential, Sentinel and GS<50 were held at their status quo levels, and
    - The ratio for GS>50-1,499 was set at 1.40 as proposed.

Response: Note that responses to questions a) b) and c) refer to the R/C ratios as filed.

a) The applicant has reproduced the table below for reference. (as filed)

Revenue to Cost Ratio Allocation

Ratio Allocation				Target Range		3 Year Revenue to Cost Allignment		
Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**	**Floor**	**Ceiling**	**2016**	**2017**	**2018**
Residential	0.91	0.93	-0.02	0.85	1.15			
General Service < 50 kW	1.05	1.06	-0.01	0.80	1.20			
General Service > 50 to 4999 kW	1.67	1.40	0.27	0.80	1.20	1.20		
Intermediate	0.67	0.80	-0.13	0.80	1.20			
Sentinel Lights	0.73	0.80	-0.07	0.80	1.20			
Street Lighting	1.16	1.17	-0.01	0.70	1.20			

The Column entitled "Calculated R/C Ratio" comes from the Cost Allocation model and the column entitled "Proposed R/C Ratio" is the ratio proposed by the utility. The 3 classes highlighted in yellow fell outside of the floor and ceiling. For the GS>50 and the Intermediate classes, the utility is moving the ratio closer to 1.00. The intent of the applicant is to keep Street Lighting and GS>50 at the status quo. The slight difference is most likely due to the error the Cost Allocation which is being rectified as part of these responses.

b) In a previous proceeding, (EB-2013-0122) the OEB stated the following; "The Board's policy is that distributors should endeavor to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. The Board has indicated that given the data limitations in the cost allocation models, as a practical matter, there may be little difference between a revenue-to-cost ratio of near one and the theoretical ideal of one".

   In a previous proceeding, (EB-2013-0139) VECC submitted that Hydro Hawkesbury should simply adjust the ratios to be within the Board-approved ranges. VECC referred to the Board's findings in the Toronto Hydro 2011 rates proceeding (EB-2010-0142) and the Horizon 2011 rates proceeding (EB-2010-0131) in which the Board adjusted the revenue-to-cost ratios to be within the Board-approved ranges and did not approve adjustments to 100%. VECC proposed that the revenue-to-cost ratios for the Street Lighting and Sentinel Lighting should be reduced to the upper end of the Board's approved range, that the GS>50 ratio should be increased to maintain revenue neutrality and that the other class ratios should remain unchanged.
   Keeping the two arguments above in mind, the utility's rational was to bring the ratios which were outside of the range, within the range. The residential class, being the class which collects the largest share of the revenue is used as a "bucket class". As a result of the rebalancing, the ratio for the residential class increases from 0.91 to 0.93. The utility is of the opinion that ideally, each class should recover its own share of the costs, however given the data limitations of the Cost Allocation model, the residential class is still being subsidized by the General Service Classes.

c) The residential class is used to offset the rebalancing of the GS<50 class.

d) Hearst has updated its Revenue Requirement and as such, the cost allocation model also had to be updated. Hearst has included the revised results below. Unfortunately, Hearst is unable to recreate the scenario the OEB has asked for because the Sentinel class now falls outside of the range and must be adjusted accordingly.

Revenue to Cost Ratio Allocation

Ratio Allocation				3 Year Revenue to Cost Allignment		
Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**	**2016**	**2017**	**2018**
Residential	0.90	0.91	-0.01			
General Service < 50 kW	1.06	1.06	-0.00			
General Service > 50 to 4999 kW	2.23	1.89	0.34	1.55	1.20	
Intermediate	0.85	0.90	-0.05			
Sentinel Lights	0.66	0.80	-0.14			
Street Lighting	0.86	0.90	-0.04			

Hearst Power Distribution Company Limited

Exhibit 8

Responses to Interrogatories

September 11, 2015

8-Staff-48

Ref: Exhibit 8, Tab 1, Schedule 5, page 15

Hearst Power states that proposes to maintain “most of” its current Retail Service Charges and Specific Service Charges.

a) Please clarify which Retail Service Charges and Specific Service Charges Hearst Power plans to eliminate and its rationale.

Response:

a) Hearst’s evidence should have stated “all of ” its current Retail Service Charges and Specific Service Charges

8-Staff-49

Ref: Exhibit 8, Tab 1, Schedule 15

Upon completing all interrogatories from Board staff and intervenors, please provide an updated calculation of the foregone revenue.

