Energy Probe (EP) Question #1 List 1

Question

Issue 3 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

OPA Province wide CDM Results for 2011
Hydro One DX CDM results for 2011, 2012 YTD and forecast 2013/2014
Methodology for incorporating CDM in Load Forecast
CDM LRAM VA

Load Forecast-CDM

Ref: Exhibit I, Tab 3, Schedule 3.01, EP 8 &
Exhibit A, Tab15, Schedule 2 &
Exhibit A, Tab15 Schedule 2, Attachment 1 A.1 Tables 4-9 &
Exhibit A, Tab15 Schedule 2, Attachment 1, Pages 24-25 &
Exhibit A, Tab15 Schedule 2, Attachment 1, Appendix E, Pages 63-73

a) Confirm CDM is not part of the Load Forecast Model, but rather an add back item
b) Confirm 2011 and 2012 YTD Province Wide CDM Numbers [2011 2,351; 1055 peak; 2012 2749; 1890 peak]
c) Compare to I/T3/S22.02 LPMA 3 [2011 1499 peak; 2012 1759 peak].
d) What is the Hydro One/OPA current forecast 2011-2014?
e) Please provide Hydro One DX CDM Plan Targets.
f) How much are these as a percentage of the Province-wide targets (Overall 2011-2014)?
g) What were/are HO Results for 2011 and 2012 (estimate)?
h) Compare Results to Plan.
i) What are the latest load projections from OPA for 2013 and 2014?
j) What are the load projections from HONI DX for its 2013 and 2014 CDM Plan?
k) Given the variability of CDM results why wouldn't HO agree to an LRAMVA?
l) OPA CDM Guidelines suggest LRAMVA for distributors. Please comment why not Transmitters.

Response

a) CDM is part of the Load forecast modeling process. As explained in Exhibit I, Tab 3, Schedule 3.01 EP 8 (d), Hydro One adds back the CDM to the left hand side variable (actual load) before running the econometric model. Hydro One does not have a separate load forecast model for CDM.

b) The forecast numbers in the following table are the latest forecast of CDM impact for the province in 2011 and 2012.

Decription	2011	2012
CDM impact on annual peak demand (MW) as shown in Exhibit A, Tab 15, Schedule 2, Table 2	2351	2749
CDM 12-month average peak impact (MW) as shown in Exhibit A, Tab 15, Schedule 2, Table 2	1605	1890

c) The requested comparison is provided below.

Decription	2011	2012
CDM impact on annual peak demand (MW) as shown in Exhibit A, Tab 15, Schedule 2, Table 2	2351	2749
CDM 12-month average peak impact (MW) as shown in Exhibit A, Tab 15, Schedule 2, Table 2	1605	1890
CDM 6-month average peak impact (MW) as shown in Exhibit I, Tab 3, Schedule 2.01, LPMA 2	1499	1759

The CDM forecasts presented in Exhibit I, Tab 3, Schedule 2.01 LPMA 2 pertain to the 6-month average peak, while the CDM numbers discussed in (b) pertain to annual peak and 12-month average peak.

d) The current Hydro One/OPA CDM peak forecasts for 2011-2014 are provided in Exhibit A, Tab 15, Schedule 2, page 9, Table 2. Detailed forecasts by policy instruments, sector and resource type are provided in Exhibit A, Tab 15, Schedule 2, Attachment 1, page 24, Table A.1.

e) Hydro One DX CDM peak and energy targets for 2011-2014 are 214 MW and 1130 GWh respectively. Annual estimates are provided below:

	2011	2012	2013	2014
GWh saving	54	121	348	606
MW saving	27	53	129	214

f) Hydro One DX CDM peak and energy targets for 2011-2014 are 16.1% and 18.8% respectively for the province-wide LDC CDM targets (1330 MW and 6,000 GWh).

g) Based on final results for OPA-funded, LDC-delivered programs released in September 2012, Hydro One achieved 35 MW of peak savings and 86 GWh of energy savings in 2011. It should be noted that 2012 OPA-funded, LDC-delivered program results would not be available until August/September 2013. The current estimates for 2012 are 53 MW of peak savings and 121 GWh of energy savings.

h) As requested, 2011 OPA-funded, LDC-delivered program results are compared to that assumed in the load forecast.

