Alectra Utilities Corporation

OEB Staff Compendium

EB-2019-0018

October 18, 2019

OEB staff Compendium for EB-2019-0018 Oral Hearing

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TAB 1

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0018** **Alectra Utilities Corporation**

VOLUME: **Technical Conference**

DATE: **October 7, 2019**

--- Recess taken at 3:20 p.m.

--- On resuming at 3:40 p.m.

MR. RITCHIE: Okay, thank you. I have only got one further area of questioning, but it does sort of follow on on this. It's basically, again still looking at the response to G-Staff 9 and also, I guess in particular, the spreadsheets that were attached to G-Staff 8.

I am just wondering what sensitivity analysis you have done with respect to your M-factor proposal. And in this, I am specifically wanting to figure out the amount that is funded through rates, and the incremental M-factor CAPEX and how these would change due to changes in inflation.

Have you done any such analysis?

[Ms. Yeates and Ms. Butany confer.]

MS. BUTANY-DESOUZA: In computing the M-factor, the threshold CAPEX calculation does include an inflation adjustment.

That being said, there isn't any further sensitivity analysis or adjustment included.

MR. RITCHIE: Okay. And I guess referring back to page 12 of Exhibit 2, tab 1, schedule 3 --

MS. BUTANY-DESOUZA: We have it.

MR. RITCHIE: -- on that, you basically used the current 2019 input price index or IPI of 1.50 percent, less the productivity factor of zero and the default stretch factor of 0.3 percent, and this was shown in the table 3 on that page.

MS. BUTANY-DESOUZA: That's correct. We've used

Alectra's stretch factor and the latest available inflation information as released by the OEB last year for 2019 rates. It was the best information available at the time that we prepared the application.

MR. RITCHIE: Okay. And this is -- and your application proposes that you will update this with the price CAPEX index for 2020, with the IPI for 2020, when it is available from the OEB?

MS. BUTANY-DESOUZA: That is correct.

MR. RITCHIE: Okay.

MR. SHEPHERD: Let me just follow up on that. Table 3; do we have a live Excel spreadsheet version of that?

MS. BUTANY-DESOUZA: We've already filed it in response to G-Staff 8 by rate zone.

MR. SHEPHERD: Oh, okay. Sorry. That table 3 is filed as attached, or the individual calculations by rate zone have been filed?

I thought you filed the ICM model for each of the rate zones.

MS. BUTANY-DESOUZA: We did.

MR. SHEPHERD: But you didn't file this table?

MS. BUTANY-DESOUZA: Correct. We filed the model by rate zone in response to G-Staff 8. That particular table, table 3, we have not filed as a live spreadsheet.

MR. SHEPHERD: Is there any reason why you couldn't?

MS. BUTANY-DESOUZA: No.

MR. SHEPHERD: Thank you.

MR. MURRAY: Is that an undertaking?

MR. SHEPHERD: Yes.

MS. BUTANY-DESOUZA: Yes.

MR. MURRAY: That would be undertaking JT1.6.

UNDERTAKING NO. JT1.6: TO FILE A LIVE EXCEL VERSION OF IR RESPONSE G-STAFF-8, TABLE 3.

MS. BUTANY-DESOUZA: Just one second. Thank you, we have it.

MR. RITCHIE: Okay. Directionally, if the IPI is higher, then it would imply that there is more CAPEX that is funded through base rates and, hence, there would be less from the overall capital budget that would need incremental funding. Would you agree with that?

[Witness panel confers]

MR. BASILIO: Isn't the outcome of that, though, that if price inflation is higher, then our costs are higher. Maybe I am missing the question. Maybe I am missing the -- what you are trying to get at here?

MR. RITCHIE: But you forecasted your capital budget for all of the years out through 2024?

MR. BASILIO: Yes. Based on inflation, underlying inflationary assumptions, yes.

MR. RITCHIE: Okay. Are those the same as what the IPI is?

[Witness panel confers]

MR. BASILIO: I think we need to validate what the inflationary assumption was in capital. I can tell you generally, we're planning right now, I think, for about one and a half for non-wage inflation. But you know, that being said, that's the plan.

To the extent that IPI increases, you know, I think -- an IPI minus...

MS. BUTANY-DESOUZA: There is still the .3 stretch factor.

MR. BASILIO: IPI minus X is 1.2...

MS. BUTANY-DESOUZA: Right now it’s 1.2.

MR. BASILIO: We're generally planning one and a half, which is the way we usually plan. We plan for what we're predicting inflation to be, rate inflation is minus the X factor.

MR. RITCHIE: Okay, maybe I am going to ask for an undertaking here in terms of can you file in fact what are your economic assumptions for inflation that underlie the 2020-2024 capital budget and which underlies this M-factor proposal.

MS. BUTANY-DESOUZA: We can undertake to provide that.

MR. SHEPHERD: So that would be the inflation factor used in your various components of your DSP, right?

MS. BUTANY-DESOUZA: Yes.

MR. MURRAY: That will be undertaking JT1.7.

UNDERTAKING NO. JT1.7: TO FILE THE ECONOMIC ASSUMPTIONS FOR INFLATION THAT UNDERLIE THE 2020-2024 CAPITAL BUDGET AND THE M-FACTOR PROPOSAL.

MR. RITCHIE: Okay. And you know, I will be symmetrical about this, and basically if the IPI is lower, the CAPEX that is funded through base rates will be lower and hence, the incremental CAPEX that would need to be funded through the M-factor from your overall capital budget would be higher, all else being equal.

MS. BUTANY-DESOUZA: Yes, that's correct.

MR. RITCHIE: Okay. Now, again, you've used the current 1.5 percent, which is the IPI for 2019 and which is reasonable.

But I've observed -- because I've been doing this stuff for a while -- that from the period since 2nd generation EDR beginning in 2007 to about 2019, the IPI over the period, whether it was just the pure GDP PI up to 2013 and now the two-factor IPI that's been in place for 4th generation IRM, would average about 1.8 percent per annum. Would you accept that subject to check?

MS. BUTANY-DESOUZA: Mr. Ritchie, not meaning to discount the number of years that you've been doing this second-generation IRM forward, I can't accept that, subject to check. I can't accept that.

I know that there have been years when the price cap adjustment has been as low as .9 percent. And so, I mean, I have no way of validating that sitting here today. I mean, maybe you could prepare a spreadsheet and put it to me.

MR. RITCHIE: Okay. I guess we could -- we, I guess, can pursue this further during the hearing and, yeah, we may have something on that.

MS. BUTANY-DESOUZA: That's fine.

MR. RITCHIE: Okay. No, the only thing is that they're not --

TAB 2

Historical OEB-issued Input Price Indices (IPIs) for Inflation for Price Cap rate adjustments

	Year		GDP-IPI			2-Factor IPI	Index (Cumulative IPI Inflation since 2006)	
			1-Jan	1-May	Average	1-Jan		Source (includes hyperlink)
4th Generation IRM	2019	2019 EDR				1.50%	125.2	2019 EDR > Updates
	2018	2018 EDR				1.20%	123.3	2018 EDR > Updates
	2017	2017 EDR				1.90%	121.9	2017 EDR > Updates
	2016	2016 EDR				2.10%	119.6	2016 EDR > Updates
	2015	2015 EDR				1.60%	117.1	2015 EDR > Updates
	2014	2014 EDR				1.70%	115.3	EB-2010-0379, Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, p. 11 and Appendix C, November 21, 2013, corrected December 4, 2013
2nd and 3rd Generation IRM	2013	2013 EDR	2.20%	1.60%	1.90%		113.4	2013 EDR > Updates
	2012	2012 EDR	1.70%	2.00%	1.85%		111.2	2012 EDR > Updates
	2011	2011 EDR		1.30%	1.30%		109.2	2011 EDR > Updates
	2010	2010 EDR		1.30%	1.30%		107.8	2010 EDR > Updates
	2009	2009 EDR		2.30%	2.30%		106.4	2009 EDR > Updates
	2008	2008 EDR		2.10%	2.10%		104.0	2008 EDR > Updates
	2007	2007 EDR		1.90%	1.90%		101.9	2007 EDR > Updates
2006 EDR (COS)	2006		1.80%				100.0	

1.74%	**Compound Average Growth Rate of IPIs 2007 to 2019** **(i.e., average annual IPI inflation from 2006 to 2019)**

Notes:

1) For 2nd Generation and 3rd Generation IRM, inflation under Price Cap IR was measured solely by the Implicit Price Index for Gross Domestic Product (Final Domestic Demand) (GDP-IPI)

2) From 2009 to 2010, there was an overlap between 2nd Generation and 3rd Generation IRM, due to staggered CoS rebasing of distribution rates for electricity distributors.

3) For 2012 and 2013, IPIs were issued for both January 1 and May 1, depending on the applied-for Effective Date for rates. As a number of utilities applied under both tranches, the January 1 and May 1 IPIs have been averaged as an approximate annual IPI for that year.

4) 4th Generation IRM is for 2014 and going forward. One IPI is announced by the OEB for rates effective on January 1 or later in the calendar year. A 2-factor IPI, which is a weighted average of labour (30%, measured by the annual percentage change in Average Weekly Earnings - Ontario - All Businesses except Unclassified, including Overtime) and non-labour (70%, GDP-IPI)

5) The Index starts at 100 in 2006. Each year's index value is measured by inflating the previous year's index value by the current year's IPI. The index thus shows the cumulative, multiplicative impact of IPI adjustments since 2006.

6) The growth rate is the geometric mean or compound growth rate from 2006 to 2019, similar to a compound average growth rate reported for bank interest rates or for growth in mutual fund values.

TAB 3

ICM Materiality Threshold and M-Factor Capex Sensitivity Analysis

Updated for revised Guelph Rate Zone growth of -0.19%

ICM Threshold

	Brampton				**Enersource**				**Guelph**			
	g =	1.84%			g =	-0.06%			g =	-0.19%		
	IPI = 1.5%	IPI = 1.74%	delta	% change	IPI = 1.5%	IPI = 1.74%	delta	% change	IPI = 1.5%	IPI = 1.74%	delta	% change
2020	$ 30,748,905	$ 32,008,775	$ 1,259,870	4.02%	$ 39,055,549	$ 40,752,267	$ 1,696,719	4.25%	$ 8,490,092	$ 8,877,574	$ 387,482	4.46%
2021	$ 31,178,122	$ 32,513,916	$ 1,335,795	4.19%	$ 39,140,748	$ 40,878,807	$ 1,738,060	4.34%	$ 8,505,791	$ 8,901,836	$ 396,046	4.55%
2022	$ 31,620,498	$ 33,035,780	$ 1,415,282	4.38%	$ 39,226,919	$ 41,007,096	$ 1,780,176	4.44%	$ 8,521,647	$ 8,926,401	$ 404,753	4.64%
2023	$ 32,076,438	$ 33,574,920	$ 1,498,482	4.56%	$ 39,314,075	$ 41,137,157	$ 1,823,081	4.53%	$ 8,537,663	$ 8,951,270	$ 413,607	4.73%
2024	$ 32,546,358	$ 34,131,909	$ 1,585,551	4.76%	$ 39,402,226	$ 41,269,014	$ 1,866,788	4.63%	$ 8,553,839	$ 8,976,449	$ 422,610	4.82%

	Horizon				**PowerStream**			
	g =	3.04%			g =	2.31%		
	IPI = 1.5%	IPI = 1.74%	delta	% change	IPI = 1.5%	IPI = 1.74%	delta	% change
2020	$ 50,049,666	$ 51,423,933	$ 1,374,268	2.71%	$ 98,534,732	$ 101,593,143	$ 3,058,412	3.06%
2021	$ 51,067,703	$ 52,563,012	$ 1,495,309	2.89%	$ 99,985,468	$ 103,260,272	$ 3,274,804	3.22%
2022	$ 52,129,315	$ 53,753,662	$ 1,624,347	3.07%	$ 101,487,493	$ 104,990,433	$ 3,502,940	3.39%
2023	$ 53,236,365	$ 54,998,219	$ 1,761,854	3.26%	$ 103,042,620	$ 106,786,009	$ 3,743,389	3.57%
2024	$ 54,390,799	$ 56,299,123	$ 1,908,324	3.45%	$ 104,652,726	$ 108,649,474	$ 3,996,748	3.75%

	Alectra (in aggregate)			
	IPI = 1.5%	IPI = 1.74%	delta	% change
2020	$ 226,878,943	$ 234,655,693	$ 7,776,750	3.37%
2021	$ 229,877,832	$ 238,117,844	$ 8,240,012	3.52%
2022	$ 232,985,873	$ 241,713,371	$ 8,727,499	3.68%
2023	$ 236,207,161	$ 245,447,575	$ 9,240,414	3.84%
2024	$ 239,545,947	$ 249,325,968	$ 9,780,021	4.00%
	Total delta (2020-2024)		$ 43,764,696	
		Average Annual	$ 8,752,939	

M-Factor capex - Alectra (in aggregate)	
$ 264,962,171	As proposed, @ IPI = 1.5%
$ 221,197,475	@ IPI = 1.74%

Note: Calculations made from using IPI at 1.5%, as applied for, and using the average 2007-2019 IPI of 1.74%, in the Excel spreadsheets Attachments 1 through 6 of G-Staff-8. The calculations are done by rate zone (i.e., former LDC) to calculate the ICM materiality threshold by year and by rate zone. The delta is the difference in the materiality threhold at IPI = 1.5% and IPI = 1.74%. The % change is the delta relative to the average of the two values. Alectra numbers are calculated as the sums of the corresponding values in all rate zones. The M-factor capex of $264,962,171 is as proposed by Alectra, while **$221,197,475** is that number less the aggregate delta of **$43,764,696**, the additional capex funded through price cap-adjusted distribution rates at IPI = 1.74%.

TAB 4

ICM Materiality Threshold and M-Factor Capex Sensitivity Analysis (IPI = 2.15% per JT1.7)

Updated for revised Guelph Rate Zone growth of -0.19%

ICM Threshold

	Brampton				**Enersource**				**Guelph**			
	g =	1.84%			g =	-0.06%			g =	-0.19%		
	IPI = 1.5%	IPI = 2.15%	delta	% change	IPI = 1.5%	IPI = 2.15%	delta	% change	IPI = 1.5%	IPI = 2.15%	delta	% change
2020	$ 30,748,905	$ 34,212,881	$ 3,463,975	10.66%	$ 39,055,549	$ 43,759,261	$ 4,703,712	11.36%	$ 8,490,092	$ 9,552,053	$ 1,061,961	11.77%
2021	$ 31,178,122	$ 34,863,907	$ 3,685,785	11.16%	$ 39,140,748	$ 43,977,197	$ 4,836,449	11.64%	$ 8,505,791	$ 9,595,447	$ 1,089,656	12.04%
2022	$ 31,620,498	$ 35,539,203	$ 3,918,705	11.67%	$ 39,226,919	$ 44,199,038	$ 4,972,118	11.92%	$ 8,521,647	$ 9,639,557	$ 1,117,910	12.31%
2023	$ 32,076,438	$ 36,239,676	$ 4,163,238	12.19%	$ 39,314,075	$ 44,424,852	$ 5,110,777	12.21%	$ 8,537,663	$ 9,684,396	$ 1,146,734	12.59%
2024	$ 32,546,358	$ 36,966,262	$ 4,419,904	12.72%	$ 39,402,226	$ 44,654,713	$ 5,252,487	12.50%	$ 8,553,839	$ 9,729,976	$ 1,176,138	12.87%

	Horizon				**PowerStream**			
	g =	3.04%			g =	2.31%		
	IPI = 1.5%	IPI = 2.15%	delta	% change	IPI = 1.5%	IPI = 2.15%	delta	% change
2020	$ 50,049,666	$ 53,771,640	$ 3,721,975	7.17%	$ 98,534,732	$ 106,881,816	$ 8,347,084	8.13%
2021	$ 51,067,703	$ 55,133,222	$ 4,065,519	7.66%	$ 99,985,468	$ 108,956,043	$ 8,970,575	8.59%
2022	$ 52,129,315	$ 56,562,201	$ 4,432,887	8.16%	$ 101,487,493	$ 111,117,395	$ 9,629,901	9.06%
2023	$ 53,236,365	$ 58,061,915	$ 4,825,550	8.67%	$ 103,042,620	$ 113,369,530	$ 10,326,910	9.54%
2024	$ 54,390,799	$ 59,635,863	$ 5,245,064	9.20%	$ 104,652,726	$ 115,716,263	$ 11,063,537	10.04%

Note: Calculations made from using IPI at 1.5%, as applied for, and using Alectra's non-labour inflation of 2.15% per the 2020-2014 DSP, in the Excel spreadsheets Attachments 1 through 6 of G-Staff-8. The calculations are done by rate zone (i.e., former LDC) to calculate the ICM materiality threshold by year and by rate zone. The delta is the difference in the materiality threhold at IPI = 1.5% and IPI = 2.15%. The % change is the delta relative to the average of the two values. Alectra numbers are calculated as the sums of the corresponding values in all rate zones. The M-factor capex of $264,962,171 is as proposed by Alectra, while **$144,213,620** is that number less the aggregate delta of **$120,748,551**, the additional capex funded through price cap-adjusted distribution rates at IPI = 2.15%.

	Alectra (in aggregate)			
	IPI = 1.5%	IPI = 2.15%	delta	% change
2020	$ 226,878,943	$ 248,177,651	$ 21,298,707	8.97%
2021	$ 229,877,832	$ 252,525,815	$ 22,647,984	9.39%
2022	$ 232,985,873	$ 257,057,394	$ 24,071,522	9.82%
2023	$ 236,207,161	$ 261,780,369	$ 25,573,209	10.27%
2024	$ 239,545,947	$ 266,703,077	$ 27,157,130	10.73%
	Total delta (2020-2024)		$ 120,748,551	
		Average Annual	$ 24,149,710	

M-Factor capex - Alectra (in aggregate)	
$ 264,962,171	As proposed, @ IPI = 1.5%
$ 144,213,620	@ IPI =2.15%

TAB 5

JT1.7

Reference:

To file the economic assumptions for inflation that underlie the 2020-2024 capital budget and the M-factor proposal.

Response:

As provided in Section 5.4.1.3 Capital Investment Planning Process, Alectra Utilities applies the CopperLeaf C55 system to optimize the capital investment portfolio. If a project is shifted to an earlier or later implementation over the five year period of the DSP, CopperLeaf C55 adjusts the capital investment by an economic inflation factor of 2.15% per annum.

TAB 6

Table 1 - Last Rebasing Forecasted In-service Additions of Alectra Utilities' Predecessor LDCs Adjusted for Inflation ($,000)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Inflation - 0.3%[1]		1.40%	1.30%	1.80%	1.60%	0.90%	1.20%	1.40%	1.40%	1.40%	1.40%	1.40%
Horizon							51,272[2]	51,990	52,718	53,456	54,204	54,963
HOBNI			32,518[3]	33,103	33,633	33,936	34,343	34,824	35,311	35,806	36,307	36,815
PowerStream					114,494[4]	115,524	116,911	118,547	120,207	121,890	123,597	125,327
Enersource	46,258[5]	46,906	47,515	48,371	49,145	49,587	50,182	50,884	51,597	52,319	53,052	53,794
Guelph				11,363[6]	11,545	11,649	11,788	11,954	12,121	12,291	12,463	12,637
Total							264,496	268,199	271,954	275,761	279,622	283,537

2020-2024 Total: 1,379,072
Alectra 2020-2024 DSP Capital Forecast per Application[7]: 1,456,500
Difference: -77,428

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[1] For years 2014-2019, this table takes the OEB-approved inflation factors for each rate year and subtracts a placeholder stretch factor of 0.3% (middle cohort). For years 2020-2024, the inflation is taken as the average of the inflations factors for years 2014-2019 (1.7%) less 0.3% for the placeholder stretch factor.

[2] Taken from "Alectra_IRR_G-Staff-8_Attach 6 V5_2020_ACM_ICM_Model - HRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[3] Taken from "Alectra_IRR_G-Staff-8_Attach 3 V5_2020_ACM_ICM_Model - BRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[4] Taken from "Alectra_IRR_G-Staff-8_Attach 2 V5_2020_ACM_ICM_Model - PRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[5] Taken from "Alectra_IRR_G-Staff-8_Attach 4 V5_2020_ACM_ICM_Model - ERZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[6] Taken from "G-Staff-8_Attach 5 V5_2020_ACM_ICM_Model – GRZ – REVISED (Oral Hearing).XLSM," Tab "5. Rev_Requ_Check," Cell C12

[7] EB-2019-0018, Alectra Utilities Corporation 2020 EDR Application, Exhibit 2, Tab 1, Schedule 3, Page 13 of 21

Table 2 - Last Rebasing Forecasted In-service Additions of Alectra Utilities' Predecessor LDCs Adjusted for Inflation and Growth ($,000)

	Growth Factors[8]	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Inflation - 0.3%[9]			1.40%	1.30%	1.80%	1.60%	0.90%	1.20%	1.40%	1.40%	1.40%	1.40%	1.40%
Horizon	3.04%							51,272[10]	53,570	55,972	58,481	61,102	63,841
HOBNI	1.84%			32,518[11]	33,712	34,882	35,844	36,941	38,148	39,393	40,680	42,008	43,380
PowerStream	2.31%					114,494[12]	118,193	122,374	126,954	131,705	136,634	141,747	147,052
Enersource	-0.06%	46,258[13]	46,877	47,458	48,284	49,027	49,438	50,002	50,671	51,350	52,037	52,734	53,440
Guelph	-0.19%				11,363[14]	11,523	11,604	11,721	11,863	12,006	12,151	12,298	12,446
Total								272,311	281,206	290,426	299,983	309,890	320,160

2020-2024 Total: 1,501,665

Alectra 2020-2024 DSP Capital Forecast per Application[15]: 1,456,500

Difference: 45,165

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[8] The growth factors for each predecessor utility is taken from their respective ACM/ICM Models filed as part of the interrogatory response to G-Staff-8. See footnotes 11-15 for the model names.

[9] For years 2014-2019, this table takes the OEB-approved inflation factors for each rate year and subtracts a placeholder stretch factor of 0.3% (middle cohort). For years 2020-2024, the inflation is taken as the average of the inflations factors for years 2014-2019 (1.7%) less 0.3% for the placeholder stretch factor.

[10] Taken from "Alectra_IRR_G-Staff-8_Attach 6 V5_2020_ACM_ICM_Model - HRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[11] Taken from "Alectra_IRR_G-Staff-8_Attach 3 V5_2020_ACM_ICM_Model - BRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[12] Taken from "Alectra_IRR_G-Staff-8_Attach 2 V5_2020_ACM_ICM_Model - PRZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[13] Taken from "Alectra_IRR_G-Staff-8_Attach 4 V5_2020_ACM_ICM_Model - ERZ_20190913.XLSM," Tab "5. Rev_Requ_Check," Cell C12

[14] Taken from "G-Staff-8_Attach 5 V5_2020_ACM_ICM_Model – GRZ – REVISED (Oral Hearing).XLSM," Tab "5. Rev_Requ_Check," Cell C12

[15] EB-2019-0018, Alectra Utilities Corporation 2020 EDR Application, Exhibit 2, Tab 1, Schedule 3, Page 13 of 21

TAB 7

5.5 Incremental Capital Module

The applicants have requested an ICM for the proposed ten-year Price Cap IR deferred rebasing period as allowed for in the MAADs Handbook. The ICM is a regulatory tool that allows for recovery of the revenue requirement for qualifying material and incremental capital additions, beyond what is funded through approved rates. Recovery is provided for through rate riders, which allow base rates to continue to be adjusted through the approved PCI formula.

The ICM policy and mechanism was first developed for the 3rd Generation IRM for electricity distributors,[39] and then was revised through reviews in 2014 and 2015 (collectively referred to as the ICM Reports).[40]

The applicants proposed to comply with the OEB's ICM policy with one exception – they proposed to use current long term debt and the current OEB issued ROE for determining the revenue requirement of any approved qualifying ICM project, instead of the current approved debt and ROE rates from the last rebasing.[41]

Testing of the evidence through interrogatories and during the Technical Conference and the oral hearing indicated that there were other areas where the applicants' ICM proposal deviated from OEB policy, as discussed in the submissions of OEB staff and some intervenors.

The applicants' rate-setting proposal would allow the majority of the capital costs in excess of the ICM materiality threshold to qualify for ICM treatment during the deferred rebasing period.

OEB staff and certain intervenors submitted that this was a misreading of the OEB policy. The OEB ACM[42]/ICM policy per the ICM Reports define ICM/ACM projects as being discrete, incremental, necessary, material, and not part of typical annual capital programs. The ICM is not a guaranteed recovery for amounts above the materiality threshold. OEB staff and other intervenors submitted that the applicants' proposal was not consistent with the OEB's ICM policy as documented in the ICM Reports and as articulated in decisions.

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[39] EB-2007-0673.

[40] *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014 and *Report of the OEB: New Policy Options for the Funding of Capital Investments - Supplemental Report (EB-2014-0219)*, January 22, 2016.

[41] EB-2017-0307, Exhibit B/Tab 1/pp.15-16.

[42] Advanced Capital Module

While the applicants acknowledged these considerations at the Technical Conference,[43] they maintained that the majority of incremental capital additions will be afforded ICM treatment. This was particularly evident in the stand-alone versus amalgamated scenarios detailed in response to an interrogatory by FRPO,[44] and to subsequent analyses based on it, including Undertaking J4.2 (assuming a 0.3% stretch factor).

A review of FRPO interrogatory 11 showed that the applicants assumed that most of the forecasted capital expenditures exceeding the materiality threshold would be afforded ICM treatment. In the case of Enbridge Gas, all capital expenditures above the materiality threshold were assumed to qualify for ICM treatment in every year except 2019, where a small amount of about $19 million is excluded. For Union Gas, there were amounts in most years where ICM funding was not expected, but, still, most capital expenditures exceeding the materiality threshold were assumed to qualify for recovery through the ICM over the proposed term plan.

Several intervenors submitted that the applicants' proposed ICM treatment was similar to the capital pass-through mechanism that is currently in place for Union Gas, and that the applicants' proposal was too favourable to Amalco and its shareholders. Accordingly, SEC, LPMA, CCC and OGVG proposed that the ICM be denied and that the capital pass-through mechanism, which is used in Union Gas' current Price Cap plan and is familiar to the utility and stakeholders, be used during the deferred rebasing period. LPMA submitted that the capital pass-through mechanism has worked well in the current Union Gas IR plan and it appropriately leaves the risk of recovery of the actual revenue requirement with the utility.

BOMA noted that the applicants' proposal to use Union Gas' 2013 rate base numbers to calculate the ICM threshold for legacy Union customers creates an artificially low materiality criteria, and a larger ICM capacity.

OEB staff supported the use of the ICM, but submitted that it should be treated the same way as in the electricity sector, both for electricity distributors and as available to OPG under the recently approved hydroelectric generation price cap plan.[45] OEB staff, LPMA and some other parties opposed the applicants' proposal that the updated cost of capital be used for each ICM.

While supporting the capital pass-through, if the ICM was adopted, LPMA submitted that the 10% deadband for the materiality threshold calculation should be replaced by a

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[43] Technical Conference Transcript, Vol. 3 (April 2, 2018), p. 152/l. 5 to p. 159/l. 11.
[44] Exhibit C.FRPO.11.
[45] EB-2016-0152

40% deadband.[46] In their reply argument, the applicants opposed this on the basis that this proposal was not tested on the record.

Some intervenors also raised the concern that the applicants do not have detailed five-year capital plans analogous to the Distribution System Plans (DSPs) that electricity distributors are required to prepare and file. DSPs allow for identification of individual capital projects and provide background for a utility's planned level of capital expenditures on a short- to mid-term horizon allowing the OEB to understand what is "normal" and what is incremental capital spending. OEB staff and some intervenors argued that the applicants need Utility System Plans (USPs)[47] to support proposed ICM applications. At the oral hearing, the applicants stated that they plan to file separate USPs as part of their 2019 rate application and to file a single asset management plan as quickly as possible.[48]

OEB Findings

The OEB approves an ICM as discussed in this section. The OEB finds that it is appropriate to have a mechanism for the funding of incremental capital. Both Enbridge Gas and Union Gas had mechanisms for the funding of capital in their last rate frameworks; Enbridge Gas through is Custom IR forecast and Union Gas through its capital pass-through mechanism.

The OEB disagrees with the characterization of the ICM as a Y-Factor. Y-Factors have been defined as a mechanism for "passing through" certain costs. The ICM is a funding mechanism for significant, incremental and discrete capital projects for which a utility is granted rate recovery in advance of its next rebasing application. The ICM is not a capital pass-through mechanism.

The ICM policy for electricity distributors states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor". The OEB has not established a project specific materiality threshold for electricity distributors to define "significant influence", and this has been determined on a case-by-case basis for other proceedings.[49] For greater regulatory certainty, the OEB has determined that, for

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[46] LPMA submission (June 15, 2018), p. 32.

[47] A Utility System Plan for gas utilities is analogous to a Distribution System Plan for electricity distributors.

[48] Transcript, Vol. 1, (May 3, 2018) REDACTED, p.95/l. 11 to p. 96/l. 12.

[49] e.g., Decision and Order EB-2014-0116 (Toronto Hydro-Electric System Limited), December 29, 2015, section 3.4, and Decision and Order EB-2017-0024 (Alectra Utilities Corporation), April 5, 2018, section 4.5.

Amalco, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million. This will reduce the chance that any proposed ICM project will be found not to be significant to Amalco's operations.

The OEB approves the proposed formula for calculating the materiality threshold for the ICM, including the 10% deadband. This formula is the same one used for the ICM for electricity distributors.

The eligible incremental capital amount will be determined using the OEB's ICM formula and each gas utility's rate base and depreciation, i.e. calculated individually for both Union Gas and Enbridge Gas. This is consistent with the policy for electricity distributors.

The OEB agrees with intervenors who noted that, through Union Gas' capital pass-through mechanism, significant capital additions have been funded through rates during the past IRM term. The rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during the IRM term, shall be added to the 2013 OEB-approved rate base and depreciation in determining the eligible incremental capital amount for Union Gas' service territory.

For Enbridge Gas, the rate base and depreciation to be used in the formula shall be the 2018 OEB-approved amounts from the most recent Custom IR update decision. [50]

The OEB does not agree with the applicant's proposal to deviate from the ICM policy by using updated cost of capital parameters. The cost of capital parameters for the ICM funding will be the most recent OEB-approved for each of the Union Gas and Enbridge Gas legacy service areas.

Consistent with the ICM policy for electricity distributors, rate riders for any ICM would be determined as part of the rate proceeding in which the ICM is approved. The rate riders continue until the next rebasing application. In that rebasing application, the OEB will review the spending against plan to determine if any true-up is warranted.

The cost allocation for the ICM rate riders will generally be based on the most recent OEB-approved cost allocation. The OEB would consider an alternative cost allocation proposal filed with the ICM request if the nature of the capital project was such that cost causality was distinctly different from what underpins the OEB-approved cost allocation.

The applicants have indicated that they plan to file separate USPs as part of their 2019 rate application and to file a consolidated asset management plan as quickly as possible. The OEB finds it reasonable that a consolidated USP will not be available for

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[50] EB-2017-0086

2019 and 2020 rates, but expects the applicants to file separate USPs as planned. The OEB also expects that a consolidated USP will be filed for any ICM request for 2021 rates and beyond.

5.6 Y-Factors

Y factors are costs associated with specific items that are subject to deferral account treatment and passed through to customers without any price cap adjustment. The applicants propose to treat the following costs as Y factors:

1. Cost of gas and upstream transportation (in accordance with current QRAM treatment)
2. Demand Side Management (DSM) costs (in accordance with current DSM treatment)
3. Lost Revenue Adjustment Mechanism (LRAM; for the contract market)
4. Normalized Average Consumption/Average Use (the Applicants propose to continue to adjust rates annually to reflect the declining trend in use)
5. Cap-and-Trade (costs will be filed in future proceedings)
6. Capital investments that qualify for ICM treatment

The only submissions were on the applicants' proposal to true up Normalized Average Consumption (NAC) / Average Use (AU) on an annual basis to reflect the declining trend in average use. At the oral hearing, the applicants explained that the objective of the NAC and AU deferral accounts was not to reduce the weather risk. Since the load is weather normalized the deferral account essentially captures decline in average use not related to weather.[51]

OEB staff submitted that a structural break occurred in the average use models of Enbridge Gas in 2016 resulting in a significant difference between the actual normalized average use and the forecast average use.[52] OEB staff noted that the average use and load forecasting model had not been revised or reviewed since 2012 for both Enbridge Gas and Union Gas. However, OEB staff agreed with the continuation of the NAC/AU deferral accounts for now on the condition that Amalco be required to file a proposed

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[51] Transcript, Volume 5, pages 21-24, May 18, 2018.
[52] Staff submission, page 8 and response to Energy Probe IR#7, EB-2017-0102.

TAB 8

4.5 ICMs for the Brampton, Enersource and PowerStream Rate Zones

The OEB has determined that Alectra Utilities is eligible for incremental funding for certain capital projects in 2018 rates through ICM rate riders.

The OEB's policy for the funding of incremental capital is set out in the Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014 (Funding of Capital Report)[24] and the subsequent Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report (Supplemental Report) (collectively referred to as ICM policy). The OEB provided further policy direction for the availability of incremental capital modules following a merger in the Report of the Board Rate-Making Associated with Distributor Consolidation (MAADs policy)[25] and in the Handbook to Electricity Distributor and Transmitter Consolidations (MAADs Handbook).

The OEB first addresses the overall eligibility for ICM recovery and the criteria that must be met for this incremental funding. The OEB then assesses each project against that criteria.

a) Overall Eligibility for ICM Recovery

General Comments

The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan that are incremental to a materiality threshold.[26] The ICM is a funding mechanism for significant, incremental and discrete capital projects for which a utility is granted rate recovery in advance of its next rebasing application.

Alectra Utilities stated that its proposed ICM projects are in accordance with OEB policies as reflected in the Funding of Capital Report and the Supplemental Report.

PWU supported Alectra Utilities' ICM application and submitted that the OEB should approve the ICM project funding in full.

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[24] EB-2014-0219.

[25] EB-2014-0138.

[26] Funding of Capital Report, September 18, 2014, p. 4.

OEB staff submitted that only two of the proposed ICM projects met all established tests, as discussed later in this Decision. OEB staff submitted that the remaining projects fail at least one of the tests and should not be approved. BOMA also submitted that only two of the ICM investments should be approved.

SEC, CCC and AMPCO submitted that none of the proposed incremental capital amounts should be approved. SEC, CCC and AMPCO also all argued the merger savings are a relevant consideration and provide context for ICM applications. SEC argued that this case should cause the OEB to rethink its policies and whether they are appropriately customer-focused.

Alectra Utilities submitted that OEB staff, BOMA, SEC, CCC, AMPCO and VECC all took issue with the application of the OEB's ICM policy, but the OEB has already determined on multiple occasions that the ICM is available to consolidating distributors.

In the ICM policy, the OEB established three tests for eligibility for the ICM: Materiality, Need and Prudence. These three tests are discussed in the sections that follow.

Materiality

There are two materiality tests related to ICM applications. The first test is the ICM materiality threshold formula, which serves to demonstrate the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor".[27]

Alectra Utilities stated that it had appropriately calculated the following materiality thresholds for the three rate zones which results in the following:

- Brampton RZ has a maximum eligible incremental capital amount of $7,113,613, which means that its proposal to recover $6,800,377 through the ICM for this rate zone is within the OEB's acceptable range.
- PowerStream RZ has a maximum eligible incremental capital amount of $25,891,795, which means that its proposal to recover $25,136,316 through the ICM for this rate zone is within the OEB's acceptable range.

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[27] Funding of Capital Report, p. 17.

- Enersource RZ has a maximum eligible incremental capital amount of $39,624,419, which means that its proposal to recover $24,247,022 through the ICM for this rate zone is within the OEB's acceptable range.

No party took issue with Alectra Utilities' calculation of the ICM materiality threshold for each rate zone.

The OEB adopted a second, project-specific materiality test in the Funding of Capital Report, as identified in a decision for Toronto Hydro Electric System Limited (Toronto Hydro).[28] The project-specific materiality test is as follows:

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[29]

Alectra Utilities submitted that each capital project was eligible for an ICM as each project exceeded the project-specific materiality level established for each rate zone.

OEB staff submitted that a project proposed for ICM treatment must not only meet the OEB-defined materiality thresholds, but must also clearly have a significant influence on the distributor. OEB staff argued that a proposed project does not qualify simply by characterizing it as a separate project that meets the materiality thresholds; the ICM was not intended to be a "capital budget top-up".

BOMA submitted that not every capital investment proposal that exceeds the "project materiality" threshold can be said to have a significant influence on a utility. BOMA argued that Alectra Utilities is the appropriate utility in respect of which the degree of impact should be addressed. BOMA acknowledged that the OEB has authorized the maintenance of separate "rate zones" for ratemaking purposes but Alectra Utilities is the actual corporate entity.

SEC argued that it was important for the OEB to send a clear message that ICM funding is not a back door way to increase rates, but is an exception to the normal rule of living within the IRM envelope and is not an invitation to spend more. SEC submitted that ICM funding is a relief valve where utilities have done everything they can to live within their

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[28] Toronto Hydro-Electric System Limited, "Partial Decision and Order," EB-2012-0064, April 2, 2013.
[29] Funding of Capital Report, p.17.

means, but that Alectra Utilities had made no attempt to do so, and therefore should be expected to live within the IRM envelope.

Alectra Utilities submitted that the project-specific materiality threshold is defined by the OEB as 0.5% of distribution revenue requirement, in accordance with the Chapter 2 Filing Requirements.[30] Alectra Utilities calculated the threshold amount for each rate zone on this basis and included projects that exceeded the identified thresholds.

Findings

The OEB accepts Alectra Utilities' calculations for the ICM materiality threshold based on the OEB's ICM formula in the Funding of Capital Report. This includes:

- Brampton RZ - maximum eligible incremental capital amount of $7,113,613
- PowerStream RZ - maximum eligible incremental capital amount of $25,891,795
- Enersource RZ - maximum eligible incremental capital amount of $39,624,419

This does not mean that all capital spending up to the maximum eligible incremental capital amount will be granted incremental funding. The OEB has established its other criteria and tests so that the ICM does not become just a top-up to the ICM materiality threshold.

The OEB does not agree with SEC that a distributor must have done everything it can to live within its means. The ICM is not a mechanism to ensure the financial viability of a distributor. The ICM is a mechanism that removes a barrier to effective planning by providing rate relief to reduce the incentive to cluster capital investments at sub-optimal times around the rebasing year. A distributor is expected to have good distribution system planning, including optimizing, prioritizing and pacing capital expenditures to control costs and promote rate predictability, irrespective of its rebasing schedule.

The OEB disagrees with Alectra Utilities' interpretation of the second materiality test. The distributor in this ICM application is Alectra Utilities. This second test is whether a specific project is significant in comparison to the overall capital budget for Alectra Utilities, not individual rate zones. With Alectra Utilities' interpretation, a large distributor with a capital budget of hundreds of millions of dollars could acquire a small distributor

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[30] Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 2 Cost of Service.

and seek ICM funding for a project of only $50,000. This would not be a reasonable request.

The OEB notes that the MAADs policy states that: "the materiality thresholds for purposes of the ICM policy shall be calculated based on the individual distributor's accounts, i.e. depreciation expense, and not the consolidated entity's".[31] The OEB finds that this statement is not relevant to the assessment of project-specific materiality. The reference to depreciation expense in the MAADs policy makes it clear that this policy statement pertains to the ICM materiality threshold formula that is calculated based on depreciation, not the project-specific materiality test that is based on a comparison of an expenditure to the overall capital budget.