Response:

a) Find attached a revised Foregone Revenue calculation over 10 months (September 2014-June 2015 incl.)

Foregone Revenue Reconciliation

Determination of Rate Rider is based on the application being 5 months late

Monthly Service Charge	**New Rate (1)**	**Existing Rate (2)**		**Difference**	**Rate Rider**
Residential	$13.00	$9.19		$3.81	$3.18
General Service < 50 kW	$19.79	$19.76		$0.03	$0.02
General Service > 50 to 4999 kW	$46.34	$54.82		-$8.48	-$7.07
Intermediate	$223.01	$223.01		$0.00	$0.00
Sentinel Lights	$9.00	$7.09		$1.91	$1.59
Street Lighting	$7.88	$7.88		$0.00	$0.00

Distribution Volumetric Rate *	**New Rate (1)**	**Existing Rate (2)**		**Difference**	**Rate Rider**
Residential	$0.0135	$0.0160		-$0.0025	-$0.0021
General Service < 50 kW	$0.0068	$0.0067		$0.0001	$0.0001
General Service > 50 to 4999 kW	$1.9726	$2.3213		-$0.3487	-$0.2906
Intermediate	$1.0228	$1.0215		$0.0013	$0.0011
Sentinel Lights	$1.9025	$3.1198		-$1.2173	-$1.0144
Street Lighting	$2.6235	$2.2937		$0.3298	$0.2748

Rate Class	**Customers/ Connections**	**Number of Customers/Connections**			**Test Year Consumption**		**Proposed Rates**			**Revenues from proposed Foregone Rev Rate Rider**	**Reconciliation**			
		Start of Test Year	**End of Test Year**	**Average**	**kWh**	**kW**	**Monthly Service Charge**	**Volumetric**			**Rev at existing Rates**	**Rev at Proposed Rates**	**Difference in Rev Requirement**	**Rev Req to remit over 10 months**
								kWh	kW					
Residential	Customers	2,272	2,272	2,271.57	24,347,981	-	$3.1750	-$0.0021		$35,776.98	$640,076.12	$683,008.50	$42,932.38	$35,776.98
General Service < 50 kW	Customers	464	464	464.29	11,155,291	-	$0.0250	$0.0001		$1,014.92	$184,833.40	$186,051.30	$1,217.90	$1,014.92
General Service > 50 to 1499 kW	Customers	41	41	41.00	22,618,065	64,865	-$7.0667		-$0.29	-$21,539.90	$169,632.29	$144,412.67	-$25,219.62	-$21,016.35
Intermediate	Customers	2	2	2.00	21,333,927	60,980	$0.0000		$0.00	$66.93	$39,851.34	$39,931.66	$80.31	$66.93
Sentinel Lighting	Connections	15	15	15.00	19,146	70	$1.5917		-$1.01	$216.00	$1,493.03	$1,752.23	$259.20	$216.00
Street Lighting	Connections	947	947	947.23	441,593	4,565	$0.0000		$0.27	$1,254.66	$100,040.58	$101,546.17	$1,505.60	$1,254.66
Total										$16,789.59	$1,135,926.76	$1,156,702.52	$20,775.76	$17,313.14

reconciles

Note

8.0 –VECC - 38
Reference: E8, pg. 5

a) Please explain why HPDCL is initiating the move to 100% fixed charge for Residential starting with its proposed 2015 rates when the Board's policy (EB-2012-0410, page 24) states that "the rate changes will begin in 2016".

Response:

a) The applicant's priority is to minimize the impacts of rate changes to its customer but also strives to achieve stability in its rates as soon as possible. Hearst's rational is that it hopes to have stable rates by 2018.

8.0 –VECC - 39
Reference: E8, pg. 8

a) With respect to the GS<50 class, please clarify whether HPDCL's rate design proposal is to maintain the existing fixed/variable split or maintain the existing monthly service charge.
b) With respect to the Sentinel and Street Lighting classes, please explain why HPDCL is proposing to maintain the existing monthly service charges for 2015 when, in each case, the current service charge is well below the maximum value calculated by the Cost Allocation Model.