	2011 Plan	2011 final results for OPA funded LDC-delievered programs
GWh saving	54	86
MW saving	27	35

i) Please see reponse to (d) above.

j) Please see response to (e) above.

k) See response to Exhibit I, Tab 3, Schedule 2.04 LPMA 5.

l) The CDM Guidelines for distributors were issued by the Ontario Energy Board (EB 2012-0003) in April 26, 2012. Hydro One does not want to speculate why the above guidelines do not cover transmitters.

Energy Probe (EP) Question #3 List 1

Question

Issue 7 Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Breakout Executive Compensation from MCP
COLA Adjustments 2013/2014

Ref: Exhibit I, Tab7, Schedule 3.14, EP 40 Corporate Staffing & Exhibit C1, Tab 3, Schedule 1

a) Please Define Executive:--President, EVP, VP and Directors??

b) Please provide requested breakdown for Executive Management headcount separate from MCP.

c) Breakout Executive from MCP- Incumbents, Base Pay Incentive Pay, Benefits and Pension.

d) What are differences for this group from MCP regarding OPEBs?

e) Has Mercer recently benchmarked HO Executive Compensation?

Response

a) Executives are defined as the President and CEO, Executive Vice Presidents, Senior Vice Presidents and Vice Presidents.

b) President and CEO - 1
Executive Vice Presidents - 3
Senior Vice President - 4
Vice President - 15

c) Breakout of Executive Pay

2011 Executive Base= $7,136,457
2011 Executive Incentive Payment= $2,333,659

d) Post-retirement benefits for MCP executive are the same as post-retirement benefits for non-executive MCP employees.

e) No.

Energy Probe (EP) Question #5 List 1

Question

Issue 8 Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

Capitalization of CCFS -Methodology
Pricing of Telecom Services

Ref: Exhibit I, Tab 8, Schedule 3.01, EP 50 &
Exhibit A, Tab 8, Schedule 3, Pages 3 -8 &
Exhibit A, Tab 8, Schedule 3 Appendix B Page 8 &
Exhibit A, Tab 8, Schedule 3, Appendix K &
Exhibit C1, Tab 4, Schedule 2, Page 2, Table 2 &
Exhibit C1, Tab 7, Schedule 1 Page 2 &
Exhibit C1, Tab 7, Schedule 2 Attachment 1 (B&V study)

a) Confirm the Outbound services amounts from Networks to HOTelecom 2012-2014.

b) Do these amounts include an asset use fee?

c) Who “owns” the assets for Telecom Functions/Services? Are these part of Networks Rate Base?

d) How much is the Net Book value of assets used to perform Telecom services 2012-2014?

e) Does HOTelecom pay for the use of these assets If so on what basis and how much a year.2012-2014?

f) Does the Asset use fee cover depreciation and return on Sustainment capital for these assets?

g) Are the assets used to provide service to others than HONI?

h) If so, how are these services priced? (Market or Fully allocated cost of HOT)

i) Provide Schedule showing fully allocated costing of HOTelecom services provided to Networks 2012-2014.

j) Explain the increases in 2012 (include 281,750 project), 2013 and 2014 A-8-3 Appendix K.

k) Explain material charge/fee increases in 2013/14 even though HOT Allocated CCFS cost are reduced by $0.9 million. Are these due to increased Service levels? (SLA for 2013 not provided)

Response

a) As detailed on Page 7 of Exhibit A Tab 8 Schedule 3, the amounts owed to Networks by Telecom for services are:
2012 - $2.19M
2013 - $2.66M
2014 - $2.62M.