Applying the Chapter 2 Filing Requirements materiality threshold test to Alectra Utilities as the distributor would result in a project-specific materiality threshold of $1 million to be applied across all rate zones. However, the OEB finds that the Chapter 2 Filing Requirements materiality threshold test is not the project-specific test set out in the ICM policy. The materiality thresholds in the Chapter 2 Filing Requirements[32] are for the purpose of variance explanations for annual changes to rate base, capital expenditures and operations, maintenance and administration costs as part of a cost of service rate application. Consistent with this purpose, the materiality threshold for the variance analysis is calculated from the revenue requirement. The project-specific materiality, per the ICM policy, is based on the capital budget.

The OEB recognizes that in an Enersource decision,[33] the OEB accepted the project-specific materiality calculated by Enersource based on 0.5% of revenue requirement. This was a project specific calculation of $0.59 million for an ICM approved of $40.5 million. There was no question that this project was not a minor expenditure in comparison to the overall capital budget i.e. the project specific calculation was not required to make the determination that this project was significant. The OEB does not find that the Enersource decision established a new condition precedent for future ICMs.

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[31] "Report of the Board Rate-Making Associated with Distributor Consolidation," EB-2014-0138, March 26, 2015, p. 10.
[32] Section 2.0.8.
[33] Decision and Rate Order "Enersource Hydro Mississauga Inc. Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2016", EB-2015-0065, April 7, 2016.

In the Funding of Capital Report, the OEB adopted the approach for the ICM policy established in the Toronto Hydro decision which stated that: "minor expenditures in comparison to the overall budget" should not be considered eligible for ICM treatment.[34] The Toronto Hydro decision emphasized that the overall capital budget is the reference point for assessing the significance of ICM requests. The OEB determined that a: "certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget", and this wording was included in the materiality criteria for an ICM. This decision disallowed ICM funding for several projects with capital spending in excess of $1 million, including a project with $2.14 million in capital expenditures and $1.68 million in capital additions. The decision stated that while the OEB accepted the need for the work: "the amount requested is not significant in the context of THESL's overall capital budget. THESL should be able to fund this project through its normal capital budget during the IRM period, and will not be permitted additional recovery for this project".[35]

The OEB finds that the basis for a project-specific materiality threshold should be the proposed capital budget of Alectra Utilities, the distributor in this ICM application. Adding the 2018 capital budgets for each rate zone results in a combined capital budget of $267.7 million.[36] While one could consider a percentage of the $267.7 million to be appropriate for the project-specific materiality test, the OEB finds that this is not consistent with the ICM policy. The ICM policy adopted the approach used in the Toronto Hydro decision, which assessed each project individually for its significance against the capital spending. The OEB therefore adopts this same approach for the ICMs for Alectra Utilities. Amending the ICM policy to include a mathematical materiality calculation for this second test should only be done through a policy review. In addition, there were no submissions on this issue during the proceeding. The OEB has applied its judgement consistent with the ICM policy. The OEB will consider whether each capital project proposed for an ICM is significant with respect to Alectra Utilities' total capital budget, not with respect to the capital budget by rate zone.

While the second materiality test may be further defined in the future, the OEB must make a decision based on the evidence and submissions in this proceeding. The OEB

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[34] Funding of Capital Report, p.17.

[35] EB-2012-0064 Toronto Hydro Decision, several projects were not approved for funding for being not significant in the context of the overall capital budget (pages 31, 32, 39, 41, 42), one example is the Downtown Station Load Transfers, pages 41 and 42 with capital spending of $2.14 million and capital additions of $1.68 million.

[36] $267.668 million = $72,683 (Enersource) + $109,773 (PowerStream) + $38,069 (Brampton) + $47,143 (Horizon Utilities EB-2014-0002 Settlement Table 18 – 2018 Capital Expenditure Plan).

is guided by the words “significant influence on the operation of the distributor” and “minor expenditure in comparison to the overall capital budget” in assessing the project-specific materiality of each project.

The assessment of each specific project is in subsequent sections of this Decision.

Need

The Funding of Capital Report indicated that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, and should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[37]

Under the Means Test, if a distributor’s regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor’s rates, then the funding for any incremental capital project would not be allowed. Alectra Utilities submitted that based on the accounts of its predecessor utilities, it had satisfied the Means Test in each rate zone.

No party took issue with Alectra Utilities passing the Means Test.

Alectra Utilities submitted that each proposed ICM project is discrete and that it had performed detailed, project-specific cost estimates based on a specific scope of work and detailed design carried out for a particular location.

Furthermore, Alectra Utilities stated that the costs of the projects for which it is seeking recovery are incremental to its capital requirements that underpin its existing rates for each rate zone.

The distinction between a discrete project versus a program was raised in many submissions. AMPCO stated that it did not accept Alectra Utilities’ distinction between a project and a program as all of the restructured initiatives have historically been part of typical annual capital programs and should not be approved. In particular, AMPCO noted that in the PowerStream RZ, 30% of the projects were disallowed by the OEB in its Custom IR decision.

CCC argued that with very few exceptions (transit projects), the proposed expenditures are essentially a continuation of normal annual capital programs, not discrete

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[37] Funding of Capital Report, page 17.

incremental capital projects, and Alectra Utilities should have sufficient funds to undertake all of its required capital investments through its price cap adjustments.

Findings

The OEB finds that Alectra Utilities has passed the Means Test. Alectra Utilities provided evidence with respect to the earnings by rate zone. The OEB finds this is acceptable for assessing the earnings the year prior to merger, i.e. 2016. This test is, however, established to determine if a distributor requires funding in advance of the next rebasing. Earnings are therefore more appropriately assessed for the distributor, not the rate zone.

In addition, the OEB finds that a discrete project is not simply one that is distinguishable or defined at a new location - or all capital would be eligible. ICM projects do need to be different in kind from those that are carried out through typical base capital programs. Otherwise, the OEB would need to scrutinize all capital projects for optimization, not just the ICM projects. Further, the criteria in the ICM policy is clear that capital projects do not need to be non-discretionary[38] or unanticipated to be eligible for incremental funding.

The OEB finds that it is not relevant whether the capital project proposed for ICM treatment was included in a previously filed DSP. Requiring a project to have been included in a previous DSP would be re-introducing the requirement for projects to be unanticipated, which the OEB previously eliminated. In addition, there is no criteria excluding capital projects that were denied funding in a previous cost of service or ICM application. Circumstances may change with respect to load, demand, cost estimates or consumer preferences that affect the business case and the needed timing of the project.

Prudence

The Funding of Capital Report specifies that the amounts to be incurred must be prudent, which means that a distributor’s decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[39]

Alectra Utilities submitted that its eligible capital projects are prudent because in the case of the Brampton RZ, the project is non-discretionary in nature, while for the

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[38] Funding of Capital Report, pp.18-19.
[39] Ibid, p. 17.

PowerStream and Enersource RZs, the projects represent the most cost effective options for ratepayers.

Alectra Utilities added that in each case, the projects are based on capital investment needs for the three rate zones for 2018 that are not funded through existing distribution rates.

Alectra Utilities submitted that to demonstrate the prudence of each capital project for which it is seeking approval, it had provided a business case summary that identifies the name, driver, cost and expected in-service date for the project, describes the project and its drivers, and sets out the various options considered for the project. In addition, Alectra Utilities stated that it had provided detailed business cases for each eligible capital project.

OEB staff argued that most of the ICM projects were not distinguishable from other expenditures that were part of normal year-to year capital programs for the rate zones.

Intervenors argued that it is not possible to determine prudence in the absence of cost information on alternative options. Alectra Utilities identified that it did provide cost estimates for alternative options for the majority of projects. Cost estimates were not provided for alternative options when the alternative options would not provide the required capabilities or meet applicable technical standards. Alectra Utilities also argued that conservation and demand management (CDM) is not an alternative for system renewal investments.

AMPCO, VECC and CCC submitted that the OEB should not approve the 2018 ICMs until Alectra Utilities has prepared a consolidated DSP. These intervenors submitted that one combined DSP would optimize need and spending across all rate zones to provide the greatest value to customers, for a merged entity with four rate zones.

AMPCO also noted that the PowerStream RZ’s 2018 proposed capital budget is below the 2017 OEB approved budget, meaning that it should be able to accommodate the 2018 capital spend within the 2018 Price Cap IR adjustment.

VECC argued that for the PowerStream RZ, Alectra Utilities had not met the burden of proof as to the need for these projects, other than a rapid transit project, because it had not explained how these projects were (or were not) contemplated in its DSP.

Alectra Utilities argued that the OEB was well aware that Alectra Utilities would not be in a position to file a consolidated DSP until 2019. Alectra Utilities concluded that it is simply wrong to say that a consolidated DSP is required before it is eligible for ICM funding.

Findings

The availability of an ICM to Alectra Utilities was neither predicated on filing a consolidated DSP, nor limited to one ICM application for the deferred rebasing period.

While a consolidated DSP is not a prerequisite to filing an ICM, the OEB acknowledges the concerns expressed by intervenors and OEB staff that the value of the current DSPs for Alectra Utilities will diminish long before the 10-year deferral period has ended. The OEB accepts these limitations for 2018, and 2019 rates if required. It would not have been reasonable to expect a new fully integrated and consolidated DSP for this proceeding. The OEB finds that the prior DSPs are sufficient for the OEB to review and decide on capital projects for this proceeding.

The MAADs decision noted that Alectra Utilities would not be in a position to file a consolidated DSP until 2019, applicable to 2020 rates. The OEB finds this proposal reasonable. The OEB requires Alectra Utilities to file a consolidated DSP as a filing requirement with any ICM application requesting rate changes for 2020 rates and beyond.

Providing an assessment of options to meet an identified need is an important element of an application for funding of capital, whether it be in a rebasing application or for an ICM. The OEB accepts that costing and detailed analysis of an option is not required if an option does not meet the required capabilities or applicable technical standards. The OEB does not accept Alectra Utilities' assertion that CDM is not an alternative for system renewal investments options. Like-for-like asset replacements for aging infrastructure should not be the only option considered. Circumstances may have materially changed since an asset was first put into service. As a result, new options, including those that do not involve distribution infrastructure, should be considered when Alectra Utilities prepares its consolidated DSP.

The OEB recognizes that because the ICM materiality threshold formula is based on the ratio between a utility's approved rate base and depreciation, it can lead to circumstances in which there is eligible ICM capital even though the capital spending in the year of the ICM is lower than the last OEB-approved capital spending. While this does not disallow an ICM outright, this is a consideration when determining whether a project is significant to operations, and outside of the base upon which the rates were derived.

TAB 9

and so that's the distinction with respect to M-factor versus ICM.

But the calculation, as laid out in the pre-filed evidence, and a table in that evidence provides the many similarities to ICM, save and except for the two items that I have identified.

MR. SHEPHERD: So I went down your list of ICM projects, and it has things like bucket trucks and stuff like that, and none of that stuff qualifies for ICM, right?

MR. BASILIO: I think it would be our position that, yes, it does. It is normal and expected capital.

The scope of ICM under the MAADs policy is normal and expected capital. This was a point we made on presentation day that we felt that the exclusion of projects on the basis -- and I know I am paraphrasing here -- that it's typical annual capital is inappropriate, because the MAADs policy document very clearly says that it's normal and expected capital. It's capital we would invest in the normal course.

MR. SHEPHERD: So the typical annual capital programs quote originated in a Toronto Hydro decision, right?

MR. BASILIO: It did. And maybe, Mr. Shepherd, just to cut to the chase, the MAADs policy document is a document that is subsequent to that decision, is it not?

MS. BUTANY-DESOUZA: It is. And subsequent to the ACM policy as well.

MR. SHEPHERD: So you're saying the ICM for MAADs purposes is different from the ICM for everybody else; is that right?

MS. BUTANY-DESOUZA: Yes.

MR. BASILIO: Very explicitly in that document. I can take you to the page reference --

MR. SHEPHERD: So --

MR. BASILIO: -- if you like. In fact, that is policy, OEB policy --

MR. SHEPHERD: So --

MR. BASILIO: -- normal and expected capital.

MR. SHEPHERD: So for the Board to approve your M-factor it has to agree with you that it has two different ICM policies, one for MAADs and one for non-MAADs. Is that right?

MS. BUTANY-DESOUZA: I guess it would have to agree with us and with its policy statements twice, separated in time by nine months.

At page 9 of EB-2014-0138, page 9, under the bold type heading, OEB policy, it says that:

> "A distributor may now apply, and of course that is the ratemaking associated with distributor consolidation, so the updated -- let's call it the updated or 2015 MAADs policy for reference purposes -- that a distributor may now apply for an ICM that includes normal and expected capital investments. This clarification of policy -- my emphasis -- should address the need of those distributors who may not consider entering into a MAADs transaction due to concerns over the

TAB 10

ONTARIO
ENERGY
BOARD

FILE NO.:	**EB-2019-0018**	**Alectra Utilities Corporation**

VOLUME:	**1**	
DATE:	**October 15, 2019**	
BEFORE:	**Emad Elsayed**	**Presiding Member**
	Lynne Anderson	**Member**
	Michael Janigan	**Member**

M-factor list, and they are tied to the specific rate zones. And we have imposed a capital investment variance account in order to true-up against the capital that's invested over that five-year period.

So notwithstanding that ACM is not available to us, in fact what we are seeking is far more restrictive on a project basis.

MR. LADANYI: Thank you for that answer. I won't argue it.

Now in part -- if you go back to page 15, which is your response to Energy Probe number 3, we asked you in part C:

> "In support of Alectra's position set out in Exhibit 2, tab 1, schedule 3, page 6, please provide the relevant extracts of the Board's guidelines and filing requirements and precedent decisions."

And as I explained to you during the technical conference, relevant extracts would be a relevant passage from a text.

In the response to this, you filed 440 pages of material, which is a lot. And I actually gave you, as you will recall, an opportunity to withdraw it and answer and file relevant extracts only, but you declined.

So we are going to go through some of these extracts -- I had to go through them, of course -- and ask you some questions about them.

So if we can now go to page 21, please. It says in the second paragraph, inside the table, it says:

> "Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment."

Are you saying that you don't agree with this? Or do you agree with this?

MS. BUTANY-DESOUZA: So you are providing me with the extract from --

MR. LADANYI: Your answer.

MS. BUTANY-DESOUZA: Yes, I understand that. Actually, let me start by saying -- and I think it is important that I offer the following, Mr. Ladanyi-- that I didn't just provide 400 pages to be difficult, or my intention -- sorry, my intention was not to be difficult.

The thing is that these Board policy instruments, they can't be read as an extract of a paragraph here or a paragraph there. In many instances, you need to read them from beginning to end in order to have a full appreciation for the policy that is set out in that document.

Then you need to read the subsequent document, and read it in its entirety.

So in offering those elements or these several attachments, in fact it was to be helpful, though I can understand that greater specificity may be helpful and I am happy to do that with you now.

Regarding the paragraph in question, "minor expenditures in comparison to the overall capital budget", we don't disagree with that. However, this is in the context of an ICM application and, as we've set out in our evidence, the aggregation -- as we set out on presentation day, which is part of our evidence of course, and then in the list of projects that we've put forward in the M-factor listing, the 194, as you can see, they very quickly add up and they are impactful in comparison to Alectra's overall capital budget.

And the continuous denial of that funding has an impact, and culminates in the snowplow that Mr. Wasik has described to you last week.

MR. LADANYI: It is in numerous places in your evidence so -- we know about snowplow. I have to correct you. Page 24 and also - which is on page 21 of my compendium is really from the Board's filing requirements issued just over a year ago. So it is not some stale old decision, it is actually quite recent.

MS. BUTANY-DESOUZA: I don't disagree with that, but it is in the context of ICM.

MR. LADANYI: So that part of ICM doesn't apply to you. You're saying you like some parts of ICM, but you don't like that part. And this is in materiality, which is a section where the Board describes what is material.

MS. BUTANY-DESOUZA: Mr. Ladanyi, we have specifically said that we haven't gone to a project level of materiality threshold.

And it's not about liking or disliking, so I would like to be clear on that. This isn't about likes and dislikes. This is about capital funding requirement -- our

TAB 11

ONTARIO ENERGY BOARD

Ontario

EB-2014-0138

Report of the Board

Rate-Making Associated with Distributor Consolidation

March 26, 2015

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A. INTRODUCTION

The Ontario Energy Board's renewed regulatory framework is a comprehensive performance based approach to regulation. The framework sets expectations that electricity distributors will seek out efficiencies to increase productivity and manage costs. The OEB issued a letter on February 11, 2013, announcing an initiative to assess how the OEB's regulatory requirements for electricity distributors may affect the ability of distributors to realize operational or organizational efficiencies (EB-2012-0397).

Consultations with stakeholders took place in early 2013 to review potential changes to the OEB's regulatory requirements that may facilitate efficiency improvements. On November 4, 2013, the OEB issued a letter, announcing that it would proceed with a further review of its policies related to service area amendments ("SAA") and rate-making associated with merger, amalgamation, acquisition and divestiture ("MAADs") transactions.

The report of the Ontario Distribution Sector Review Panel, issued in December 2012, set out a vision for consolidation resulting in the less costly and more efficient delivery of electricity, with a predicted cost savings of $1.2 billion over the next ten years. When the Minister of Energy responded to the Panel's report, he indicated that he expected that the sector would find ways to achieve those savings through more efficient service delivery, including negotiated consolidations. This view was carried forward in the government's December 2013 Long Term Energy Plan ("LTEP"), where it is stated that the government expects electricity distributors to pursue innovative partnerships and transformative initiatives that will result in savings for electricity ratepayers.

On March 31, 2014, the OEB issued a OEB staff Discussion Paper (the "Discussion Paper") providing background on the current policies, summarizing stakeholder input received in relation to those policies, and setting out questions for stakeholder comment with respect to potential changes to those policies.

On November 13, 2014, the Advisory Council on Government Assets issued its findings which included the view that consolidation was needed to encourage modernization of the electricity distribution system.

After considering the government's policy expectations, the results of the consultations, and the OEB's own expectations that the distribution sector should continue to seek out efficiencies especially through consolidation, **the OEB has concluded that it will proceed at this time with amendments to its rate-making policy associated with electricity distributor consolidation.**

This Report sets out the OEB's amendments to its rate-making policy for electricity distributors following a MAADs transaction.

The OEB has identified two specific policy matters that it intends to address at this time:

- The duration of the deferral period for rebasing following the closing of a MAADs transaction; and,

- A mechanism for adjusting rates to reflect incremental capital investments during the deferred rebasing period.

The amendments to the OEB's policy in relation to each of these matters are discussed below. The OEB has also provided clarification regarding the incentive rate mechanism that will apply to a distributor during a rebasing deferral period.

B. DEFERRAL PERIOD FOR RATE REBASING

Consolidating distributor(s) may elect to defer rebasing for a period of up to 10 years after the closing of the transaction.

Consolidating entities that elect a re-basing period of up to five years after the closing of the transaction may do so as set out under the current policy[1].

Consolidating entities may also apply for an extended rate rebasing deferral period of up to 10 years. For the extended period (i.e. – the period between year 5 and year 10), the OEB will require the consolidating entity to implement an earnings sharing mechanism. The earnings sharing split shall be a 50:50 sharing with customers where the return on equity for the consolidated distributor is greater than 300 basis points above the allowed rate of return for the consolidated distributor.

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[1] *Report of the Board regarding Rate-Making Policies Associated with Distributor Consolidation*, issued July 23, 2007.

The OEB's current policy with regards to rate issues associated with MAADs transactions was developed in 2007, and is found in its *Report of the Board regarding Rate-making Policies Associated with Distributor Consolidation* (the "2007 Policy").

Under the 2007 Policy, when a distributor applies for approval of a MAADs transaction it may propose to defer rebasing of the rates of the consolidated entity for up to five years from the date of the closing of the transaction. The purpose of this policy is to allow the net savings of a consolidation to accrue to a distributor's shareholder(s) for an extended period. The OEB recognized that providing a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction is an important factor in a utility's consideration of the merits of a given consolidation initiative. The five-year period was selected based on a review of practice in other jurisdictions, and taking into consideration the fact that the maximum duration of any rate plan for distributors at the time was three years.

The principal focus of distributor comments received both through the 2013 consultation and the responses to the Discussion paper, was concern regarding the length of time over which rebasing of a consolidated entity's rates can be deferred.
It is the view of distributors that the current policy may not provide sufficient time to achieve the savings and efficiency gains necessary to enable the recovery of transaction costs. Distributors expressed the view that the risk for shareholders of not recovering transaction costs is a significant impediment to consolidation.

Distributors explained that the transition and integration costs of a MAADs transaction, although largely incurred upfront can continue for two to four years following the completion of the transaction. Whereas efficiency gains and savings resulting from the transaction will not start to be realized until the transaction is completed and the new entity has begun to operate. Distributors indicated that given the nature and timing of these costs and savings, annual net benefits (operational costs less transition and integration costs) are in many cases negative during the first two to four years. Therefore, it may take anywhere from six to ten years to reach a break-even point, where the cumulative savings exceed the cumulative acquisition and integration costs.

Distributors therefore suggested that greater flexibility in terms of the rebasing time frame and the ability to retain any achieved savings for a longer deferral period will provide encouragement to those who may be interested in pursuing consolidation opportunities.

Representatives of consumers expressed the view that savings that result from a MAADs transaction should be shared equitably between the distributor’s ratepayers and the distributors’ shareholders. There are concerns that extending the deferral period will provide an opportunity for shareholders to retain more savings than those necessary to recover costs, which may result in a windfall for shareholders at the expanse of ratepayers. Ratepayer representatives suggested that for the rebasing to be deferred, other benefits for consumers would need to be provided, either in the form of new services or, of a certainty of savings that would continue after the rebasing.

Consumer representatives also suggested that allowing a distributor to choose its own time for rebasing may not benefit consumers. A distributor that is able to cut costs could delay rebasing to keep its savings, but a distributor who experiences higher costs would rebase immediately in order to pass those incremental costs on to ratepayers. Such an approach would relieve the shareholders of risk at the expense of the ratepayers. There were also concerns expressed that allowing shareholders to recover additional savings may reduce the market forces that lead to efficient consolidations.

OEB Policy

The OEB believes that the decision to extend the deferred rebasing period for distributors who are party to a MAADs transaction supports the OEB’s own expectations, as well as those of the government, that the distribution sector should continue to seek out efficiencies, especially through consolidation.

The OEB has determined that providing an extension of the allowed deferral period to up to 10 years after the closing of the transaction, would address distributors’ key concern about the 2007 policy; would reduce the risk of a MAADs transaction, which may encourage more consolidation; and would provide distributors with the flexibility to manage their own, unique circumstances.

The OEB believes that the requirement for the MAAD’s application to include an earnings sharing mechanism (ESM) will address ratepayer concerns that the accumulated savings could amount to a windfall for shareholders.

The ESM would operate during the term of the extended deferred rebasing period. (i.e. – for any extended periods beyond the initial five year deferral period). The ESM would be in keeping with the OEB’s current incentive rate-making policy under which a regulatory review may be initiated if a distributor’s annual reports show performance outside of the +/- 300 basis points earnings dead band. In the case of a MAADs transaction, if the consolidated entity’s actual ROE rose above the 300 basis points over the allowed ROE, the ESM will be implemented. The ESM for the purpose of the extended period will employ a 50:50 sharing with customers of excess earnings. This sharing provides for the shareholders to continue to recover transaction costs while ensuring customers of the consolidated entity will benefit from the efficiencies and savings the new distributor has achieved.

During the deferred re-basing period, whether up to five years or beyond five years, once the original incentive rate-making period of one of the distributors who are party to the transaction expires, the consolidated entities may apply to the OEB for cost-of-service rate setting for the consolidated entity. The OEB believes that it is in the best interest of consumers to have consolidating entities operate as one entity as soon as possible after the MAADs transaction. The consolidated entity application will allow the OEB to establish rates that reflect the efficiencies from the consolidation transaction. Therefore, there is no requirement for the consolidated entity to wait until the deferred re-basing period is completed to apply to the OEB for re-basing.

The OEB also notes that despite the ability for consolidated entities to extend the rate re-basing period, all other regulatory requirements, including the requirement to file Distribution System Plans every five years remain in effect.

The OEB will continue to make use of its monitoring tools, available through distributor’s annual reporting requirements, to determine whether the results of MAADs transactions for consumers and the industry warrant additional consumer protection measures. If so, future changes to the policy may be considered.

C. INCREMENTAL CAPITAL INVESTMENTS DURING THE DEFERRAL PERIOD

The Incremental Capital Module (“ICM”) will now be available to consolidating entities during the rate rebasing period.

When developing the 2007 Policy, the OEB considered the issue of how to deal with capital investments during the deferred rebasing period. The OEB determined that it would not establish a mechanism to adjust for capital investment during the deferred rebasing period, and suggested that the matter should be considered as part of the next incentive regulation review.

Subsequently, in its September 17, 2008, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, the OEB established the Incremental Capital Module ("ICM") as the mechanism by which distributors could seek funding for extraordinary and unanticipated capital investments (but not normal expected investments) during the incentive regulation term. Of the three RRFE rate-setting options, the ICM application is available only to distributors that have chosen the Price Cap IR.

Distributors have indicated that while an extended deferral period may allow for the recovery of costs, the treatment of capital investments during this period may reduce the benefits of the extension. Some of the distributors suggested that few, if any, distributors would be able to operate over an deferred rebasing period without incorporating normal and expected capital expenditures into rate base. Their concern is that, if capital additions cannot be incorporated into rate base, the shareholder's rate of return would diminish and there would be impacts on financing for capital investments.

Distributors also expressed concern that they will be forced to choose between early rate-rebasing to address capital spending, or deferred rebasing in order to enhance the viability of a MAADs transaction. In their view, this may have a dampening effect on consolidation because the recovery of transaction costs will come at the expense of foregoing the recovery of capital expenditures. By contrast, if distributors who are considering a MAADs transaction know that they have the ability to apply to the OEB for the inclusion of on-going capital investments into rate base during the deferred rebasing period, they may be more willing to consider consolidation.

Stakeholders representing consumers suggested that the existing incentive rate-setting mechanisms already provide for the funding of capital, and that any additional mechanisms may result in an over-recovery from the consumer and could possibly reward underperforming distributors. Stakeholders who disagree with the proposed approach suggest that there is a risk that using a modified ICM would impact ratepayers worse than if no merger took place. Some parties have also suggested that the proposed approach would go against objective of the Annual IR which provides distributors with opportunity for increased rates, while protecting ratepayers with low rate stable increases. They are concerned that the proposal would turn Annual IR into "Selective IR", in which the full impacts of a utility's costs would be deliberately ignored by the OEB for as long as the utility wanted. Other stakeholders have suggested that if a distributor has the need to incorporate capital investments into rate base, it should go through a Custom IR.

On September 18, 2014, the OEB issued the Report of the Board, New Policy Options for Funding of Capital Investments: The Advanced Capital Module. In this Report, the OEB clarified that the opportunity for requests for review and approvals of incremental capital during an IR term will be maintained for projects that were unanticipated at the time of the development of a distributors' system plan, and/or for projects anticipated but for which sufficient rationale was not available at the time of the system plan to establish need and prudence. The ability to apply for an ACM remains only with those distributors who are under the Price Cap IR.

On page 15 of the September 18th Report, the OEB stated the following:

> *"The Board is of the view that the availability of incremental capital funding during the IR term should no longer be limited to non-discretionary projects. Any discrete project (discretionary or otherwise) adequately supported in the DSP (Distribution System Plan) is eligible for ACM funding subject to capital funding availability flowing from the formula results. The same approach shall apply going forward to new projects proposed as ICMs during the Price Cap IR term." (emphasis added)*

OEB Policy

The OEB believes that the clarification set out in the September 18th Report establishes that a distributor may now apply for an ICM that includes normal and expected capital investments. This clarification of policy should address the need of those distributors who may not consider entering into a MAADs transaction due to concerns over the ability to finance capital investments.

The one remaining limitation is that the ability to apply for an ICM continues to be limited to those distributors under the Price Cap IR, and it is anticipated that distributors considering a MAADs transaction will be operating under one or more of the other rate setting options. The question that needs to be addressed, in the OEB's view, is the situation where one or more distributors that are part of a MAADs transaction are operating under Custom IR or Annual IR and the impact of the ICM policy for the combined entity.

As discussed in the next section, distributors who are part of a MAADs transaction and have their Custom IR plan expire during the deferred rebasing period, would transition to the Price Cap IR. Once the distributor has made this transition, it will have the option to utilize the ICM consistent with the OEB's existing approach to incentive regulation.

Distributors who are in the midst of their Custom IR plan at the time of the MAADs transaction and consolidate with an entity operating under a Price Cap IR or an Annual IR may only apply for an ICM that relates to investments incremental to its Custom IR plan.

The OEB believes that its proposal to allow a combined entity who is operating under an Annual IR plan to make use of the ICM is reasonable, effective and will address distributor's concerns over capital investment during a deferred rebasing period which may encourage consolidation efforts.

The OEB notes that distributors proposing amounts for recovery by way of an ICM must be assessed by the OEB through a hearing and must meet the tests of materiality, need and prudence. Therefore, ratepayers continue to be protected under the OEB's proposed approach. Further the OEB is of the view that part of a review of any ICM requests by the combined entity, where one of the combined distributors was on a Custom IR, would include a test to determine whether the requested amounts for ICM recovery were separate from the amounts that had been included in the distributor's Custom IR plan.

In regards to making an application for an ICM, the materiality thresholds for purposes of the ICM policy shall be calculated based on the individual distributor's accounts, i.e. depreciation expense, and not the consolidated entity's.

D. INCENTIVE MECHANISM DURING THE DEFERRAL PERIOD

Under its renewed regulatory framework, the OEB has established three rate-setting approaches for distributors. A distributor may now choose amongst: Custom IR, Price Cap IR, and Annual IR.

As there are now three rate-setting options available to distributors, there will be potential for parties to a MAADs transaction to be on different rate options at the time of consolidation. The question that arises is which plan would apply to a distributor where its current approved rate plan ends during the deferred rebasing period

Distributor groups have suggested the consolidated entity should be allowed to continue under the existing Custom IR plan during the deferred re-basing period. Ratepayer groups believe the consolidated entity should undergo a Custom IR as soon as possible, in order to ensure any savings are properly shared.

Continuing to operate under a Custom IR where this is a form of rate adjustment is not feasible as the OEB has not approved rates for that distributor beyond the initial five years. Also, requiring a merged entity to undergo a Custom IR immediately would be counter to the intent of the 2007 policy as the consolidated entity would immediately lose any efficiency savings it expected to pay for transaction costs.

OEB Policy

The OEB wishes to clarify which incentive rate plan would apply to distributors who are party to a MAADs transaction during any deferred rebasing period after the distributors original IR plan is complete.

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap adjustment mechanism during the remainder of the deferral period. This approach is consistent with the current policy.

- A distributor on the Annual IR, whose plan expires, would continue to have rates based on the Annual IR index, until it selects a different option. This approach is consistent with the current policy, as there is no set rate rebasing timeframe under the Annual IR.

- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism, during the remainder of the deferral period.

The OEB believes that its proposal is in keeping with the original 2007 Policy and RRFE's focus on reducing regulatory burden and costs. This proposal will also assist in the efficient implementation of a deferred rebasing period, which in turn will support the objective of finding efficiencies through consolidation.

E. NEXT STEPS

The policy changes made by the OEB are intended to encourage efficient and beneficial consolidation transactions within the electricity distribution sector. The OEB has made changes that reflect concerns of the industry with the current policy while ensuring consumers will benefit through earlier rebasing or sharing of savings.

Some of the policy changes outlined in the Report will require amendments to be made to the MAADs filing requirements. In the case of the policy statements that have been made in the Report, these are summarized below and are considered amendments to the existing policies.

1. Allow consolidating entities to choose a deferred rebasing period of up to 10 years after the closing of the transaction. Those consolidating entities that elect a re-basing period of only up to five years may do so as set out under the current policy.

2. Those consolidating entities requesting a deferred re-basing period of greater than five years will be required to present the OEB with an ESM plan that would be implemented if the consolidated entity's ROE was greater than 300 basis points above the allowed ROE as set out under the incentive regulation policy. The ESM will be based on a 50:50 sharing of excess earnings with consumers.

3. Distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the Incremental Capital Module during the deferred rebasing period.

4. Distributors who are party to a MAADs transaction that are on the Price Cap IR at the time of consolidation will to continue to have their rates adjusted under the same mechanism until rebasing. In the case of distributors on the Annual IR the consolidated distributor would continue to operate under the Annual Index option unless and until it selects a different option. Distributors whose Custom IR plan expires during the deferred rebasing period will move to the Price Cap IR.

TAB 12

Ontario Energy Board

Commission de l’énergie de l’Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications. This Handbook uses the term consolidation to be inclusive of mergers, acquisitions, amalgamations and divestitures (MAADs).

The Commission on the Reform of Ontario’s Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.

Consolidation also enables distributors to address challenges in an evolving electricity industry. This includes new technology requirements to meet customer expectations, changing dynamics in the electricity sector with the growth of distributed energy resources and to undertake asset renewal. Distributors will need considerable additional investment to meet these challenges and consolidation generally offers larger utilities better access to capital markets, with lower financing costs.

Distributors are also expected to meet public policy goals relating to electricity conservation and demand management, implementation of a smart grid, and promotion of the use and generation of electricity from renewable energy sources. Delivering on these public policy goals will require innovation and internal capabilities that may be more cost effective for larger distributors to develop or retain.

The OEB recognizes that there is a growing interest in and support for consolidation. The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.

Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applicants. This Handbook will provide further clarity to applicants, investors, shareholders, and other stakeholders. The Handbook also discusses the rate-making policies associated with consolidations and sets out the timing of when such matters will be considered by the OEB.

While the Handbook is applicable to both electricity distributors and transmitters, most of the OEB's policies and prior OEB decisions have related to distributors. Transmitters should consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations.

2. The OEB Authority and Review Process

This section describes the OEB's legal authority in approving consolidation applications and clarifies how the OEB reviews these applications.

The OEB legislative authority

OEB approval is required for consolidation transactions described under section 86 of the *Ontario Energy Board Act, 1998* (OEB Act). (For ease of reference, Section 86 is reproduced in Schedule 1 of this Handbook.) Briefly, these transactions are as follows:

- A distributor or transmitter sells or otherwise disposes of its distribution or transmission system as an entirety or substantially as an entirety to another distributor
- A distributor or transmitter sells a part of a distribution or transmission system that is necessary in serving the public
- A distributor or transmitter amalgamates with another distributor or transmitter
- A person acquires voting securities of a transmitter or distributor or acquires control of a corporation with voting shares

Section 86(2) relating to voting securities does not, however, apply to the acquisition or sale of shares in Hydro One, a company created by the Crown under section 50(1) of the *Electricity Act, 1998*, which is explicitly exempt under section 86(2.1) from the conditions stipulated in section 86(2).

The Application Review Process

This Handbook applies specifically to applications under sections 86(1)(a) and (c) and sections 86(2)(a) and (b) of the OEB Act, which are processed through the OEB's adjudicative review process. Sections 86(1)(a) and (c) of the OEB Act relate to asset sales and amalgamations. Section 86(2) of the OEB Act relates to voting securities. To assist applicants, the OEB has developed Filing Requirements in Schedule 2 of this Handbook which set out the information that needs to be provided in an application. These Filing Requirements replace the form entitled **Application Form for Applications under Section 86 of the OEB Act** that was previously posted on the OEB's website.

Applications filed under section 86(1)(b) of the OEB Act are generally processed through the OEB's administrative review process, typically without a hearing. These applications generally include the sale of smaller scale distribution or transmission assets from one distributor or transmitter to another, or to a large consumer who is served by the same assets. For these applications, applicants may continue using the form entitled **Application Form for Applications under Section 86(1)(b) of the OEB Act** that is posted on the OEB's website, (http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms#maad).

The OEB may elect to process a section 86(1)(b) application under its adjudicative review process if the OEB considers that certain aspects of an application could affect service to the public and/or have a material effect on rates. This will be determined once the application is filed with the OEB. In those circumstances, this Handbook will be applicable. Applicants who are of the view that their transaction is material should use this Handbook to inform their application.

3. The OEB Test

The No Harm Test

In reviewing an application by a distributor for approval of a consolidation transaction, the OEB has, and will continue, to apply its "no harm test". The "no harm" test was first established by the OEB in 2005 through an adjudicative proceeding (the Combined Proceeding).[1]

The “no harm” test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives, as set out in section 1 of the OEB Act. The OEB will consider whether the “no harm” test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The OEB’s objectives under section 1 of the OEB Act are:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
    1.1 To promote the education of consumers.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer’s economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

4. The OEB Assessment of the Application

This section sets out how the OEB applies the “no harm” test within the context of the performance-based regulatory framework, the Renewed Regulatory Framework for Electricity Distributors[2] (RRFE). This framework was established by the OEB in 2012 to

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[1] Combined Proceeding Decision - OEB File No. RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

[2] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

ensure that regulated distribution companies operate efficiently, cost effectively and deliver outcomes valued by its customers.

The Renewed Regulatory Framework

Ongoing performance improvement and performance monitoring are underlying principles of the RRFE. The OEB's oversight of utility performance relies on the establishment of performance standards to be met by distributors, ongoing reporting to the OEB by distributors, and ongoing monitoring of distributor achievement against these standards by the OEB.

An electricity distributor is required, as a condition of its licence, to provide information about its distribution business. Metrics are used by the OEB to assess a distributor's services, such as frequency of power outages, financial performance and costs per customer. The OEB uses this information to monitor an individual distributor's performance and to compare performance across the sector. The OEB also has a robust audit and compliance program to test the accuracy of reporting by distributors.

As part of the regulatory framework, distributors are expected to achieve certain outcomes that provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance by distributors and that utilities deliver on system reliability and quality objectives. The OEB uses processes to hold all utilities to a high standard of efficiency and effectiveness.

The OEB has a proactive performance monitoring framework that inherently protects electricity customers from harm related to service quality and reliability and has established the mechanisms to intervene if corrective action is warranted. The OEB will be informed by the metrics that are used to evaluate a distributor's performance in assessing a proposed consolidation transaction.

All of these measures are in place to ensure that distributors meet expectations regardless of their corporate structure or ownership. The OEB assesses applications for consolidation within the context of this regulatory framework.

The No Harm Test

The “no harm” test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives. While the OEB has broad statutory objectives, in applying the “no harm” test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector. The OEB considers this to be an appropriate approach, given the performance-based regulatory framework under which all regulated distributors are required to operate and the OEB’s existing performance monitoring framework.

The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB’s statutory objectives relating to conservation and demand management, implementation of smart grid and the use and generation of electricity from renewable resources. With these tools and the ongoing performance monitoring previously discussed, the OEB is satisfied that the attainment of these objectives will not be adversely effected by a consolidation and the “no harm” test will be met following a consolidation. There is no need or merit in further detailed review as part of the OEB’s consideration of the consolidation transaction.

Scope of the Review

The factors that the OEB will consider in detail in reviewing a proposed transaction are as follows:

Objective 1 – Protect consumers with respect to price and the adequacy, reliability and quality of electricity service

Price

A simple comparison of current rates between consolidating distributors does not reveal the potential for lower cost service delivery. These entities may have dissimilar service territories, each with a different customer mix resulting in differing rate class structure characteristics. For these reasons, the OEB will assess the underlying cost structures of the consolidating utilities. As distribution rates are based on a distributor’s current and projected costs, it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors. A key expectation of the RRFE is continuous improvement in productivity and cost performance by distributors. The OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers.

Consistent with recent decisions,[3] the OEB will not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of "no harm" as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term. In reviewing a transaction the OEB must consider the long term effect of the consolidation on customers and the financial sustainability of the sector.