Response:

a) The applicant wishes to keep its existing monthly fixed charge of $54.82
b) The applicant has replicated the Minimum and Maximum Fixed rates as proposed by the Cost Allocation model.
Increasing the fixed charge to the maximum would create a fixed to variable split that is unrealistic as it would result in a credit as a variable rate. The utility felt that keeping its rates at the same level as the existing rates would be more prudent. In the case of the Sentinel Class, increasing the rate to $8.40 would result in a 100% fixed charge. In the case of the Street Lights, increasing the fixed charge to 9.02 would result in a 100% fixed charge.

		Cost Allocation – Minimum Fixed Rate			Cost Allocation – Maximun Fixed Rate	
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$10.79	44.02%	55.98%	$26.57	108.43%	-8.43%
General Service < 50 kW	$11.44	33.99%	66.01%	$29.58	87.92%	12.08%
General Service > 50 to 4999 kW	$21.38	7.42%	92.58%	$46.34	16.09%	83.91%
Intermediate	$7.61	0.37%	99.63%	$27.16	1.31%	98.69%
Sentinel Lights	$4.56	54.33%	45.67%	$15.59	185.66%	-85.66%
Street Lighting	($0.02)	-0.19%	100.19%	$9.29	103.09%	-3.09%
TOTAL						

8.0 –VECC - 40
Reference: E8, pg. 10-11

a) With respect to the RTSRs, the Application states (page 10) that the current rates are over-collecting in the case of the Connection Service and the proposal is to offset this inequity. However, the proposal calls for an increase in Connection Service rates (see page 11). Please reconcile.

Response:

a) The evidence at Exhibit 8 page 10-11 should have stated " under-collecting" rather than "over-collecting".

8.0 –VECC - 41
Reference: E8, pg. 21

a) How were the forecast 2015 LV charges of $55,936 derived?

Response

a) The LV charges are based on Hydro One's LV charges for power purchased. Their LV charge includes their following items:
   - Volumetric Rate Rider #14A
   - Volumetric Rate Rider #14B
   - Volumetric Rate Rider #16
   - Volumetric Rate Rider #19
   - Monthly Service Charges
   - Common ST Lines
   - Meter Charge

   Since the Hydro One charges are variable, HPDC forecasted its 2015 LV by using the average of the last 3 years and added a 2% increase for inflation.

8.0 –VECC - 42
Reference: E8, pg. 23

a) How was the Supply Facilities Loss Factor of 1.0034 determined?

Response:

a) The rational for using 1.0034 as a SFLF is based on Board Staff's view on the matter. (Board Staff submitted in case EB-2013-0122 that "Board staff is unaware of why the SFLF should not be 1.034, which to Board staff's knowledge has remained unchanged for at least 10 years and was approved most recently in the Board's Rate Order EB-2012-0136".
b) That said, the utility has updated the loss factor to use an average of the supply facility factor from both Hydro One and IESO since electricity is being purchased by both.
c) Details are shown at the next page.

Loss Factors

		Historical Years						5-Year Average
		2009	2010	2011	2012	2013	2014	
	Losses Within Distributor's System							
A(1)	"Wholesale" kWh delivered to distributor (higher value)	80,601,482	79,509,530	80,704,953	81,742,651	85,473,147	86,123,559	81,606,353
A(2)	"Wholesale" kWh delivered to distributor (lower value)	78,291,808	77,598,404	78,808,832	80,148,426	83,591,984	84,294,612	79,687,891
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)							-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	78,291,808	77,598,404	78,808,832	80,148,426	83,591,984	84,294,612	79,687,891
D	"Retail" kWh delivered by distributor	77,457,009	73,683,490	78,049,427	79,919,925	82,731,372	84,214,727	78,368,245
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-			-
F	Net "Retail" kWh delivered by distributor = **D - E**	77,457,009	73,683,490	78,049,427	79,919,925	82,731,372	84,214,727	78,368,245
G	Loss Factor in Distributor's system = **C / F**	1.0108	1	1	1	1	1	1
	Losses Upstream of Distributor's System							
H	Supply Facilities Loss Factor	1.0295	1.0246	1.0241	1.0199	1.0225	1.0217	1.0241
	Total Losses							
I	Total Loss Factor = **G x H**	1.0406	1.0790	1.0341	1.0228	1.0331	1.0227	1.0414