b) Yes, an asset fee is included in the amount that Networks charges Telecom for services. More detail on this is available at Exhibit I Tab 6 Schedule 10.01 CCC 16.

c) Networks owns the assets necessarily used to provide services. Generally these are included in Rate Base and any revenues from affiliates serve to defray costs charged to Networks' customers.

d) The estimated NBV of the Telecom portion of the assets used to calculate the transfer price charge for 2013 and 2014 is $1.56M.

e) Yes, Hydro One Telecom pays an asset transfer price charge for the use of these assets (as per Exhibit A-8-3). The Common Asset study (C1-7-3) also has more detail on the computation of this amount.

f) Yes. We calculate the transfer price charge using a revenue requirement model so the charge includes allowances for depreciation, return, and taxes.

g) Some of Networks' assets provide services to affilates. Also some external revenues are generated as a result of using Networks'assets. Those external revenues are detailed in Exhibit E1 Tab 2 Schedule 1 of prefiled evidence.

h) These services are priced on a fully allocated cost basis.

i) The cost of Telecom services provided to Networks is provide at Exhibit A Tab 8 Schedule 3 Page 8.

j) The Telecom Expense Management solution is outdated and no longer vendor-supported. Hydro One Telecom has engaged a third party to install a new application to collect the necessary information. Networks will fund the project for both the services and the Telecom involvement in the implementation, and will include a charge to recover an appropriate share of the asset cost from Telecom.

k) Hydro One is unable to reconcile the references with the question as written and thus cannot provide a specific answer. Charges to Networks for telecommunication Services do increase as outlined on Page 8 of Exhibit A Tab 8 Schedule 3. Allocated costs charged to Telecom are materially unchanged over the test period as shown on page 7 of the same exhibit.

Energy Probe (EP) Question #6 List 1

Question

Issue 8 Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

Overhead Capitalization (CCFS costs)
Ref: Exhibit I, Tab 8, Schedule 3.02, EP 51&

Exhibit C1, Tab 7, Schedule 2, Attachment 1, Appendix
EP IR 51 meant Additions to Ratebase i.e. In-Service Assets (ISA) not Ratebase as Denominator.

a) Please provide requested Calculation with/without Capital contributions based on ISAs for 2011-2014.
b) Compare to current formula/method in terms of % and Volatility.
c) Comment whether a lag between OM&A Cost incurrence and ISA would be appropriate.

Response

a)

i. Attachment 1 of this exhibit shows the Overhead Cap Rate computed using In-Service Additions as the denominator (line 82). Rates calculated using this method are higher and more volatile than the rates computed by Hydro One (line 83).

ii. Attachment 2 of this exhibit shows the Overhead Cap Rate computed by using In-Service Additions as the denominator and by removing Capital Contributions (line 83). While these rates are higher and more volatile than the rates computed by Hydro One (line 84), the costs capitalized under this approach (line 79) are lower than computed by Hydro One (line 80) because the higher rate gets applied to a lower amount (that is, Capital Spending without including Capital Contributions).

b) See response to part a).

c) Capital Expenditures is the more appropriate denominator for the determination of an overhead capitalization rate as it is more representative of when the expenditures are incurred and the physical construction of an asset. In-Service Additions represents when is the asset is complete and used and useful which would not match with when the overhead expense is incurred to support the construction.