To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. While the rate implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility.

Adequacy, reliability and quality of electricity service

In considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

The OEB's *Report of the Board: Electricity Distribution Systems Reliability Measures and Expectations*, issued on August 25, 2015 sets out the OEB's expectations on the level of reliability performance by distributors. In the Report, the OEB noted that continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or to maintain the same level of performance at a reduced cost.

Under the OEB's regulatory framework, utilities are expected to deliver continuous improvement for both reliability and service quality performance to benefit customers. This continuous improvement is expected to continue after a consolidation and will continue to be monitored for the consolidated entity under the same established requirements.

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[3] Hydro One Inc./Norfolk Power Distribution Inc. – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. – OEB File No. EB-2014-0244

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

The impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity) will be assessed based on the applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

The impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will also be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and integration costs) to implement the consolidation transaction

In the Combined Proceeding decision, the OEB made it clear that the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test. While there may not be a premium involved with mergers, the OEB will nevertheless consider the financial viability of the newly consolidated entity.

Electricity distribution rates are currently based on a return on the historic value of the assets. If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity. In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed. Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.

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The OEB considers that certain aspects of a consolidation transaction are not relevant in assessing whether the transaction is in the public interest, either because they are out of scope, or because the OEB has other approaches and instruments for ensuring that statutory objectives will be met. Accordingly, the OEB will not require applicants to file evidence on the following matters as part of a consolidation application.

1. *Deliberations, activities, and documents leading up to the final transaction agreement*

As set out in the Combined Proceeding decision, and confirmed in recent decisions,[4] the question for the OEB is neither the why nor the how of the proposed transaction. The application of the “no harm” test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB’s statutory objectives.

The OEB determined in the Combined Proceeding decision that it is not the OEB’s role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB. Accordingly, the OEB will not consider, whether a purchasing or selling utility could have achieved a better transaction than that being put forward for approval in the application.

Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants’ consolidation plans nor the negotiating strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB.

Applicants and stakeholders should not file any of the following types of information as they are not considered relevant to the proceeding:

- Draft share purchase agreements and other draft confidential agreements and documents utilized in the course of the negotiation process

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[4] Hydro One Inc./Norfolk Power Distribution Inc. Decision and Order and Procedural Order No. 8 – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Woodstock Hydro Services Inc. Decision and Procedural Order No. 4 – OEB File No. EB-2014-0213

- Negotiating strategies or conduct of the parties involved in the transaction
- Details of public consultation prior to the filing of the application

2. *Implementing public policy requirements for promoting conservation, facilitating a smart grid and promoting renewable energy sources*

As previously discussed, the OEB's performance-based regulation, which includes performance monitoring and reporting based on standards, combined with the regulatory instruments of codes and licences, establishes a framework for success in achieving public policy requirements. A utility that does not meet established performance expectations is subject to corrective action by the OEB. Given these means for ensuring that public policy objectives are met by all regulated entities, the OEB is satisfied that the "no harm" test will be met for these objectives following a consolidation and there is no need or merit in further detailed consideration as part of a consolidation transaction. For these reasons, no evidence is required to be filed for these issues.

3. *Prices not related to a utility's own costs*

The OEB's review is limited to the components of the distribution business and the costs and services directly under a distributor's control. For example, one of the mandates of a distributor is to pass-through certain wholesale market and commodity related costs to customers. These costs are passed through and not part of a utility's underlying costs to serve its customers. Accordingly, the prices of these services are not considered by the OEB in its review of a consolidation application.

5. Rate-Making Considerations Associated with Consolidation Applications

The OEB's policies on rate-making matters associated with consolidation in the electricity distribution sector are set out in two reports of the OEB. The first report titled "*Rate-making Associated with Distributor Consolidation*" issued on July 23, 2007 (2007 Report) was supplemented by the 2015 Report, issued under the same name, as previously indicated.[5]

This section of the Handbook consolidates information that is provided in these two reports and identifies the key rate-making considerations expected to arise in

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[5] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015

consolidation transactions. Applicants are, however, encouraged to review both reports in preparing their applications for both the consolidation transaction and subsequent rate application.

Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g. a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review of a utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers.

Rate-Setting Policies

The rate making considerations relating to consolidation that applicants and parties need to be aware of are:

- Deferred Rebasing
- Early Termination of Pre-Consolidation Rate-Setting term
- Early Termination or Extension of Deferred Rebasing Period
- Rate Setting During Deferred Rebasing Period
- Off Ramp
- Earnings Sharing Mechanism
- Incremental Capital Investments During Deferred Rebasing Period
- Future Rate Structures
- Deferral and Variance Accounts

Deferred Rebasing

The setting of rates for a consolidated entity using a cost of service methodology or a Custom Incentive Rate-setting method (both referred to in this document as rebasing of rates) involves a detailed assessment by the OEB of a utility's underlying costs. A consolidated entity is required to file a separate application with the OEB under Section 78 of the OEB Act for a rebasing of its rates. This typically takes place at some point in time following the OEB's approval of a consolidation.

To encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any achieved savings. The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. The 2015 Report also states that consolidating entities deferring rebasing for up to five years may do so under the policies established in the 2007 Report.[6] The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period subject to the minimum requirements set out below.

While the OEB has determined that allowing a longer deferred rebasing period is appropriate to incent consolidation, there must be an appropriate balance between the incentives provided to utilities and the protection provided to customers. The OEB will therefore require consolidating distributors to identify in their consolidation application the specific number of years for which they choose to defer. It is not sufficient for applicants to state that they will defer rebasing for up to 10 years. Distributors must select a definitive timeframe for the deferred rebasing period. This will allow the OEB to assess any proposed departure from this stated plan.

In addition, distributors cannot select a deferred rebasing period that is shorter than the shortest remaining term of one of the consolidating distributors. Therefore, a consolidated entity can only rebase when:

i) The selected deferred rebasing period has expired, and
ii) At least one rate-setting term of one of the consolidating entities has also expired.

Early Termination of Pre-Consolidation Rate-setting Term

At the time distributors first enter into a consolidation transaction, consolidating distributors may be on any one of the rate setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates.

A consolidated entity may apply to the OEB to rebase its rates as a consolidated entity through a cost of service or Custom IR application following the expiry of the original rate-setting term of at least one of the consolidating entities and once the selected deferred rebasing period has concluded. If, however, a consolidated entity wishes to rebase its rates prior to the end of the pre-consolidation rate-setting term of the distributor that has the earliest termination date, the consolidated entity must demonstrate the need for this “early rebasing” as part of the early rebasing application.

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[6] Report of the Board on Rate-making Associated with Distributor Consolidation, July 23, 2007

The OEB established its approach to early rebasing in a letter dated April 20, 2010 and reiterated it in the RRFE. The OEB expects a distributor that seeks to have its rates rebased earlier than scheduled to clearly demonstrate why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remaining years of its current rate term.

Early Termination or Extension of Selected Deferred Rebasing Period

The OEB considers that consolidations can provide for greater efficiencies and benefits to customers and is committed to reducing regulatory barriers to consolidations. The OEB has allowed for a deferred rebasing period to eliminate one of the identified barriers to consolidations. The OEB remains of the view that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. That being said, when a consolidating entity has opted for a deferred rebasing period, it has committed to a plan based on the circumstances of the consolidation. For this reason, if the consolidated entity seeks to amend the deferred rebasing period, the OEB will need to understand whether any change to the proposed rebasing timeframe is in the best interest of customers.

Distributors who subsequently request a shorter deferred rebasing period than the one that has been selected (and where at least one of the pre-consolidation rate-setting plans has expired) will be required to file rationale to support the need to amend the previously selected deferred rebasing period. Similarly, a consolidated entity having selected a deferred rebasing period less than 10 years, that seeks to extend its selected deferred rebasing period must explain why this is required.

Rate Setting during Deferred Rebasing Period

Under the OEB's RRFE, there are three rate-setting options: Price Cap Incentive Rate-Setting (Price Cap IR or PCIR), Custom Incentive Rate-Setting (Custom IR or CIR) and Annual Incentive Rate-Setting Index (Annual IR Index or AIRI). The term of the Price Cap IR and Custom IR options is normally five years. The Annual IR Index option has no specific term.

Consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates. The 2015 Report clarified how rates will be set for a distributor who is a party to a consolidation transaction during any deferred rebasing period after the distributor's original incentive rate-setting plan has concluded:

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on the Annual IR Index will continue to have rates based on the Annual IR Index, until it selects a different rate-setting option.

Table 1 below illustrates six potential scenarios for rate-setting during the deferred rebasing period, assuming the consolidation of two distributors. The table also sets out the conditions that must be met by a consolidated entity that elects to rebase its rates. While Table 1 is intended to illustrate a situation of two consolidating distributors, the OEB is aware that future consolidations may involve several consolidating distributors as well as the possibility of multiple successive consolidation transactions by a single consolidated entity. For unique circumstances, the OEB may need to assess the rate-setting proposals on a case by case basis.

Table 1 - Rate-Setting Options During the Deferred Rebasing Period

Going in Rates
As of the date of the closing of the transaction. Assumes two distributors.

	Both on PCIR	One on PCIR and one on CIR	Both on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	LDC on PCIR continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.	Continue with current plans. Once each term expires, each LDC will move to PCIR for the remaining years of the chosen deferred rebasing period.
	OR	OR	OR
Rebasing Options	Rebase as a consolidated entity following the expiration of one of the entities' term and once the selected deferred rebasing period has concluded.	LDC on PCIR continues on current plan. If its term expires in advance of the expiration of the other LDC's CIR term the consolidated entity may rebase once the selected deferred rebasing period has concluded.	Continue with current plans. Once the earlier of the two terms expires the consolidated entity may rebase once the selected deferred rebasing period has concluded.
		OR	
		If the term for the LDC on CIR expires first, the consolidated entity may rebase following the expiration of the CIR term and once the selected deferred rebasing period has concluded.	

	One on PCIR and one on AIRI	Both on AIRI	One on AIRI and one on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	Continue with current plans for chosen deferred rebasing period.	LDC on AIRI continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.
	OR	OR	OR
Rebasing Options	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.

Off Ramp

As set out in the OEB's RRFE, each incentive rate-setting method includes an annual return on equity (ROE) dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated by the OEB. The OEB requires consistent, meaningful and timely reporting to effectively monitor utility performance and determine if expected outcomes are being achieved. The OEB's performance monitoring framework allows the OEB to take corrective action if required, including the possible termination of the distributor's rate-setting method and requiring the distributor to have its rates rebased.

The dead band of ±300 basis points on ROE continues to apply to utilities who have deferred rebasing due to consolidation. For utilities who defer rebasing up to five years, the OEB may initiate a regulatory review if the earnings are outside of the dead band. For utilities deferring rebasing beyond five years, an earnings sharing mechanism is required above ±300 basis points as discussed in the next section.

Earning Sharing Mechanism (ESM)

Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.[7] The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

In the 2015 Report, the OEB determined that under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report.

There are numerous types and structures of consolidation transactions, and there can be significant differences between utilities involved in a transaction. The ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the

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[7] Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015, p.6

deferred rebasing period. For example, a large distributor that acquires a small distributor may demonstrate the objective of consumer protection by proposing an ESM where excess earnings will accrue only to the benefit of the customers of the acquired distributor.

Incremental Capital Investments during Deferred Rebasing Period

The Incremental Capital Module (ICM) is an additional rate-setting mechanism under the Price Cap IR option to allow adjustment to rates for discrete capital projects. The details of the mechanism are described in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued on September 18, 2014 and a supplemental report with further enhancements will be issued in January 2016.

The ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.

The 2015 Report sets out that a distributor who is in the midst of the Custom IR plan at the time of the transaction and who consolidates with an entity operating under a Price Cap IR or an Annual IR Index may only apply for an ICM for investments incremental to its Custom IR plan. The rules that apply to a specific rate-setting method continue to apply even following a consolidation of distributors. To be specific, an ICM would not be available for the rates in the service area for which the Custom IR plan term applies until the term of the Custom IR ends and Price Cap IR applies. Materiality thresholds for the ICM will be calculated based on the individual distributors' accounts and not that of the consolidated entity.

Future Rate Structures

A consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time it files its rebasing application. Distributors are not required to file details of their rate-setting plans, including any proposals for rate harmonization, as part of the application for consolidation. These issues will be addressed at the time of rate rebasing of the consolidated entity.

A rate harmonization plan can propose the approach and timeline for harmonizing rate classes or provide rationale for why certain rate classes should not be harmonized based on underlying differences in cost structures and drivers. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. However, the OEB expects that whichever option is adopted, rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.

Deferral and Variance Accounts

Where a transmitter or distributor has accumulated balances in a deferral or variance account, the question of who should pay for, or receive credits from the clearance of these balances is relevant to the consolidation only if it affects the financial viability of the acquiring utility or consolidated entity. A decision on the actual clearance of deferral or variance accounts would be part of a rate application, not an application seeking approval for consolidation.

INDEX: Schedule 1 – Relevant Sections of the OEB Act

Section 86 of the OEB Act

Change in ownership or control of systems

86. (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or

(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a transmitter or distributor or of a corporation that owns securities in a transmitter or distributor. 2002, c. 1, Sched. B, s. 9 (1).

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

  (a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or

  (b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2).

INDEX: Schedule 2 – Filing Requirements for Consolidation Applications

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Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements
For
Consolidation Applications

January 19, 2016

Table of Contents

Filing Requirements for Consolidation Applications

1. Introduction

Completeness and Accuracy of an Application

These filing requirements provide direction to applicants in preparing a consolidation application. It is expected that applicants will file applications consistent with the filing requirements. Applications must be accurate, and information and data presented must be consistent throughout the application. If an application does not meet all of these requirements, or if there are inconsistencies identified in the information or data presented, the OEB may put the application in abeyance, unless satisfactory justification for missing or inconsistent information has been provided or until revised satisfactory evidence is filed. If circumstances warrant, the OEB may require an applicant to file evidence in addition to what is identified in the filing requirements. An applicant should only file information that is relevant to the OEB's statutory objectives in relation to electricity. Applicants should refer to the Handbook on the OEB's expectations and approach to reviewing consolidation applications.

Certification of Evidence

An application filed with the OEB must include a certification by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his or her knowledge.

Updating an Application

When material changes or updates to an application or other evidence are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure* (the Rules). When changes or updates are contemplated in later stages of a proceeding, updates should only be done if there is a material change to the evidence already before the OEB. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part(s) revised.

Interrogatories

Interrogatories are an important part of the process of clarifying and testing evidence, however they must focus on issues that are relevant to the OEB's decision. Excessive interrogatories introduce inefficiency into the application process. The OEB advises applicants to consider the clarity, completeness and accuracy of their evidence and refer to the Handbook for what will be considered or not in order to reduce the need for interrogatories. The OEB also advises parties to carefully consider the relevance and materiality of information before requesting it through interrogatories. Parties must consult Rules 26 and 27 of the OEB's *Rules of Practice and Procedure*, April 24, 2014 revision, for additional information on the filing of interrogatories and responses and matters related to such filings.

Confidential Information

The OEB relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The OEB's expectation is that applicants will make every effort to file material contained in an application publicly and completely, and without redactions in order to ensure the transparency of the review process. The OEB's Rules and the *Practice Direction on Confidential Filings* (the Practice Direction) allow for applicants and other parties to request that certain evidence be treated as confidential. Where such a request is made, parties are expected to review and follow the Practice Direction. This includes assessment of the relevance of any requested document prior to filing it with the OEB and requesting confidential treatment. There is no requirement or expectation on applicants to file documents that are out of scope of the areas the OEB has determined are relevant to its consideration of a consolidation application as defined in the Handbook.

2. Information Required of Applicants

The OEB expects an application for consolidation to have the following components:

2.1 Exhibit A: The Index

	Content	Described in
Exhibit A	Index	2.1
Exhibit B	The Application	2.2
	Administrative	2.2.1
	Description of the Business of the Parties to the Transaction	2.2.2
	Description of the Transaction	2.2.3
	Impact of transaction on the OEB's statutory objectives	2.2.4
	Rate considerations for consolidation applications	2.2.5
	Other Related Matters	2.2.6

2.2 Exhibit B: The Application

2.2.1 Administrative

This section must include the formal signed application, which must incorporate the following:

- Legal name of the applicant or applicants
- Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses
- Legal name of the other party or parties to the transaction, if not an applicant
- Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses
- Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants

2.2.2 Description of the Business of the Parties to the Transaction

This section of the application requires the applicant to provide the following information on the parties to the proposed transaction:

- Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity.

- Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries.

- Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

- Describe the proposed geographic service area of each of the parties after completion of the proposed transaction.

- Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

- If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction. The OEB will, in the absence of exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility.

2.2.3 Description of the Proposed Transaction

This section of the application requires the applicant to provide the following:

- Provide a detailed description of the proposed transaction.
- Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the *Ontario Energy Board Act, 1998*.
- Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.
- Provide all final legal documents to be used to implement the proposed transaction.
- Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction.

2.2.4 Impact of the Proposed Transaction

In reviewing an application, the OEB will apply the no harm test as outlined in the Handbook. Applicants are required to provide the following evidence to demonstrate the impact of the proposed transaction with respect to the OEB’s first two statutory objectives.

Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

- Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.
- Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction.

- Provide a comparison of the OM&A cost per customer per year between the consolidating distributors.

- Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

- Describe how the distribution or transmission systems within the service areas will be operated.

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

- Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative).

- Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.

- Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.

- If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.

- Provide details of the financing of the proposed transaction.

- Provide financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

- Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.

2.2.5 Rate considerations for consolidation applications

Applicants are required to provide the information with respect to the following rate making considerations relating to consolidation:

- Indicate a specific deferred rate rebasing period that has been chosen.
- For deferred rebasing periods greater than five years:
    - Confirm that the ESM will be as required by the 2015 Report and the Handbook
    - If the applicant's proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor

2.2.6 Other Related Matters

Applicants have, in previous consolidation applications, made the following additional requests to the OEB which have formed part of the OEB's determination of a consolidation application:

a) Implementation of new or the extension of existing rate riders
b) Transfer of rate order and licence
c) Licence amendment and cancellation
d) Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB
e) Approval to use different accounting standards for financial reporting following the closing of the proposed transaction

Applicants are required to provide justification for these types of requests and for any other requests for which a determination is being sought from the OEB as part of a consolidation application.

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TAB 13

Report of the OEB

EB-2014-0219

New Policy Options for the Funding of Capital Investments: Supplemental Report

January 22, 2016

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1 Executive Summary

This Report outlines the OEB's policy with respect to the matters addressed in a supplemental phase of the consultation on *New Policy Options for the Funding of Capital Investments* (EB-2014-0219).

The OEB engaged KPMG and formed a working group composed of utility and stakeholder representatives. The OEB has considered the work of KPMG and OEB staff, and the feedback provided by working group participants. In this Supplemental Report the OEB has determined that:

- No changes will be made to the manner in which the OEB applies the half-year rule in a test year and its persistence over the incentive rate-setting (IR) term.

- The materiality threshold formula will be modified as follows:
    - A multi-year formula
    - An annualized growth factor
    - A dead band of 10% (down from the previous 20%)
    - Use of the stretch factor assigned to the middle cohort (currently 0.3%) for every distributor for the determination of the materiality threshold, irrespective of the actual stretch factor at any one point in time

This Supplemental Report augments the policies adopted in the September 2014 ACM Report, and must be read in conjunction with that report. The changes adopted herein will be reflected in the Filing Requirements applicable to cost of service and IR applications when the Filing Requirements are next updated by the OEB. The ACM excel model used by the OEB has been updated to reflect the changes adopted in this Supplemental Report.

2 Background

The OEB initiated this policy review in 2014. The review considered two aspects on the OEB's approach to funding capital additions:

- The effect of the half-year rule on test year capital additions for the intervening years between rebasing applications

- The introduction of a new funding mechanism that would enable review during a cost of service application for the need and prudence of any incremental capital module (ICM) funding requests for discrete projects that are part of a distributor's Distribution System Plan, and that are planned to come into service during the IR period (i.e., the Advanced Capital Module (ACM))

On September 18, 2014, following work by OEB staff and a consultation with a working group of utility and stakeholder representatives, the OEB issued its *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the ACM Report).

In the ACM Report, the OEB established the Advanced Capital Module. This is a new mechanism to assist electricity distributors in their progress towards developing and justifying a long-term strategy for delivering distribution services that their customers value and that reflect manageable rate impacts over the long term. The ACM advances the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IR term) to the preceding cost of service application in which a distributor is required to file a five year Distribution System Plan (DSP) encompassing the cost of service test year and the four subsequent incentive rate-setting years.

The OEB retained an incremental capital module (the ICM) for the IR years for projects not included in a DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence.

The ACM Report also revised certain of the existing criteria and established new criteria to assist with the testing of incremental capital requests (under both an ACM and ICM).

In the ACM Report, the OEB did not make a determination with respect to the elimination of the effect of the half-year rule on test year capital additions for the IR years. There were other matters on the ACM/ICM approach which were considered during the initial work, particularly related to the materiality threshold formula, which remained unresolved as well. The OEB indicated that it would continue to review these matters. This Supplemental Report provides the result of that additional review.

KPMG was retained to assist OEB staff and a new working group was established for this latest policy review. In addition to continuing the assessment of the impact of the half-year rule, the working group and KPMG reviewed specific components of the ICM materiality threshold formula.

KPMG was specifically tasked with reviewing two rate making issues:

- The half-year rule
    - A jurisdictional review of the treatment of new capital additions in rate base and revenue requirement (i.e., the use of the half-year rule or other approaches)
    - The adequacy of price-cap adjustments for funding capital investments under the OEB's Price Cap IR regime in which the half-year rule persists during the term
- The materiality threshold formula
    - A review of the appropriateness of the current definition of the growth (g) factor
    - A review of the appropriateness of the current definition of the dead band due to any impacts arising from the adoption of the following on the suitability of the materiality threshold formula and its parameters
        - Total Factor Productivity (TFP) versus the use of the previous Partial Factor Productivity (i.e. OM&A benchmarking) for deriving the productivity adjustment under IR
        - International Financial Reporting Standards (IFRS)

- Related to another project, a jurisdictional review of how the Working Capital Allowance (WCA) is established for rate regulation.

The research on the WCA is related to the *Policy Review of Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance: A Review of Cash Working Capital Funding (EB-2014-0198),* and was considered in the consultation of that project. It has no further impact on this project.

The working capital portion of the KPMG report was issued in draft form on June 3, 2015 along with the OEB's letter setting out the new default WCA. That excerpt has now been finalized with no changes and is included for completeness in KPMG's final report,

New Policy Options for the Funding of Capital Investments: EB-2014-0219, supporting this supplemental phase of the consultation and can be found on the OEB's website, at *http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0219/KPMG_Report_EB-2014-0219_20150626.pdf*.

3 The Half-Year Rule

The application of the half-year rule has been the subject of much discussion since it was first adopted by the OEB in the context of an incentive rate-setting mechanism. Distributors have been generally concerned that the persistence of the half-year rule into an IR period deprives them of half of the depreciation and return on their test year investments during the IR term and that this effect has been exacerbated by the extension of the IR term from four to five years under the Renewed Regulatory Framework for Electricity (the RRFE).

This section reviews and assesses the current OEB policy. For the reasons set out below, the OEB has determined that no changes will be made to the manner in which the OEB applies the half-year rule in a test year and its persistence over the IR term.

3.1 Test Years

The current OEB policy, established in the OEB Report on the *2006 Electricity Distribution Rate Handbook*, allows for recovery of a half-year depreciation and a half-year of the return on capital for the year that capital assets enter service, while the full year's depreciation and cost of capital is recovered on assets already in service.[1] This policy was adopted as most new capital additions only come into service part-way through the year. Since ratepayers only receive the benefit of the capital additions once the assets enter into service, earning a full year's depreciation and return would over-compensate the utility relative to the benefit that ratepayers receive during that first year.

Specifically, the half-year of the return on capital is accomplished through the calculation of the average net book value of in-service assets during the year, calculated as the average of opening (January 1) and closing (December 31) balances. For depreciation expense, one-half of the annual straight-line depreciation expense is allowed in the year that assets enter service. In subsequent test years, the full annual depreciation expense for the assets is reflected in the revenue requirement and recoverable in rates, until the last year of that asset class' expected useful life, when the final half-year of depreciation expense is recovered.[2]

For electricity distributors, the OEB has employed this default approach as a means of ensuring that the full year's depreciation and return on capital are not included in rates

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[1] Report of the Board: 2006 Electricity Distribution Rate Handbook (RP-2004-0188), May 11, 2005, p. 15 (regarding the ½ year treatment for new in-service additions).

[2] Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – Chapter 2: Cost of Service, July 16, 2015, p. 41

in the absence of more detailed information as to the specific in-service dates of projects. This is commonly referred to as the “half-year” rule. For non-rebasing years subsequent to a test year, assets that went into service in the preceding test year would continue to attract only a half year of return of and return on capital, until the next rebasing application.

The half-year rule is an approximation of when, during a test year, assets enter service. In the absence of more detailed forecasts, the half-year rule assumes that all new assets enter service on July 1 (half way through the test year) for ratemaking purposes. In some cases, more refined in-service date forecasts are available which result in “partial-year” treatment, as appropriate, as opposed to exactly “half-year” treatment.

KPMG identified alternative methods that have been used in other jurisdictions that provide more refined calculations based on when assets enter service. These include the following:[3]

- Average of quarter-end balances. The average net book value is the average of the four quarterly balances, and depreciation expense is comparably calculated. This provides a slightly more accurate representation than the half-year of the average net book value, but with additional accounting and slightly more complex calculations for rate-setting.

- 12-month average of month-end balances. This is a more refined and accurate representation of when assets actually enter service, but which requires additional accounting and more complex calculations for rate-setting. Ontario natural gas distributors and some electricity distributors employ this approach as they generally forecast monthly in service dates for their new assets.

- 13-month average of month-end balances. Some U.S. jurisdictions use 13-months, calculated as the values for December 31 of the prior year, plus the twelve month-end values in the test year. This provides an average from the opening test year to closing test year balances but provides a more accurate average NBV of assets during the year than does the half-year rule as it reflects more accurately when assets enter service. Like other approaches, it requires more accounting of data and more complexity in rate-setting calculations.

KPMG’s review found that the half-year rule or a more detailed quarterly or monthly approach is used for rate-setting purposes in Canadian and U.S. jurisdictions

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[3] KPMG’s Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219* – Summary, pp. 3-6

surveyed.[4] Ofgem in the United Kingdom provides for no depreciation expense to be recovered in the year that assets enter service, but provides for full year recovery in subsequent years. No jurisdiction surveyed allows the full amount of depreciation and return in the test year for assets that enter service in that year.

3.2 Incentive Rate-setting Years

In the traditional environment of annual cost of service rate applications, the use of the half-year rule or a more detailed variation does not pose an issue for subsequent years following the inclusion of an asset into rate base for the first time. The rate base and the revenue requirement are updated every year; assets that receive half-year (or partial-year) treatment in the year that they enter service receive full-year treatment in subsequent years.

The nature of economic regulation, particularly rate-setting, has evolved. Since the 1980s, performance-based regulation (PBR)/incentive regulation mechanisms (IRM) have evolved as an alternative to more traditional cost of service regulation. PBR/IRM can provide for any form of regulatory oversight that may be a better representation of the market forces that discipline the performance of firms in competitive markets.

With the OEB's performance based incentive rate-setting methodology, rates are no longer established on an annual cost of service approach. As a result, the half-year rule, or similar treatment, continues during the IR years. During the IR years, depreciation expense is the return of originally invested capital that is available for re-investment in the replacement assets when the original assets reach end-of-life. On that theoretical basis, a utility can invest in future capital with no adverse impact on financial metrics. However, the theoretical approach does not consider inflation or growth in electricity demand and growth in number of customers.

KPMG undertook various analyses to assess the impact of the half-year rule under the OEB rate setting approach of a cost of service review followed by four years of IR adjustments. KPMG compared the OEB approach against annual cost of service applications, where the utility was held whole through the annual update of the rate base and revenue requirement, and also against the scenario of cost of service and IR with full-year depreciation.

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[4] However, in most cases, it appears to the OEB that the approach adopted has been so long institutionalized that the justification for the approach is long forgotten. Nor does there appear to be questions of the appropriateness of the approach persisting during non-rebasing periods and whether it raises concerns of sufficiency or deficiency of recoveries.

While the analyses were hypothetical, KPMG used data that would be representative of a “typical” utility. Various assumptions of growth, capital additions-to-depreciation, and other parameters were modelled. The analyses demonstrate how sensitive the results can be to assumptions about the parameters. Nonetheless, the OEB considers that the analyses were informative.

KPMG concluded that the half-year rule creates a notional deficiency assuming no customer growth when capital expenditures are greater than or equal to the amount of capital expenditures notionally reflected in base rates. However, KPMG also noted that, with revenue growth above 1.1%, a revenue sufficiency could result.[5] KPMG notes that results can vary as they are sensitive to the operational circumstances and parameters of individual distributors.

The jurisdictional review by KPMG does not reveal any general concerns with the use of the half-year rule or a similar mechanism persisting into non-rebasing years. KMPG recommended that “IR rates not be normalized for the effect of the half year rule in the rebasing year on a pro forma basis for all distributors due to the potential for normalized IR rates to be greater than those associated with an annual cost of service rates scenario”. KPMG noted that whether any revenue deficiency was material was dependent on the circumstances of each utility.[6] While there was no consensus in the working group on whether IR rates should be normalized for the effect of the half year rule, there was general agreement that the level of any deficiency would be dependent on the circumstances of each utility.

The OEB recognizes that, due to inflation, the replacement value of many assets will be higher than the original price of that asset. However, there are many other factors to consider, such as contributed capital policies, customer growth, changes in technology and the age demographic of assets (and when they become fully depreciated) that can vary from distributor to distributor. Setting rates through the IR mechanism inherently disconnects the rates from the underlying costs of the utility in order to incent efficiency improvements. The very nature of the mechanism recognizes that there can be many different factors that can influence both positively and negatively on a utility’s return. The half-year rule is just one of these factors.

The OEB will not alter its policy of allowing the half-year rule (or analogous approaches) to persist through the Price Cap IR period. It is not appropriate to adjust for one factor, such as any shortfall due to the use of the half year rule, without considering all other factors that arise through an IR period. The OEB has already included several options

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[5] KPMG’s Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219*, p. 12
[6] *Ibid*., p. 44

that distributors can leverage to address their unique circumstances. In 2012, the OEB established rate-setting options for distributors, including the Custom IR method. With Custom IR, a five-year forecast of a distributor's costs is considered. Distributors opting for the Price Cap IR option have access to a capital module (either the ACM or ICM) to fund material capital costs.[7] As part of this Supplemental Report, the OEB is reducing the dead band in the materiality threshold calculation for both the ACM and ICM, making these mechanisms more accessible to distributors. In addition, distributors experiencing extraordinary events can file an application for a Z-factor to recover costs of material events that are beyond their control.

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[7] The ICM option has been available since its introduction in late 2008 for 3rd Generation IR, and continued under the RRFE options. The ACM Report, issued in September 2014, introduced the ACM concept as an evolution of the ICM and modifying some of the policies applicable to both ACM and ICM requests.

4 The ACM/ICM Materiality Threshold Formula

In the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673), (the 3rd Gen IR Supplemental Report) the OEB introduced the Incremental Capital Module. The ICM included a materiality threshold to determine qualifying capital projects and the associated incremental capital amounts that would be recoverable during the IR period, until the distributor's next cost of service application. The ICM materiality threshold is discussed in section 2.3 of the 3rd Gen IR Supplemental Report.

The OEB established the following formula to be used by a distributor to calculate the materiality threshold that will apply to it:[8]

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right] + 20\%$$

This formula has been used since that time.

In September of 2014, the OEB issued the ACM Report. The ACM Report retained the same materiality formula while providing further guidance and clarity on its application on ICM and the new ACM options for funding eligible incremental capital. At that time, the OEB noted that it intended to further review certain components of the formula in light of the experiences with ICM applications to date and in consideration of the evolution of the ACM/ICM concept in support of the OEB's RRFE rate-setting approach.

KPMG examined the growth factor g and the dead band, currently at 20%. OEB staff also considered how to adapt the formula, which was single-year in nature, to be applicable to the multi-year Price Cap IR term currently in place. A further consideration was whether the use of the actual distributor-specific stretch factor is reasonable given the purpose of the formula is to derive an incremental amount of capital that may be eligible for funding during the IR term.

The following concepts of the materiality threshold formula are discussed below.

- The Multi-Year Formula
- The Growth Factor
- The Dead Band
- The Stretch Factor

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[8] Definitions of the terms are provided in Appendix B.

4.1 The Multi-Year Formula

The original materiality threshold formula for an ICM was structured to support a single year-over-year change (i.e., from the cost of service rebasing to the first IRM rate adjustment application in the following year). However, a distributor could apply for an ICM as part of its annual IRM rate adjustment for any year subsequent to its cost of service application. The single year-over-year formula does not take into account the passage of time over the subsequent IRM period (i.e., the cumulative impacts of cost, inflation, productivity and changes in customers and demand). In addition to the lack of multi-year impacts, as originally conceived and applied, the formula would give the same value regardless of which IR year past rebasing the application was addressing.[9]

Under 3rd Generation IR, there were originally three annual price rate adjustments between rebasing applications. Now there are routinely four under the Price Cap IR regime instituted as part of the RRFE. Further, in conjunction with the OEB's recent policy relating to deferring rebasing pursuant to executed mergers, acquisitions, amalgamations and divestitures, the period between rebasing applications could be considerably longer.[10]

Having reviewed more than a dozen ICM applications since adopting the ICM, the OEB is of the view that the materiality threshold should change over time during the IR term. The amount of capital that is funded each year should change relative to what was funded in rebased rates to reflect the current price cap adjustment and growth in demand.

This concept may not have been as important when the ICM was first introduced because at that time the normal cycle was four years (cost of service to rebase rates followed by three years of IR adjustments). With the adoption of a five year cycle (rebasing followed by four years of Price Cap IR) and the introduction of the ACM review for projects in conjunction with the 5-year DSP, the cumulative temporal impact is more significant.

In the recent working group, OEB staff proposed a variation on the formula to address this matter, noting that it would be the multiplicative and cumulative impact of both the price cap adjustment and growth that increases the amount effectively funded through

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[9] This is true for an ACM application where the variables in the formula are not affected by which year of the IR period the ACM is being requested. However, for an ICM, the PCI will change from year to year during the IR period and this will change slightly the corresponding threshold amount.

[10] *Report of the Board: Rate-Making Associated with Distributor Consolidation (EB-2014-0138)* March 26, 2015, section C

rates in each subsequent price cap year. OEB staff prepared a modified formula to be used for ACM and ICM applications. No concerns were raised by the working group.

The OEB adopts the multi-year formula to be used for ACM and ICM applications. This applies both with respect to ACM proposals reviewed in cost of service applications, and to ACM/ICM applications for rate riders to fund qualifying ACM/ICM capital projects coming into service during the Price Cap IR term.

4.2 The Growth Factor

In the OEB's view, a reasonable growth estimate should also be accounted for in the materiality threshold calculation. Capital additions are often, at least in part, to connect and serve new customers. However, new customers and demand also mean new revenues that help to recover the costs to serve the new demand. This is in addition to increased revenue due to the $I - X$ (i.e., price cap index or PCI) price cap adjustment to base rates each year.

As originally formulated and implemented in the 3rd Gen IR Supplemental Report, growth is represented by the change in (economic) demand[11] between two time periods. Economic demand is composed of three elements for electricity distribution:

- Number of customers
- kilowatt hours (kWh) of electricity consumption
- kilowatts (kW) of energy demand, for demand-billed customers

Growth is estimated as the weighted average of the change in each of these demand components between two time periods, where the weights correspond to the revenue weights. For this calculation, prices are held fixed between the two periods, as the impact of changes in prices due to price cap adjustments is captured by the PCI variable in the formula.

4.2.1 Weather Normalized vs. Weather Actual Data

The original growth calculation established by the OEB compares the weather-normalized load forecast from the most recent cost of service application to recent weather-actual demand. Variability in weather (and in other factors, notably economic activity) can influence the period-over-period change in demand. Comparing weather-normal against weather actual demand introduces variability into the results.

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[11] The use of the term "economic demand" is used to distinguish it from "electricity demand" (i.e. peak demand in *kW).*

However, KPMG determined that this is largely unavoidable given the methodology. It also noted that there is no tangible quantitative evidence that the present calculation is resulting in a systematic bias in the materiality threshold formula, resulting in a misspecification of the amount of capital that is reflected in rates.[12]

The OEB observes that any error introduced is reduced by the proportion of revenues that are from non-weather-sensitive charges – the monthly fixed service charge, variable charges for non-weather-sensitive customer classes, and due to the fact that there is base load consumption even for weather-sensitive customers. The rate design initiative implemented following the completion of the KPMG Report, for the Residential customer class, will also reduce the distribution revenues subject to weather variability, so that any weather-sensitive errors will be further minimized.

Accordingly, the OEB will not revise this component of the approach to the calculation of the growth factor.

4.2.2 Annualized Growth Factor

Consideration of the previous issue, and of potential options, revealed another matter related to the operationalization of the ACM/ICM policy. As originally derived (and discussed above), the materiality threshold is a single year-over-year change.

The ICM spreadsheet, and now the new ACM module, compare the most recent actuals (excluding the cost of service year) against the cost of service test year forecast. A review by OEB staff revealed that with the previous formula, a two-year growth is calculated for ICM applications that are filed in year three of the IR period. This is because it is dependent on the year of the most recent actuals relative to the test year, as documented in Appendix C of this Supplemental Report. The analysis indicated that this was unlikely to have been an issue when the ICM was introduced in 3rd Generation IR, when there were normally only three years of price cap adjustment applications between cost of service applications to rebase rates. A review of ICM applications to date has indicated that no ICM applications with two-year growth rates have been considered.

With the extended term for Price Cap IR, whereby there are now normally four years between rebasing applications, there is an increased possibility that a two-year growth factor will occur for an ACM/ICM application. Also, where an ACM is filed as part of a cost of service application there is, almost without exception, a two-year difference between the most recent historical actuals and the test year forecast.

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[12] KPMG's Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219*, p. 35

With the adoption of a multi-year formula, it is appropriate that the growth factor g, like the approach to the current PCI, be annualized. Where the module calculates a two-year growth rate (i.e. for the ACM in a cost of service application or in the fourth Price Cap IR application), a proxy for the annual growth rate is realized by dividing the growth rate calculation by two.[13,14] The proposed revision to the growth factor was discussed and no concerns were raised by the working group.

The ACM materiality threshold formula will be modified to incorporate an annualized growth factor.

4.3 The Dead Band

As enunciated by the OEB in the 3rd Gen IR Supplemental Report:

> Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.[15]

In the end, the choice of the level of the dead band is not founded on any theoretical basis, but is a practical decision to balance identification of legitimate proposals for necessary incremental capital funding versus numerous marginal applications.

The KPMG analysis, and in particular its modelling of various scenarios, examined the influence of the dead band and the impacts of the adoption of TFP and IFRS on the dead band variable. In its report, KPMG concluded that the adoption of TFP as the basis for the productivity factor for Price Cap IR and the adoption of IFRS have no

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[13] While a more exact calculation is possible, this proxy is simpler. Further, as growth in demand is typically less than 2%, any error is likely immaterial.

[14] Under the recent report on rate setting under distributor consolidation (see footnote 5), three-year, four-year or longer period growth rates in the ACM spreadsheet could result under extended deferral periods. Dividing by 3, 4, etc., as appropriate, would give a suitable annualized growth rate. These will be exceptions dealt with on a case-by-case basis.