8.0 –VECC - 43
Reference: E8, pg. 30-31

a) Please explain the basis for the statement that the Application was filed 6 months late when the required filing date was August 1, 2014 and the Application is dated June 8, 2015.
b) Please confirm that HPDCL is requesting that its approved 2015 rates be both implemented and effective in November 2015.
c) If part (b) is confirmed, please explain why a foregone revenue rate rider is required.
d) Please explain why the text on page 30 states the Application is 6 months late but the calculations on page 31 state it was 5 months late.
e) Please explain why the new rates set out on page 31 don't equal the proposed rates per E8, page 9.
f) Based on the most recent 12 months of billing data please indicate how many Residential customers fall into each of the following average monthly use categories:
   - 0-100 kWh
   - >100-250 kWh
   - >250-500 kWh
   - >500-800 kWh
   - >800-1,000 kWh
   - >1,000-1,500 kWh
   - >1,500-2,000 kWh
   - >2,000 kWh

Response:

a) The required filing date was August 29, 2014 (as per the OEB letter published February 20, 2014. The applicant filed its application on March 5, 2015 which is exactly 188 days (or 6 months and 5 days) past the due date.

Most of the reasons for the delays were explained in a letter submitted to the Board April 11, 2014. In the letter, the applicant requested a deferral in filing its cost of service. In its letter, the applicant informed the Board that the general manager had left without notice and that the utility was left without proper resources to put together an application. In its reply, the Board stated its expectation that Hearst Power will make best efforts to file a 2015 cost of service application in a timely manner, and in any event, no later than May 1, 2015. It is the applicant's view that it take approximately 9 months to compile the evidence necessary to file a Cost of Service application. The general manager also struggled with compliance issues and requirements that were not in place. While preparing to refile the application, the applicant asked Board

Staff if it should recalculate to foregone revenue and was advised to leave it as is.

b) The applicant is requesting a November 1 2015 implementation date.

c) The reason for the foregone revenue is that the proposed rates are calculated based on 12 months. For the period of November to April, it's the applicant's understanding that rates should be calculated on a 6 month basis rather than 12 months.

d) The calculations on page are calculated for a period of 6 months. The column header is incorrect.

e) Hearst inadvertently missed updating the fixed chages in the Foregone Revenue table.

f) See below

Category	# of residential clients	% of residential clients
0-100 kWh	55	3%
>100-250 kWh	100	5%
>250-500 kWh	306	14%
>500-800 kWh	559	26%
>800-1,000 kWh	318	15%
>1,000-1,500 kWh	472	22%
>1,500-2,000 kWh	179	8%
>2,000 kWh	171	8%

- Average of 980kWh
- Median of 835kWh

Hearst Power Distribution Company Limited

Exhibit 9

Responses to Interrogatories

September 11, 2015

9-Staff-50

Ref: Exhibit 9, EDDVAR Continuity Schedule
Ref: Regulatory Audit Report, page 2

Hearst Power has shown several adjustments in the “Adjustments – Other” columns for 2012 and 2013. The Note 2 at the bottom of the EDDVAR model states the following:

a) Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

b) Please explain each adjustment shown under the “Adjustments – Other” columns in Hearst Power’s EDDVAR schedule.

Response:

a) There were 3 reasons for all the adjustments identified in "Adjustment – Other" in Hearst Power's EDDVAR Schedule. The reasons are as follows:

   a. Most of the adjustments are due to findings of the OEB audit by Audit and Performance group. All these adjustments are detailed in the Appendixes included in our answer to question 9-Staff-51.

   b. While carrying out the smart meter disposal in 2014, classification of expenses were required as per the smart meter model and its classification of assets and OM&A expenses. Adjustments were made to account 1555 and 1556 accordingly.

   c. In 2009, there was and adjustment on prior year revenue account #4075 and expense #4750 which was recorded in the related variance account

b) Here below is a explanation for the "Adjustments – Other" in Hearst Power's EDDVAR schedule:

   - Box H24 – 2009 LV Variance: Adjustment on prior year revenue account #4075 and expense #4750 which was recorded in variance account
   - Box H77, H80, R77, R80, AB77, AB80, AO77, AO80, BB77, BB80, BO77, BO80 – 2009 to 2014 Smart Meter Capital and OM&A accounts: While carrying out the smart meter disposal in 2014, reclassification of expenses were required as per the smart meter model and its classification of assets and OM&A expenses. Adjustments were made to account 1555 and 1556 accordingly.
   - Box BU77, BU80 – 2014 Interest on Smart Meter Capital and OM&A accounts: Due to reclassification of assets and OM&A expenses required as per the smart meter model, interest adjustments in 2014 were made accordingly.