USE RATE BASE FOR DENOMINATOR

		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
1	**Capital Expenditures**					
2	Total capexp	974.2	1,070.4	1,088.5	985.9	1,067.6
3	Less: Minor fixed assets	(31.4)	(26.0)	(27.3)	(25.4)	(25.9)
4	Less: Capitalized overhead	(115.2)	(116.5)	(117.0)	(109.9)	(111.2)
5	Less: Capitalized interest	(48.9)	(43.7)	(56.4)	(59.9)	(57.6)
6	Add: Capital contributions	198.2	291.0	310.2	67.1	16.2
7	Add: Removal costs	23.9	35.9	36.2	41.9	35.8
8		1,000.9	1,211.1	1,234.3	899.8	924.7
9						
10	**OM&A**					
11	Total OM&A	430.6	452.0	459.8	485.2	499.7
12	Less: CCF&S costs	(113.5)	(113.2)	(112.6)	(113.2)	(113.2)
13	Less: Facility costs	(22.2)	(22.7)	(23.5)	(24.0)	(24.5)
14	Less: Asset Management \1	(71.7)	(71.6)	(73.0)	(74.3)	(75.2)
15	Add: Capitalized overheads	115.2	116.5	117.0	109.9	111.2
16		338.3	360.9	367.8	383.6	398.0
17						
18	**Capitalized CCF&S Costs**					
19	Total Costs per Model	184.4	185.5	187.2	189.1	189.9
20	Less: AM	(35.3)	(35.8)	(37.0)	(37.4)	(37.2)
21	Less: Operations	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)
22	Less: Network Operations	(31.4)	(32.2)	(33.2)	(33.9)	(34.9)
23	Less: CBR	(3.6)	(3.6)	(3.7)	(3.8)	(3.9)
24	Net CCF&S Costs	113.5	113.2	112.6	113.2	113.2
25	Add: Facility costs	22.2	22.7	23.5	24.0	24.5
26						
27	Less operating-type CCF&S costs:					
28	Inergi - CSO	-	-	-	-	-
29	Inergi - ETS CSO Apps	-	-	-	-	-
30	Inergi - ETS Market Ready	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)
31	Inergi - Settlements	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
32		(1.3)	(1.3)	(1.3)	(1.3)	(1.2)
33						
34	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	154.3	172.3	175.5	196.0	204.2
38	Labour in capexp	237.5	262.1	269.0	244.1	267.9
39		391.8	434.4	444.5	440.1	472.1
40	% capexp	60.6%	60.3%	60.5%	55.5%	56.7%
41						
42	Portion capitalized based on total spending:					
43	OM&A	338.3	360.9	367.8	383.6	398.0
44	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
45		1,339.2	1,572.0	1,602.1	1,283.4	1,322.8
46	% capexp	74.7%	77.0%	77.0%	70.1%	69.9%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	67.7%	68.7%	68.8%	62.8%	63.3%
53						
54	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
55						
56	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
57						

		USE RATE BASE FOR DENOMINATOR				
		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
58	**Capitalized AM, NO, OP Costs**					
59	Network AM, NO, OP (Tx + Dx):					
60	Asset Management group	64.2	62.5	62.7	63.4	63.4
61	Network Operating department	45.7	47.0	48.3	49.4	50.8
62	Operations group (certain departments, see Report)	17.3	17.4	18.9	19.8	19.5
63		127.3	126.8	129.9	132.5	133.7
64						
65	Portion capitalized (per time study):					
66	Asset Management group	24.3%	24.3%	24.3%	24.3%	24.3%
67	Network Operating department	11.6%	11.6%	11.6%	11.6%	11.6%
68	Operations group (certain departments, see Report)	4.3%	4.3%	4.3%	4.3%	4.3%
69						
70	Capitalized AM, NO, OP costs:					
71	Asset Management group	15.6	15.2	15.2	15.4	15.4
72	Network Operating department	5.3	5.4	5.6	5.7	5.9
73	Operations group (certain departments, see Report)	0.7	0.8	0.8	0.9	0.8
74		21.6	21.4	21.6	22.0	22.1
75						
76	**Overhead Capitalization Rate**					
77	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
78	Capitalized AM, NO, OP costs	21.6	21.4	21.6	22.0	22.1
79	**TOTAL SHARED COSTS CAPITALIZED**	112.6	113.8	114.3	107.3	108.5
80	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
81	**In-Service Additions**	1294.7	904.1	1,023.0		
82	**Overhead capitalization rate**	**9.0%**	**13.0%**	**11.0%**		
83	*As filed by Hydro One*	*11.0%*	*9.0%*	*9.0%*	*12.0%*	*12.0%*
84						
85	\1 Asset Management excludes facility costs					