[15] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors EB-2007-0673*, September 17, 2008, p. 33

material or sustained impacts on the materiality threshold formula as it was first derived in 2008.[16]

However, KPMG recommended that the dead band could be reduced, even to zero, in order to balance what it viewed as competing objectives such as encouraging effective distributor planning, including the development of appropriate asset management plans, while reflecting the static nature of the materiality threshold formula and protecting rate payers from paying for incremental capital expenditures that are already notionally reflected in base rates. KPMG noted that the determination of the dead band is ultimately a discretionary matter for the OEB, using its expert judgment to balance competing objectives. KPMG also provided an analytical example that if the dead band is maintained at the 20% level, the materiality threshold formula would generate a dollar value of capital in rates which is larger than the notional capital reflected in rates throughout the IR period.

For the reasons set out in the 3rd Gen IR Supplemental Report, the OEB is of the view that the dead band should remain above zero. The dead band being set at zero means that any qualifying incremental capital above what is factored into rates, and adjusted by the Price Cap Index and growth, would be fundable through an ACM/ICM rate rider. However, the OEB recognizes the imprecision in the Price Cap IR formula, and in the estimates and data used in the formula and in rate-setting generally.

Further, a utility’s management is expected to control or influence what it needs to do from both a capital project perspective and ongoing operations to distribute electricity to customers in a safe, reliable and high quality manner. Regulatory approaches such as IR, and augmented by the OEB’s RRFE approach, provide flexibility for the utility’s management to do so.

With this in mind, the OEB considers that a dead band remains an appropriate means to allow for appropriate funding for qualifying ACM/ICM projects, while discouraging numerous applications for marginal amounts that the utility would be expected to manage under the RRFE and Price Cap IR framework. However, maintaining the dead band at 20% may not be responsive to the OEB’s RRFE objectives of enhanced distributor planning and effective access to available regulatory tools to facilitate pacing and prioritizing needed capital investments.

Furthermore, with the adoption of the multi-year formula discussed in 4.1 above, the OEB concurs that the dead band should decrease. The materiality threshold has been

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[16] KPMG’s Report, New Policy Options for the Funding of Capital Investments: EB-2014-0219, p. 38 and pp. 40-41

used in its original formulation regardless of which year in the IR term the ICM application was proposed. The multi-year formula now explicitly and appropriately factors in the cumulative, multiplicative impact of both growth and the price cap index over the years since the utility's last cost of service rebasing application. In part, this may have been captured implicitly (and imperfectly) through the earlier dead band.

The OEB has determined that a dead band of 10% is more appropriate in light of the changes being made to the materiality threshold formula, and balancing the need for appropriately funding necessary incremental capital investments while avoiding numerous marginal applications and providing some protection that amounts are not already funded through rates.

In the OEB's view the redefined materiality threshold formula and the redefined growth and dead band variables should provide better information on when incremental capital projects qualify and on the quanta of qualifying capital investment dollars that should be funded in advance of the next cost of service application.

4.4 The Stretch Factor

Currently, as an input to the materiality threshold formula, a utility uses the most recent stretch factor applicable to it, as derived from the annual benchmarking analysis commissioned by the OEB. The stretch factors are primarily used for calculating the price cap adjustment for IR applications. Under the current IR framework, the stretch factors range from 0% to 0.6%, with more efficient utilities, as determined through the econometric analysis, assigned a lower stretch factor. However, most utilities will be grouped into the middle cohort and have a 0.3% stretch factor. The stretch factors are updated annually, and can change over time, although movements are typically gradual.

As part of the working group's discussions, OEB staff noted that, with the multi-year formula, the stretch factor could change from year to year. In addition, the stretch factor has an impact on the materiality threshold calculation, as it is included in the PCI variable. OEB staff observed that the impact of the stretch factor on the materiality threshold is counter to the incentive that underpins the price cap adjustment: a more efficient utility would have a lower stretch factor and a higher PCI and, consequently, a higher materiality threshold result than would a less efficient utility. This means that a more efficient utility would have less available capital for incremental funding than would a less efficient utility, all else being equal.

OEB staff recommended that the middle stretch factor of 0.3% be used as a default, instead of updating with the distributor's most recently published stretch factor. This would eliminate any counter-intuitive impacts as mentioned above and put utilities on an equal footing regardless of their efficiency ranking with respect to access to qualifying incremental capital. Use of the 0.3% would also simplify calculations.

There was no consensus on this proposal, as one view suggested that this was a change in the methodology that needed to be considered from the start, or as part of a review of the entire materiality threshold formula. The change would disadvantage utilities with less efficient rankings.

The OEB considers that the proposal to use the 0.3% stretch factor as the default is reasonable in that it neutralizes the threshold test in terms of being impacted by performance. An analysis conducted by the OEB staff using filed ICM models from previous applications indicates that the impact of using a 0.3% stretch factor instead of 0.6% is approximately 4% on the resulting capital expenditure threshold, even with the adoption of the multi-year formula. While the difference in available capital is not insignificant, on an annual revenue requirement basis it is likely below a distributor's materiality threshold as outlined in the OEB's Filing Requirements[17] . Since a 0.3% stretch factor would apply to most utilities, and in most years, any bias would be minimal.

The OEB has determined that the stretch-factor assigned to the middle cohort (currently 0.3%) be used in the materiality threshold calculation for any ACM/ICM application.

4.5 The New ACM/ICM Materiality Threshold Formula

As a result of the work of KPMG and OEB staff, and considering the feedback from the working group members, the OEB will alter the materiality threshold formula by adding the highlighted portion as follows:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where n is the number of years since the cost of service rebasing. Other parameters are as defined in the original formula, except for the following changes:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

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[17] *Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, Chapter 2*, pp. 13-14

Appendix B provides further details on the updated formula and parameters.

The right-hand side of the equation has been altered to reflect the cumulative and multiplicative impact of both growth and the price cap adjustment over time during the Price Cap IR term.

5 Filing Requirements

Section 5 of the ACM Report provided information on the filing requirements related to ACM and ICM applications as part of cost of service or Price Cap IR applications. The nature of the information required for an ACM or ICM application is unchanged by the policies adopted by the OEB in this Supplemental Report.

The OEB-issued model for the ACM/ICM has been updated to reflect the changes in the materiality threshold formula and associated parameters adopted in this Supplemental Report. The updated ACM/ICM model is posted on the OEB's website, and applicants should use that version in cost of service or Price Cap IR applications, as necessary.

The changes to the materiality threshold formula adopted herein and the determinations made by the OEB on the half-year rule will be reflected in the Filing Requirements applicable to cost of service and Price Cap IR applications for electricity distributors when the Filing Requirements are next updated.

Appendix A

The Capital Module Policy [Unchanged from the ACM Report]

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Appendix B

Materiality Threshold Calculations [Updated]

The following table explains the variables used to determine the preliminary materiality threshold for ACM/ICM proposals in both cost of service applications and as part of Price Cap IR applications for rate riders to recover qualifying ACM/ICM incremental capital investments.

General Formula:		$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + 10\%$	
Parameters		**Preliminary Calculation for proposed ACM-qualifying capital projects, as part of a Cost of Service Application**	**Final Calculation for pre-qualified ACM projects or for proposed ICM projects, as part of a Price Cap IR Application**
Rate Base	RB	In its application, the utility should use its proposed test year rate base.	The distributor should use the approved rate base from its last cost of service application.
Depreciation	d	In its application, the utility should use its proposed depreciation expense for the test year.	The distributor should use the approved depreciation expense from its last cost of service application.
Growth	g	g is always to be expressed as an annual growth rate. Growth is calculated based on the percentage difference in distribution revenues between the forecast distribution revenues for the test year and the distribution revenues from the most recent complete year. There is normally a two-year gap between the most recent actuals and the test year forecast in the cost of service application, so the growth factor is annualized by dividing by two.	g is always to be expressed as an annual growth rate. Growth is calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application. In the first and second Price Cap IR years following rebasing, a distributor will not have a complete year of data following the cost of service base year. For these years, the growth factor reflects the difference between the OEB-approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year. By the fourth year of Price Cap IR following rebasing, there will be a two year gap between the most recent actuals and the approved cost of service test year forecast; the growth factor is annualized in this situation by dividing by two.[18]
Price Cap Index (IPI – stretch_factor)	PCI	Distributors should use the IPI from its most recent Price Cap IR application and the stretch factor assigned to the middle cohort.	Distributors should use the IPI from its most recent Price Cap IR application as a placeholder for the initial application filing. This information is updated if new information becomes available during the proceeding. Distributors must use the stretch factor assigned to the middle cohort as the default stretch factor.
Years Since Rebasing	n	n is the number of years after rebasing	n is the number of years since the last rebasing.

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[18] *See Appendix C for a more detailed breakdown*

Appendix C
Growth Factor Calculation for Final ACM/ICM Materiality Threshold

2016 Test Year Example

Price Cap IR Year (past rebasing in 2016)	**Year**	**Growth Factor Revenues**		**Is Growth one-year or multi-year?**
		Numerator	**Denominator**	
1	2017	OEB-approved 2016 test year	2015 historical actuals	One-year
2	2018	OEB-approved 2016 test year	2015 historical actuals	One-year
3	2019	2017 historical actuals	OEB-approved 2016 test year	One-year
4	2020	2018 historical actuals	OEB-approved 2016 test year	Two years (will be annualized)
5[19]	2021	2019 historical actuals	OEB-approved 2016 test year	Three years (will be annualized)
etc.				

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[19] *If longer than four years on Price Cap IR (e.g. due to a merger or amalgamation, or approved deferred rebasing)*

TAB 14

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2014-0219

Report of the Board

New Policy Options for the Funding of Capital Investments: The Advanced Capital Module

September 18, 2014

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1 Introduction

On July 18, 2014, the Board released Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications (for applications filed under cost of service). In that document the Board continued its promotion of a change to the way electricity distributors think about the future. The Filing Requirements noted that the *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") "emphasized the importance of good distribution system planning, including optimizing, prioritizing and pacing distributor's capital expenditures to control costs and promote rate predictability."

The Board also noted that it will "review the single test year application not just in the context of the projects and programs that are requested for the test year, but from the perspective of the distributor's plans for the subsequent four years until the next scheduled rebasing application. It is the Board's expectation that at a minimum, cost of service proceedings will consider the entire five year distribution system plan as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the Distribution System Plan."

In this *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the "ACM Report"), the Board continues its progress towards incenting electricity distributors to develop and justify a long-term strategy for delivering distribution services that their customers value and that reflect manageable rate impacts over the long term. Accordingly, this ACM Report establishes a new mechanism to assist electricity distributors in these efforts.

This ACM Report is the culmination of the first phase of a brief consultation initiated by the Board on June 20, 2014. The consultation was on *New Policy Options for the Funding of Capital Investments* (EB-2014-0219). In the letter initiating the consultation, the Board indicated that Board staff had developed two new policies on which it will be seeking comments before bringing the new policy options to the Board for consideration:

- The elimination of the effect of the half year rule on test year capital additions for the intervening years between rebasing applications; and

- The introduction of a new funding mechanism that would enable review during a cost of service application for the need and prudence of any incremental capital module funding requests for discrete projects that are part of a distributor's

Distribution System Plan, and that are planned to come into service during the IRM period (the Advanced Capital Module or "ACM").

It was the Board's intention that these policy options, if approved, would be available to distributors under the Price Cap IR option. They would not apply to distributors under the Annual Index option. Distributors that have specific needs for capital funding that cannot be accommodated under Price Cap IR, should consider whether their specific circumstances would be best addressed through an application for a 5-year Custom IR plan.

A working group consisting of several representatives from electricity distributors who had adopted the Price Cap IR option for 2015 rates, as well as other stakeholders, was convened on June 25, 2014. Based on the feedback provided by the working group, the Board has decided to establish the Advanced Capital Module mechanism.

The purpose of this ACM Report is to articulate the Board policy on the ACM, and how the current policy regarding the Incremental Capital Module ("ICM") mechanism is changing.

The Board does not intend to proceed with the elimination of the effect of the half year rule on test year capital additions for the IRM years at this time. The Board will continue to review this matter and may proceed with a further consultation at some point in the future.

2 Background

In July and September of 2008 the Board established its framework for 3rd Generation Incentive Regulation with the release of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "July 2008 Report of the Board")*, and the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - EB-2007-0673)* (the "Supplemental Report"), respectively. As part of that framework, the Board introduced the approach for the ICM as a means by which a distributor could apply for and receive funding for significant capital projects that would be undertaken in years between cost of service applications.

The ICM was intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The materiality threshold represented a distributor's financial capacities underpinned by existing rates, including growth. The requested amount for an ICM claim had to satisfy the eligibility criteria of materiality, need and prudence as set out in section 2.5 of the July 14, 2008 Report of the Board. Notably, the "need" criterion involved a demonstration that the amounts should be directly related to the claimed driver, which must be clearly non-discretionary.

The ICM was in essence a funding mechanism for significant capital projects for which a utility required rate recovery in advance of its next regularly scheduled cost of service application. Distributors were required to make specific requests for ICM funding as part of their incentive regulation mechanism ("IRM") applications. Applications were required to be accompanied by comprehensive evidence to support the claimed need as well as the proposed rate riders to establish the funding for the IRM period. Approved projects would then flow into the distributor's rate base at their remaining net book value, at the time of the next cost of service application.

Since 2008, the Board has reviewed 13 applications for ICM funding. Appendix C to this Report is a listing of these applications.

While the three key criteria of materiality, need and prudence have underpinned the review of all applications filed to date, the Board has evolved its approach to the ICM over the years, specifically with respect to its scope.

2.1 The Evolution of the Scope of the ICM

Preceding this ACM Report, the Board did not issue an updated policy paper on the ICM. The Board's policy and specifically, the criteria underpinning that policy have evolved and been refined in the Board's decisions which have in turn been incorporated into the Board's Filing Requirements over the years.

In the first application before the Board for an ICM, Hydro One Networks Inc.[1] identified its capital budget for the 2009 rate year and requested approval for ICM funding for the entire difference between the capital budget and the materiality threshold. In its decision, the Board noted that:

> *In considering Hydro One's application in this case it is apparent that Hydro One has conflated the calculation of the threshold and the eligibility criteria. While the relationship between depreciation expense and capital spending establishes the base materiality threshold, the relationship itself is not the determinative factor in assessing the appropriateness of the use of the incremental capital*

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[1] *EB-2008-0187*

> *module. Hydro One has substantially predicated its application on the gap between its depreciation expense and its capital spending plan. In fact what the Board requires in considering an application under the incremental capital module is a demonstration that the distributor is facing extraordinary and unanticipated capital spending requirements; i.e. something other than the normal course of business. (Emphasis added)*

While the Board's September 2008 Supplemental Report specifically refers to unusual circumstances in giving rise to eligibility under the module, the Board noted that Hydro One's claim that the gap between its depreciation expense and its capital spending could not be considered unusual circumstances given that Hydro One had been operating since 2002 with a similar gap. While the Board afforded some relief to Hydro One, it did not consider Hydro One's application under the Incremental Capital Module. The Board thus evolved the ICM policy through this decision by clarifying that projects were not only required to be part of a capital budget that is incremental to the materiality threshold, but must also be driven by capital spending requirements that are extraordinary and unanticipated.

No ICM applications were filed for the 2010 rate year. For the 2011 rate year, two distributors filed requests for ICM funding in relation to new municipal transformer stations. In its decisions for Oakville Hydro Electricity Distribution Inc. and Guelph Hydro Electric Systems Inc.,[2] the Board approved ICM funding for both applications noting that the projects were non-discretionary expenditures that were clearly outside of the base upon which rates were derived.

These two decisions clarified two significant principles. First, they clarified that ICM requests must first establish the amount of eligible capital available to distributors by subtracting the materiality threshold result from the total non-discretionary capital budget for the subject year. This clarification was consistent with the Board's decision on Hydro One's 2009 application which noted that the mere existence of a gap between the threshold and the capital budget is not determinative for ICM funding.

Second, in approving ICM funding for transformer stations, which have longer lead times for design and construction as compared to most other distribution-related capital projects, the Board had in essence set aside the criteria of extraordinary and

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[2] *EB-2010-0104 and EB-2010-0130 respectively*

unanticipated. This was reflected in the Board's 2013 Filing Requirements[3] in which these criteria were removed.

To date, nine out of the 13 ICM applications filed have included transformer-related assets as the focal point of the funding request.

The one remaining notable application for ICM funding was that of Toronto Hydro-Electric System Ltd.'s[4] three year application for 2012 to 2014 inclusive. While Toronto Hydro proposed a number of unique approaches to the Board's ICM policy in effect at the time, the two most notable that were approved were the multi-year approach and the request for multiple projects encompassing most of the eligible incremental capital available to the company in each of the three years.[5]

In its decision, the Board determined that both proposed approaches for incremental funding were approved in light of Toronto Hydro's unique circumstances.[6] While the Board approved funding for both the 2013 and 2014 rate years, it stated its expectation that future IRM filings will only be for one year, unless there are appropriate circumstances that justify a multi-year approach to IRM.

Following are a number of excerpts from the Board's decision:

> *The Board finds that on a case by case basis, some projects that might be characterized as "business as usual" may be eligible for ICM. The criteria in the Reports do not require that capital expenditures are on an "emergency or urgency basis" but rather, that the work must be undertaken and that the existing capital in the rebasing year is insufficient to do so. The Board rejects the notion that projects that might be "routine" or "business as usual," are ineligible categorically for an incremental capital module […]*[7]
>
> *The Board's Supplemental report (p. 31) does refer to unusual circumstances but does not refer to unanticipated circumstances. The Board finds that the aging infrastructure and the associated capital needs of the magnitude faced by*

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[3] *Chapter 3 of the Filing Requirements for Transmission and Distribution Applications (Incentive Regulation Mechanism)*

[4] *EB-2012-0064: This proceeding took place in two phases with Phase 1 reviewing 2012 and 2013, and Phase 2 reviewing 2014.*

[5] *It should be noted that for the 2012 rate year, no eligible capital was available once the Board established that Toronto Hydro's non-discretionary capital budget for the 2012 calendar year did not exceed the materiality threshold for that year. Therefore, no ICM recovery was approved for that year.*

[6] *In its Part 1 decision for the 2013 test year, the Board disallowed ICM treatment for certain planned capital projects, although the majority of capital projects and costs were approved. (Partial Decision and Order, April 2, 2013). The 2014 capital program was subject to a Settlement Agreement subsequently approved by the Board (Transcript, Vol. 11, December 19, 2013, pg. 5, ll. 3-8).*

[7] *EB-2012-0064, Partial Decision and Order, April 2, 2013, pg. 18*

> *THESL can be considered "unusual" in the broader context of Ontario utilities […]*[8]
>
> *The Board notes that most previous ICM applications approved by the Board have been for one or a few discrete large projects. While the Board will not adopt the suggestion of some parties that each project put forward by THESL should meet the overall materiality threshold, the Board does not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget.*[9]

In summary, as of the end of the 2014 rate year, the scope of the Board's ICM policy, as implemented in its decisions (aside from the unique circumstances of Hydro One and Toronto Hydro), have involved discrete non-discretionary capital projects that have a significant influence on the operations of a distributor, that are not limited to extraordinary or unanticipated investments, and whose allowable cost is limited to the difference between the non-discretionary capital budget and the materiality threshold.

The above experiences, along with the outcomes of the June 25 Working Group session, and the impact of the adoption of the Renewed Regulatory Framework with its emphasis on planning, have informed the content of this ACM Report; specifically, why requests for incremental capital funding should be proposed much earlier in a distributor's planning horizon, and what criteria (both new and existing), should be established, revised or maintained given this shift.

The next section discusses the impact of the adoption of the Renewed Regulatory Framework.

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[8] *Ibid., pg. 18*

[9] *Ibid., pp. 18-19*

3 The Need for a Revised Incremental Capital Module Mechanism

The Board's RRFE Report represented a significant evolution of the approaches for rate regulation of the sector. In the RRFE Report, the Board established three rate-setting options for electricity distributors:

- Price Cap Incentive Rate-Setting ("Price Cap IR"), under which rates are rebased through a cost of service application followed by four years of rate adjustments through an annual formulaic price cap adjustment;
- Annual Incentive Rate-setting ("Annual IR"), whereby the distributor files for annual rate adjustments under the price cap formula, without rebasing, but subject to rates being adjusted by the highest stretch factor; and
- Custom Incentive Rate-setting ("Custom IR"), whereby the distributor proposes a plan to be effective for rate setting for five years, and with an approach that the distributor feels would reflect its capital and operating needs more appropriately than would the other approaches.

The subsequent *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379)* ("the Price Cap IR Report"), issued November 21, 2013 and updated December 4, 2013, provided further details on these three rate-setting mechanisms.

A risk for any form of regulation is the emergence of unintended consequences as a result of regulated entities responding to incentives that emerge inadvertently from the regulatory framework within which they operate. One such tension that has been observed is the regular pacing of capital projects at certain points within the rate-setting cycle. There appears to be a tendency for capital projects, particularly major ones, to be clustered around the test year when the distributor rebases its rates through a cost of service application. In subsequent years, capital expenditures and additions may be substantially less than the levels in the bridge and test year(s), possibly as a means of managing capital and operating expenses relative to the often smaller changes in revenues in those years where a price cap formula is used to adjust rates.

The concern is that this volatility (i.e. the "roller coaster" effect) of capital investments to fit the rate-regulation schedule does not necessarily align with when the investments should be made under prudent asset management practice. While a significant portion of capital investment may be “routine” (i.e., fairly predictable and levelized), some volatility and lumpiness is not uncommon. The nature of major capital projects, such as transformer station builds or replacement, is one reason that some “bumps” in capital spending may be unavoidable. However, while timing these around when the rate base is “reset” in a cost of service application provides greater assurance of recovery of the investments (if approved), such clustering of projects is often not optimal from an asset management perspective, nor desirable from a rate impact perspective.

As the Board has identified in the RRFE Report and other documents[10], the Board is of the view that the industry would be better served by a more disciplined approach to capital planning. In recent years, the Board established expectations that distributors conduct and file Asset Management Plans as part of cost of service applications. This has evolved into the current Distribution System Plan (“DSP”) requirement. Under the RRFE, distributors are also expected to provide documentation on their efforts to engage customers on the necessary capital and operating costs and on the associated cost consequences that will be ultimately impacting customers.

Incenting distributors to adopt a longer term planning horizon for capital and operating projects should enable the distributor to optimize its resource requirements (financial, human and equipment) so as to be able to efficiently and effectively serve existing customers while planning for and making investments to serve future needs in a timely manner.

Accordingly, the Board has decided to advance the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IRM term) to the preceding cost of service application in which a distributor is required to file a five year Distribution System Plan encompassing the cost of service test year and the four subsequent incentive rate-setting[11] (“IR”) years.

As will be explained further in section 5 of this ACM Report, the opportunity for requests for review and approvals of incremental capital during the IR term will be maintained for projects that were unanticipated at the time of the development of the Distribution System Plan, or for projects anticipated but for which sufficient rationale was not available at the time of the DSP to establish need and prudence.

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[10] e.g., *Filing Requirements for Distribution Rate Applications – Chapter 5 - Consolidated Distribution System Plan Filing Requirements*.

[11] *This Report uses Incentive Regulation Mechanism (“IRM”) and Incentive Rate-setting (“IR”) interchangeably.*

4 The Revised Capital Module Policy

In light of the Board's expectations, as signalled in the RRFE Report and associated documents, the Board is establishing the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").

The review and approval process of the rate riders intended to implement cost recovery of approved ACM projects, will be maintained as part of the IR application process.

This approach adapts and adds to the ICM mechanism**.** Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.

When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should reduce incentives for clustering capital projects around the rebasing year. Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle. While some lumpiness of capital projects may be unavoidable (particularly for distributors with smaller rate bases, where a single project such as a transformer station build or replacement would be a major fraction of any annual capital budget), the Board expects that the volatility that has been observed in some cost of service applications in recent years will be reduced.

The ACM approach will also assist in large part to preserve the regulatory efficiency of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides greater assurance of recovery for prudent and appropriately prioritized capital projects regardless of when the investments might be made.

The Board would also expect improved performance with respect to capital forecasting both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.

Following any approvals in a cost of service application, the distributor would still have to file information in the applicable IR application to confirm that the ACM is on schedule to be completed as planned, that the costs of the projects have not significantly changed from the original forecast, and to determine the appropriate rate riders for approval.

In general, the details and need for a project that has received ACM approval in a previous cost of service application should not need to be re-examined in an IR application; however, if the forecasted costs (or timing) are significantly different than what was in the DSP, the onus is on the distributor to support the changes.

In particular, if costs are 30% (or more) above what was documented in the DSP, the distributor has the option of seeking approval for the incremental costs but would typically treat the project as a new ICM and re-file the business cases and other relevant material in the applicable IR year. It is expected that the Board will include this condition as part of the ACM approval. This would provide the applicant and parties an opportunity to argue for a different (higher or lower) percentage depending on the nature of the project.

If costs are less than 30% above what was documented in the DSP, the distributor should still explain the need for the increased costs, whether and how re-prioritizing of capital projects has been considered, how impacts on the rates and bills of the distributor's ratepayers have been taken into account and finally, whether the project is still the best option. Any changes in project scope must be clearly explained and justified.

If the in-service date has been delayed to the following rate year (or beyond), distributors should identify this fact in the earliest possible IR application and confirm in which IR application the distributor expects to seek to commence funding for the project. Funding shall not commence for any projects that are not forecasted to be in service during the subject IR year.

Following a cost of service application, per the current ICM policy (which is now extended to ACMs), the actual costs and the recoveries would be reviewed for any material discrepancies. If there are significant variances between the revenue requirement based on actuals and the revenues collected through the ACM rate riders, the Board may decide to true up any differences. The following sections provide further discussion and details on ACM and ICM approvals during the IR period.

The Board will retain an incremental capital module (or "ICM") for the IR years for projects not included in the DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence. Further information on the scope of the revised ICM are outlined in section 5 below.

4.1 New and Revised Criteria

The Board considers that the current ICM approach has been tested and, most importantly, is serving the purpose for which it is intended. The ACM concepts build on this experience and takes advantage of the information available in the DSP that is filed as part of a cost of service application.

Applications for requests for determination of the need and prudence for proposed projects to be included in ACMs as identified and documented in the DSP will use similar criteria as is required currently for an ICM project as part of an IR application. However, in this regard there have been some revisions to the current ICM criteria, as well as the adoption of new criteria, that will apply to both ACMs and ICMs. These are set out below. Criteria that will continue to apply unchanged to both an ACM and ICM are outlined in section 4.2.

4.1.1 The Adoption of the "Discrete" Project Criterion

The Board is of the view that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs. This would apply to both ACMs and ICMs going forward.

The Board will make a determination on whether projects are discrete on a case by case basis. However, there must be a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year), and the Custom IR method. The use of an ACM is most appropriate for a distributor that:

- does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
- is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. “business as usual” type projects); or
- is not proposing to use the entire eligible incremental capital envelope available for a particular year.

4.1.2 The Adoption of a Preliminary Materiality Threshold Calculation

The Board will not require distributors to forecast final details of the ICM formula (i.e. the materiality threshold) for each of the IR years at the time of the cost of service application. Instead, any approvals sought at the time of the cost of service application will be based on need and prudence. The final assessment on whether or not the quantum of the approved project fits within the maximum allowable capital amount (i.e., the total eligible incremental capital amount) will take place at the time of the applicable Price Cap IR application. If the costs of the project(s) exceed the total available envelope for the subject year, the amount allowed for recovery will be limited to the maximum allowable capital amount.

However, **as part of the cost of service application, distributors must provide a preliminary estimate of the materiality threshold value (and consequently, the total eligible incremental capital amount) for the subject year in which the proposed project is planned to enter service in order to provide the Board with a degree of certainty that the distributor will meet the threshold criteria**. As noted above, the quantum of the threshold and the maximum allowable capital amount for the applicable year will be confirmed at the time of the IR application.

The Board has outlined in section 6 of this ACM Report a preliminary threshold calculation to be used for each IR year at the time of the COS application based on the current ICM formula. The Board is not making any substantive changes to the main ICM formula at this time. Some minor adjustments to the description of certain variables have been made to accommodate the timing of the preliminary threshold calculation. The Board intends to continue to review the formula and will determine a course of action, if any, in the future.

4.1.3 The Elimination of the Non-Discretionary Criterion

The Board is of the view that the availability of incremental capital funding during the IR term should no longer be limited to non-discretionary projects. **Any discrete project (discretionary or otherwise) adequately supported in the DSP is eligible for ACM funding subject to capital funding availability flowing from the formula results. The same approach shall apply going forward to new projects proposed as ICMs during the Price Cap IR term.**

With the establishment of a requirement to file a five year DSP, distributors will be expected to develop well-paced plans to maximize the efficiency and effectiveness of their distribution systems in serving customers, and smooth rate impacts where possible. The current approach of limiting incremental funding to non-discretionary projects could inappropriately incent a distributor to time certain projects in their DSP so that funding is available. By expanding the incremental funding to both discretionary and non-discretionary projects, distributors will have the opportunity to develop their most robust plans without limiting their opportunity for incremental funding.

Distributors are required to identify the total annual capital budget for each of the five years as part of their DSP, at the time of the cost of service application. This amount will now be used in the calculation of the total eligible incremental capital amount for any given year (as opposed to the current policy that requires the non-discretionary component to be used as the starting point in the calculation). The same approach shall apply going forward for new projects proposed as ICMs during the IR term.

4.1.4 The Adoption of a Means Test

The Board is of the view that establishing a means test would be prudent in qualifying distributors for incremental capital funding. Any distributor approved for an ACM in its most recent cost of service application must file its most recent calculation of its regulated return (RRR 2.1.5.6) at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. **If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.** Therefore, any approvals provided for an ACM in a cost of service application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The same means test shall also apply going forward for new projects proposed as ICMs during the Price Cap IR term.

While a means test that doesn't allow incremental funding if a distributor is earning more than its Board-approved ROE may be a barrier to a distributor seeking efficiency improvements during the IR term, a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective. Distributors will have the option of explaining any overearnings.

4.1.5 Revisions to the Eligibility Criteria

The eligibility criteria to recover amounts that are incremental to capital investment needs were first set out in section 2.5 of the July 14, 2008 Report of the Board.

The following are the current definitions of Materiality, Need and Prudence as they apply to ICMs.

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (no necessarily least initial cost) for ratepayers.

In order to reflect the new and revised criteria discussed above and to further clarify the purpose of the materiality threshold calculation, the Board has made revisions to the formal eligibility criteria applicable to both ACMs and ICMs.

Most notable of the changes is the Board's decision to revise the reference to amounts (i.e. referring to projects) "exceeding" the Board-defined materiality threshold. While this language has been used in the Board's past reports and in decisions, it has caused much confusion as to its meaning. Specifically, approved amounts do not "exceed" the materiality threshold, rather they must fit within the total eligible incremental capital, which is the difference between the total capital budget for the subject year and the result flowing from the materiality threshold calculation.

Any reference to "exceeding" the Board-defined materiality threshold is therefore in reference to the total capital budget, the starting point to the calculation of the total eligible incremental capital amount. Therefore, the materiality test would be met if there is a positive variance between a distributor's capital budget (typically the budget included in the previous cost of service application) and the Board-defined materiality threshold. The distributor would therefore be eligible to identify projects for ACM or ICM treatment if its capital budget for the subject year exceeds the Board-defined materiality threshold. The materiality threshold is in effect a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates.

In addition, the Board has adopted a project-specific materiality threshold, as identified in the Toronto Hydro decision.[12]

Distributors proposing amounts for recovery by way of an ACM or ICM must meet all three of the following criteria, and their sub-parts.

Criteria	Description
Materiality	A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	The distributor must pass the Means Test (as defined in this ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

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[12] *EB-2012-0064, op.cit. pp. 18-19. Specific projects were not approved on the basis that they were minor expenditures in comparison to the overall capital budget.*

4.2 Current Criteria That Continue to Apply Unchanged

Distributors must file, at the time of the cost of service application, a description of the actions the distributor would take in the event that the Board does not approve the ACM proposal. Similarly, distributors must file comparable information for any ICM requests at the time of the IR application.

Distributors must also include a discussion on any offsets associated with each incremental project for which ACM or ICM treatment is proposed due to revenue to be generated through other means (e.g. customer contributions in aid of construction), at the time of the cost of service application, along with an estimate of the revenue requirement impact associated with those offsets. The final offset amounts, if any, would be confirmed at the time of the IR application.

The ACM and ICM are only available to electricity distributors opting for Price Cap IR. The ACM/ICM approach is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold defined below, while allowing the distributor to obtain necessary recovery of capital investments on a planned and prioritized basis over the whole IR period. Applicants should note that custom approaches to rate-setting should be addressed through selecting the Custom IR option, not by customizing an ACM or ICM proposal. The ACM/ICM approach is not available to distributors filing under the Annual IR plan.

Finally, the Board notes that ACM and ICM mechanisms are intended to provide utilities with an opportunity to establish reasonable rate impacts for customers. In fact, with the longer-term planning horizon of the DSP and of engaging customers on their needs, expectations and willingness to pay, the Board continues to expect that distributors will exhibit greater discipline on the pacing and prioritization and hence on consistency in the levels of capital expenditures over time. At the same time, these options increase the assurance of recovery from when the investments are made and go into service, and the Board expects that distributors will take this into consideration in planning and managing their capital programs.

5 The Scope of the Incremental Capital Module

While the Board has advanced the opportunity for distributors to apply for early identification of projects during the cost of service application to be included for ACM treatment during the subsequent Price Cap IR terms, **the Board will retain the availability of new ICM requests in each of the IR years, with the same scope as exists with the current approach.** ICM projects will not be limited to those that are unanticipated, but will be subject to the revised criteria discussed in this paper such as the elimination of the non-discretionary requirement and the means test. The Board may revisit the criteria for the ICM in the future as experience is gained with the use of the ACM.

As one example of a situation that could trigger a capital project which may be identified in the DSP, but may not contain sufficient detail to address need and/or prudence at the time of the cost of service application, would be where a distributor is required to make a significant investment during its Price Cap IR term based on the outcome of a Regional Plan. The Regional Plan investment might not have been detailed sufficiently at the time of the DSP and cost of service application, but could become a significant capital project in which the distributor may have to invest during the later period of the IR term. ICM treatment would allow for recovery of costs beginning when the investment is made and goes into service, rather than awaiting the next cost of service application to rebase rates.

ICM proposals as part of Price Cap IR applications will result in a more involved Price Cap IR application. Since the nature and need for the ICM-qualifying project has not been pre-identified or pre-tested, all such information would need to be detailed in the Price Cap IR application.

For distributors currently under incentive rate-setting, the current scope, criteria and definitions of the ICM shall continue to apply, subject to the revisions noted in this paper. For example, the elimination of the non-discretionary criterion will apply not just to ACMs going forward, but also to all ICMs that may be filed by distributors currently on incentive rate-setting.

6 Materiality Threshold Calculation

The ICM materiality threshold is discussed in section 2.3 of the Supplemental Report. The Board determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right] + 20\%$$

This formula will continue to apply for IR years. The application of the formula for the final calculation to be provided at the time of approval of ACM rate riders, and ICM projects and associated rate riders in Price Cap IR applications remains unchanged.

This formula will also be used for the preliminary materiality threshold calculation to be provided at the time of an ACM request in a cost of service proceeding. The Board has made minor revisions to the definitions of the variables for the preliminary calculation to address the advanced timing of an ACM request, but does not expect that these changes will significantly alter the results from the previous formula. Appendix B of this ACM Report summarizes the definitions for both the preliminary and final calculations.

As noted earlier in this ACM Report, the Board intends to continue to review the components and applicability of the formula and will determine a course of action, if any, in the future.

Definitions of the terms are as follows:

RB is the rate base in the distributor's most recent cost of service application. This will be the Board-approved rate base in the most recent cost of service application for new ICM requests and for ACM rate rider approvals in a Price Cap IR application. For the preliminary materiality threshold calculation for a distributor is applying for an ACM in a cost of service application, the distributor should use its proposed rate base.

d is the depreciation expense approved in the distributor's most recent cost of service application. This will be the Board-approved depreciation expense in the most recent cost of service application for ICM requests and for ACM rate rider approvals in a Price Cap IR application. For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its proposed depreciation expense.

The value for g is the percentage difference in distribution revenues between the most recent complete year and the approved base year, for ICM requests and for ACM rate rider approvals in a Price Cap IR application. In the first or second IR years following rebasing, a distributor may not have a complete year of data following the cost of service base year. Therefore, for these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year.

For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its forecast distribution revenues as the base year and compare those with the most recent complete year.

Some concerns with respect to the current definition of the growth rate g have been identified previously, as it is derived comparing weather normalized (i.e., last Board-approved) to non-weather-normalized (i.e. actuals). This matter may be reviewed as part of any broader formula review in the future. For now, the Board does not view this discrepancy as materially affecting the formula results.

PCI is the price cap index, calculated as $PCI = IPI - X - stretch\_factor$ as defined in the Price Cap IR Report. Under the Price Cap IR, $X = 0$. For ICM requests and ACM rate rider approvals in a Price Cap IR application, distributors should use the most recently approved IPI and stretch factor as placeholders in their initial filings, and then update that information during the course of the proceeding once the Board establishes updated parameters for the subject year. For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its most recently approved stretch factor and the most current version of the IPI.

The following is a numerical example of a preliminary calculation of a materiality threshold value for an IR year, but calculated at the time of the cost of service application.

Assumptions	Proposed Rate Base	RB	$100 million
	Proposed Depreciation Expense	d	$5 million
	Growth (forecasted dx revenues compared to dx revenues from most recent complete year)	g	(0.01275)
	Current IPI at the time of the application	IPI	1.7%
	Most recently approved Stretch Factor at the time of the application	$stretch\_factor$	0.4%
	Price Cap Index	$PCI = IPI - stretch\_factor$	1.7% - 0.4% = 1.3%
Calculation	$1 + \left(\frac{100{,}000{,}000}{5{,}000{,}000}\right) \times \left(0.01275 + 0.013 \times (1 + 0.01275)\right) + 0.20 = 171.8315\%$		
Result	The materiality threshold (Capex/Depreciation) is 1.718315 or 171.8315%. That is, given the assumptions in this example, the Board would expect the distributor to be able to fund capital expenditures (Capex) up to $8.591575		

	million ($5 million X 1.718315) during the Price Cap IR adjustment following rebasing before being eligible to apply to recover amounts for incremental capital expenditures for qualifying ACM capital projects.

Following the above calculation, the total incremental capital amount can then be calculated for each IR year by subtracting the threshold result from the proposed capital budget identified in a distributor's DSP for each of the four years.

For ACM requests at the time of a cost of service application, this preliminary threshold result may be used for each of the four IR years as an estimate for purposes of providing the Board some degree of comfort that a distributor has a capital budget that exceeds the materiality threshold. The preliminary calculation will demonstrate that the distributor is likely to be eligible to apply for incremental capital before the Board expends efforts in assessing need and prudence for the project.

6.1 The Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amounts sought for recovery should be capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula set out above, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. Section 4 of this ACM Report clarifies the reference to capital in excess of the materiality threshold.

The determination of the maximum allowable incremental capital amount has not changed from the guidance provided in the Board's recent Filing Requirements other than to remove the reference to non-discretionary. **It is now determined by taking the difference between the forecasted <u>total</u> capital expenditures for a subject year and the materiality threshold for that year.**

If the forecasted total capital expenditures identified in a Price Cap IR application, are higher than what the distributor documented in its DSP in its previous cost of service application, the distributor needs to document the increases and the reasons for these. This approach is unchanged from the current ICM policy.