- Box AB24, AB26, AB27, AB28, AB29, AB30, AB33, AB47 – 2011Group 1 and 2 DVA accounts: All adjustments were as per OEB audit findings. All adjustments were approved by OEB Staff prior to being recorded. Please refer to answer of question 9-Staff-51 for additional details.

- Box AO24, AO27, AO28, AO29, AO30, AO33, AO34, AL47, AO65, AO66, AO67, AT24, AT65, AT66 – 2012 Group 1and 2 DVA accounts, including its related expense accounts: All adjustments were as per OEB audit findings. All adjustments were approved by OEB Staff prior to being recorded. Please refer to answer of question 9-Staff-51 for additional details.

- Box BB33, BB34, BG33, BG34 – 2013 Group 1 DVA accounts, including its related expense accounts: All adjustments were as per OEB audit findings. All adjustments were approved by OEB Staff prior to being recorded. Please refer to answer of question 9-Staff-51 for additional details.

9-Staff-51

Ref: Exhibit 9, EDDVAR Continuity Schedule
Ref: Regulatory Audit Report, page 2

OEB staff has calculated the difference between the Approved Interim Balance and the Revised Audited Balance as follows:

	Interim approved	Revised Audit	Diff.
1550	-34,263	-30,860	-3,403
1580	-13,762	-92,166	78,404
1584	-33,069	43,371	-76,440
1586	-10,549	-10,537	-12
		-	
1588	-73,765	120,553	46,788
1588GA	72,567	72,782	-215
1590	3,037	-993	4,030
		-	
Total	**-89,804**	**138,956**	**49,152**
		-	
EX GA	**-162,371**	**211,738**	**49,367**

OEB staff has also calculated the amounts shown in the "Adjustments – Other" columns as follows:

Adjustments on Continuity Schedule

	2012 p	2012 i	2013 p	2013 i	Total adjs.
1550	-51,755	-3,424			-55,179
1580					0
1584	-1,409				-1,409
1586	-1,374				-1,374
1588	33,714				33,714
1588GA	-13,842				-13,842
1590					0
			-		-
1595 -10	29,509		184,523	-15,382	170,396
1595 - 11	48,512		-22,010	-6,092	20,410
			-		-
Total	**43,355**	**-3,424**	**206,533**	**-21,474**	188,076
EX GA	**57,197**	**-3,424**			

1562	-7379	-423			-7,802
1592	7379	423			7,802
1592	-5267				-5,267
			-		-
Grand Total	**38,088**	**-3,424**	206,533	-21,474	193,343

a) Please reconcile the differences between the two Tables above for each account.

Response:

a) We cannot reconcile the differences between the two Tables as they are separate years.

Table 1:

If you refer to the 2015 Deferral/ Variance Account Workform, the adjustments during 2011 – other, agrees to the amount reported on the letter address to Kirsten Walli on April 8, 2014 written by Mr. Daria Babaie, Appendix 2 and also to the summary prepare by Mrs Donna Kwan for all the findings by Group 1 and Group 2 DVA'S, Appendix 3.

Per the summary prepared by Donna and the letter from Daria, the adjustment are in agreement, please refer to Appendix 1.

The amount presented in the Audit of Group 1 and Group 2 Deferral and Variance accounts, page 2 are not in agreement with the amount agreed by Donna and Daria, during the audit. They had also approved all our journal entries in regard to each finding, with the numbers presented in the attached appendixes.

Table 2:

Please refer to Appendix 4 which addresses all of the adjustments entered in the year 2012 of the 2015 Deferral/ Variance Account Workform, they are all entries in relation to the findings from the audit performed in 2013-14. All entries were approved by the OEB when they were prepared by HPDC.

9-Staff-52

Ref: Exhibit 9, page 11, Account 1595

Ref: EDDVAR Continuity Schedule

a) Hearst Power has stated that only Account 1595 - 2008 has been proposed in this application for disposition. However, OEB staff notes that the EDDVAR Continuity schedule shows a zero balance with respect to 2008 residual amounts. Please clarify and confirm the amount requested for disposition in this proceeding.
b) Account 1595 – 2010 – The amount proposed for disposition per Exhibit 9, page 11 is a credit of $233,640. The EDDVAR schedule shows the claim amount to be a credit of $152,852. Please clarify and confirm the amount proposed for disposition in this proceeding.
c) Account 1595 – 2011 – OEB staff notes that there were no dispositions in 2011 rates for Hearst Power.
   i. Please provide the correct rate year for this proposed disposition
   ii. The amount shown in Exhibit 9, page 11 differs from the amount shown on the continuity schedule. Please correct the error and file the appropriate evidence as needed.
   iii. Please confirm that balances in Account 1595 requested for disposition are audited residual balances, i.e. the rate riders had ended as of December 31, 2014 for the proposed dispositions.