USE RATE BASE FOR DENOMINATOR

TRANSMISSION OVERHEAD CAPITALIZATION RATES

	($ millions)	2012	2013	2014	2015	2016
1	**Capital Expenditures**					
2	Total capexp	974.2	1,070.4	1,088.5	985.9	1,067.6
3	Less: Minor fixed assets	(31.4)	(26.0)	(27.3)	(25.4)	(25.9)
4	Less: Capitalized overhead	(115.2)	(116.5)	(117.0)	(109.9)	(111.2)
5	Less: Capitalized interest	(48.9)	(43.7)	(56.4)	(59.9)	(57.6)
6	Add: Capital contributions					
7	Add: Removal costs	23.9	35.9	36.2	41.9	35.8
8		802.7	920.1	924.1	832.7	908.6
9						
10	**OM&A**					
11	Total OM&A	430.6	452.0	459.8	485.2	499.7
12	Less: CCF&S costs	(113.5)	(113.2)	(112.6)	(113.2)	(113.2)
13	Less: Facility costs	(22.2)	(22.7)	(23.5)	(24.0)	(24.5)
14	Less: Asset Management \1	(71.7)	(71.6)	(73.0)	(74.3)	(75.2)
15	Add: Capitalized overheads	115.2	116.5	117.0	109.9	111.2
16		338.3	360.9	367.8	383.6	398.0
17						
18	**Capitalized CCF&S Costs**					
19	Total Costs per Model	184.4	185.5	187.2	189.1	189.9
20	Less: AM	(35.3)	(35.8)	(37.0)	(37.4)	(37.2)
21	Less: Operations	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)
22	Less: Network Operations	(31.4)	(32.2)	(33.2)	(33.9)	(34.9)
23	Less: CBR	(3.6)	(3.6)	(3.7)	(3.8)	(3.9)
24	Net CCF&S Costs	113.5	113.2	112.6	113.2	113.2
25	Add: Facility costs	22.2	22.7	23.5	24.0	24.5
26						
27	Less operating-type CCF&S costs:					
28	Inergi - CSO	-	-	-	-	-
29	Inergi - ETS CSO Apps	-	-	-	-	-
30	Inergi - ETS Market Ready	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)
31	Inergi - Settlements	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
32		(1.3)	(1.3)	(1.3)	(1.3)	(1.2)
33						
34	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	154.3	172.3	175.5	196.0	204.2
38	Labour in capexp	237.5	262.1	269.0	244.1	267.9
39		391.8	434.4	444.5	440.1	472.1
40	% capexp	60.6%	60.3%	60.5%	55.5%	56.7%
41						
42	Portion capitalized based on total spending:					
43	OM&A	338.3	360.9	367.8	383.6	398.0
44	Capexp	802.7	920.1	924.1	832.7	908.6