For clarification, the Board's ICM models refer to a "threshold capex". This refers to the dollar value associated with the materiality threshold result and is subtracted from the total forecasted capital expenditures to determine the maximum amount eligible for recovery, for the applicable year.

7 Filing Requirements

Section 2.5.2 of Chapter 2 of the Filing Requirements contains additional information on filing requirements related to capital expenditures. In addition, Chapter 5 of the Filing Requirements deals with the 5-year Distribution System Plan, which will normally be dealt with as part of a cost of service application. An ACM/ICM is an application for recovery of needed and reasonable expenditures for a capital project, and a distributor making an application for an ACM/ICM should reflect the appropriate documentation as detailed in these sections of the Filing Requirements.

7.1 Revenue Requirement Calculation

Distributors must file the calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each approved ACM or proposed ICM, in the applicable Price Cap IR application. Distributors must also identify any revenue requirement offsets associated with each incremental project due to revenue to be generated through other means (e.g. customer contributions in aid of construction).

When calculating the revenue requirement associated with either an approved ACM or an ICM proposal at the time of the Price Cap IR application, a distributor should use the following parameters and methodologies.

7.1.1 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.[13] The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.

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[13] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order*, p. 15. This is appropriate, as the full year of depreciation expense will be explicitly reflected in the determination of the rate base and revenue requirement in the cost of service application for the following test year. Full year treatment of a ICM capital addition in the last year before rebasing would increase the probability of a true-up being required when the actual capital project costs are reviewed and included in rate base to determine rebased rates.

7.1.2 Working Capital Allowance

A distributor shall use the WCA approach approved by the Board in the distributor's most recent cost of service application when calculating the revenue requirement associated with the ACM/ICM.

7.1.3 Cost of Capital

In the December 11, 2009 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084) the Board confirmed the continuation of a deemed 60/40 debt-equity ratio. A distributor filing for ACM or ICM rate riders shall use the cost of capital parameters approved by the Board in the distributor's most recent cost of service application when calculating the revenue requirement associated with the incremental funding.

7.1.4 Taxes / PILs

Since currently known legislated tax changes from the level reflected in the Board-approved base rates for a distributor will be reflected in the rate adjustments for Price Cap IR, a distributor filing for ACM or ICM rate riders should apply the current tax rates for calculating the revenue requirement associated with the incremental funding.

7.1.5 Rate Riders

Distributors must file the calculation supporting the proposed rate riders to recover the incremental revenue from each applicable customer class, and the rationale for the proposed approach.

7.1.6 Bill Impacts

Distributors must also provide bill impacts in a Price Cap IR application and the Board notes that its rate generator model used by most distributors in a Price Cap IR application contains detailed bill impacts for all classes.

7.2 Need and Prudence

A distributor requesting relief for incremental capital (both ACMs and ICMs) must include comprehensive evidence to support the need. If the ACM request is proposed as part of a cost of service application, it is expected that most of the following information would be included as part of the DSP, in any event:

- A preliminary threshold calculation demonstrating that there is a reasonable expectation that the final materiality threshold test at the time of the IR application will be met and that the amounts will have a significant influence on the operation of the distributor;

- A description of the proposed capital projects and expected in-service dates and their costs. In general, this would be satisfied by the filing of a business case and engineering study, as appropriate, for each capital project for which the applicant is seeking ACM or ICM approval;

- Details, by project, for the entire capital spending plan for the subject year. This analysis includes projects that are not being proposed for ACM or ICM treatment.

- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers; and

- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in significant part, included in base rates or being funded by the expansion of service to include new customers and other load growth).

In the Price Cap IR application for the year in which the capital project(s) will go into service and the applicant is seeking to commence recovery through rate riders, the distributor should provide updated, current information with respect to the above for any approved ACMs for any material changes from what was reflected in the DSP.

In the case of an ICM proposal for recovery of an unanticipated capital project, or for a project for which a distributor did not have sufficient information to address need and prudence at the time of the cost of service application, this will be the first time that the distributor is providing such evidence. Therefore full and complete details of the project(s) must be filed, as is the current ICM policy and practice.

7.3 Confirmation of Cost and Timing

If the timing of an approved ACM project is advanced or deferred from when the distributor expected that it would incur the project (in the DSP reviewed in its cost of service application), the distributor must provide an explanation on the reasons for the change in timing, and on how the change in pacing and prioritization may have affected its five-year DSP overall, at the earliest opportunity as part of a Price Cap IR application.

7.4 Reporting Requirements

At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.

7.5 Accounting Treatment

The distributor will record eligible ACM/ICM amounts in Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, subject to the assets being used or useful (i.e. in service). For incremental capital assets under construction, the normal accounting treatment will continue as construction work in progress ("CWIP") prior to these assets going into service and hence being eligible for recording in the 1508 sub-account listed below.

In its July 18, 2014 Filing Requirements applicable to 2015 cost of service applications for electricity distributors, the Board provided further guidance on the recording of amounts related to approved ICM projects and revenues received from approved rate riders.[14] Distributors shall record actual amounts in the following sub-accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures;
- Account 1508 – Other Regulatory Assets, Sub-account Depreciation Expense;
- Account 1508 – Other Regulatory Assets, Sub-account Accumulated Depreciation; and
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues.

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[14] *Filing Requirements for Distribution Rate Applications – 2014 Edition for 2015 Rate Applications*, July 18, 2014, section 2.5,2.7: Addition of ICM Assets to Rate Base

The distributor shall also record monthly carrying charges in the following sub-accounts. Carrying charge amounts are calculated using simple interest applied to the monthly opening balances:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, Carrying charges.
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges;

The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period as published on the Board's web site.
All of these sub-accounts should be used for both approved ACM and ICM projects. If the Board approves the true-up of any variances for ACM/ICM projects at the next cost of service application, the recalculated revenue requirement relating to the actual ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period, plus the carrying charges in the respective sub-accounts. These variances would then be refunded to, or collected from, customers through a rate rider.

7.6 Rate Models

The revised Capital Module work form (applicable to ACMs and ICMs) supporting the IRM Rate Generator model will assist distributors in calculating the distributor's final threshold at the time of the IR application. The distributor will then tabulate the value of its eligible investments and compare this to the threshold result to determine the amount that would be eligible for recovery. The tabulated revenue requirement will then be converted into class specific rate riders.

The work form has also been altered so that it can calculate the preliminary threshold and identify qualifying capital projects from the distributor's DSP for inclusion in the ACM request in the cost of service application.

Appendix A

The Revised Capital Module Policy

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the Board may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Appendix B
Materiality Threshold Calculations

The following table explains the variables used to determine the preliminary materiality threshold, which will be updated in the Price Cap IR application to deal with the implementation of an ACM or ICM project and associated rate riders.

General Formula:		$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right] + 20\%$	
Parameters		**Preliminary Calculation for proposed ACM-qualifying capital projects (as part of a Cost of Service Application)**	**Final Calculation for pre-qualified ACM projects or for proposed ICM projects (as part of a Price Cap IR Application)**
Rate Base	RB	In its application, the utility should use its proposed test year rate base.	The distributor should use the approved rate base from its last cost of service application.
depreciation	d	In its application, the utility should use its proposed depreciation expense for the test year.	The distributor should use the approved depreciation expense from its last cost of service application.
Growth	g	g is always to be expressed as an annual growth rate. Growth should be calculated based on the percentage difference in distribution revenues between the forecast distribution revenues for the test year and the distribution revenues from the most recent complete year.	g is always to be expressed as an annual growth rate. Growth should be calculated based on the percentage difference in distribution revenues between the distribution revenues from the most recent complete year and the distribution revenues from the most recent approved test year. In the first and second IR years following rebasing, a distributor will likely not have a complete year of data following the cost of service base year. For these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year.
Price Cap Index	PCI	Distributors should use the Price Cap Index $(IPI - stretch\_factor)$ from its most recent Price Cap IR application.	Distributors should use the Price Cap Index from its most recent Price Cap IR application as a placeholder for the initial application filing. This information should be updated if updated parameters become available during the course of the proceeding.

Appendix C
List of ICM Decisions (to date)
Issued under the Board's previous policy

File Number	Applicant	Decision Date
EB-2008-0187	Hydro One Networks Inc.	May 13, 2009
EB-2008-0205	Oshawa PUC Networks Inc.	June 10, 2009
EB-2010-0104	Oakville Hydro Electricity Distribution Inc.	March 14, 2011
EB-2010-0130	Guelph Hydro Electric Systems Inc.	March 14, 2011
EB-2011-0178	Kingston Hydro Corporation	April 19, 2012
EB-2011-0207	Woodstock Hydro Services Inc.	March 22, 2012
EB-2011-0160	Centre Wellington Hydro Ltd.	March 22, 2012
EB-2011-0173	Hydro Hawkesbury Inc.	May 3, 2012
EB-2012-0064	Toronto Hydro Electric System Limited	April 2, 2012
EB-2012-0124	Festival Hydro Inc.	April 4, 2013
EB-2013-0166	PowerStream Inc.	February 20, 2014
EB-2013-0178	Wellington North Power Inc.	March 13, 2014
EB-2013-0127	Espanola Regional Hydro Distribution Corporation	March 13, 2014

TAB 15

EB-2016-0025

IN THE MATTER OF Sections 86 and 18 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B, as amended;

AND IN THE MATTER OF an application for the relief necessary to effect the consolidation of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc. into an entity referred to in the Application as "LDC Co", in the manner set out in this Application.

REPLY SUBMISSIONS OF THE APPLICANTS

A. INTRODUCTION

1. In this proceeding, the Ontario Energy Board ("OEB" or the "Board") has established a process for consideration of an application for relief under sections 86 and 18 of the *Ontario Energy Board Act, 1998* (the "OEB Act")[1]. Specifically, the Applicants have requested approval of the relief necessary to effect the consolidation of Enersource Hydro Mississauga Inc. ("Enersource"), Horizon Utilities Corporation ("Horizon Utilities"), PowerStream Inc. ("PowerStream") and Hydro One Brampton Networks Inc. ("HOBNI") into a single entity, which is referred to as LDC Co in this application[2] (the "Application").

2. The Applicants have also requested leave for Enersource, Horizon Utilities, PowerStream and HOBNI to transfer their distribution licences and rate orders to LDC Co[3]. Further, the Application has been amended to include a request for the issuance of a new distribution licence for LDC Co that will come into existence on the completion of the transfer of the distribution-related assets of the consolidating entities to LDC Co, to be followed immediately by the cancellation of the distribution licences of the consolidating entities[4].

3. Through the course of the proceeding, the Board has issued a number of procedural orders. Procedural Order No. 5 sets out a process for final arguments that includes the filing of submissions by OEB Staff and intervenors by October 7, 2016 and the filing of a reply submission by the Applicants. The following submissions have been filed in this proceeding:

   (i) Ontario Energy Board Staff ("Board Staff") filed the OEB Staff Submission ("Staff Submissions") on October 7, 2016;
   (ii) the Association of Major Power Consumers in Ontario ("AMPCO") filed AMPCO Final Submissions ("AMPCO Submissions") on October 8, 2016;
   (iii) the Building Owners and Managers Association Toronto ("BOMA") filed its Written Submissions ("BOMA Submissions") on October 4, 2016;
   (iv) the Consumers Council of Canada ("CCC") filed the Final Argument of the Consumers Council of Canada ("CCC Submissions") on October 7, 2016;

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[1] S.O. 1998, C. 15, Sched. B., as amended.
[2] Exhibit B-2-1, pages 8-9.
[3] Exhibit B-2-1, page 9.
[4] Exhibit B-2-1, page 9, as amended on September 16, 2016.

5.3 Incremental Capital Module Applications

99. The Handbook specifically addresses the availability of the Incremental Capital Module ("ICM") during a rebasing deferral period. Among other things, the guidance of the Handbook with respect to ICM applications indicates that the rules that apply to a specific rate-setting method continue to apply even following a consolidation of distributors. To be specific, the Handbook says that an ICM would not be available for the rates in the service area where a Custom IR plan term applies until the term of the Custom IR ends and Price Cap IR applies; materiality thresholds for the ICM will be calculated based on the individual distributors' accounts and not that of the consolidated entity[99].

100. The Applicants have confirmed that ICM applications during the rebasing deferral period will be made in accordance with the applicable policies of the Board[100].

101. Board Staff submits that the OEB will consider any ICM request upon the filing of an application[101]. However, CCC asserts that the Board may consider setting out, in its decision in this case, the conditions under which LDC Co may apply for an ICM during the rebasing deferral period[102].

102. The Applicants concur with the submission by Board Staff that the Board should consider the appropriate treatment of ICM applications during the deferred rebasing period when those applications are actually made. As noted by AMPCO, the Board is not approving ICM amounts in this Application and the ICM projections are not informed by a new DSP for LDC Co[103].

103. The suggestion by CCC that the Board attempt to pre-set conditions for ICM applications should not be adopted because any such conditions are best considered in the context of the actual circumstances of an ICM application. If the Board attempts to set conditions in the absence of an actual ICM application, then such conditions cannot be framed so as to take account of circumstances arising in the future that are not known or foreseen at this time.

6. LDC Co Licence

104. As referred to above, the Application originally included requests for the transfers of the electricity distribution licences and rate orders of each of the Applicants and HOBNI to LDC Co[104]. On September 16, 2016, the Applicants amended the relief sought in the original Application to include a request that the OEB issue an electricity distributor licence that would allow LDC Co to own and operate the distribution systems serving the former Enersource, Horizon Utilities, PowerStream and HOBNI service areas[105].

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[99] Handbook, page 17.

[100] Exhibit B-7-1, page 1.

[101] Staff Submissions, page 13.

[102] CCC Submissions, pages 11-12.

[103] AMPCO Submissions, page 9.

[104] Exhibit B-2-1, page 9, paragraph 1(f).

[105] The Applicants' September 16, 2016 cover letter to the amendment and licence application is available at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/543025/view/.

TAB 16

EB-2016-0025

IN THE MATTER OF Sections 86 and 18 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B, as amended; and

AND IN THE MATTER OF an application for the relief necessary to effect the consolidation of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc. into an entity referred to in this Application as "LDC Co", in the manner set out in this Application.

APPLICATION

FILED: APRIL 15, 2016

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REBASING DEFERRAL PERIOD

The Applicants have chosen to defer the rebasing for LDC Co for ten years from the date of closing of the last of the proposed transactions, consistent with the Consolidation Policy and the Handbook. Accordingly:

(a) the Enersource and HOBNI rate zones would maintain Price Cap Incentive Regulation ("IR") until the end of the ten year rebasing deferral period;

(b) the Horizon Utilities rate zone would remain on Custom IR until 2019 and after that would maintain Price Cap IR until the end of the ten year rebasing deferral period;

(c) the PowerStream rate zone would remain on Custom IR until 2020, assuming approval of the PowerStream application for a 2016-2020 Custom IR term pending before the Board, and beyond that term the PowerStream rate zone would maintain Price Cap IR until the end of the ten year rebasing deferral period; and

(d) During the rebasing deferral period, LDC Co may apply for rate adjustments using the Board's ICM as may be necessary and in accordance with applicable Board policies with respect to eligibility for, and the use of, the ICM.

TAB 17

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2016-0025
EB-2016-0360

ENERSOURCE HYDRO MISSISSAUGA INC. HORIZON UTILITIES CORPORATION & POWERSTREAM INC.

Application for approval to amalgamate to form LDC Co and for LDC Co to purchase and amalgamate with Hydro One Brampton Networks Inc.

BEFORE: Ken Quesnelle
Presiding Member and Vice-Chair

Christine Long
Vice-Chair

Cathy Spoel
Member

December 8, 2016

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1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) regarding an application filed by Enersource Hydro Mississauga Inc. (Enersource), Horizon Utilities Corporation (Horizon), and PowerStream Inc. (PowerStream), (collectively, the applicants) requesting approval to amalgamate to form LDC Co and for LDC Co to purchase and amalgamate with Hydro One Brampton Networks Inc. (Hydro One Brampton) under section 86 of the *Ontario Energy Board Act,1998* (Act).

As part of the application, approvals were requested for: (a) transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co; (b) an electricity distributor licence for LDC Co; and (c) temporary exemptions from section 2.6.1A of the *Distribution System Code* (DSC).

Section 86 of the Act requires that the OEB review applications for a merger, acquisition of shares, divestiture or amalgamation that result in a change of ownership or control of an electricity transmitter or distributor and approve applications which are in the public interest.

The OEB issued a Handbook to Electricity Distributor and Transmitter Consolidation in January 2016 (Handbook) which provides guidance on the process for the review of an application, the information the OEB expects to receive in support of an application, and the approach it will take in assessing whether the transaction is in the public interest.

In reviewing an application, the OEB applies a no harm test, first established in the OEB's Combined Decision[1]. The no harm test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives as set out in section 1 of the Act. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The OEB has determined that the proposed amalgamation meets the no harm test and therefore the OEB approves this transaction.

The OEB also approves the LDC Co licence application and the transfer of the rate orders for each of the applicants and Hydro One Brampton to LDC Co but finds that a

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[1] RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

transfer of the distribution licences of each of the amalgamating entities to LDC Co is no longer required. The licences of the amalgamating entities will be cancelled upon the effective date of LDC Co's licence.

The OEB approves temporary exemptions from section 2.6.1A of the DSC until June 30, 2017 for Horizon and until December 31, 2018 for Enersource.

2 THE APPLICATION

Enersource, Horizon and PowerStream filed an application with the OEB on April 18, 2016 seeking approval for several transactions under section 86 of the Act:

1. Amalgamation of Enersource, Horizon, and PowerStream to form LDC Co
2. LDC Co share purchase and amalgamation with Hydro One Brampton
3. Enersource Holdings Inc. share purchase of Enersource
4. Transfer of PowerStream's existing shares of Collus PowerStream Utility Services Corp to LDC Co
5. Transfer of Hydro One Brampton's distribution system to LDC Co

As part of the application, approval was requested for:

a) Transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co under section 18 of the Act

b) An electricity distributor licence for LDC Co under section 60 of the Act

c) Temporary exemptions from section 2.6.1A of the DSC under section 74 of the Act

The applicants made several confidentiality requests with respect to the filed evidence and interrogatory responses. The OEB issued two decisions on August 12, 2016 and September 2, 2016 setting out its determination on the confidentiality requests.

The proposed amalgamation of the four distributors will create the largest municipally-owned distributor in Ontario, serving over 960,000 customers, with a total rate base of approximately $2.5 billion. The consolidation involves the amalgamation of Enersource, Horizon and PowerStream to form LDC Co, followed by LDC Co's acquisition of the shares of Hydro One Brampton at a purchase price of $607 million and subsequent amalgamation of Hydro One Brampton with LDC Co.

Process

The OEB issued a Notice of Application and Hearing on May 16, 2016, inviting intervention and comment. The OEB approved intervention requests by the Association of Major Power Consumers in Ontario (AMPCO), Energy Probe Research Foundation (Energy Probe), Power Workers' Union (PWU), School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC), Building Owners and Managers Association, Greater Toronto (BOMA), Consumers Council of Canada (CCC), Electrical Contractors Association of Ontario (ECAO), and International Brotherhood of Electrical Workers, Local 636 (IBEW).

A presentation of the application was provided to the OEB Panel and intervenors on June 23, 2016. The OEB provided for interrogatories and a transcribed technical conference took place on August 24, 2016 to clarify matters arising from the interrogatories. The OEB held five days of oral hearing. The OEB received submissions from OEB staff and the parties.

3 REGULATORY PRINCIPLES

3.1 The No Harm Test

As set out in the Handbook, the OEB applies the no harm test in its assessment of consolidation applications. The OEB considers whether the no harm test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.

The statutory objectives to be considered are those set out in section 1 of the Act:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

   1.1 To promote the education of consumers.

2 To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3 To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario.

4 To facilitate the implementation of a smart grid in Ontario.

5 To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

While the OEB has broad statutory objectives, in applying the no harm test, the OEB's review primarily focuses on the impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the consolidating utilities. The OEB considers this an appropriate approach, given the performance-based regulatory framework under which regulated entities are required to operate and the OEB's existing performance monitoring framework.

The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB's statutory objectives relating to conservation and demand management, implementation of smart grid, and the use and generation of electricity from renewable resources. With these tools and the existing performance monitoring framework, the OEB is satisfied that the attainment of these objectives will not be adversely affected by a consolidation and the no harm test will be met following a consolidation.

3.2 OEB Policy on Rate-Making Associated with Consolidation

To encourage consolidations, the OEB has put in place policies on rate-making that provide consolidating distributors with an opportunity to offset transaction costs with savings achieved as a result of the consolidation. The OEB sets out its policies on rate-making associated with consolidation in a report entitled *Rate-making Associated with Distributors Consolidation*, issued July 23, 2007[2] (the 2007 Report) and a further report issued under the same name on March 26, 2015 (the 2015 Report).

The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period. Consolidating entities, must, however, select a definitive timeframe for the deferred rebasing period.

The 2015 Report sets out the rate-setting mechanisms during the deferred rebasing period, requiring consolidating entities that propose to defer rebasing beyond five years to implement an earnings sharing mechanism for the period beyond five years to protect customers and ensure that they share in increased benefits from consolidation.

The 2015 Report extended the availability of the Incremental Capital Module (ICM), an additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating

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[2] Report of the Board on Rate-making Associated with Distributor Consolidation, July 23, 2007

distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned.

As set out in the Handbook, rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation, e.g. a temporary rate reduction. Rate-setting for a consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB.

4 APPLICATION OF THE PRINCIPLES TO THE APPLICATION

4.1 The No Harm Test

Price, Cost Effectiveness and Economic Efficiency

The Handbook states that to demonstrate no harm, applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve customers following a consolidation will be no higher than they would otherwise have been. The Handbook also states that the impact the proposed transaction will have on economic efficiency and cost effectiveness will be assessed based on an applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

In this case, the applicants submit that the effect of the consolidation on underlying cost structures will be positive, that costs to serve customers will not be higher as a result of the consolidation and that the consolidation will have a positive effect on economic efficiency and cost effectiveness.

The applicants submit that these positive outcomes are confirmed by the evidence identifying synergies and savings that the applicants are able to achieve as a result of the proposed consolidation. These synergies arise from specific, concrete initiatives to lower underlying cost structures and to promote economic efficiency and cost effectiveness, by reducing the number of call centres and control rooms, by integrating back-office functions and reducing the number of back-office employees, and by moving to single, common information systems.

The applicants' evidence is that during the proposed ten-year rebasing deferral period, customers will benefit from distribution rates that are lower than they would be under the status quo scenario (in the absence of a consolidation). The status quo assumes that each of the LDCs continue to rebase their rates once their current plans have expired and thereafter have 5-year Custom Incentive Regulation plans in place. The applicants submit that the interests of consumers with respect to price will be protected because rates for the Horizon Utilities and PowerStream rate zones will continue to be charged in accordance with previous rebasing-related OEB decisions, until the effective period of each of those decisions has come to an end. Otherwise, during the rebasing deferral period, the OEB's Price Cap Incentive Regulation model will be used to determine rates for LDC Co's rate zones, in accordance with the OEB's policies.

The applicants provide a year over year distribution revenue trend analysis of the merged entity compared to the status quo that shows the relative benefit to customers as follows:

- Average decrease of $19.5 million per year or 3.3% in the first 10 years
- Average decrease of $69.3 million per year or 8% post rebasing
- Average decrease of $ 48.6 million per year or 5.9% across the forecast period[3]

The applicants assert that ratepayers benefit from a $195 million reduction in revenues during the ten year deferred rebasing period, simply based on the fact that the entities would otherwise file rate applications in the absence of the merger. This amounts to a net present value of $98 million during the deferred rebasing period[4].

The applicants project that overall anticipated savings net of transaction costs (approximately $96 million) amount to $426 million over the deferred rebasing period and confirmed that all of these synergies are to the benefit of the shareholder for the duration of the 10 year period[5]. The applicants state that upon rebasing in 2027, customers will benefit from the $69 million in sustainable savings relative to the status quo. The applicants anticipate the net present value of savings for ratepayers beyond the 10 year rebasing deferral period to be approximately $306 million[6].

Intervenors submit that the applicants have provided high level estimates of the projected net synergies in the first ten years without detailed evidence to support these estimates and have not provided credible evidence that savings realized in the deferred rebasing period are sustainable in perpertuity. Consequently, intervenors submit that the OEB should give little weight to the projected net present savings of $98 million during the rebasing deferral period and the post rebasing net present value of savings of $306 million. Intervenors argue that the high level estimated net synergies provided in the evidence is likely a very conservative estimate of the savings to be achieved,

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[3] Forecast Period (2016-2039),Application, Exh B/T6/S1, p.4
[4] Transcript, Vol. 1, pp.82-83
[5] Transcript, Vol. 1, p. 27
[6] Transcript, Vol. 1, p. 82

noting that through-out cross-examination, it became evident that there are many potential synergies and savings that have not been counted nor was any attempt made to quantify them[7].

CCC and BOMA submit that the status quo scenario assumes that each of these LDCs will get approval for successive 5-year Custom IR plans over the next ten years, arguing that the OEB has approved very few Custom IR plans over the last few years. CCC also submits that if during the course of the next ten years the OEB did not approve the implementation of successive 5-year Custom IR plans for each of the four LDCs then the projected savings would be reduced or essentially eliminated. CCC argues that this is the one financial benefit the applicants are claiming for their customers during the deferred rebasing period, and the full realization of this benefit is highly questionable. SEC submitted that based on the evidence, the OEB should conclude that the status quo rate increases forecast by the applicants are overstated.

Energy Probe submits that the approach taken by the applicants in calculating status quo revenues only takes into account the distributor's forecasts (revenue and costs, inflation and productivity) and does not reflect the OEB's inflation and productivity analyses or any benchmarking to assess the reasonableness of the forecasts as required by the October 2012 *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*.

The applicants expect to file an ICM in each year for each rate zone under Price Cap IR during the deferred rebasing period. During the course of the hearing, the applicants updated the total forecasted ICM revenue from $130 million to $168.4 million as a result of the OEB's PowerStream Decision (EB-2015-0003) and used a 10% deadband in place of a 20% deadband in calculating the ICM materiality threshold. The total incremental capital that is expected to be sought through the ICM is $414.2 million, plus an additional $173.5 million of incremental capital as a result of the PowerStream Decision and the use of a 10% deadband, resulting in a total of $587.7 million[8].

Intervenors submit that any incremental increases in the ICM projections negatively impact the projected annual savings for customers. Intervenors also express concern that the ICM projections are not based on the Distribution System Plans (DSP) that

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[7] SEC submissions p. 26; AMPCO submissions p.7
[8] Technical conference undertaking responses - JTC 1.8, J1.1

have been approved by the OEB, are not informed by a new DSP for LDC Co, and do not reflect reductions in existing capital.

Intervenors argue that the applicants' proposal to share benefits with customers only upon rebasing, while acknowledging that these savings are not guaranteed to materialize for ratepayers, means that there is no certainty that ratepayers will receive these benefits and creates intergenerational equity issues. Intervenors submit that given that the regulatory framework in place at that time is unknown, there is also uncertainty as to whether these savings will serve to reduce costs to customers in perpetuity.

OEB staff submits that the evidence provided by the applicants supports the claim that the proposed amalgamation can reasonably be expected to result in cost savings and operational efficiencies. OEB staff, however, notes that the degree of certainty regarding forecast savings diminishes over the length of the forecast period.

BOMA submits that Hydro One Brampton's OM&A/customer in 2014 was $178.92, 23% lower than the lowest of the three merging utilities, with PowerStream at $242.92, Horizon at $251.24 and Enersource at $260.39. BOMA argues that the need to insulate Hydro One Brampton ratepayers from spillover effects from the higher cost utilities is obvious but the applicants have not filed evidence on how they will do this.

SEC submits that Hydro One Brampton customers have the lowest rates of the four LDCs and their rates will have to increase substantially if there is a harmonization of rates. SEC asserts that according to the Handbook, for an acquisition the OEB focuses its attention in the no harm test on the customers of the acquired LDC. SEC argues that in this case, the acquired customers of Hydro One Brampton will face a greater rate increase through harmonization. SEC submits that application of the no harm test necessitates consideration by the OEB of how to ensure that those customers are specifically protected, particularly since these customers will not have a municipal shareholder protecting them.

OEB Findings

The OEB notes that this merger application is the first transaction that involves multiple entities coming together to form a single utility and it is also the first merger application since the release of the Handbook. The Handbook provides guidance on how the OEB reviews consolidation applications and clarifies the OEB's rate-making policy associated with consolidation. As with any articulated OEB policy, the OEB examines the facts of a specific application. The OEB has considered the specific facts in this application and is of the view that the features of this transaction are anticipated within the framework of the OEB's policy and the outcomes are aligned with the articulated policy objective of improving the efficiency of electricity distribution. The OEB finds that the scale enhancements of service delivery embedded in this transaction can be expected to result in long term benefits to customers.

The OEB considers the long term effect of a proposed transaction on cost structures. This is aligned with the long-term investment cycles of the distribution sector where most distribution assets have life expectancies in the 40 year range. Hydro One Brampton is identified as being the lowest cost entity involved in this transaction. The OEB notes that Hydro One Brampton will have additional scale available to it in the long term and its existing cost structures are embedded in its rates for the next 10 years. The OEB will consider the matter of its rates and the impact of rate harmonization in the context of a rate application. In the OEB's view, there will be no net negative impact on Hydro One Brampton's customers in the long term in comparison to the status quo.

The intervenors submit that the amounts proposed by the applicants in terms of costs and potential savings are estimates and do not reflect the amounts with certainty. The OEB takes notes of these arguments, but is satisfied that the estimates are sufficiently accurate for the purposes of the analysis under the no harm test.

The applicants' evidence suggests potential savings from the proposed merger flowing to shareholders of $426 million over the ten year period on a rate base of $2.5 billion. This is approximately 1.7 percent on an annualized basis. Earnings of LDC Co that, on an annual basis are more than 300 basis points above the applicable rate of return for LDC Co, will be shared with customers on a 50:50 basis. In the OEB's view, this result may be compared to the status quo scenario, from an earnings potential perspective, whereby each entity could rebase at least once more within 10 years, and any earnings above 300 basis points over the regulated rate of return would all flow to the shareholder until the rates are reset. The OEB therefore finds that customers will be not be harmed by the proposed transaction in the short term, and will, in fact, be better off and will likely benefit from the enduring benefits of scale in the long term.

Reliability and Quality of Electricity Service

The Handbook sets out that under the OEB's regulatory framework, consolidating utilities are expected to deliver continuous improvement for both reliability and quality of service performance to benefit customers.

The applicants submit that they are committed to maintaining the quality, reliability, and adequacy of electricity service for customers, stating that they currently have a total of six service centres across their service areas which will continue to be used for de-centralized functions such as construction and maintenance, trouble response, logistics, fleet services, and metering, such that the adequacy, reliability, and quality of electricity service will be maintained.

The applicants further expect LDC Co to maintain and improve upon the five-year average reliability indices and the OEB customer service standard metrics for its customers. During the oral hearing, the applicants testified that LDC Co will be accountable for meeting performance metrics relating to service quality and reliability and compliance with licence conditions, in relation to the individual rate zones of each of the amalgamating distributors that will continue after consolidation. The applicants submit that customers will benefit from being served by a larger utility that will have an expanded ability to monitor, report on and improve system reliability and power quality, given its greater resources.

OEB staff submits that LDC Co can reasonably be expected to maintain the service quality and reliability standards currently provided by each of the amalgamating utilities. OEB staff also submits that the OEB is able to monitor the performance of LDC Co on an ongoing basis through performance scorecards as well as the OEB's Electricity Reporting and Record Keeping Requirements (RRRs) which constitute the OEB's requirements to maintain and file information under the licence conditions.

AMPCO submits that based on the evidence, LDC Co can reasonably be expected to maintain service quality and reliability standards so that reliability and service quality will not deteriorate as a result of the consolidation. However, AMPCO also asserts that given the level of proposed capital spending over ten years identified in the application, a forecast of improved reliability over time would be a better proposition for customers to accept.

Energy Probe submits that the applicants have indicated that they cannot guarantee that none of the service quality indicators will deteriorate but have also indicated that as a merged entity, more resources would be available to deal with issues that may arise in one area or in one rate zone. Energy Probe submits that this is a reasonable assumption and the OEB should interpret this to mean that service quality should not deteriorate as a result of the merger.

BOMA expressed concern that the applicants have not targeted higher SAIDI and SAIFI and asserted that SAIDI and SAIFI should not be averaged for reporting, scorecard formulation or any other purpose because, in BOMA's view, that would ultimately lead to a degradation of Hydro One Brampton's SAIDI results. BOMA submits that the OEB should require the applicants to set reliability targets for each of the four utilities, with the possible exception of Hydro One Brampton which is better than the average of the other three. BOMA submits that the OEB should require the applicants to file an annual customer survey which deals separately with each of the four predecessor utilities, so as to measure their level of satisfaction with LDC Co's services to each of the four ratepayer groups. BOMA states that the summary and the detailed results should be filed each year with the OEB and intervenors, as part of the four divisions' annual rate adjustment applications and that LDC Co should consult with the intervenors and OEB staff prior to starting the consultation process.

OEB Findings

The OEB finds that no issues of concern have been raised regarding the transaction resulting in a potential deterioration of overall reliability. The OEB has the ability to monitor the reliability performance of licensed entities on an ongoing basis and also has the authority to intervene and impose corrective action where a licensed entity does not meet established performance expectations.

The OEB also finds that reporting as a licensed entity on reliability is appropriate in the circumstances of this case and does not accept BOMA's view that each customer group must be monitored to ensure its current reliability status is maintained. As set out in the Handbook, in considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the no harm test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

Financial Viability

The Handbook states that the OEB's primary considerations in assessing the impact of a proposed transaction on the financial viability of the consolidating entities are: (1) the effect of the purchase price, including any premium paid above the historic (book) value of the assets involved; and (2) the financing of incremental costs (transaction and integration costs) to implement the consolidation transaction.

The application indicates that of the $607 million purchase price payable for the shares of Hydro One Brampton, a premium of $202 million is being paid. The applicants acknowledge that the rate base portion of the consideration payable is recoverable from ratepayers whereas the premium is not recoverable from ratepayers.

The applicants propose to finance the share acquisition through debt financing of $424.9 million, while the remaining $182.1 million will be financed by shareholder contributions. The applicants anticipate maintaining a capital structure of approximately 60% debt as a result of the acquisition of Hydro One Brampton. The applicants submit that the financial ratios and indicators will continue to be consistent with an A-range credit rating and therefore the purchase price will not have an adverse effect on the financial viability of LDC Co.

The applicants submit that incremental transaction costs for items such as data and other IT systems integration, regulatory approvals and legal advice will be financed through productivity gains associated with the transaction and are not expected to be recovered through rates.

The applicants submit, however, that while incremental transaction costs are self-financing by the associated savings, there will be timing differences between expense outlays and their recovery. The applicants have arranged a $500 million commitment for a 364-Day credit facility from two large banks. This facility is expected to be sufficient to finance: i) the temporary shortfall between implementation costs and their recovery through corresponding savings; and ii) the ongoing working capital requirements of LDC Co.

OEB staff submits that the applicants' evidence regarding the proposed financing of the Hydro One Brampton acquisition and the premium to be paid demonstrates that no adverse impact on the applicants' financial viability is anticipated and accepts the applicants' assertions that the use of credit facilities as proposed by the applicants will be adequate to finance timing differences between receivables and payables and to bridge capital expenditures for a period of time.

The submissions by intervenors do not raise any issue regarding the impact of the proposed consolidation on the financial viability of the consolidating entities and LDC Co.

The applicants submit in their reply submissions that altering the proposed deferred rebasing period or the earnings sharing mechanism would have an impact on financial viability. The applicants state that the associated borrowing for the Hydro One Brampton acquisition and ongoing capital program is supported by shareholder cashflows expected during the rebasing deferral period and that such cash flows provide interest coverage and manage debt and equity levels in a manner that supports a financial profile consistent with the current credit ratings of the predecessor entities.

OEB Findings

The OEB accepts OEB staff's submissions that the evidence relating to the proposed financing of the Hydro One Brampton acquisition and the premium to be paid will not impact the applicants' financial viability and finds that the proposed transaction therefore meets the no harm test with respect to financial viability.

4.2 Rate-making Considerations

Deferred Rate Rebasing and Earnings Sharing Mechanism

In the consultation with distributors leading up to the issuance of the 2015 Report, distributors indicated that incremental transaction and integration costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the 2015 Report allows distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction in order to realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction. The 2015 Report requires that consolidating entities that propose to defer rebasing beyond five years implement an earning sharing mechanism (ESM) for the period beyond five years, whereby excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual return on equity (ROE).

The applicants choose to defer rebasing for LDC Co for ten years from the date of closing of the last of the proposed transactions and propose an ESM for years six to ten of the deferred rebasing period whereby earnings of LDC Co that, on an annual basis, are more than 300 basis points above the applicable ROE for the consolidated entity will be shared with customers on a 50:50 basis. The applicants submit that these proposals are consistent with the OEB's consolidation policies, including the guidance provided in the Handbook.

OEB staff submits that the applicants' proposed ESM aligns with the expectations of the OEB as set out in the Handbook and also submits that the applicants should file plans for ESM, rate structures and rate harmonization by December 31, 2019, in order to provide sufficient time to plan for any ESM implementation.

The applicants submit that they do not expect rates to be harmonized and intend to operate individual rate zones with separate rate-setting methods for each of the existing distributors until rate differences are immaterial. The applicants submit that at the time of rebasing, rate harmonization options will be evaluated, with a view to available OEB policies and tools. The applicants submit that if the OEB finds it to be helpful, the applicants will accept OEB staff's suggestion and, to the extent possible, file plans for the ESM by December 31, 2019.

Intervenors submit that the selection of the 10 year deferred rebasing period is not appropriate and poses a threat of harm to customers. Intervenors submit that the proposed ten year rebasing period is not required to offset the costs of the transaction as the evidence in this case is that the transition and integration costs will be recovered by the end of year three of the consolidation. Intervenors submit that the proposed ESM does not adequately benefit customers and results in a significant imbalance between the incentives provided to the shareholders and the protection provided to customers. Intervenors further submit that if the OEB approves the consolidation, adjustments to the proposed ESM are required.

Intervenors submit a number of proposals for the OEB's consideration which include the following: approve a deferral period of five years rather than 10 years, amend the ESM to provide for no deadband, require an ESM where savings are shared with customers earlier than year six, reduce rates by an amount sufficient to share the benefits over the first ten years, and adjust the sharing of the savings on a 75:25 ratepayer/shareholder basis.

SEC argues that the OEB is required to determine if (or to what extent) the OEB's rate-making policy should be applied on the facts of the current case and that the legal test for doing so is whether the resulting rates will be just and reasonable. SEC submits that the policy cannot be applied unmodified to this case as the resulting rates would not be just and reasonable. SEC submits that the application of the policy unmodified would result in LDC Co exacting monopoly rents from the customers, unprotected by the regulatory process.

In reply submissions, the applicants argue that a change to the ten year rebasing deferral period could fundamentally alter the proposed transaction and the basis on which it has been accepted by shareholders as providing adequate incentive for entering into the transaction. The applicants submit that there is no basis in the evidence in this case to expect that, without a ten year rebasing deferral period, the applicants and their shareholders will assume the consolidation risks and absorb the Hydro One Brampton premium, nor is there any evidence offered by intervenors upon which it can be expected that this could be done without any adverse impact on financial viability.

The applicants submit that intervenor arguments with regard to the relative balance of impacts overlook the risks taken on by the distributors and their shareholders and the premium they incur to complete the transaction. The applicants argue that the impact of reducing the rebasing deferral period or altering the ESM relative to the Business Plan as proposed by the intervenors will likely result in the rejection of the deal by shareholders on the basis of insufficient consolidation incentives and unacceptable impairment of financial viability.