Response:

a) The statement at page 11 which 2008 has been included in this application is incorrect. The years 2010 and 2011 are sought for disposition
b) Again, the evidence most likely showed the balances of an outdated model. The evidence should have been updated to show 233,640
c) Hearst's auditors completed the EDDVAR model and as such, the utility believes that the continuity schedule is accurate. Hearst believes that the balances in 1595 (2011) are as a results of the DVA audit however, the utility was unable to reach its auditors in time to file these responses. The utility will get a confirmation from its auditors and provide confirmation to Board Staff and VECC as soon as possible.

9-Staff-53

Ref: Exhibit 9, Tab 4, Schedule 2 – Rate Rider Calculations

Ref: EDDVAR Continuity Schedule

OEB staff notes a discrepancy between the evidence filed for disposition term, amount for disposition for all accounts, and amount for disposition for Global Adjustment as follows:

	Ex. 9/Tab 4/Sch. 2	EDDVAR Tab "Rate Rider Calculations"
Term of disposition – all accounts except GA	2 years	1 year
Balance for disposition – all accounts except GA	-$236,637	-$506,432
Balance for disposition – GA	$134,528	$14,598

a) Please correct the appropriate evidence and refile the corrected schedules as necessary.

Response:

a) The reason for the discrepancy is most likely and error in transposing the amounts. Hearst is looking to dispose of its balances over a period of 2 years.

9-Staff-54

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition, s. 3.5

Board staff notes that Hearst Power has not followed all of the requirements of Guideline G-2011-0001 in support of its request to recover smart meter costs. Specifically, section 3.5 outlines the minimum information that should be provided.

a) Please provide a copy of the letter from the Fairness Commissioner indicating Hearst Power's authorization to conduct smart meter activities.

b) Please provide a general description of contractual arrangements with selected vendors.

c) Please provide the meter types and numbers of each type installed for each rate class.

d) Please indicate when Hearst Power commenced TOU billing, and describe any delays which may have occurred.

Response:

a) Please refer to "OEB – 9 Staff 54a"
b) HPDC, as well as 6 other District 9 Distribution Utilities, collaborated together to reduce their Smart Meter costs and hired Util-Assist to prepare a Smart Meter budget. Util-Assist helped the District 9 utilities through the smart meter process. Util-Assist has a standard contracting fee for their services that was shared equally among the 7 utilities.
Legal fees for contracts with the various vendors (Sensus, Erth Holdings/Harris North star, Olameter) were also shared equally among the 7 utilities of District 9.

Please refer to "OEB – 9-Staff-54b" for contract agreement with Util-Assist

c) Please refer to document "OEB 9-Staff-54c"

d) HPDC commenced TOU billing on November 1st 2011. No delays have occurred.

9-Staff-55

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition

Ref: Smart Meter Model

Board staff notes that installation of smart meters for GS >50kW and Intermediate customers is beyond minimum functionality.

a) Please provide the rationale for installation of smart meters for these two customer classes.

Response

a) Since the cost of the setup of billing software and meter readings was already completed as required with the Residential and GS<50 classes, HPDC determined that replacement of conventional meter with demand for the GS> 50 and intermediate classes would bring significant savings to the monthly reading cost of HPDC (refer to table in “9-Staff-56” below).

   With this upgrade to smart meters, HPDC was able to further assist its larger customers with access to behind the meter information. Overall it has been a very positive upgrade for the GS>50 and intermediate classes, even more than the Residential class as larger businesses have more opportunities to reduce their consumption through CDM and have better understanding of their consumption.

9-Staff-56

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Smart Meter Model

Please outline and quantify any incremental costs savings realized through the installation of smart meters.

The cost savings related to the smart meter installation are all related to the meter reading costs. The table below shows a typical month meter reading costs that would be applicable in 2015 for each type of meter with total savings.