		USE RATE BASE FOR DENOMINATOR				
		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
45		1,141.0	1,281.0	1,291.9	1,216.3	1,306.6
46	% capexp	70.3%	71.8%	71.5%	68.5%	69.5%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	65.5%	66.1%	66.0%	62.0%	63.1%
53						
54	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
55						
56	Capitalized CCF&S costs	88.0	89.0	88.9	84.2	86.2
57						
58	**Capitalized AM, NO, OP Costs**					
59	Network AM, NO, OP (Tx + Dx):					
60	Asset Management group	64.2	62.5	62.7	63.4	63.4
61	Network Operating department	45.7	47.0	48.3	49.4	50.8
62	Operations group (certain departments, see Report)	17.3	17.4	18.9	19.8	19.5
63		127.3	126.8	129.9	132.5	133.7
64						
65	Portion capitalized (per time study):					
66	Asset Management group	24.3%	24.3%	24.3%	24.3%	24.3%
67	Network Operating department	11.6%	11.6%	11.6%	11.6%	11.6%
68	Operations group (certain departments, see Report)	4.3%	4.3%	4.3%	4.3%	4.3%
69						
70	Capitalized AM, NO, OP costs:					
71	Asset Management group	15.6	15.2	15.2	15.4	15.4
72	Network Operating department	5.3	5.4	5.6	5.7	5.9
73	Operations group (certain departments, see Report)	0.7	0.8	0.8	0.9	0.8
74		21.6	21.4	21.6	22.0	22.1
75						
76	**Overhead Capitalization Rate**					
77	Capitalized CCF&S costs	88.0	89.0	88.9	84.2	86.2
78	Capitalized AM, NO, OP costs	21.6	21.4	21.6	22.0	22.1
79	**TOTAL SHARED COSTS CAPITALIZED**	109.6	110.3	110.6	106.2	108.3
80	*As filed by Hydro One*	*112.6*	*113.8*	*114.3*	*107.3*	*108.5*
81	Capexp	802.7	920.1	924.1	832.7	908.6
82	**In-Service Additions**	1294.7	904.1	1,023.0		
83	**Overhead capitalization rate**	**8.0%**	**12.0%**	**11.0%**		
84	*As filed by Hydro One*	*11.0%*	*9.0%*	*9.0%*	*12.0%*	*12.0%*
85						
86	\1 Asset Management excludes facility costs					

Energy Probe (EP) Question #8 List 1

Question

Issue 12 Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Head Office Capital Expenditures

Ref. Exhibit I, Tab 12, Schedule 3.04, EP 55 &
Exhibit D1, Tab 4, Schedule 4, Page 1, Tables1-3

a) Has the Project been tendered? If so, provide the total cost and term of contract.

b) Please provide a Budget breakdown into major components by year for this project.

c) Please provide the actual 2011 and 2012 YTD CAPEX.

Response

a) As stated in Exhibit I, Schedule 13, Tab 10.03 CCC35, the total projected cost for head office improvements was $36.6M (not including landlord base building improvements) for major capital and $15.3M for MFA. A portion of the improvement project was tendered as a pilot project. There are five separate contracts with various service providers and the terms vary for each contract. The value of the contracts in total is $4.4M.

b) See Exhibit I, Schedule 13, Tab 10.03 CCC35.

c) 2011= $0.3M; 2012 June YTD=$1.5M.

Energy Probe (EP) Question #9 List 1

Question

Planned Disposition
Ref: Exhibit F2, Tab 1 Schedule 2, Pages 1-2

a) Please provide an estimate of the 2013 Deferral Account Balance in the same format as the Table on Page 1.

b) Will the actual 2014 Balance be cleared in 2014 and if so, when?

c) Please provide an estimate the impact of clearing the forecast 2012 balance over 2014 only on the revenue requirement increase for 203 and 2014.

d) Comment on the smoothing effect on rates.

Response

a) For clarification, we have assumed that the question intended to ask for 2013 information updated similar to the table in Exhibit F2, Tab1, Schedule 3, rather than Exhibit F2, Tab 1, schedule 2. Please find the table updated with 2013 information in Attachment 1.

b) If the ($30.3m) disposition is approved, as per Exhibit F2 Tab 1 Schedule 2, the principal and interest amounts requested will be recovered during the two year drawdown period and would complete in December 2014.

During the requested approved drawdown period of 2013 and 2014 interest improvement will be calculated on the principal balance outstanding at each-month-end, in line with OEB direction. Additional principal additions to regulatory accounts, where approval for continuation of use in 2013 and 2014 is being requested, are not forecastable at this time and are included in Attachment 1 to part a) of this question.

c) Analysis is based on 100% disposition of the requested regulatory account balance in 2014, rather than 50% in 2013 and 2014 as pre the rate filing application.