OEB Findings

The intervenors argue that the application of the policy with its 10 year term results in too much of the realized saving being to the benefit of the shareholder. The applicants have structured their proposal as a comparison of the cost structures of the merged entity operating within the OEB's incentive rate plan in the deferral period versus the anticipated cost structures of the individual utilities in the status quo scenario. The

OEB's incentive framework is intended to provide sufficient financial gains over and above the status quo to incent utilities to seek out merger or acquisition efficiency gains opportunities. The incentive framework is also intended to have customers share in large savings through earnings sharing beyond the 5-year deferred rebasing period.

As set out earlier in the no harm analysis, the OEB finds that this transaction is within the range of transactions anticipated by the OEB's policy. The outcomes are aligned with the policy's objective of improving the efficiency of electricity distribution. As discussed earlier, the proposal should be compared to the status quo scenario, from an earnings potential perspective, whereby each utility could rebase at least once more within the 10 years, and any earnings above 300 basis points over the regulated rate of return would all flow to the shareholder until rates were reset. The OEB finds that customers will be not be harmed and will likely benefit in the long term from the enduring benefits of scale enhancements of service delivery arising from this transaction. In view of the policy objectives of this incentive scheme, the OEB does not consider the particular outcomes related to potential earnings relative to the status quo to be unreasonable.

5 LICENCE APPLICATION

As part of the consolidation application, the applicants request the OEB's approval for an electricity distributor licence that would allow LDC Co to own and operate the distribution systems serving the former Enersource, Horizon, PowerStream and Hydro One Brampton service areas.

The applicants provided a draft form of licence, containing several proposals.

OEB Findings

The OEB is prepared to grant the licence application for LDC Co but notes that the incorporation of the merged entity will only occur within thirty days of the OEB's decision on the merger application. Consequently, while the OEB approves the licence application, the licence for the merged entity will only be effective once the applicants have notified the OEB that the merged entity has been incorporated and provided to the OEB the legal name of the merged company.

The OEB's findings on each of the applicants' proposals regarding the licence are set out below.

Proposed Deletions

The applicants propose deletions relating to certain temporary exemptions previously granted by the OEB to each of the amalgamating distributors and which have now expired. The applicants have also proposed that the following Code and Reporting and Record-Keeping Requirements (RRR) exemptions set out in the four amalgamating distributors' licences should be eliminated as they are no longer needed and/or because they have expired:

> The Hydro One Brampton, Enersource and PowerStream licences contain the following exemption:
>
> "1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code [the "SSS Code"] with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal

> billing plan as described in its application for exemption from Fixed ReferencePrice, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it."

The applicants submit that section 2.5.3 was removed from the SSS Code, and is no longer applicable. As a result, that exemption is no longer needed and propose that this be deleted from the proposed Schedule 3 (List of Code Exemptions) to the LDC Co. licence

> The Hydro One Brampton licence contains the following exemption:
>
> 2. The Licensee is exempt from the requirements of section 6.5.4 of the Distribution System Code [the "DSC"] until June 30, 2009 in relation to 15 load transfer customers located within the City of Brampton with the following municipal addresses:
>
> (a) 2868 Bovaird Drive;
>
> (b) 10221, 10231 &10245 Old Pine Crest; and
>
> (c) 10253, 10315, 10333, 10431, 10451, 10475, 10605, 10625, 10827, 11507 and 11511Winston Churchill Blvd.

The applicants submit that the exemption, which expired on June 30, 2009, applied to a version of section 6.5.4 of the DSC that would have required the elimination of long term load transfers by October of 2008. The OEB's requirements (including the deadlines) related to the elimination of long term load transfers have changed over time, and the deadline for the elimination of those load transfers was extended a number of times. The applicants submit that the DSC currently provides (at section 6.5.3) that "All load transfer arrangements shall be eliminated by transferring the load transfer customers to the physical distributor by June 21, 2017."

The applicants submit that they do not require an exemption from this requirement at this time, and the current exemption may be removed.

> The Enersource licence contains the following exemption:
>
> 2. The Licensee is exempt from the requirement to implement time-of-use pricing as of the mandatory date for its RPP customers with eligible time-of-use

> meters as required under the Standard Supply Service Code for Electricity Distributors. The mandatory time-of-use pricing date exemption expires on May 31, 2012.

The applicants submit that Enersource has implemented time-of-use pricing as of the mandatory date for its RPP customers with eligible time-of-use meters. The applicants further submit that this exemption has expired and is no longer applicable.

> The PowerStream licence contains the following exemption:
>
> The Licensee is exempt from the following sections of the Electricity Reporting and Record Keeping Requirements:
>
> 1. Section 2.1.8, sub-sections, b) ii; c) i, ii, iii, iv, vi, viii, ix, x; d) i, ii, iv; e) ii, iv; f) iii, iv and g). This exemption will expire on June 30, 2014.

The applicants submit that the exemption has expired, and is no longer needed in respect of the PowerStream rate zone in any event and should not be included in the LDC Co. licence.

The applicants submit that there are other provisions in the standard form of licence that may be outdated, such as certain provisions in Appendix A related to Market Power Mitigation Rebates. However, the applicants state that they have only proposed to eliminate certain exemptions specific to the four consolidating distributors and do not propose to remove generic provisions of the licence, as they believe that it would be more appropriate for the OEB to deal with those matters on a generic basis.

OEB staff submits that the elimination of the exemptions specific to each of the amalgamating distributors as set out by the applicants is appropriate. OEB staff submits that many of the other provisions in the standard form of licence that may be outdated were incorporated as a result of Ministerial directives and it is more appropriate for the OEB to consider the removal of these provisions on a generic basis.

OEB Findings

The OEB accepts the deletions proposed by the applicants identified in each of the amalgamating distributors’ existing distribution licences.

Proposed Exemptions

The applicants are requesting exemptions from section 2.6.1A of the DSC, as the applicants will not be able to bill former Enersource and Horizon Residential and General Service <50kW customers on a monthly basis as required by this section of the Code, which comes into force on December 31, 2016. The applicants submit that as Enersource and Horizon will be migrating to the PowerStream customer information system (CIS), it will be necessary to complete that migration for a rate zone before monthly billing can be implemented and because that migration will be staggered, the applicants do not expect to be able to bill Residential and GS < 50 kW customers in the Enersource rate zone and Horizon rate zone on a monthly basis until later in 2018 (for Enersource) and until later in 2019 (for Horizon). The applicants submit that they are requesting these exemptions so as to not strand assets or to make unnecessary investments in the predecessor companies' existing systems.

The applicants request that the OEB approve exemptions from section 2.6.1A that would expire December 31, 2018 in the case of the Enersource rate zone and December 31, 2019 in the case of the Horizon rate zone, as part of its disposition of the licence application for LDC Co. The applicants have proposed that the requested exemptions be included in the new Schedule 3 to the LDC Co licence.

OEB staff submits that the OEB should only approve the exemptions for monthly billing requested by the applicants for a limited period of time – three to six months from the closing of the transaction. SEC agrees with the proposal to phase in monthly billing as CIS systems are harmonized, submitting that the avoidance of additional costs and transitional billing issues through a staged approach outweigh the goal of getting to monthly billing as soon as possible.

In response to submissions, the applicants propose to advance the migration of Horizon's customers to monthly billing by 30 months to June 30, 2017 but propose to maintain the December 2018 date for the migration of Enersource customers stating that they will not have sufficient resources to support both the monthly billing implementation and CIS convergence and that there is a high potential for customer billing errors.

OEB Findings

The OEB's requirement that distributors provide monthly billing flows from the concern that customers receive billing information on a timely basis. The exemptions sought by the applicants would not achieve this goal. However, the OEB recognizes that the exemption request is for a limited period of time. The applicants have committed to advance the migration of Horizon's customers to monthly billing by June 30, 2017 and to make monthly billing available to Enersource customers by December 31, 2018. The applicants have stated that there is a high potential for customer billing errors if they are required to implement CIS convergence and monthly billing at the same time. While timely billing information is important, so too is accurate billing information. Given the high potential for customer billing errors, the OEB will not force the applicants to achieve monthly billing at earlier dates than they can reasonably commit to. As a result, the OEB will allow the exemptions to June 30, 2017 for Horizon and December 31, 2018 for Enersource.

Proposed conditions

The applicants have proposed three conditions that they submit would allow the OEB to consider the operations of the consolidated utility in the context of the OEB's statutory objectives related to adequacy, reliability and quality of electricity service, as that service is provided to customers in each of the four proposed rate zones:

1. LDC Co. shall track its operations in four separate rate zones (equivalent to the service areas of the former Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc.) until the end of the third year following the completion of the consolidation of the four predecessor utilities. The end of the third year following the completion of the consolidation is expected to be December 31, 2019.
2. LDC Co. shall report to the OEB on Electricity Service Quality Requirements (ESQRs) and other reportable financial metrics as set out in the OEB's Reporting and Record-Keeping Requirements (RRR) separately for each of the four rate zones for that three-year period.

3. LDC Co. may, at its option, report to the OEB under the RRR on a consolidated basis, instead of separately for the four rate zones, after the end of the third year following the completion of the consolidation of the four predecessor utilities.

Energy Probe and OEB staff support conditions 1 and 2 and Energy Probe submits that LDC Co should be required to report on a consolidated basis in addition to each of the four rate zones. OEB staff submits that the OEB should revise Condition 3 to clarify what happens going forward from year four. OEB staff also submits that, while the consolidation will be complete after three years, the OEB may wish to consider whether the reporting of certain metrics, such as reliability, is still required on an individual rate zone basis. Energy Probe disagrees with the proposed Condition 3, arguing that this should be at the OEB's option not the applicants' option.

VECC argues that the proposed licence amendments were made at the end of the proceeding without the aid of discovery and makes no submissions on the merits of the proposed amendments. VECC and CCC submit that parties should be given a further opportunity to make submissions on any licence conditions.

SEC submits that the proposed reporting requirements are inadequate to ensure that the OEB has sufficient information to protect the customers. SEC proposes that , as long as the rates for each of the consolidating distributors is different, LDC Co should be required to file full annual reporting of accounting results, and scorecard results, on a segmented basis for each of the four service areas.

SEC submits that it has concerns with the applicants' proposal to delay the filing of a combined DSP until 2019, arguing that this represents insufficient prioritization of the DSP in the transitional period. SEC submits that the DSP is a central element of distributor planning and operational effectiveness. SEC submits that the OEB should require, as a condition of the new licence for LDC Co, that it file a DSP for the combined entity no later than December 31, 2017.

The applicants submit that there is insufficient time to develop a DSP by the end of 2017. The applicants submit that they are able to report on reliability on an individual rate zone basis until the end of the rebasing deferral period.

BOMA submits that the OEB should require that a coherent governance plan be put in place and filed with the OEB and intervenors prior to closing and that the OEB approve the governance plan prior to the closing, and prior to the issuance of a licence for the new utility. In support of its submission, BOMA submits that the Board of Directors for LDC Co has not yet been appointed and there is no evidence on the composition of this Board. BOMA further submits that the applicants' evidence is that key executives of LDC Co are being appointed by and will report to different people which complicates the accountability and could lead to confusion of mandates.

OEB Findings

The OEB notes that the applicants have proposed that LDC Co track the operations of each of the four predecessor utilities and that reporting to the OEB take place separately until December 31, 2019, when the completion of the consolidation of the four predecessor utilities is expected to occur. The Handbook, however, sets out that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. The OEB is of the view that this principle continues to be applicable in this case. The OEB does not require, nor encourage reporting on a "separate" utility basis. Rather the expectation of the OEB is that LDC Co shall report in accordance with the requirements of its licence. Consequently, the OEB considers that the applicants' proposed conditions are not necessary and will not be included in the LDC Co licence.

BOMA has submitted that the OEB should approve a governance plan for LDC Co prior to the issuance of a licence arguing that the process for appointing key executives of LDC Co and the proposed reporting structure complicates the accountability and could lead to confusion of mandates. The applicants have confirmed in oral testimony[9] that Mr. Max Cananzi, in his role as president of LDC Co, will be responsible for the certification of all RRR and electricity distribution rate applications and will also be accountable for compliance matters and regulations. Mr. Cananzi further attests in the licence application to his accountability for compliance with all of LDC Co's licence conditions and OEB Codes[10]**.** As a result, the OEB is satisfied that accountability has been established and will not require a governance plan to be filed and approved by the OEB.

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[9] Transcript, Vol. 4, pp. 35-36 and Undertaking J3.1
[10] LDC Co licence application, p. 22

6 OTHER REQUESTS

The applicants make the following requests for approval by the OEB:

1. Transfer of the distribution licences and rate orders for each of the applicants and Hydro One Brampton to LDC Co

   OEB staff submits that if the OEB approves the licence application for LDC Co., the requested transfer of the licences of each of the applicants and Hydro One Brampton to LDC Co. is not necessary as the licence granted to LDC Co. permits LDC Co. to own and operate the distribution systems serving the former Enersource, Horizon, PowerStream and Hydro One Brampton service areas. SEC submits that the applicants have provided a draft distribution licence for LDC Co so that the licences of the merging entities can be cancelled when the new licence is issued.

   OEB staff support the applicants' request for the transfer of the rate orders of each of the amalgamating distributors to LDC Co. SEC submits that the rate order only applies to the company for whom it was originally made and that if a successor to the business, whether by acquisition of assets, or by amalgamation or other re-organization, wants to rely on the rate order, it must get a new order of the OEB allowing them to do so.

2. Continue to track costs to the regulatory asset accounts or deferral and variance accounts (DVAs) currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date and to seek disposition of Group 2 accounts in Annual Custom IR updates or in IRM applications, should the balances in these accounts become material.

   OEB staff submits that the OEB should approve the tracking of costs to the DVAs and that the disposition of Group 2 accounts should be consistent with the OEB's policy on disposition of Group 2 DVAs. OEB staff commented that ten years is a long time for Group 2 accounts not to be disposed and submits that Group 2 accounts should be cleared at least every five years, as would be the case for a non-consolidating distributor on the Price Cap IR rate-setting option and that this can be done through a stand-alone application. OEB staff further submits that the applicants should continue to maintain the capability to track the DVAs separately, so as to enable the appropriate disposition of the DVAs should the OEB decide that the DVAs are to be disposed separately to each rate zone in a future rates proceeding.

OEB Findings

The OEB approves the requested transfer of the rate orders of each of the applicants and Hydro One Brampton to LDC Co. The OEB agrees with OEB staff that the requested transfer of the licences to LDC Co is not required as the licence granted to LDC Co permits LDC Co to own and operate the distribution systems of the predecessor utilities.

The OEB grants approval to the applicants to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date. The OEB supports the OEB staff submission that the applicants should continue to maintain the capability to track the DVAs separately. Doing so will allow the DVAs to be disposed of separately by rate zone if such a determination is made in a future rates proceeding. In this application the OEB will not make a determination regarding future rate issues, but the OEB wants to ensure that the necessary information is available for a future panel to consider in a rates application.

7 CONCLUSION

The OEB concludes that the proposed amalgamation of Enersource, Horizon, PowerStream and Hydro One Brampton meets the no harm test and therefore the OEB approves this transaction.

The OEB also approves the LDC Co licence application and the transfer of the rate orders for each of the applicants and Hydro One Brampton to LDC Co but finds that a transfer of the distribution licences of each of the amalgamating entities to LDC Co is no longer required. The licences of the amalgamating entities will be cancelled upon the effective date of LDC Co's licence.

The OEB approves temporary exemptions from section 2.6.1A of the DSC until June 30, 2017 for Horizon and until December 31, 2018 for Enersource.

8 ORDER

THE BOARD ORDERS THAT:

1. Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc. are granted leave to amalgamate to form LDC Co.

2. LDC Co is granted leave to purchase all of the issued and outstanding shares of Hydro One Brampton Networks Inc.

3. LDC Co and Hydro One Brampton Networks Inc. are granted leave to amalgamate and continue as LDC Co.

4. Enersource Holdings Inc. is granted leave to purchase all of the issued and outstanding shares of Enersource Hydro Mississauga Inc.

5. LDC Co is granted leave to purchase PowerStream Inc.'s existing shares of Collus PowerStream Utility Services Corp.

6. Hydro One Brampton Networks Inc. is granted leave to transfer its distribution system to LDC Co

7. The applicants shall promptly notify the OEB of the completion of the transactions referred to in paragraphs 1-5 above.

8. The applicants shall promptly notify the OEB of the completion of the transaction referred to in paragraph 6 above.

9. Once the notice referred to in paragraphs 7 and 8 is provided to the OEB, the OEB will transfer the Rate Orders of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc., and Hydro One Brampton Networks Inc. to LDC Co.

10. The leave granted in paragraphs 1-6 above shall expire 18 months from the date of this Decision and Order.

11. The application for an electricity distribution licence for LDC Co is granted, on such conditions as are contained in the attached licence.

12. The applicants shall promptly notify the OEB when the incorporation of LDC Co has occurred and provide the legal name of the merged entity to the OEB.

13. The licences of Enersource Hydro Mississauga Inc. Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc. shall be cancelled upon the effective date of LDC Co's licence.

14. Temporary exemptions from section 2.6.1A of the DSC are approved for Horizon Utilities Corporation until June 30, 2017 and for Enersource Hydro Mississauga Inc. until December 31, 2018.

15. The applicants are granted approval to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the applicants and Hydro One Brampton and to seek disposition of their balances at a future date. The applicants are to continue to maintain the capability to track the DVAs separately for each rate zone.

16. The applicants shall file plans for the ESM by December 31, 2019.

17. Eligible intervenors shall file with the OEB and forward to the applicant their respective cost claims no later than 7 days from the date of issuance of this Decision and Order.

18. The applicants shall file with the OEB and forward to the intervenors any objections to the claimed costs of the intervenors within 17 days from the date of issuance of this Decision and Order.

19. Intervenors shall file with the OEB and forward to the applicant any responses to any objections for cost claims within 24 days from the date of issuance of this Decision and Order.

20. The applicants shall pay the OEB's costs of and incidental to, this proceeding immediately upon receipt of the OEB's invoice.

DATED at Toronto December 8, 2016

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

TAB 18

G-Staff-11

Reference 1: EB-2016-0025, Applicant's Reply Submissions, October 18, 2016, Page 22
Reference 2: EB-2016-0025, Decision and Order, December 8, 2016, Page 10

In the mergers, acquisitions, amalgamation and divestitures (MAADs) application that formed Alectra Utilities (the MAADs application), the applicant's (Alectra Utilities) final reply submission stated that "The Applicants [Alectra Utilities] have confirmed that [Incremental Capital Module (ICM)] applications during the rebasing deferral period will be made in accordance with the applicable policies of the Board."

The Decision and Order issued on December 8, 2016[1] noted that the applicants (Alectra Utilities) estimated to seek $587.7 million through ICMs over the course of its deferred rebasing period.

a) At the time of the MAADs application, did the applicants (Alectra Utilities) review the OEB's ICM policies on what projects would be eligible for ICM funding?

b) Please explain if the $587.7 million estimate was based on projects that the applicants (Alectra Utilities) determined would be eligible for ICM funding.

c) During the MAADs proceedings, did the applicants (Alectra Utilities) explain the reason for needing $587.7 million in ICM funding? If yes, please provide the reasons.

d) At the time of the MAADs application, were the applicants (Alectra Utilities) aware that ICM funding would not be available for typical annual capital programs?

  i. If yes to d), please explain why Alectra Utilities chose a ten year deferred rebasing period despite the apparent shortfall in funding for its typical annual capital programs.

e) Did the applicants (Alectra Utilities) assess the regulatory risk of the OEB denying any of Alectra Utilities ICM requests?

  i. If yes to e), what plans did the applicants (Alectra Utilities) have to mitigate or deal with the risks.

  ii. If no to e), why not?

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[1] Decision and Order, EB-2016-0025, issued December 8, 2016

Response:

a) In Alectra Utilities' Mergers, Acquisitions, Amalgamation and Divestitures ("MAADs") proceeding (EB-2015-0025), in its final reply submission, Alectra Utilities indicated at page 5 *"that it would be able to manage and maintain financial viability as a result of the cash flow support from the synergy/savings of the consolidation; this results in a customer benefit via rates lower than would have been otherwise."* Alectra Utilities identified at that time that, consistent with the MAADs policy, "*While customers <u>do not share directly in the benefits of synergy/savings during the rebasing deferral period</u>, they do benefit from them indirectly, as the ability to retain those synergies/savings permits LDC Co to continue on lower Price-Cap IR/ICM rates for this period*."

At the time of the MAADs Application, the Applicants reviewed EB-2014-0138 – *The Report of the Board: Rate Making Associated with Distributor Consolidation* (the "MAADs Policy"). In the MAADs Policy, the OEB clearly identified the concerns of distributors regarding consolidations; it states that if distributors could "*[include] on-going capital investments into rate base during the deferred rebasing period, they may be more willing to consider consolidation*". Further, in the MAADs Policy, the OEB stated that distributors had identified that *"…few, if any, distributors would be able to operate over a deferred rebasing period without incorporating normal and expected capital expenditures into rate base*."[2]

Of particular significance was the consideration that, in its findings on page 9 of the MAADs Policy, the OEB states that "*The OEB believes that the clarification set out in the September 18th Report establishes that a distributor may now apply for an ICM that includes normal and expected capital investments*."

The Applicants also reviewed EB-2014-0219 - *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.*

As identified in the Oral Hearing for the MAADs Application, in order to project the volume of ICM during the rebasing deferral period the Applicants considered the capital needs of the predecessor utilities based on past system planning. They undertook an assessment of capital needs going forward, which prompted the intention to use successive ICM funding applications to meet the estimated need.[3]. Neither Alectra Utilities, nor its predecessors, undertook a project-based evaluation for ICM funding comparable to what was provided to

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[2] EB_2014-0138, p. 8

[3] EB-2015-0025, Oral Hearing Transcript, vol. 1, p.46; vol. 2, p. 146.

the OEB in Alectra Utilities' previous two ICM applications or in the DSP provided in this application. However, the OEB, in stating in the MAADs Decision and Order that the Applicants were seeking ICM funding over the course of the rebasing deferral period, understood the nature of the evaluation that had been undertaken, to that point.

b) As provided in Alectra Utilities' response to part a), the estimated volume of ICM funding required, $587.7MM, was based on a mathematical evaluation of capital eligibility at the time of the merger transaction, based on a comparison of the capital program to the capital available in rates, having regard to the ICM methodology as had then been articulated by the Board. The capital program reflected the distribution system and investment plans of the consolidating utilities. The modelling was presented in evidence and was subject to examination during the MAADs proceeding. The M-factor funding sought in this application for five years of the ten year rebasing deferral period seeks recovery for approximately half of this amount.

c) In the MAADs Application proceeding, Alectra Utilities specified that it had ongoing capital funding needs in all of its rate zones and that it anticipated confirming that need annually. On that basis, it would file ICM applications for the rate zones for which such funding was required. Further, as the OEB identified at page 10 of the Decision and Order (EB-2015-0025), Alectra Utilities had revised its projected ICM funding requirements to $587.7MM as a result of the PowerStream rate application decision (EB-2015-0003). On Day 1 of the MAADs Application Oral Hearing, Alectra Utilities identified that it expected to file a consolidated DSP by 2019, to identify and in support of future ongoing capital needs[4].

d) No. Alectra Utilities relied on the *Report of the Board: Rate-Making Associated with Distributor Consolidation* (the "MAADs Policy") , dated March 26, 2015, and the *Handbook to Electricity Distributor and Transmitter Consolidations* (the "MAADs Handbook"), dated January 19, 2016. The MAADs application was filed on April 15, 2016. As identified in part a) above, the MAADs Policy unambiguously states, on page 9, that "*The OEB believes that the clarification set out in the September 18th Report establishes that <u>a distributor may now apply for an ICM that includes normal and expected capital investments</u>. This clarification of*

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[4] EB-2015-0025, Oral Hearing Transcript, vol. 1, p.119

policy should address the need of those distributors who may not consider entering into a MAADs transaction due to concerns over the ability to finance capital investments. The <u>*one remaining limitation*</u> *is that the ability to apply for an ICM continues to be limited to those distributors under the Price Cap IR* . . ." Subsequently, in the MAADs Handbook, at page 17, the OEB stated that *"[t]he ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index,* <u>*thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.*</u>" At the time of the MAADs Application, based on the MAADs Policy and the MAADs Handbook, the Applicants understood that ICM funding would therefore be available to fund "normal and expected capital" and that the MAADs Handbook governed what was acceptable in the context of ICM funding requests during the rebasing deferral period. The OEB's interpretation of this aspect was not known to Alectra Utilities until the OEB's issued its decision with respect to Alectra Utilities' application for ICM funding in EB-2017-0024. Please also see Alectra Utilities' response to Staff-18 a).

e) Consistent with its understanding that all applications to the OEB bear a degree of regulatory risk, Alectra Utilities did consider the regulatory risk of the OEB not approving all of its ICM requests at the time of its MAADs application. However, this consideration of risk was made on the understanding that the Applicants had at the time of the MAADs application based on the MAADs Policy and MAADs Handbook, as identified in response to part c), above. Moreover, Alectra Utilities had clearly articulated in evidence its ongoing capital funding needs through the ten-year rebasing deferral period, that it was relying on incremental capital funding each year of the ten-year period and that the opportunity for ICM recovery was a significant consideration in determining whether to complete the consolidation. The OEB understood this expectation and confirmed in the Decision and Order that Alectra Utilities had identified that it would be making applications for incremental capital funding through the rebasing deferral period. While Alectra Utilities estimated a prospect of risk in filing the ICM applications, it also relied on the OEB policies, as articulated in the MAADs Policy and then reconfirmed in the MAADs Handbook that it could reasonably expect to be able to finance capital investments during the rebasing deferral period without a need to rebase earlier than otherwise anticipated[5]. Inherent in such a statement by the OEB was the implication that funding would not be denied based on a subsequent interpretation of the MAADs Policy and Handbook such that capital funding levels are so low as to require the consideration of a variation to ICM funding through the M-Factor.

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[5] MAADs Handbook, p.17

TAB 19

2018 ELECTRICITY DISTRIBUTION RATES

Alectra Utilities Corporation

EB-2017-0024

APPLICANT'S REPLY SUBMISSION

January 30, 2018

Issue 2.2

Is Alectra Utilities' application of the Incremental Capital Module (ICM) criteria in accordance with the OEB policies, practices and requirements, and if not, are any proposed departures adequately justified?

Issue 2.3

Is the level of planned capital expenditures proposed in the ICMs appropriate and is the rationale for planning, prioritization and pacing choices appropriate and adequately explained and should the level of expenditures be approved by the OEB, giving due consideration to:

- ***customer feedback and preferences***
- ***productivity***
- ***compatibility with historical expenditures***
- ***compatibility with applicable benchmarks***
- ***reliability and service quality***
- ***impact on distribution rates***
- ***impact on OM&A spending***
- ***government-mandated obligations***
- ***the objectives of Alectra Utilities and its customers***
- ***the five-year Distribution System Plans***

Issue 2.4

Are Alectra Utilities' proposals regarding the ICM true-ups appropriate?

To more efficiently respond to the arguments raised by parties in respect of Issues 2.2, 2.3 and 2.4, these issues are considered together as follows.

As set out in Alectra Utilities' Argument-in-Chief, the ICM is a mechanism available to electricity distributors whose rates are established under the Price Cap IR regime.[62] The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed DSP. It is not limited to extraordinary or unanticipated investments and it may be applied to projects that might be considered to be 'routine' or 'business as usual'.[63]

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[62] Argument-in-Chief, p. 12.

[63] Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pp. 5-8 ("ACM Report).

Alectra Utilities has investment needs for the Brampton, PowerStream and Enersource RZs for 2018 that are not funded through existing distribution rates and therefore has filed an ICM application in respect of each of these rate zones.[64]

PWU supports Alectra Utilities' request for incremental funding.[65] OEB staff supports three of Alectra Utilities' projects – the Brampton RZ Pleasant TS True-up, the PowerStream RZ Road Authority YRRT Yonge St. Project, and the Enersource RZ Road Widening Project, QEW (Evans to Cawthra) – but otherwise opposes Alectra Utilities' request.[66] BOMA supports the funding of two projects through the ICM, namely the PowerStream RZ Mill Street MS835 Transformer Upgrade – Tottenham and the Enersource RZ City Centre Drive Rebuild (Walmart Cables).[67] All other parties oppose the Applicant's request for incremental funding through the ICM in its entirety.

Opposing parties and OEB staff make three types of arguments. First, they attack the availability of the ICM at all in the context of a consolidating distributor such as Alectra Utilities. Second, they advance a largely generalized critique of the specific projects for which Alectra Utilities seeks incremental capital funding. Third, they criticize Alectra Utilities' customer engagement efforts. Each of these types of submissions is responded to below.

Availability of ICM

OEB staff, SEC, CCC, VECC, AMPCO and BOMA all take issue with the application of the OEB's ICM policy to Alectra Utilities.[68] Each opposes what the OEB has already stated or determined on multiple occasions in prior decisions: that the ICM, as expressed in the March 26, 2015 *Report of the Board on Rate Making Associated with Distributor Consolidation* and in the MAADs Handbook, is available to consolidating distributors, such as Alectra Utilities.[69] Their opposition is such that it permeates all of their comments in relation to Alectra Utilities' request for ICM funding, including their project-specific complaints

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[64] Exhibit 1, Tab 1, Schedule 1, pp. 6-9.

[65] PWU Submission, January 16, 2018, para 12 ("PWU Submission").

[66] OEB Staff Submission, pp. 21, 27.

[67] BOMA Submission, pp. 2, 32 and 49.

[68] OEB Staff Submission, pp. 21-24; SEC Submission, pp 12-21; CCC Submission, pp. 9-10; VECC Submission, pp. 3-5; AMPCO, pp. 4-5; BOMA, pp. 9-12.

[69] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015, pp. 7-9.

CCC acknowledges that the “Board has, through a series of reports established policies regarding mergers and acquisitions” but argues that “strict adherence” to those policies may well conflict with just and reasonable rates.[70] It goes on to ask the OEB to “rethink its policies”.[71] In support of this position, and as what it describes as relevant context, CCC includes a table from Alectra Utilities’ MAADs proceeding setting out the then forecasted net synergies over the deferred rebasing period. CCC then argues that, because Alectra Utilities “from a management standpoint” has consolidated and is beginning the process of integrating its capital planning function, it should be precluded from incremental capital funding until it has filed a consolidated DSP.[72]

VECC, despite protestations to the contrary, also attacks the MAADs Handbook. As it says, “[W]e think the Board’s amalgamation policies unfortunate.”[73] Like CCC, VECC concludes by submitting that the OEB “should not approve any ICMs for Alectra Utilities before reviewing a comprehensive distribution system plan”.[74]

AMPCO takes a similar approach. It begins by arguing that, “Alectra Utilities’ ICM request coincides with significant merger savings”, and also points to the forecast in the MAADs application. It too argues that the OEB should not approve the 2018 ICMs until Alectra Utilities has prepared a consolidated DSP.[75]

BOMA makes the same argument with respect to the need for a consolidated DSP – before any ICM funding, in any rate zone, may be approved.[76]

OEB staff make a somewhat different argument. They begin by observing, correctly, that the availability of the ICM was considered and resolved in the MAADs Decision. In fact, the availability of ICM was of such importance to the OEB that, in the MAADs Decision, it dedicated a section of the decision to re-articulating the MAADs policy as it specifically relates to the ICM. There, the OEB states that “[t]he 2015 Report extended the availability of the Incremental Capital Module (ICM), an

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[70] CCC Submission, pp. 3-4.

[71] Ibid., p. 5.

[72] Ibid., p. 6.

[73] VECC Submission, para. 16.

[74] Ibid., para. 19.

[75] AMPCO Submission, pp. 2, 4.

[76] BOMA Submission, p. 40.

additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned".[77]

Nevertheless, OEB staff goes on to say in its submission that, because Alectra Utilities intends to file annual ICM applications, the "IRM filing requirements would suggest that the Custom IR option would be the most appropriate option to deal with the circumstances outlined by Alectra Utilities in the current application".[78] The Applicant takes issue with this suggestion from OEB staff for three main reasons. First, OEB staff is wrong to infer that Alectra Utilities intends to make annual ICM applications during the rebasing deferral period. As indicated by the Applicant during the Technical Conference, it will assess annually whether or not an ICM application will be required.[79] Second, it is the Applicant's view that using the Custom IR option would entirely defeat the purpose of the incentives, provided by the OEB through its consolidation policies, for shareholders to pursue consolidations. Third, OEB staff's suggestion that Alectra Utilities use the Custom IR option instead of pursuing recovery of incremental capital costs through the ICM mechanism undermines the OEB's MAADs Decision as it implies that Alectra Utilities should submit such an application prior to the end of the rebasing deferral period that the OEB expressly approved.

While also arguing that a consolidated DSP is a prerequisite to ICM finding[80] and adding its own particular gloss on the "profits" it says are being earned during the deferred rebasing period, SEC puts the matter even more bluntly in its submission when it states as follows:

> **3.2.36** But the Applicant should not be able to have their cake and eat it too. The Board has a mechanism for utilities with long-term, recurring capital programs that cannot be accommodated under Price Cap IR. Horizon is on that rate plan, Custom IR.

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[77] MAADs Decision, p. 8.

[78] OEB Staff Submission, p. 23.

[79] Transcript, Technical Conference (Day 1), p. 19-21.

[80] SEC Submission, paras. 3.2.31, 3.6.1 (d).

Later, in discussing the ICM application for the Enersource RZ, SEC devotes a full page to essentially repeating this submission.[81]

The OEB developed the MAADs Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and "subsequent rate applications".[82] The OEB did so in the context of the Renewed Regulatory Framework ("RRF"). The policy articulates incentives for shareholders of distributors to pursue consolidations, ultimately in the interests of customers. Subject to the conditions of specific MAADs decisions and concluded merger transactions, shareholders should have the opportunity to avail themselves of those incentives. Contrary to the submissions of opposing parties, the OEB established its policy creating those incentives while remaining mindful of its fundamental obligation to set just and reasonable rates, as well as to ensure the outcome-based approach called for under the RRF.

As the MAADs Handbook begins:

> The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.[83]

The OEB recognized this interest in, and support for, consolidation. The OEB stated that, in discharging its statutory obligation to review and approve consolidation transactions where they are in the public interest, it was committed to reducing regulatory barriers to consolidation. The OEB concluded the introduction to the MAADs Handbook by advising that:

> Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applicants. This Handbook will provide further clarity to applicants, investors, shareholders, and other stakeholders. The Handbook also discusses the rate-making

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[81] See SEC Submission, paras 3.4.18 to 3.4.23.

[82] MAADs Handbook, p. 1.

[83] Ibid.

> policies associated with consolidations and sets out the timing of when such matters will be considered by the OEB.[84]

In the MAADs Handbook, the OEB set out its policy with respect to the availability of ICM funding to consolidating distributors during a deferred rebasing period.[85] That policy is clear: to encourage consolidation, the ICM is available to consolidating distributors that are on Price Cap IR to provide those distributors with the ability to finance capital investments during the deferral period.

As has been conceded, the availability of ICM was considered and resolved in the MAADs proceeding.[86] Intervenor arguments opposing the availability of ICM were rejected.[87] The OEB had before it the "context" that parties such as CCC again reply upon. The OEB held that its policy is to permit distributors to retain savings achieved as a result of the merger "to offset transaction costs" – not to fund incremental capital requirements during the deferral period.[88]

The OEB was also well aware of the possibility that Alectra Utilities may be required to file multiple ICM applications. As the OEB noted at p. 10 of the MAADs Decision, "the applicants expect to file an ICM in each year for each rate zone under Price Cap IR during the deferred debasing period." Whether this will, in fact, be required is an open issue. As set out above, the evidence here is that Alectra Utilities will evaluate the need for ICM annually and that it does not know whether, or if so to what extent, ICM applications will be filed going forward. But, in any event, the point is that even if multiple ICM applications are required, the OEB rendered the MAADs Decision in full recognition of this fact.

Likewise, the OEB was well aware that Alectra Utilities would not be in a position to file a consolidated DSP until 2019.[89] Indeed, echoing submissions it makes in this case, SEC had argued that the OEB should require Alectra Utilities to file a DSP for the combined entity no later than December 2017 as a condition of its license.[90] The OEB disagreed.[91] While noting that the MAADs

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[84] Ibid., p. 2.

[85] Ibid., p. 17.

[86] EB-2016-0025/EB-2016-0360, Decision and Order, December 8, 2016, pp. 10-11 ("MAADs Decision").

[87] Ibid., p. 12.

[88] Ibid., p. 6.

[89] Ibid., pp. 10-11.

[90] EB-2016-0025, Final Argument of the School Energy Coalition, October 10, 2016, para. 4.2.3.

[91] MAADs Decision, p. 12.

Handbook encourages consolidating entities to operate as one as soon as possible – something Alectra Utilities is actively doing – it imposed no such requirement. Nor did it limit the availability of ICM funding to post-2019. It is simply wrong to say that a consolidated DSP is required before Alectra Utilities is eligible for ICM funding.

Response to ICM Specific Projects

The following are Alectra Utilities' responses to the submissions of OEB staff and other parties on specific projects proposed for ICM treatment within each of the Alectra Utilities rate zones. The proposed ICM projects reflect incremental capital requirements within the context of Alectra Utilities' financial capacity underpinned by its existing rates, and each project satisfies the eligibility criteria of materiality, need and prudence. Further to the above, that the proposed ICM projects all qualify for ICM treatment, Alectra Utilities submits the full amount proposed for ICM treatment for each proposed ICM project should be approved. For reference purposes, Table 1 below provides a summary of the proposed ICM projects by rate zone and project classification.

Table 1 – ICM Projects by Rate Zone

CATEGORY	PROJECT	2018 BUDGET
BRAMPTON RZ		
System Access	1. Pleasant TS True-Up	$6.8MM
POWERSTREAM RZ		
System Access	1. York Region Rapid Transit VIVA Bus Rapid Transit Y2 and H2 Projects	$11.24MM
System Renewal	2. Station Switchgear Replacement - 8th Line MS323	$1.39MM
	3. Rear Lot Supply Remediation - Royal Orchard - North	$1.68MM
	4. Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive	$1.84MM
	5. Cable Replacement – (V08) - Steeles Ave and New Westminster	$2.64MM
	6. Circuit Breaker Replacement – Richmond Hill TS#1	$1.19MM
System Service	7. Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie	$1.37MM
	8. Mill St. MS835 Transformer Upgrade – Tottenham	$1.3MM
	9. Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview	$1.2MM
	10. Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306	$1.28MM
ENERSOURCE RZ		

System Access	1. QEW – Evans to Cawthra Roads Project	$1.29MM
System Renewal	2. Glen Erin & Montevideo Subdivision Rebuild	$1.96MM
	3. Glen Erin & Battleford Subdivision Rebuild	$2.06MM
	4. Credit Woodlands & Wiltshire Subdivision Rebuild	$1.55MM
	5. Tenth Line Main Feeder Subdivision Renewal	$1.14MM
	6. Folkway & Erin Mills Main Feeder Subdivision Rebuild	$1.03MM
	7. City Centre Drive Rebuild (Walmart Cables)	$1.55MM
	8. Lake/John Area Overhead Rebuild	$0.93MM
	9. Church St. Area Overhead Rebuild	$1.02MM
	10. Transformer Replacement Project	$8.45MM
System Service	11. York MS	$3.27MM

Materiality

As discussed in the Applicant's Argument-in-Chief, the OEB, in the ACM Report, explains that the materiality threshold is, in effect, a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates.[92] The Report goes on to state that "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing".[93] The means for determining the OEB-defined materiality threshold was updated in the Supplemental Report and is set out in section 3.3.2.2 of the Filing Requirements; it is also reproduced in the pre-filed evidence.[94] Alectra Utilities has appropriately calculated the materiality thresholds, and the corresponding eligible incremental capital amounts (i.e. maximum amounts eligible for recovery through ICM), in accordance with the ACM Report, Supplemental Report, Filing Requirements and the *Report of the Board: Rate Making*

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[92] ACM Report, pp. 16-17.