Monthly meter ready costs

	Residential and GS<50 - Conventionnal (Outside)	Smart Meter	Savings per month
# of meters	2,740	2,740	
Admin. Assist time	$ 44.00	$ 165.00	
Crew time	$ 5,376.00		
Vehicle	$ 800.00		
Erth holding		$ 3,216.23	
Cleo		$ 64.65	
Iron Mountain		$ 65.65	
Sensus		$ 1,672.44	
	$ 6,220.00	$ 5,183.97	$ 1,036.03
Cost per meter	$ 2.27	$ 1.89	$ 0.38

	Conventionnal meter w/demand	S.Meter w/demand	Savings per month
# of meters	42	42	
Admin. Assist time	$ 22.00	$ 88.00	
Crew time	$ 672.00		
Vehicle	$ 150.00		
Erth holding		$ 49.30	
Cleo		$ 0.99	
Iron Mountain		$ 1.02	
Sensus		$ 25.65	
	$ 844.00	$ 164.96	$ 679.04
Cost per meter	$ 20.10	$ 3.93	$ 16.17

9-Staff-57

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Smart Meter Model, Sheet 3

Board staff notes that Hearst Power has entered the minimum corporate tax rates into the model for 2010 and beyond. Board staff notes that Hearst Power's 2010 Final Rate Order incorporates tax credits which reduce its tax rate built into rates to 6.97%.

a) Please correct the tax rate in the model to reflect the effective tax rate approved in Hearst Power's last cost of service application, or explain the use of an unadjusted minimum tax rate.

b) Please verify and correct as necessary the aggregate corporate income tax rate for 2006 to 2009 to reflect an organization of Hearst Power's size.

Response

a) Please refer to document "OEB – 9 Staff 57" which includes a table to show the actual tax rate paid each year on the T2's. HPDC pays PIL's like a CCPC and is allowed the small business deduction. Also in some of the prior years, HPDC has applied for Apprenticeship tax credit (ATTC's) which reduced the taxable rate. HPDC requires clarification if the correct value to use is the corporation tax rate with or without the ATTC's. If the correct tax rate is the rate that the HPDC would be taxed on, it would be the first section of the table line 32 to 36. Also HPDC had a few years with losses; therefore the taxable rate is still the same but impact of 0% which affects the calculations.

b) Please refer to document "OEB – 9 Staff 57"

9-Staff-58

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Smart Meter Model, Sheet 3

Board staff notes that the cost of service parameters on page 3 of the model are incomplete and contain certain anomalies.

a) Please verify and enter the appropriate cost of service parameters for 2006 to 2009.
b) Please verify and enter the approved short term interest rate for all years.
c) Please ensure the entries on Line 31 of page 3 reflect approved return on equity, rather than total cost of capital.

a), b), c) The revised model filed along with these responses reflect the correct inputs.

9-Staff-59

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Smart Meter Model, Sheets 8 and 8A

Hearst Power has applied for rates effective November 1, 2015. Board staff notes that Hearst Power has not applied interest beyond June 2014 for either its funding revenues or OM&A expense.

a) Please update the model to include interest on both Sheet 8 and 8A to November 1, 2015.

Response:

b) The 1000 number was a default value that was not updated. The correct value should be 2,735 smart meters forecasted for year 2015 (2272 smart meters in the Residential class + 463 smart meters in GS<50 class).The revised model filed along with these responses reflect the correct inputs.

9-Staff-60

Ref: Exhibit 9, Tab 5, Schedule 2

Ref: Smart Meter Model, Sheet 9

Board staff notes that Hearst Power's model shows 1000 metered customers for 2015 on Sheet 9.

a) Please correct the value in cell Y46 to show Hearst Power's metered customers.

Response:

a) The revised model filed along with these responses reflect the correct inputs.

9.0 –VECC -44
Reference: E9/Appendix 2-U & Table 9.0

a) Please reconcile the account 1508 amount of $36,358 shown in Table 9.0 with the amount of $35,936 ($35,500 + 436 carrying charges) shown in Appendix 2-U.
b) Please confirm that Hearst Power's IFRS consultants reviewed the account 1575/1576 proposal in this Application.

Response:

a) The carrying charges should be in the amount of $ 958 and not of $436 which explains the difference of $422.
b) The balance in account 1576 represents the difference between the CGAPP and MIFRS accounting changes in regards to amortization and capitalization. This account was revised and approved by the auditor's at year end. The balance per table 9 is in the amount of $41,479 per our year end trial balance the amount should be $74,176.

   There are no balances in 1575 per auditor's.

End of document