Year	Energy Probe Requested Scenario 2013	Prefiled Evidence 2013	Variance 2013	Energy Probe Requested Scenario 2014	Blue Page Prefiled Evidence 2014	Variance 2014
Rates Revenue Requirement ($M's)	1,413.6	1,398.5	15.1	1,478.1	1,493.2	-15.1
Rate Impact (%)	1.7%	0.6%	1.1%	6.9%	9.1%	-2.2%
Bill Impact (%)	0.1%	0.0%	0.1%	0.5%	0.7%	-0.2%

d) Based on the analysis in part c) of this question, there is a minor rate impact smoothing benefit for 2013 and 2014 under the scenario requested by Energy Probe.

Year Ending December 31, 2012

Account Description	Account Number	Opening Principal Amounts	Transactions During Year	Closing Principal Balance	Opening Interest Amounts	Interest	Closing Interest Balance	Total Principal plus Interest
Deferred Export Service Credit Revenue	2405	$0.7	$0.0	$0.7	($3.6)	$0.0	($3.6)	($2.9)
Excess Export Service Revenue	2405	($18.6)	$0.0	($18.6)	($0.2)	($0.3)	($0.5)	($19.0)
External Secondary Land Use Revenue	2405	($14.2)	$0.0	($14.2)	($0.3)	($0.2)	($0.5)	($14.6)
External Stations Maintenance and EC&S Reven	2405	($5.1)	$0.0	($5.1)	($0.1)	($0.1)	($0.2)	($5.2)
Tax Rate Changes	1592	($3.8)	$0.0	($3.8)	($0.5)	($0.1)	($0.5)	($4.3)
Rights Payments	2405	($1.7)	$0.0	($1.7)	($0.0)	($0.0)	($0.0)	($1.8)
Long Term Project Planning Costs	1508	$4.6	$0.0	$4.6	$0.1	$0.1	$0.2	$4.7
Pension Cost Differential	2405	$12.4	$0.0	$12.4	$0.2	$0.2	$0.4	$12.8
Total		($25.6)	$0.0	($25.6)	($4.3)	($0.4)	($4.7)	($30.3)

Year Ending December 31, 2013

Account Description	Account Number	Opening Principal Amounts	Transactions During Year [1]	Closing Principal Balance	Opening Interest Amounts	Interest	Closing Interest Balance	Total Principal plus Interest
Deferred Export Service Credit Revenue	2405	$0.7	($0.4)	$0.3	($3.6)	$0.0	($3.6)	($3.3)
Excess Export Service Deferred Revenue	2405	($18.6)	$11.0	($7.6)	($0.5)	($0.2)	($0.7)	($8.2)
External Secondary Land Use Revenue	2405	($14.2)	$8.4	($5.8)	($0.5)	($0.1)	($0.6)	($6.4)
External Stations and EC&S Revenue	2405	($5.1)	$3.0	($2.1)	($0.2)	($0.1)	($0.2)	($2.3)
Tax Rate Changes Account	1592	($3.8)	$2.2	($1.5)	($0.5)	($0.0)	($0.6)	($2.1)
Rights Payments	2405	($1.7)	$1.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.8)
IPSP & Other Long Term Project Planning Costs	1508	$4.6	($2.7)	$1.9	$0.2	$0.0	$0.2	$2.1
Pension Cost Differential	2405	$12.4	($7.3)	$5.1	$0.4	$0.1	$0.6	$5.6
Total		($25.6)	$15.2	($10.5)	($4.7)	($0.3)	($5.0)	($15.4)

1. As per direction from the OEB's Accounting Procedure Handbook (APH), the order of drawdown for approved components of regualtory assets and liabilities should begin with the principal being fully amortised, followed by any approved interest balances. This methodology is following in completing the 2013 schedule.