[93] ACM Report, p. 17.

[94] See Exhibit 2, Tab 2, Schedule 10, p. 7; Exhibit 2, Tab 3, Schedule 10, p. 17; Exhibit 2, Tab 4, Schedule 11, p. 29.

Associated with Distributor Consolidation[95] for each of the Brampton, PowerStream and Enersource RZs.[96]

In addition to the materiality thresholds used for determining the total eligible incremental capital amounts for each rate zone, the OEB requires distributors to meet project-specific materiality thresholds.[97] The project-specific materiality threshold, which has been defined by the OEB as 0.5% of distribution revenue requirement,[98] has been calculated for each of the Brampton, PowerStream and Enersource RZs and, in each rate zone, the individual eligible projects each exceed the identified project-specific materiality threshold.[99]

OEB staff agree that Alectra Utilities has correctly determined the materiality threshold for each RZ and each of the project-specific materiality thresholds, and acknowledge that each of the projects for which ICM recovery is sought exceed the applicable threshold.[100] Given that the last rebasing for the Enersource RZ was in 2013,[101] and that the 2016 Custom IR application for the PowerStream RZ resulted in a single forward test year cost of service decision,[102] the extent of Alectra Utilities' incremental capital needs should not be surprising.

Need

In the ACM Report, the OEB explains that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, which should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[103]

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[95] See p. 10.

[96] See Argument-in-Chief, p. 14.

[97] ACM Report, p. 17.

[98] See ACM Report, p. 17; See also OEB, Decision and Order in Enersource's 2016 ICM (EB-2015-0065) at section 3.2: "Each capital project approved for ICM funding must be material to the distributor. Project materiality is 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million."

[99] See Argument-in-Chief, p. 15.

[100] See OEB staff Submission, pp. 18-19.

[101] Decision and Order, EB-2012-0033, December 13, 2012.

[102] Decision and Rate Order, EB-2015-0003, September 27, 2016.

[103] ACM Report, p. 17.

Under the Means Test, if a distributor's regulated return (as most recently calculated in accordance with RRR 2.1.5.6) exceeds 300 basis points above the deemed return on equity ("ROE") embedded in the distributor's rates, then the funding for any incremental capital project will not be allowed.[104] Alectra Utilities has demonstrated that, based on the accounts of the predecessor utilities, it has satisfied the Means Test in respect of each rate zone.[105]

Within the Brampton, PowerStream and Enersource RZs, each eligible capital project is a discrete project that exceeds the corresponding project-specific materiality level. Each project is distinct and has been evaluated in the asset management and capital planning process as required in 2018.[106] Unlike recurring capital program work, where costing is typically done at a high level (such as by multiplying unit costs based on historical expenditures), for each of the eligible capital projects Alectra Utilities has performed detailed, project-specific estimates based on a specific scope of work and detailed design carried out for a particular location.[107] Moreover, the costs of the projects for which Alectra Utilities seeks recovery through the ICM are incremental to the Applicant's capital requirements that underpin its existing rates for each RZ. Intervenor submissions with respect to the need for specific projects that have been proposed for ICM recovery by Alectra Utilities are addressed below.

An often-repeated argument made by parties is that certain of the projects are not discrete because they contemplate work that is similar in nature to recurring annual capital work. It is unfortunate that the OEB has not clearly articulated how its requirement, that projects be "discrete" in order to meet the "need" criterion for ICM eligibility, should be applied. Intervenors would have the OEB understand this to mean that if work is of a similar nature to or somehow connected to recurring annual capital work, then it is not "discrete" and should thereby be ineligible for ICM treatment. In Alectra Utilities' view, for the reasons that follow this is not what the OEB intended and would be wrong.

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[104] ACM Report, p. 15.

[105] See Exhibit 2, Tab 2, Schedule 10, p. 9 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, p. 20 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, p. 32 (Enersource RZ).

[106] See Exhibit 2, Tab 2, Schedule 10, p. 9 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, p. 21 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, p. 32 (Enersource RZ).

[107] See Technical Conference Transcript, Day 1, pp. 141-142

First, given the well-defined range of assets they own, operate and maintain – poles, conductors, transformers, stations – it is unlikely that distributors will encounter work that by its nature that is different than all other work that it regularly performs in connection with its system. The nature of the work is not what needs to be discrete. Rather, the intention is that the project be clearly defined, relate to a specific location or specific assets on the distribution system, and have a specific scope and timeframe for execution. A project that has these characteristics should be considered "discrete".

Second, there is no requirement that projects be unique or relate to work that is different in kind from work that is carried out as part of ongoing base capital work programs.[108] These are simply not criteria for ICM eligibility. To repeat, the ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in a distributor's previously filed DSP. It is not limited in its availability to extraordinary or unanticipated investments and it may be applied to projects that may be considered to be routine or business as usual.[109]

Prudence

The ACM Report and the *Filing Requirements* specify that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[110]

The Applicant's eligible capital projects are prudent because, in the case of the Brampton RZ, it is for a non-discretionary project and, for the PowerStream and Enersource RZs, the projects represent the most cost effective options for ratepayers. In each case, the projects are based on capital investment needs for the Brampton, PowerStream and Enersource RZs for 2018 that are not funded through existing distribution rates.

To demonstrate the prudence of each eligible capital project for which Alectra Utilities is seeking approval, the Applicant has provided a business case summary that identifies the name, driver, cost and expected in-service date for the project, describes the project and its drivers, and sets out the

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[108] ACM Report, p. 15.

[109] Ibid., pp. 6-7.

[110] ACM Report, p. 17; Filing Requirements, section 3.3.2.

various options considered for the project.[111] In addition, the Applicant has provided detailed business cases for each eligible capital project. The detailed business cases include relevant background information including with respect to the location and history of the project, detailed description of the scope of the project, as well as explanation as to the options considered and the budget and in-service dates for the work.[112] Where an option was considered and was determined to be feasible because it provided an alternative means of addressing the identified project needs, the Applicant has provided costing information for that option to assist in demonstrating that the recommended approach to implementing the project is the most effective option for its ratepayers. Intervenor submissions with respect to the prudence of specific projects proposed for ICM recovery by the Applicant are addressed below.

2.1 Brampton Rate Zone

2.1.1 Pleasant TS True-Up (System Access, $6.8MM)

This investment is required under the terms of the Connection and Cost Recovery Agreement ("CCRA") between Alectra Utilities and HONI for the construction of the Pleasant TS expansion in the Brampton RZ. The CCRA was entered into by the former Hydro One Brampton, in connection with its efforts to increase available transformation capacity for anticipated load growth in the northwest area of Brampton. The 10-year true-up payment under the CCRA is due in June 2018 and the Applicant estimates a shortfall of revenue to HONI relative to the forecasted demand used to calculate the capital contribution initially made. The Applicant therefore anticipates being required by HONI, under the terms of the CCRA, to provide a further contribution of $6.8MM in June 2018, with the specific amount and payment terms to be finalized at that time.

OEB staff and the PWU support approval for recovery of the full amount proposed.[113] All other parties oppose recovery.[114]

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[111] See Exhibit 2, Tab 2, Schedule 10, pp. 10-11 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, pp. 22-33 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, pp. 33-46 (Enersource RZ).

[112] See Attachment 21 (Brampton RZ), Attachment 33 (PowerStream RZ), and Attachment 47 (Enersource RZ).

[113] OEB Staff Submission, p. 27; PWU Submission, para. 12.

[114] SEC Submission, pp. 21-26; CCC Submission, pp. 11-12; AMPCO Submission, p. 6; BOMA Submission, pp. 66-69.

TAB 20

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

AND IN THE MATTER OF an Application by Alectra Utilities Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2019.

REPLY SUBMISSION OF ALECTRA UTILITIES

January 9, 2019

1.0 INTRODUCTION

Alectra Utilities Corporation ("Alectra Utilities" or the "Applicant") filed an application with the Ontario Energy Board ("OEB" or the "Board") on June 7, 2018, under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to its electricity distribution rates for each of its Horizon Utilities, Brampton, PowerStream and Enersource rate zones ("RZs") to be effective January 1, 2019 (the "Application"). The Application was prepared in accordance with the OEB's *Filing Requirements for Incentive Regulation Rate Applications* (the "Filing Requirements") and other relevant OEB guidance. The OEB accepted the Vulnerable Energy Consumers Coalition ("VECC"), the Association of Major Power Consumers in Ontario ("AMPCO"), the Consumers Council of Canada ("CCC"), the School Energy Coalition ("SEC"), the Building Owners and Managers Association of Greater Toronto ("BOMA") and Energy Probe Research Foundation ("Energy Probe") as Intervenors (collectively, the "Parties"). In Procedural Order ("PO") No. 3, the OEB bifurcated the application such that items that were not eligible for cost awards would proceed by way of written hearing. Alectra Utilities received submissions from OEB Staff and SEC on November 23, 2018. Alectra Utilities filed its reply submission on November 30, 2018. The OEB provided a decision for that portion of the Application on December 20, 2018.

The PO also provided for an oral hearing that was convened on December 5 and 6, 2018 to address the York Region Rapid Transit ("YRRT") Incremental Capital Module ("ICM") project and the Earnings Sharing Mechanism ("ESM") for the Horizon Utilities Rate Zone ("RZ"). Alectra Utilities and the Parties reached a Settlement Agreement on the ESM for the Horizon Utilities

Alectra Utilities engaged Innovative Research Group ("IRG") to undertake customer engagement for the ICM projects in the PowerStream and Enersource rate zones. This is a continuation of the customer engagement activities undertaken for the Enersource RZ Distribution System Plan ("DSP") and ICM projects in Alectra Utilities' 2018 EDR Application. Further, Alectra Utilities has considered the submissions from OEB Staff and Intervenors during the 2018 EDR Application proceeding in order to refine its 2019 ICM-related customer engagement. Alectra Utilities has also considered and had regard to the OEB's findings in the 2018 Application proceeding. As provided in the IRG Report that was filed as Attachment 34 (PowerStream RZ) and Attachment 49 (Enersource RZ): a telephone survey was conducted using stratified random samples for Residential and General Service Customers; and an online survey was also deployed for Large Use Customers. This approach allowed Alectra Utilities to capture customer views on the emerging needs or shifting priorities and to generate feedback on the specific projects being considered for this application. The engagement indicates that most customer groups support the ICM projects tested at the investment levels proposed or even higher.

3.0 ALECTRA UTILITIES INCREMENTAL CAPITAL MODULE REQUEST

OEB Policy

As described in Section 3.3.2 of the *Filing Requirements*, the ICM is a mechanism available to electricity distributors whose rates are established under the Price Cap IR regime. The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed Distribution System Plan. It is not limited to extraordinary or unanticipated investments and may be applied to projects that might be considered to be 'routine' or 'business as usual'.[3]

The availability of ICM was decided in the MAADs Decision. In that proceeding, Alectra Utilities had advised that it intended to file ICM applications during the rebasing deferral period. Intervenors disagreed that this should be permitted. The Board disagreed with Intervenors and stated the following at p. 6 of the MAADs Decision:

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[3] ACM Report, pp. 5-8.

> *The 2015 Report extended the availability of the Incremental Capital Module (ICM), an additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned.*

The *Filing Requirements* specify that the amount requested for an ICM claim must be incremental to the distributor's capital requirements within the context of its financial capacities underpinned by existing rates, and that the request must satisfy the eligibility criteria of materiality, need and prudence. [4] These eligibility criteria, discussed below, are as set out in section 4.1.5 of the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (*EB-2014-0219*),* issued September 18, 2014 (the "ACM Report"). In addition, changes to the materiality threshold were made in the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 22, 2016 (the "Supplemental Report"). The ICM projects for the Enersource and PowerStream RZs are in accordance with OEB policies, practices and requirements as reflected in the ACM Report, the Supplemental Report and the *Filing Requirements*. The Applicant has not proposed any departures therefrom.

Materiality

In the ACM Report, the Board explains that the materiality threshold is, in effect, a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates.[5] The Report goes on to state that "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor."[6]

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[4] *Filing Requirements*, Section 3.3.2, p. 24.

[5] ACM Report, pp. 16-17.

[6] ACM Report, p. 17.

The means for determining the Board-defined materiality threshold was updated in the Supplemental Report and is set out in section 3.3.2.2 of the *Filing Requirements*; it is also reproduced in the pre-filed evidence.[7] Alectra Utilities has appropriately calculated the materiality thresholds, and the corresponding eligible incremental capital amounts (i.e. maximum amounts eligible for recovery through ICM), in accordance with the ACM Report, Supplemental Report, Filing Requirements and the *Report of the Board: Rate Making Associated with Distributor Consolidation* for the PowerStream and Enersource RZs. Based on the foregoing, the applicant has determined as follows:

- PowerStream RZ has a maximum eligible incremental capital amount of $25,510,168.[8] The Applicant's proposal to recover $20,872,246[9] through the ICM in respect of the PowerStream RZ is therefore within the range acceptable to the Board.

- Enersource RZ has a maximum eligible incremental capital amount of $38,783,623.[10] The Applicant's proposal to recover $10,700,000[11] through the ICM in respect of the Enersource RZ is therefore within the range acceptable to the Board.

In addition to the materiality thresholds used for determining the total eligible incremental capital amounts for each rate zone, the Board requires distributors to meet project-specific materiality thresholds.[12] This second materiality threshold, a project-specific materiality threshold, has not been defined by the Board. In Alectra Utilities' 2018 EDR Decision on p. 15, the Board stated: *"Amending the ICM policy to include a mathematical materiality calculation for this second test should only be done through a policy review."* Further, the OEB goes on to state: *"The OEB has applied its judgement consistent with the ICM policy. The OEB will consider whether each capital project proposed for an ICM is significant with respect to Alectra Utilities' total capital budget, not with respect to the capital budget by rate zone."*

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[7] See Exhibit 2, Tab 3, Schedule 10, p. 13; Exhibit 2, Tab 4, Schedule 11, p. 10.

[8] Exhibit 2, Tab 3, Schedule 10, Table 111, p. 15

[9] Exhibit 2, Tab 3, Schedule 10, Table 112, p. 15

[10] Exhibit 2, Tab 4, Schedule 11, Table 154, p. 12

[11] Exhibit 2, Tab 4, Schedule 11, Table 155, p. 12

[12] ACM Report, p. 17.

Need

In the ACM Report, the Board explains that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, which should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[13]

Under the Means Test, if a distributor's regulated return (as most recently calculated in accordance with Reporting and Record Keeping Requirements ("RRR") 2.1.5.6) exceeds 300 basis points above the deemed return on equity ("ROE") embedded in the distributor's rates, then the funding for any incremental capital project will not be allowed.[14] The Applicant has demonstrated that, based on its 2017 RRR filing, it has satisfied the Means Test.[15]

Within the PowerStream and Enersource rate zones, each eligible capital project is a discrete project, not funded through existing rates and significant relative to Alectra Utilities' overall capital expenditure, whether taken alone or as part of the group of projects proposed as part of the application. Further, each project is unrelated to a recurring annual capital program, and has been evaluated in the asset management and capital planning process as required in 2019.

Prudence

The ACM Report and the *Filing Requirements* specify that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[16]

The Applicant's eligible capital projects are prudent because, in the case of the PowerStream RZ, it is for non-discretionary projects. All three projects are mandatory and will need to be completed, in order for Alectra Utilities to be compliant with the *Public Service Works on Highways Act* ("PSWHA") for the YRRT and Bathurst projects; and Measurement Canada as

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[13] ACM Report, p. 17.

[14] ACM Report, p. 15.

[15] See Exhibit 2, Tab 3, Schedule 10, p. 16 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, p. 13 (Enersource RZ).

[16] ACM Report, p. 17; Filing Requirements, section 3.3.2.

well as the IESO Market Rules for the Barrie TS project. In the case of the Enersource RZ, the transformer replacement project is a mandatory project, and the Rometown project is required to address aging infrastructure, and is further supported by customer engagement. In each case, the projects are based on capital investment needs for the PowerStream and Enersource RZs for 2019 that are not funded through existing distribution rates.

To demonstrate the prudence of each eligible capital project for which Alectra Utilities is seeking approval, the Applicant has provided a business case summary that identifies: the name, cost; and expected in-service date for the project; describes the project and its drivers; and sets out the various options considered for the project.[17] In addition, the Applicant has provided detailed business cases for each eligible capital project. The detailed business cases include relevant background information including with respect to the location and history of the project, detailed description of the scope of the project, as well as explanation as to the options considered and the budget and in-service dates for the work.[18] Concise summaries of the business cases are provided below and the key rationale for the projects and their proposed timing are summarized in the table at Appendix A.

Summary of ICM Projects

The five eligible ICM projects consist of two System Access projects in the PowerStream RZ, a System Service Project in the PowerStream RZ, and two System Renewal projects in the Enersource RZ, as follows:

- The Road Authority York Region Rapid Transit ("YRRT") VIVA Bus Rapid Transit Y2 and H2 Project is a System Access project in the PowerStream RZ with a budget of approximately $13.27MM. System access investments are projects outside of Alectra Utilities' control that are required to meet customer service obligations to provide customers with access to electricity services via the distribution system and include modifications (including asset relocation) to the distribution system. This project is not included in distribution rates. The Applicant has been relocating overhead and underground distribution assets in the PowerStream RZ to accommodate the YRRT's Bus Rapid Transit developments, which is being undertaken to meet the transportation

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[17] See Exhibit 2, Tab 3, Schedule 10, pp. 18-21 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, pp. 14-17 (Enersource RZ).

[18] See Attachment 31 (PowerStream RZ), and Attachment 46 (Enersource RZ).

TAB 21

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0018** **Alectra Utilities Corporation**

VOLUME: **Technical Conference**

DATE: **October 7, 2019**

MS. BUTANY-DESOUZA: Mr. Shepherd, the statements that follow on slide 6 are related to the 2018 decision.

When we calculated our M-factor, we did it on the basis of the ICM calculation that includes materiality thresholds and the 10 percent dead band, as is laid out in volume 1 of the pre-filed evidence.

MR. SHEPHERD: Sorry, I am not sure I understand. What are the two materiality tests you're using?

MS. BUTANY-DESOUZA: We didn't use two materiality tests. We are saying these are issues related to the M-factor based on the fact that we're modelling it off of ICM.

MR. SHEPHERD: Well, your third bullet there says all projects that are above the second threshold and meet the other ICM criteria would be considered to qualify for the M-factor.

So doesn't that mean that individual projects have to qualify, or is that not what you intended to say?

[Witness panel confers]

MS. BUTANY-DESOUZA: I think it would be helpful if Ms. Yeates would walk you through how we calculated the threshold and the project qualification for the M-factor.

I would take you to Exhibit 2, tab 1, schedule 3, table 3; that lays out how projects -- how each of the -- lays out on a per rate zone basis the CAPEX calculation.

MS. YEATES: So we applied the OEB's threshold calculation that's currently used in the ICM model.

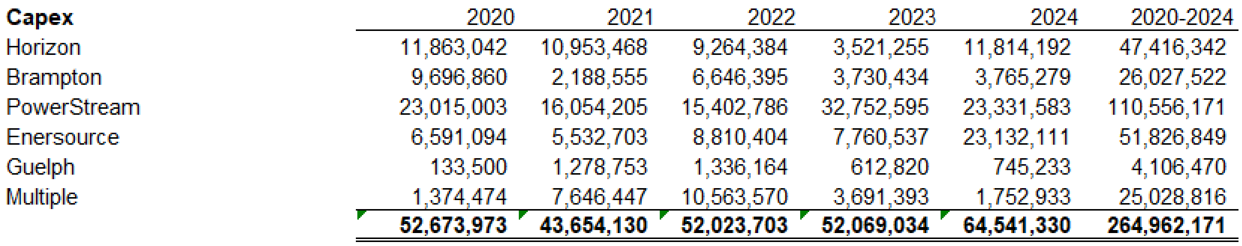
So there is only one threshold that was used in the

TAB 22

G-Staff-4

Reference: Exhibit 5, Attachment 3, M-factor Revenue Requirement

Alectra Utilities provided the following table in the "Summary by RZ" tab within the Attachment 3 excel workbook:



Capex	2020	2021	2022	2023	2024	2020-2024
Horizon	11,863,042	10,953,468	9,264,384	3,521,255	11,814,192	47,416,342
Brampton	9,696,860	2,188,555	6,646,395	3,730,434	3,765,279	26,027,522
PowerStream	23,015,003	16,054,205	15,402,786	32,752,595	23,331,583	110,556,171
Enersource	6,591,094	5,532,703	8,810,404	7,760,537	23,132,111	51,826,849
Guelph	133,500	1,278,753	1,336,164	612,820	745,233	4,106,470
Multiple	1,374,474	7,646,447	10,563,570	3,691,393	1,752,933	25,028,816
	52,673,973	**43,654,130**	**52,023,703**	**52,069,034**	**64,541,330**	**264,962,171**

a) Please provide a breakdown by rate zone of all the individual projects that are to be funded by the M-factor.

b) Please explain how Alectra Utilities determined which projects would be funded through the M-factor and which projects would be funded through Alectra Utilities' base rates.

c) If the M-factor is not approved, please confirm that the projects listed in part a) are the projects that would not proceed absent M-factor funding. Otherwise, absent any M-factor funding, please explain Alectra Utilities' methodology for choosing the projects it would defer.

Response:

a) Tables 1-4 include all capital investments proposed for M-Factor funding provided by rate zone including a set of projects applicable to all rate zones labeled as Multiple.

Table 1 – Proposed M-Factor Funded Capital Investments for Horizon Rate Zone ($MM)

Project	Investment ($MM)
Deerhurst MS Voltage Conversion	$7.8
HaLRT_New Stirton Feeder for TPSS#4 and 8852X load shedding	$4.8
Dewitt MS Voltage Conversion	$4.1
Eastmount MS Voltage Conversion	$3.8
Aberdeen MS Voltage Conversion_2020 to 2022	$3.3
Galbraith MS Voltage Conversion	$3.3

Rear Lot Conversion - Marsdale	$3.1
Elmwood MS Voltage Conversion	$2.8
Rear Lot Conversion - Richlieu Dr and Trelawne Dr	$2.4
North Central feeders capacity (Carlton TS to Lakeshore/Lake) relief	$2.0
Montgomery Dr Voltage Conversion and Rear Lot Relocate_ANC	$1.8
Waterdown 3rd Feeder	$1.7
Vansickle TS True-up Payment	$1.6
Rear Lot Conversion - Strathcona Dr	$0.9
2D7X Pimlico Dr - Voltage Conversion and Rear Lot	$0.6
Nebo TS 27.6kV True-up Payment	$0.5
New WiMAX Communications System - West	$0.5
Facilities Reno John St Roof Deck	$0.4
Fleet_2023_West_Vehicle_Replacement_Bucket Truck_1-354	$0.4
Fleet_2020_West_Vehicle Replacement_Step Vans	$0.4
Fleet_2024_West_Vehicle_Replacement_Pickups	$0.2
SS-2019-Installation of SWI Video security system at 4 MS stations per year	$0.2
Fleet_2020_West_Vehicle Replacement_SUVs_1-268,1-226,1-227	$0.1
Fleet_2023_West_Vehicle_Replacement_Pickups	$0.1
Fleet_2023_West_Vehicle_Replacement_Trailer	$0.1
SS-Driveway Paving- Various Stations -WEST	$0.1
Fleet_2024_West_Vehicle Replacement_Forklift	$0.1
Fleet_2023_West_Vehicle Replacement_ Pole Trailer_1-405	$0.1
Fleet_2022_West_Vehicle_Replacement_Trailers	$0.1
SS-2019-Station LED Lighting Upgrades - West	$0.1
Total Horizon Rate Zone	$47.4

Table 2 – Proposed M-Factor Funded Capital Investments for Brampton Rate Zone ($MM)

Project	Investment ($MM)
Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	$5.6
MS-12 Hansen Rd 4.16kV Voltage Conversion	$5.5
MS-2 Church St 4.16kV Voltage Conversion	$4.4
42M69 Feeder Extension Williams Pkwy - Main St to Kennedy Rd	$1.1
Cable Injection Project - (F4-G4) - Main - Steeles - Chinguacousy - Queen, Brampton	$1.1
Cable Replacement Project - (F4-G4) - Main - Steeles - Chinguacousy - Queen, Brampton	$1.0
136M6 Goreway TS Extensions	$1.0
Cable Injection Project - (F3-G3-H3) - Phase 2, Brampton	$0.8
Fleet_2024_ Central North Vehicle Replacement_Reel Carriers	$0.7
Facilities_2022_Reno_Sandalwood - CDM Relocation from Jane	$0.6

Cable Injection Project - (G1) - Hwy 410 - Kennedy - Wanless - Main, Brampton	$0.6
Fleet_2024_ Central North Vehicle Replacement_S/Bucket	$0.5
Fleet_2023_ Central North Vehicle Replacement S/Bucket 8910	$0.5
Fleet_2020_ Central North Vehicle Replacement-180 Loader	$0.3
Fleet_2023_ Central North Vehicle Replacement_Stake Trucks	$0.3
New WiMAX Communications System - Central North	$0.3
Fleet_2021_ Central North Vehicle Replacement_ Step Vans 6310	$0.3
Fleet_2020_ Central North Vehicle Replacement-Step Van 8108	$0.2
SS-2019-Station LED Lighting Upgrades -EAST	$0.1
136M9 Feeder Extension Castlemore Rd, Goreway Dr to McVean Dr	$0.1
42M66 OH Feeder Egress Mississauga Rd, Bovaird to CNR	$0.1
SS-2019-Upgrade to Station Facilities (Building / Civil work) MultiYear-EAST	$0.1
Fleet_2023_ Central North Vehicle Replacement_Trailer	$0.1
42M64 Feeder Extension Mississauga Rd, Williams Pkwy to Queen / Embleton	$0.1
JY TS1 Bus & Main Breaker Protections Replacement	$0.1
Fleet_2021_ Central North Vehicle Replacement_Vans	$0.1
SS-2019-Driveway Paving- Various Stations-Program-EAST	$0.1
Fleet_2022_ Central North Vehicle Replacement pick ups	$0.1
Fleet_2023_ Central North Vehicle Replacement pick ups	$0.1
Fleet_2021_ Central North Vehicle Replacement Pick up 9514	$0.1
Fleet_2020_ Central North Vehicle Replacement-Van 5910	$0.1
Total Brampton Rate Zone	$26.0

Table 3 – Proposed M-Factor Funded Capital Investments for PowerStream Rate Zone ($MM)

Project	Investment ($MM)
Vaughan TS#4 Feeder Integration - Part 3	$8.8
Residential Meter "ICON F" Meter Replacement Program - East	$7.3
Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	$5.5
Markham TS #4 Feeder Egress Part 3	$4.9
Residential solar-storage	$4.0
Rear Lot Supply Remediation - Royal Orchard - North	$4.0
Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	$3.7
Bathurst Street Widening	$3.4
Connection Cost Recovery Agreement (CCRA) – Midhurst TS – 15th Anniversary True-up	$3.2
Cable Replacement - (V15) - Jardin Dr	$2.9
Cable Replacement - (A02) - Steeplechase Ave	$2.9

Cable Injection Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.8
Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	$2.6
Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	$2.6
Rear Lot Supply Remediation - Main Street / Unionville / Carlton	$2.5
Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.4
New Barrie 20MVA Substation - Harvie	$2.2
Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills	$2.2
Cable Replacement - (M33) - 16th Avenue and Village Parkway	$2.1
27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	$2.0
Aurora MS6 Expansion - (Year 1 of 2) - Design & Order Equipment	$2.0
New Alliston 10MVA Substation - Industrial Parkway	$1.9
Rear Lot - Gunn/Oakley Park/St.Vincent	$1.8
Rear Lot - East of Queen Street/North of Mill Street	$1.8
Cable Replacement – (Barrie) - Cook St and Steel St	$1.7
Net Zero Energy Emissions	$1.6
Two Ccts on Birchmount Rd from ROW to 14th Ave	$1.6
Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	$1.5
Cable Injection Project - (V50) - Hwy 7 - Kipling - Steeles - Hwy 27, Vaughan	$1.5
Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	$1.4
Install a new 4 ccts CNR yard overhead crossing on the south side of Hwy 7	$1.4
Add one Additional 27.6 kV Cct on Major Mack Dr and 9th Line	$1.3
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1.3
Cable Injection Project - (V25) - Major Mackenzie - Keele - Rutherford - Jane, Vaughan	$1.3
Cable Injection Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	$1.3
Install 44kV & 13.8kV Bryne Drive	$1.1
Cable Replacement - (Barrie) - Cundles Rd and Janine St	$1.1
Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	$1.0
Cable Replacement Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	$1.0
Fleet East 2024 Vehicle replacement - Cube Vans	$0.7
Fleet East Unit # 75 83' Double Bucket	$0.7
Cable Injection Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	$0.7
Fleet East Unit # 125, 83' Double Bucket	$0.7
Install 2nd 27.6 kV Cct on Woodbine Ave from Elgin Mills Rd to 19th Ave	$0.6

Cable Injection Project - (V31) - Langstaff - Weston - Rutherford - Jane, Vaughan	$0.6
Hydro One Asset Purchase - Alliston	$0.5
Redundant Fibre Path to Aurora MS#4 Sub-Station	$0.5
Markham TS#2 Line Protections and HMI Upgrade - KDU-10 Replacement	$0.5
Split the 1/0 loop on Cityview Blvd into two loops	$0.5
Fleet East Unit # 61 Digger truck replacement	$0.4
Vaughan TS#1 Bus Differential & Overcurrent Protections Upgrades	$0.4
Dufferin St S, between MS431 and Albert St S, Alliston	$0.4
Markham TS#1 Bus Differential & Overcurrent Protections Upgrades	$0.4
Markham TS#3 Bus Differential & Overcurrent Protections Upgrades	$0.3
Markham TS#2 Bus Differential & Overcurrent Protections Upgrades	$0.3
Markham TS#1 T1/T2 "B" Overcurrent Protections and HMI Upgrade	$0.3
Vaughan TS#2 Bus Differential and Overcurrent Protections Upgrade	$0.3
Rear Lot Supply Remediation - Blake/Kempenfelt	$0.3
Fleet East 2024 Vehicle replacement - Extened Vans	$0.2
Markham TS#2 T1/T2 "B" Differential Protections Upgrade	$0.2
Vaughan TS#1 T1/T2 "B" Differential Protections Upgrade	$0.2
Markham TS#3 T1/T2 "B" Differential Protections Upgrade	$0.2
Richmond Hill TS#2 Upgrade Bus, Line & Transformer Protections	$0.1
Aurora MS6 (AMS6) Transformer and Bus Protection Upgrade	$0.1
New Three Sector WiMAX Node - MS305	$0.1
Vaughan TS3 - Station Service Transfer Upgrade	$0.1
Cityview microgrid enhancements	$0.1
Vaughan TS#2 T1/T2 "B" Differential Protections Upgrade	$0.1
Fleet East 2024 Vehicle replacement - Work Van	$0.1
Fleet East 2024 Vehicle replacement Pickup truck 2500	$0.1
Total PowerStream Rate Zone	$110.6

Table 4 – Proposed M-Factor Funded Capital Investments for Enersource Rate Zone ($MM)

Project	Investment ($MM)
44kV New Feeder Extension Centre View Dr	$6.5
Duke MS New 20 MVA Substation	$6.2
27.6kV Feeder Extension Traders	$5.5
Port Credit Village East New Feeders (Marina)	$4.4
Left behind - ERZ	$2.7
Clarkson Voltage Conversion 4.16-27.6kV (4 Sections)	$2.7
Windjammer	$2.7

Mini-Orlando MS 27.6kV Land Purchase	$2.2
27.6kV New Feeders Lakeview Development	$1.9
44kV Feeder Extension York/Meadowpine	$1.8
13.8kV Feeder Extension 9th Line, Derry to Argentia	$1.2
Shelter Bay Rd.	$1.1
QEW Expansion Dixie West OH Betterment	$1.1
Truscott Plaza Voltage Conversion 4.16 - 27.6kV (3 Sections)	$1.0
MS Transformer & HV Switchgear Replacement (ACA)Munden MS35 T1 & HV1	$0.9
MS Transformer & HV Switchgear Replacement (ACA) Western MS36 T1 & HV1	$0.8
Fleet_2024_Central South Vehicle Replacement-Step Vans	$0.7
Mason Heights	$0.7
Bough Beeches Blvd.	$0.7
Station Switchgear Replacement (ACA) Bloor MS38 LV1	$0.7
Fleet_2024_Central South Vehicle Replacement- Material Handler	$0.6
Airport 88M5 & 88M7 HONI Purchase	$0.5
Distribution Cable Replacement - Area of Erin Mills pkway. and South Millway	$0.5
Fleet_2024_Central South Vehicle Replacement-209-09 S/bucket	$0.5
Fleet_2023_Central South Vehicle Replacement-236-10 S/bucket	$0.5
Fleet_2021_Central South Vehicle Replacement-210-09 S/bucket	$0.5
New WiMAX Communication Network - Central South	$0.4
Fleet_2024_Central South Vehicle Replacement-Vans	$0.3
King St. Voltage Conversion & Loop (LRT Betterment)	$0.3
Fleet_2022_Central South Vehicle Replacement-Step Vans	$0.2
Fleet_2020_Central South Vehicle Replacement-Step Van	$0.2
Fleet_2022_Central South Vehicle Replacement- Vans	$0.2
Fleet_2024_Central South Vehicle Replacement-Trailers	$0.2
SS-2019-Installation of SWI Video security system at 4 MS stations per year - Annual Program-CENTRAL	$0.2
Fleet_2024_Central South Vehicle Replacement-Pick ups	$0.2
Fleet_2022_Central South Vehicle Replacement-Pick ups	$0.2
SS-2019-Station LED Lighting Upgrades -CENTRAL	$0.1
SS-2019-Driveway Paving- Various Stations-Program-CENTRAL	$0.1
Fleet_2024_Central South Vehicle Replacement-SUV	$0.1
Fleet_2022_Central South Vehicle Replacement- SUV	$0.1
Fleet_2020_Central South_Vehicle Replacement -Vans	$0.1
Fleet_2020_Central South Vehicle Replacement-Pick ups	$0.1
Fleet_2024_Central South Vehicle Replacement-Van	$0.1
Fleet_2021_Central South Vehicle Replacement- Van	$0.1
Fleet_2021_Central South Vehicle Replacement- trailer	$0.0

Fleet_2020_Central South Vehicle Replacement-SUV	$0.0
Fleet_2023_Central South Vehicle Replacement-Bocat	$0.0
Fleet_2023_Central South Vehicle Replacement- Arrowboard	$0.0
Total Enersource Rate Zone	$51.8

Table 5 – Proposed M-Factor Funded Capital Investments for Guelph Rate Zone ($MM)

Project	Investment ($MM)
GUELPH - Campbell TS 36M63 Feeder PHASE 2	$1.2
GUELPH - Campbell TS 36M63 Feeder PHASE 1	$1.2
GUELPH - Rear Lot Conversions	$0.6
GUELPH - Southgate Dr to Maltby Rd O/H Extension	$0.6
GUELPH - Arlen MTS - New Feeder	$0.5
GUELPH - Capacitor Bank Installations	$0.1
Total Guelph Rate Zone	$4.1

Table 6 – Proposed M-Factor Funded Capital Investments for Multiple Rate Zone ($MM)

Project	Investment ($MM)
CC&B upgrade 2021 - 2022	$13.3
Alectra Workforce Management Software	$4.7
Alectra Drive at Home	$2.7
Blockchain	$2.4
Alectra Drive for the Workplace	$0.8
Alectra Single Platform Website ongoing	$0.3
Fieldworker Upgrade 2020	$0.3
Back-end Automation (Orchestration Tool\Setup)	$0.2
IT Innovation (ITx, 2024)	$0.2
Total Multiple Rate Zones	$25.0

b) Please see Alectra Utilities’ response to G-Staff 9.

c) Alectra Utilities cannot speculate on potential investment options without the full context of the OEB’s decision. As described in Exhibit 1, Tab 3, Schedule 1, pages 4-5, under-investing will result in a growing population of deteriorated assets, declining reliability, and a “snowplow” of capital costs for future customers. It will also lead to more expensive reactive capital investments when asset failures occur.

In the event that Alectra Utilities is denied the M-factor, it will also have to file annual ICM applications during the remainder of the rebasing deferral period.

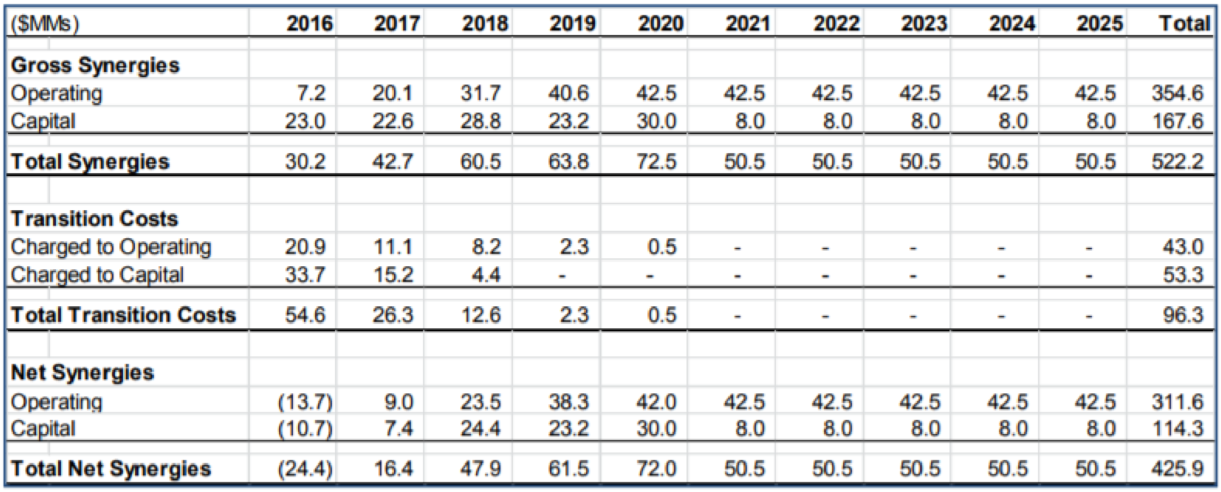
TAB 23

G-Staff-15

Reference: EB-2016-0025, Application, Exhibit B, Tab 6, Schedule 1, Page 1-2 of 4

The MAADs application stated that “The total anticipated savings net of transaction costs over a ten year rebasing deferral period […] total approximately $312 [million] in operating costs and approximately $114 [million] in avoided capital costs, which represent $426 [million] in total cash savings.” The following table was provided to show the annual breakdown of net synergies:

Figure 25 – Total Net Synergies



($MMs)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Gross Synergies											
Operating	7.2	20.1	31.7	40.6	42.5	42.5	42.5	42.5	42.5	42.5	354.6
Capital	23.0	22.6	28.8	23.2	30.0	8.0	8.0	8.0	8.0	8.0	167.6
Total Synergies	30.2	42.7	60.5	63.8	72.5	50.5	50.5	50.5	50.5	50.5	522.2
Transition Costs											
Charged to Operating	20.9	11.1	8.2	2.3	0.5	-	-	-	-	-	43.0
Charged to Capital	33.7	15.2	4.4	-	-	-	-	-	-	-	53.3
Total Transition Costs	54.6	26.3	12.6	2.3	0.5	-	-	-	-	-	96.3
Net Synergies											
Operating	(13.7)	9.0	23.5	38.3	42.0	42.5	42.5	42.5	42.5	42.5	311.6
Capital	(10.7)	7.4	24.4	23.2	30.0	8.0	8.0	8.0	8.0	8.0	114.3
Total Net Synergies	(24.4)	16.4	47.9	61.5	72.0	50.5	50.5	50.5	50.5	50.5	425.9

a) Please provide the actual amount of synergies achieved to date by Alectra Utilities.

b) Please explain why Alectra Utilities has not proposed applying the net synergies amounts in excess of transaction costs towards its capital funding gap.

Response:

a) The actual amount of synergies achieved to date and a forecast for the remainder of the rebasing deferral period is provided in Table 1, below. Actual net synergies have been included for 2017, 2018, and year to date June 2019. Forecasted net synergies have been provided for July to December 2019, and for the 2020 to 2026 period.

Table 1 – Total Net Synergies Actual and Forecast

($MMs)	2015-Jan 2017	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Gross Synergies												
Operating	0.0	29.2	36.0	35.8	42.8	43.7	43.2	44.4	44.8	44.8	44.8	409.5
Capital	0.0	21.8	42.2	36.9	15.3	23.0	13.2	7.5	7.5	7.5	7.5	182.6
Total Synergies	**0.0**	**51.0**	**78.3**	**72.7**	**58.1**	**66.7**	**56.4**	**51.9**	**52.3**	**52.3**	**52.3**	**592.0**
Transition Costs												
Charged to Operating	0.0	21.8	3.6	4.3	2.3	0.2	0.3	0.0	0.0	0.0	0.0	32.5
Charged to Capital	0.0	25.1	43.0	36.5	6.6	3.6	0.0	0.0	0.0	0.0	0.0	114.8
Total Transition Costs	**0.0**	**46.9**	**46.5**	**40.8**	**8.9**	**3.8**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**147.2**
Net Synergies												
Operating	0.0	7.3	32.5	31.5	40.5	43.5	42.9	44.4	44.8	44.8	44.8	377.0
Capital	0.0	(3.3)	(0.7)	0.3	8.8	19.4	13.2	7.5	7.5	7.5	7.5	67.8
Total Net Synergies	**0.0**	**4.0**	**31.7**	**31.9**	**49.2**	**62.9**	**56.1**	**51.9**	**52.3**	**52.3**	**52.3**	**444.8**
Transaction Costs	**24.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**24.8**
Synergies, Net of Transaction Costs	**(24.8)**	**4.0**	**31.7**	**31.9**	**49.2**	**62.9**	**56.1**	**51.9**	**52.3**	**52.3**	**52.3**	**420.0**

b) On March 26, 2015, the OEB issued the *Report of the Board - Rate-making Associated with Distributor Consolidation* (the “MAADs Policy”). In the MAADs Policy, the OEB extended the rebasing deferral period from five years to a period up to ten years following the closing of a consolidation transaction. The purpose of the rebasing deferral period is to enable consolidated distributors to fully realize the anticipated efficiency gains from the transaction and retain the achieved savings for a period of time to help offset transaction and transition/integration costs, as well as to encourage distributors to consolidate.[1] Specifically, the OEB stated at p. 5, in regard to the policy of allowing a deferred rebasing period, that “*its purpose…is to allow the net savings of a consolidation to accrue to a distributor’s shareholder(s) for an extended period. The OEB recognized that providing a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction is an important factor in a utility’s consideration of the merits of a given consolidation initiative.*”

The OEB’s MAADs Policy also noted, at p. 5, the suggestion from distributors that *“greater flexibility in terms of the rebasing time frame and the ability to retain any achieved savings for a longer deferral period will provide encouragement to those who may be interested in pursuing consolidation opportunities*.”

The MAADs Policy also clarifies, at p. 7-10, that the availability of capital funding is not a function of synergy savings. Under the MAADs Policy, the deferral period and the retention of savings are independent of future capital expenditures funded by the ICM or any capital recovery mechanism like the M-Factor. With or without the ICM, the savings are retained by the utility over the deferral period. The M-Factor is designed to work within the basic paradigm of the ICM, with some deviations to deal with the programmatic nature of the investments contemplated in the DSP and the need for flexibility in order to execute and fund the capital need. On this basis, the MAADs Policy remains intact whereby the merged utility retains the benefit of the synergies for the deferral period and satisfies incremental capital needs through the ICM. This proceeding is about the determination as to whether the M-factor is appropriate and not about the reallocation of the synergies.

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[1] MAADs Policy, p. 5-7.

Alectra Utilities also identifies that with respect to Table 1 above, the synergies are largely consistent with expectations provided in the evidence in its MAADs Application (EB-2016-0025) and as understood by the OEB in rendering its MAADs decision, establishing the balance of benefits/ incentives expected to be shared between customers and shareholders.

However, given the “financial pressures” identified in Alectra Utilities’ response to SEC-29, despite an expectation of achieving synergies more or less as expected, cashflow and net income during the rebasing deferral period are significantly lower than expected in the merger business case for reasons arising from aspects such as: previous ICM decisions and provincial policy changes regarding Conservation and Demand Management. Consequently, a focus on the merger savings does not lend itself to the full economic picture of the utility; it results in a very narrow overall view.

TAB 24

Ontario Energy Board

Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

July 14, 2008

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1 Introduction

Purpose

In 2006, the Board announced its intention to implement a multi-year rate-setting plan for distributors (the "Rate Plan"), to be effected through a number of initiatives. The Board has since confirmed the cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond, and established a mechanistic price cap rate adjustment ("2nd Generation IR") for electricity distributors over the period 2007 to 2009. The Board has issued a report which sets out its policy on key rate-making issues that may be associated with consolidation in the electricity distribution sector and which builds on and complements the work of the Board in relation to incentive regulation. Work has also concluded on the regulatory framework for conservation and demand management ("CDM") activities undertaken by electricity distributors, and on the codification of the service quality requirements for electricity distributors. The Board continues its electricity distributor cost allocation review, and has consulted with the sector on a comparative utility cost analysis methodology for electricity distributors. Also, the Board is examining the design of electricity distribution rates in light of emerging issues and industry developments in relation to matters such as metering, CDM, and distributed generation.

Board staff have undertaken research, commissioned expert advice and consulted with stakeholders on the principles and methodology for the 3rd generation incentive regulation ("3rd Generation IR") mechanism that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review.

Consultations were informed by the advice of: Dr. Lawrence Kaufmann of the Pacific Economics Group, LLC ("PEG"), staff's consultant; Prof. Adonis Yatchew of the University of Toronto, consultant to the Electricity Distributors Association; Dr. Francis

Cronin, consultant to the Power Workers' Union; and Ms. Julia Frayer of London Economics International, LLC, consultant to the Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.) and Hydro One Networks, Inc.

These consultations considered all of the necessary elements of an IR mechanism framework including the form and term of the plan, the inflation and productivity factors, the potential for earnings sharing, and the treatment of unforeseen events. The consultations also included a focus on specific issues associated with capital investment to support infrastructure maintenance and development, lost revenue due to changes in electricity consumption and distributor diversity. These activities began in August 2007 and have culminated in the policies set out in this report.

This report sets out the Board's policies and approach to 3rd Generation IR and presents guidelines that the Board expects distributors to use in preparing their rate applications. With few exceptions, this report represents the Board's final determination of its policies regarding 3rd Generation IR. As indicated elsewhere in this report, the Board will consult further on the outstanding issue of the values for the productivity factor, the stretch factor, and the capital module materiality threshold before determining those values. The Board will also in due course provide further guidance on the issue of tax changes in relation to the Z-factor (see section 2.6).

Organization of this Report

This report is organized as follows. The Board's policy for, and analysis of, 3rd Generation IR are outlined in Section 2 with brief descriptions of the matters being addressed, the Board's policies and rationale, and summaries of the issues and options raised in consultations. Written comments made by participants throughout this consultation have been considered by the Board in developing the policies set out in this report, and are available from the Board's website. This report makes reference to participant comments to the extent necessary, but does not contain an exhaustive description of those comments.

Section 3 outlines in more detail how and when the adjustments to distribution rates will be implemented. Section 4 provides a summary. Section 5 contains a guide to assist interested participants in preparing their presentations at a stakeholder conference that will be held the week of August 5, 2008 to address the outstanding values referred to above. Guidelines associated with the policies set out in this report are provided as an Appendix.

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2 Elements of the Plan

This is the third time the Board has adopted an incentive rate setting mechanism for electricity distributors. The first mechanism was established in 2000 ("1st Generation IR") and is described in the Board's first electricity distribution rate handbook. The second mechanism - 2nd Generation IR - was established in 2006 and is set out in the December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation IR for Ontario's Electricity Distributors".

Building incrementally on the 2nd Generation IR plan, the 3rd Generation IR plan is a more sustainable incentive regulation ("IR") plan for electricity distributors. The 3rd Generation IR plan is more specifically grounded in empirical analysis and takes the differences in the operations of distributors into account.

2.1 Form

There are various approaches to IR. Two popular approaches that use indexing are price caps and revenue caps – a price cap sets the maximum price that a distributor may charge, and a revenue cap sets the maximum allowable revenue requirement.

Issues and Options Raised in Consultation

The February 28, 2008 Board staff Discussion Paper on 3rd Generation IR for Ontario's Electricity Distributors (the "Discussion Paper") described various forms of IR and various individual mechanisms to address the specific issues associated with capital investment, lost revenue and distributor diversity.

Prof. Yatchew provided an analysis of three alternative approaches that were described in the Discussion Paper and that combine some of those mechanisms. In his presentation to participants during the stakeholder meeting held on May 6, 2008, Prof.

Yatchew commented that under comprehensive multi-year cost of service, incentives are substantially less powerful relative to properly implemented IR; and moreover, the regulatory burden is high for the regulator and distributors. He noted that the hybrid approach (under which OM&A would be indexed and capital costs would be forecasted) would create incentives to increase capital expenditures, in order to maintain or improve a good OM&A performance profile - a disadvantage of the hybrid approach. According to Prof. Yatchew, the third approach, the comprehensive price cap index, has the highest efficiency incentives, if properly implemented. However, he also observed that while the comprehensive price cap is by far the most appealing, it has the potential of doing financial harm for some distributors in contrast with the revenue cap, particularly those that are experiencing declining per-customer energy consumption.

Policy and Rationale

The Board will retain a comprehensive price cap form of adjustment mechanism for electricity distributors. The price cap, used in the 1st and 2nd generation IR plans, continues to be supported by distributors and other stakeholders and is a simple approach that will, along with the implementation of mandatory service quality requirements, provide balanced incentives for efficiency improvements and the maintenance of adequate service quality over the course of an IR term. The concern of potential financial harm for some distributors in contrast with revenue caps is mitigated by the other elements of the 3rd Generation IR plan described in this report.

2.2 Term

Staff’s consultations over the last year have considered IR plan term length in dealing with the specific issues associated with capital investment to support infrastructure maintenance and development, lost revenue due to changes in electricity consumption and distributor diversity. The longer the period of time between rate rebasings (i.e., the longer the IR plan term), the greater the potential need for some form of special treatment of incremental capital investment and/or lost revenues. Also, one way to recognize distributor diversity in an IR plan may be to give the distributor choice with respect to the length of the plan term. By and large, capital replacement, distributor diversity and similar issues are likely to be more manageable with shorter plan terms.

Issues and Options Raised in Consultation

In the Discussion Paper, seeing merit in allowing for flexibility in the plan term, staff suggested that distributors have the choice of plan term which could vary from three to five years. In a presentation during the stakeholder meeting held on May 6, 2008, staff proposed a fixed term of four years (i.e., rebasing year plus four years) as a reasonable plan term. This proposal was in response to the varied comments received on the need for a shorter or longer term and to concern over giving distributors choice. Further consultation on this issue continued to demonstrate a divergence of opinion.

Policy and Rationale

The Board has determined that the plan term for 3rd Generation IR will be fixed at three years (i.e., rebasing year plus three years). The rates of the distributor are not expected to be subject to rebasing before the end of the plan term other than through an eligible off-ramp.

The Board is of the view that a shorter term is appropriate in view of important refinements anticipated by 2012 to empirical work on the electricity distribution sector, including total cost benchmarking, an Ontario total factor productivity (“TFP”) study, and input price trend research. Participant support for a shorter term is evident in their concerns over distributor data limitations, evolving government policy which continues to mandate new roles for Ontario distributors, and the Board’s commitment to reviewing rate design policies.

2.3 Inflation Factor

Under cap mechanisms, changes in price indices drive allowed changes in output prices for regulated services (i.e., indices escalate the allowed prices).

The inflation factor could be established in two ways: either an industry-specific price index (“IPI”) designed to track the inflation of the industry inputs, or a macroeconomic index.

Issues and Options Raised in Consultation

The choice of inflation factor affects the X-factor. When an IPI is used, the X-factor has two main components. The first is the productivity factor, and the second is the stretch factor. When economy-wide inflation factors are used, the X-factor has additional components to capture the expected difference between changes in the selected inflation factor and input prices for the regulated industry. This difference is often referred to as the input price differential. Depending on how the productivity factor in an index is derived, a productivity differential may also be considered in conjunction with an economy-wide inflation factor in order to reflect any differences. As explained by Dr. Kaufmann in his presentation to participants at the stakeholder meeting held on May 6, 2008, input price differentials can be measured directly by comparing the change in industry input prices to the change in the selected economy-wide inflation measure. This approach is mathematically equivalent to computing both “productivity differentials” and “input price differentials,” but it is simpler and requires less information. Computing an input price differential in this manner therefore eliminates the need to obtain estimates of economy-wide TFP trends which are needed to compute both productivity and input price differentials.

In the Discussion Paper, staff provided an illustrative example of an IPI using the methodology adopted by the Board in the 1st Generation IR with a different labour price index and different weights calculated by PEG to reflect the most recent cost structure.

The Discussion Paper invited comments on this illustration, the choice of the indices and the options to address the volatility of the resulting IPI. In light of participants' comments, summarized below, at the May 6, 2008 stakeholder meeting staff proposed the use of a macroeconomic index (the Canada Gross Domestic Product Implicit Price Index for final domestic demand or “GDP IPI FDD”) instead of an IPI, and asked PEG to estimate the requisite input price differential. To do this, PEG looked at the relationship between input prices of the industry and the selected macroeconomic inflation measure. PEG examined the relationship between input price trends for Ontario distributors and Canada's GDP IPI FDD, as well as the relationship between input prices for U.S. distributors and a measure of US economy-wide inflation (the GDP-PI). PEG found that economy-wide inflation was much greater than industry input price inflation in Ontario, while in the U.S. the opposite was true. PEG was of the view that this disparity demonstrates that there is considerable uncertainty about the appropriate value for an input price differential in 3rd Generation IR. In the absence of persuasive empirical evidence, PEG therefore recommended an input price differential equal to zero.

Generally, participants agreed with the benefits of an IPI. However, concerns were expressed about implementation details of the IPI. Some of these concerns referred to the choice of input price indices and whether distributor-specific data would better track the inflation of inputs. Also, some participants commented on the weights of the sub indices. Many participants expressed concern about the methodology used for the calculation of the capital price sub index and the resulting volatility. Some participants proposed alternative approaches to smooth the index, while distributors suggested that further work is required to ensure that the index tracks actual cost pressures and reflects distributor costs going forward and suggested that in the meantime, the Board use a macroeconomic index.

Support for the use of the GDP IPI FDD and PEG's recommended input price differential was mixed. While some participants accepted the proposal, other participants continued to support the use of an IPI or expressed concern over the issue of tax changes in relation to the GDP IPI FDD (as it is currently being considered in the

EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation) or disagreed with the recommended input price differential. In particular, three participants estimated non-zero input price differentials. One participant representing a group of ratepayers estimated that the input price differential should be positive 0.43% based on the Ontario differential calculated by PEG. Another participant proposed that the differential should be positive 0.65% and argued that a differential of zero would be unfair to ratepayers and that the number should be based on judgment rather than on empirical studies. Dr. Cronin argued that the input price differential should be different from zero because distributor input prices have consistently grown more slowly than macro input prices. Based on a historical assessment of trend relationships, Dr. Cronin proposed a negative differential, estimating that based on Ontario data the input price differential has ranged from -1.1 to -2.3 over the last twenty years. Dr. Cronin also calculated productivity differentials and showed that for various periods this differential has also been non-zero.

Policy and Rationale

The Board will use the Canada Gross Domestic Product Implicit Price Index for final domestic demand (GDP IPI FDD) as the inflation factor.

The Board is of the view that a macroeconomic index is easier to implement for 3rd Generation IR: only one index needs to be obtained and the only calculation necessary will be the annual change in the index. In addition, the macroeconomic index that will be used, GDP IPI-FDD, tends to grow at a relatively stable rate over time and it is familiar to Board staff and stakeholders, since it is currently being used in 2nd Generation IR and in both gas IR plans.

The Board recognizes that an IPI would track industry input price fluctuations better than an economy-wide measure. It may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. However, the Board observes that the implementation of the IPI methodology that was used in 1st Generation IR with recent data produces a very volatile index, as shown in the illustrative example presented in the Discussion Paper. Such volatility could be harmful to both ratepayers and distributor shareholders, if reflected in rates. The Board believes that further research is required on the methodological approach to address such volatility and to ensure that the chosen sub indices appropriately track the inflation faced by the industry.

The Board has determined that the input price differential in 3rd Generation IR will be equal to zero.

A sustainable incentive regulation framework requires confidence in the parameters of the rate adjustment formula, and without greater certainty on input price trends in the sector, the Board believes that the determination of an input price differential is premature. Absent a solid methodology for the calculation of the industry IPI for Ontario as well as a TFP based on Ontario data, the Board is concerned that an input price differential that is not equal to zero may result in rates that are not just and reasonable from the perspective of both ratepayers and distributors. Therefore, until Ontario data are used to set the productivity factor in the indexing formula, the Board believes that a value of zero for the input price differential is reasonable for 3rd Generation IR.

Participant comments reinforce to the Board that further research is needed to better understand the input price trends of Ontario electricity distributors before an IPI or an input price differential can be considered for implementation. This research could be carried out for consideration in future IR plans.

Implementation

The Board will continue to use the year-over-year change in the GDP IPI FDD (Series V3840594) to calculate price escalation. The change will be calculated early in March, once Statistics Canada publishes the last year's index and the latest available information on any changes to the index of two years ago. As with 2nd Generation IR, there will be no explicit adjustments for return on equity or debt costs.

2.4 Productivity and Stretch Factors

Under a price cap mechanism, the allowed rate of change in the price of regulated services is restricted by the growth in an inflation factor minus an X-factor. Generally, the X-factor has two main components: the productivity factor and the stretch factor.

The productivity component of the X-factor is intended to be the external benchmark which all firms are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.

The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that firms are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by company and depend on the efficiency of a given company at the outset of the IR plan. Stretch factors are generally lower for firms that are relatively more efficient.

Issues and Options Raised in Consultations

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") makes specific recommendations for the productivity and stretch factor components of the X-factor and provides a discussion of relevant IR precedents.

In brief, PEG recommended in the PEG IR Report that for Ontario distributors, the X-factor be comprised of: (1) an industry TFP-based component reflecting TFP growth potential estimated using U.S. data; and (2) an efficiency benchmark-based stretch factor based on Ontario data.

The Productivity Factor

As detailed in the PEG IR Report, TFP trends were computed using an index based approach and on three sets of available data: U.S. data for the period 1988-2006, Ontario data for the period 1988-1997, and Ontario data for the period 2002-2006. Ontario data for the period 1998-2001 was not available. Dr. Kaufmann noted the results of these analyses show a slowdown in productivity in the most recent years of the U.S. TFP trend and in the latest Ontario TFP trend, and expressed uncertainty over the persistence of the trend. In the case of Ontario, Dr. Kaufmann advised in the PEG IR Report that four years of TFP changes are insufficient to compute a reliable, long-run TFP trend. He also believed that there is an identifiable, downward bias in the Ontario TFP measure which could not be explained given available information, and that the quality of the Ontario TFP measure was generally diminished by the lack of available data (especially data on distributors' capital additions). In the case of the U.S., Dr. Kaufmann commented that much of the measured TFP decline for the U.S. electricity industry in the period 2002-2006 was due to transitory factors that will not persist.

Because of concerns with relying solely on the four years of Ontario data, the recommendation in the PEG IR Report for the productivity factor was based on a comparative analysis of TFP growth between 1988 and 2006 for the U.S. and Ontario electricity distribution industries. TFP growth for Ontario distributors in the period 1988-1997 was previously computed for the purposes of the 1st Generation IR, and PEG considered this information as well as the trends it computed for Ontario distributors in 2002-2006 and for the U.S. industry for the entire 1988-2006 period. Dr. Kaufmann concluded that TFP trends for U.S. power distributors were a reasonable, although not perfect, proxy for contemporaneous TFP trends in Ontario. Overall, the average TFP growth rate for the Ontario TFP industry was almost identical to the average TFP growth rate for the U.S. industry over the thirteen years for which TFP growth could be computed.

PEG's analysis concluded that: 1) there was not enough historical data to compute a long-run TFP estimate for the Ontario distributors; and 2) TFP growth of U.S. distributors was a reasonable proxy for the Ontario industry. Therefore, PEG's recommended productivity factor was based on the long-term TFP trend for the U.S. electricity distribution industry. In the TFP study, PEG determined its sample period using a "start date analysis" designed to ensure that the estimated TFP trends were not affected by transitory conditions, such as abnormal economic or weather conditions, which can distort measured TFP trends. Based on this analysis, PEG chose a sample period of 1995 to 2006. PEG's recommended productivity factor of 0.88% was equal to the average rate of TFP growth for U.S. electricity distributors over this period.

The consultants retained by participants agreed that the index based approach is appropriate. However, their views differed as to the details involved in carrying out the analysis.

Four participants commented on the issue of the sample period used in PEG's TFP study. Two participants supported PEG's analysis to select the sample period and two participants did not. Prof. Yatchew disagreed with PEG's selected sample period. He argued that PEG's approach is conceptually deficient because, in selecting the start of the period, PEG's analysis searched for only a single year that is likely to be most similar to the most recent year in terms of factors that could distort TFP, rather than searching for an entire period that is likely to be representative of the future.

Dr. Cronin did not support PEG's recommended approach for developing a productivity factor for three main reasons: the belief that the U.S. industry was too dissimilar to that in Ontario to provide a basis for a productivity factor; the belief that PEG's measure of capital was flawed; and concern that PEG's output measure was incorrectly specified. Rather than having a single productivity factor, Dr. Cronin recommended a productivity factor-menu approach. Distributors would be allowed to select from a menu of productivity factors, each with an associated allowed return on equity ("ROE"). The "baseline" option would be a productivity factor of 0.8% with an associated allowed ROE of 8.5%. The proposed menu also included four other options, where increments of 0.2% in the productivity factor are associated with 100 basis point increments in the allowed ROE. The maximum productivity factor of 1.6% was therefore associated with a 12.5% allowed ROE.

In general, distributors raised similar concerns in their comments. These participants noted that the average TFP growth for the U.S. electricity distribution industry was 0.72% over the 1988-2006 period. These participants also noted that TFP has decelerated in both the U.S. and Ontario in recent years. They further argued that there are likely to be continued cost pressures over the term of 3rd Generation IR due to, among other things, increasing capital replacement expenditures and the impacts of government policy. These participants therefore expressed the belief that more emphasis should be placed on the Ontario TFP data, and greater weight put on the recent trend evident from that data, as the basis for the productivity factor. Ms. Frayer raised concerns that PEG's computed TFP trend did not include peak demand as an output measure. She also commented that PEG's capital measures for Ontario are likely to be biased. Ms. Frayer developed an alternative TFP measure that included peak demand and substituted a physical measure of capital (total distribution line length) for the inflation-adjusted, monetary value of capital. According to this specification, TFP for Ontario distributors declined between 1.3% and 2.5% per annum over the 2002-2006 period. In summary, distributors recommended a productivity factor of 0.55% for 3rd Generation IR. This recommendation was based on the midpoint of what these participants believed was a reasonable range of TFP growth rates estimated by Prof. Yatchew and Ms. Frayer. These participants argued that it was reasonable to have a lower TFP target than that recommended by PEG given the recent deceleration in TFP. They also argued that this approach was consistent with a Board precedent, since the productivity factor approved for purposes of the 1st Generation IR placed more weight on recent TFP growth than on more distant TFP growth.

Participants representing ratepayers generally supported PEG's recommended approach for establishing a productivity factor. Two groups commented that using the

U.S. data as a basis for the productivity factor was reasonable until sufficient Ontario data could be developed. Two other participants representing ratepayers commented that PEG's research shows that TFP trends for the U.S. industry are a reasonable proxy for contemporaneous Ontario trends. All of these participants supported PEG's recommended productivity factor of 0.88%.

The Stretch Factor

As described in the PEG IR Report, PEG's recommended stretch factors are informed by work it has done for Board staff in a separate project on the benchmarking of Ontario distributors' OM&A costs[1]. The PEG IR Report did not present final, recommended stretch factor assignments and values because the benchmarking work had not been finalized at the time the report was issued. The PEG IR Report illustrates a methodology for using these benchmarking evaluations to assign stretch factors to distributors. Distributors were assigned by PEG to different efficiency cohorts based on the following benchmarking evaluations:

Table 1: PEG's February Proposal

Group	Benchmarking Evaluations
I	Statistically superior
II	Not statistically superior but in top third on OM&A unit cost comparison
III	In middle third on OM&A unit cost comparison
IV	Not statistically inferior but in bottom third on OM&A unit cost comparison
V	Statistically inferior

Given these identified efficiency cohorts, PEG recommended stretch factors that were the same for all firms in a given cohort but differed between cohorts. Smaller stretch factors were assigned to the more efficient cohorts. More particularly, Group I had a

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[1] The March 20, 2008 final report prepared for Board staff by PEG, entitled "Benchmarking the Costs of Ontario Power Distributors" (the "PEG Benchmarking Report") details the benchmarking evaluations and is available on the Board's web site.

recommended stretch factor of 0, Group II had a recommended stretch factor of 0.15%, Group III had a recommended stretch factor of 0.3%, Group IV had a recommended stretch factor of 0.45%, and Group V had a recommended stretch factor of 0.6%. These specific values were based on judgment but were also broadly supported by precedents from North American index-based IR plans. However, in light of participant comments, as summarized below, Dr. Kaufmann presented a revised proposal at the May 6, 2008 stakeholder meeting. In response to staff's request to simplify the proposal, the number of efficiency cohorts and stretch factors was reduced from five to three, and distributors were assigned to different efficiency cohorts based on the following benchmarking evaluations:

Table 2: PEG's Revised Proposal

Group	Benchmarking Evaluations
I	Statistically superior and in top quartile on OM&A unit cost comparison
II	In middle two quartiles on OM&A unit cost comparison
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison

This updated recommendation led to a kind of "bell curve" for efficiency evaluations. That is, about two-thirds of Ontario distributors were in the middle and "average" performers in Group II, about one-sixth of the distributors were identified as "superior" performers in Group I, and about one-sixth of the distributors were classified in Group III.

In this revised proposal, PEG also linked its recommended values for the stretch factors more closely to regulatory precedents from Ontario rather than from all of North America. In the revised proposal, the stretch factor for Group I was 0, the stretch factor for Group II was 0.25%, and the stretch factor for Group III was 0.5%. These values generally conform to the values approved to date in Ontario, where 0.47% and 0.5% were the stretch factors approved in the early Enbridge and Union plans, respectively, and 0.25% was the stretch factor approved for all distributors in the 1st Generation IR plan.

Most participants supported the concept of stretch factors. However, participants differed on the appropriate magnitudes of stretch factors and whether the available data and analysis were sufficient to support the use of differentiated stretch factors at the present time.

Most participants representing groups of ratepayers generally supported PEG’s approach to both proposals but believed the proposed values for the stretch factors were too low.

Several participants did not support PEG’s recommended approach to both proposals because the underlying benchmarking evaluations focus on OM&A costs only. Some of these participants argued that benchmarking must also consider capital costs and reliability in order to benchmark company performance appropriately. They also commented that a benchmarking study that focuses only on OM&A can create perverse incentives to cut operating costs, which can be achieved through excessive capitalization or at the expense of reliability. As an alternative, one participant proposed a menu approach, in which distributors could select one of five stretch factors that ranged between 0.15% and 0.75%. Under this proposal, all distributors would be subject to an earnings sharing mechanism, and those firms selecting the higher stretch factors would be allowed to retain greater shares of their actual earnings. Dr. Cronin also supported a menu approach.

Prof. Yatchew commented that there was no theoretical rationale supporting the need for a stretch factor at the present time. He argued that stretch factors were warranted only immediately after distributors switched from cost of service regulation to IR. Because he maintained that Ontario distributors have been subject to some form of IR since 2000, he did not support a stretch factor and commented that it would be unreasonable to expect acceleration in productivity growth on this basis. As an alternative to stretch factors, Prof. Yatchew suggested that “diversity factors,” that could be positive or negative relative to the industry TFP, may be more appropriate.

However, he and some other participants representing distributors also maintained that there is no evidence of productivity differences among the distributors. In spite of these fundamental concerns, some distributors did support the application of stretch factors in principle but claimed that they should be deferred until appropriate data and benchmarking analyses that focus on the total cost of distribution services could be developed.

In response to PEG's revised proposal, most participants reiterated their prior comments. One participant representing ratepayers did not support PEG's approach of establishing separate stretch factors for different distributors and recommended that a single stretch factor of 0.5% be applied to all firms.

Policy and Rationale

The Board has determined that X-factors for individual distributors will consist of an empirically derived industry productivity trend (productivity factor) and stretch factor. The approach to setting these factors will be based on economic theory and empirically derived from objective, data-based analysis.

The Productivity Factor

The index based approach is widely used in other jurisdictions for the purpose of calculating TFP. In addition, the approach is simpler compared to the alternative "econometric" approach and is therefore better understood by stakeholders.

Implementation

All distributors will be subject to the same productivity factor that will be set at the start of 3rd Generation IR and will remain fixed throughout the term of the plan. This will provide distributors with greater certainty as to the time to achieve or surpass the external benchmark and retain any achieved savings. The Board's Rate

Plan for the electricity distribution sector will stagger distributors' commencement onto 3rd Generation IR. To set the external benchmark that all distributors will be expected to achieve, the productivity factor will be the same for all distributors regardless of when they commence the plan.

While it is clear to the Board that participants support an index based approach for the derivation of an industry productivity trend to form the basis for the productivity factor for the IR plan, the Board would be assisted by further consultation on the interpretation of the results in order to determine the appropriate value for the productivity factor. The issue of the appropriate value for the TFP trend for 3rd Generation IR will therefore be included on the agenda for the August stakeholder conference (see Section 5).

The Stretch Factor

The Board has determined that non-negative (i.e., >0 or =0) stretch factors will be included in the X-factor. The Board believes that stretch factors are required in 3rd Generation IR and is not persuaded by the arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Productivity stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.

On the issue of the application of benchmarking to OM&A costs rather than total cost, The PEG IR Report describes OM&A benchmarking as a well-established technique with ample precedent in the academic literature and regulatory proceedings. Further, OM&A benchmarking can lead to appropriate inferences on a firm's efficiency provided that the model contains appropriate controls for capital stock. PEG's econometric model included two such capital-related control variables. The Board notes that the consultants generally agree that benchmarking OM&A costs is, in principle, a legitimate benchmarking approach, although they disagree as to whether PEG's analysis has sufficient controls for capital. In contrast to 2nd Generation IR, where all distributors were subject to the same X-factor, the Board is of the view that, as an incremental approach for 3rd Generation IR, distributor diversity should be recognized. The Board does not agree with comments that there is no evidence of productivity differences within the sector. The Board's comparative cost analyses demonstrate that there is a range of productivity levels across distributors. These differences in measured productivity levels support the position that distributors have different abilities to achieve incremental productivity gains and, therefore, that it may be appropriate to have different stretch factors for distributors.

Therefore, **the Board has concluded that distributors will be assigned to one of three groups with stretch factors based on their efficiency as determined through comparative cost analysis**. Using the resultant efficiency ranking, superior performers could be assigned a lower stretch factor and inferior performers could be assigned a relatively higher stretch factor. All others could be assigned an average stretch factor.

Establishing the Efficiency Ranking

The Board will use the results of two benchmarking evaluations to divide the Ontario industry into three efficiency "cohorts." Until total cost data is available, and the models are revised in consultation with stakeholders to carry out total cost benchmarking, these evaluations will be done using the most recent three years of OM&A cost data available in July of each year. For example, for the 2009 rate year the efficiency evaluations will be based on efficiency evaluations done using OM&A cost data for the years 2005, 2006 and 2007.

The first benchmarking evaluation will use an econometric model to assess the efficiency of each distributor's costs. The econometric model set out in the PEG Benchmarking Report controls for the impact of various factors beyond management control on a distributor's OM&A costs. These factors, determined by PEG's analysis to be significant drivers of OM&A costs, include the number of customers served, kWh deliveries, the price of OM&A inputs (including labour), the percent of distribution line that was underground, system age and whether or not the distributors' territory is located on the Canadian Shield. This benchmarking model will be used to predict each distributor's OM&A costs, and the distributor's actual OM&A costs will be compared to the econometric prediction. A distributor will be deemed to be "statistically superior" if its actual OM&A costs are lower than the costs predicted by the econometric model and the difference is statistically significant. A distributor will be deemed to be "statistically inferior" if its actual OM&A costs are higher than the costs predicted by the econometric model and the difference is statistically significant. All distributors that are neither statistically superior nor statistically inferior will be deemed to be average cost performers.

The second evaluation will be based on comparisons of distributors' OM&A costs per unit of comprehensive distribution output. These unit cost evaluations will be based on a comparison between a given distributor's unit OM&A costs and the average unit OM&A costs of a peer group. There are a total of 12 peer groups identified in the PEG Benchmarking Report, which are defined based on the size of distributors, location in the Province (Northern, Southern or Greater Toronto Area), the degree of undergrounding, and whether the distributor has been experiencing rapid growth. PEG determined that these factors were most strongly associated with similarities in unit cost levels across distributors.

The two evaluations will then be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II, as shown in Table 3.

Table 3: Efficiency Cohorts for Stretch Factor Assignments

Group	Benchmarking Evaluations
I	Statistically superior and in top quartile on OM&A unit cost comparison
II	In middle two quartiles on OM&A unit cost comparison
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison

Using this approach, the Board expects that the resultant efficiency ranking will approximate a normal distribution (i.e., “bell curve”) where about two-thirds of Ontario distributors will be in the middle and “average” performers, about one-sixth of the distributors will be identified as “superior” performers in Group I, and about one-sixth of the distributors will be classified in Group III.

Implementation

Each year the cohorts for the entire sector will be re-evaluated. This means that the stretch factor for a given distributor may change during the term of the IR plan. This approach will recognize and reward distributors for efficiency improvements during the term of the IR plan. A distributor’s individual ranking can be directly affected by its own efforts and can also be affected by the efficiencies achieved by other distributors. This means, for example, that a distributor initially ranked as a superior performer must continue to outperform its peers to maintain that ranking and associated stretch factor. The approach will call for the Board to publish revised cohort rankings by the end of August each year. This will give distributors sufficient time to incorporate changes in their individual stretch factors when they apply to have their rates set for the following year.

However, while the Board has determined that there will be three stretch factors representing diversity of efficiency and that these will be revised annually to reflect changes in efficiencies in the sector, the Board has not yet determined what the three stretch factor values will be. The Board would be assisted by

further consultation on the appropriate stretch factor values for the three groups for 3rd Generation IR. The issue of the appropriate stretch factor values will therefore be included on the agenda for the August stakeholder conference (see Section 5).

2.5 Incremental Capital

In the consultation on 2nd Generation IR that occurred in 2006, a number of participants commented that the IR regime needs to ensure that sufficient incentives are available in order to achieve efficiencies, recognizing the time patterns of costs and savings; and to provide for the expeditious review and approval of capital expenditure programs. Some participants argued that certainty in relation to capital expenditures beyond the single future test year is needed. It was suggested that the regime could include some form of approval of a multi-year capital plan and not just capital items that may arise in the following year.

In its July 23, 2007 “Report of the Board on Rate-making Associated with Distributor Consolidation” and associated covering letter, the Board indicated that electricity distributors’ concerns over partial rebasing to account for needed capital expenditures should be examined as part of the development of the 3rd Generation IR plan.

Issues and Options Raised in Consultation

Staff’s Initial Proposals

The Discussion Paper noted that participants differed as to whether special treatment of capital spending is necessary in an IR framework; however, the Discussion Paper described an option that staff thought might be reasonable. The approach would allow for the intra-term approval by the Board and appropriate pass-through of incremental capital expenditures associated with growing capital program demands. Dr. Kaufmann advised in his May 6th presentation to participants that implicit in an X-factor is a historical pattern of capital expenditures for the industry, and that generally a separate capital module should not be required under a comprehensive rate indexing plan. However, he commented that if, going forward, projected capital investment is substantially different than the history of what is reflected in the X-factor, then there could be an issue and a capital module could be designed to address the disparity.

At the May 6, 2008 stakeholder meeting, staff proposed the introduction of an incremental capital module as a flexible and practical means of accommodating reasonable spikes in incremental capital investment needs during 3rd Generation IR. In brief, staff proposed that the module should only be invoked by a distributor intra-term and that any Board-approved amounts and rate base treatment should be fully resolved through comprehensive rebasing.

Under staff's proposal, in order to invoke the module a distributor would make specific application to the Board for review and approval. Staff proposed that the application would substantiate the need for incremental capital due to drivers that are non-discretionary in the control of the distributor's management such as: life-cycle replacement of aging distribution plant; and additions of non-revenue earning plant to meet new growth demands and/or address system impacts from customer choice of location for connection. Further, for incremental capital expenditures to be considered for recovery, staff proposed that the amounts would have to satisfy the eligibility criteria listed in Table 4.

Table 4: Staff's Proposed Incremental Capital Investment Eligibility Criteria

Criteria	**Description**
Causation	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Staff further proposed that applications should be accompanied by comprehensive evidence to support a claim for incremental capital and that subsequently there should be annual reporting requirements on actual amounts spent.

With regard to a materiality threshold, staff proposed a threshold of 25% of the capital budget reflected in base rates going in to IR and that the threshold must be met on an individual driver basis.

Staff's Revised Proposal

In response to participant comments, as summarized below, staff revised its proposal as described in the Board's May 15, 2008 letter to participants. To address comments from distributors, staff proposed a threshold of the distributor's average annual CAPEX since the Board-approved base year relative to 150% of the distributor's depreciation expense embedded in base rates. Staff believed that 150% would be appropriate in order to allow for the impact of inflation and to provide a cushion to ensure that only serious cases of incremental capital need are considered.

Staff also proposed changes in relation to the proposed scope for capital expenditures eligible for recovery through the module. Staff noted that, to date, revenue-earning plant had not been included in discussions. However, for reasons of simplicity, staff suggested that the threshold test be indifferent to the driver, and proposed instead that the need driving any amount applied for by a distributor should be dealt with in the distributor's application.

Finally, staff proposed that a distributor's application to the Board requesting rate relief for incremental CAPEX during IR include the following:

- An analysis demonstrating that the threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;

- A description of the underlying causes and timing of the capital expenditures, including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, return on rate base and payments in lieu of taxes (“PILs”) associated with the incremental capital), and a specific proposal as to the amount of rate relief sought;
- Justification that the impact on revenue required is incremental to what was included in the application for the base year. Amounts being sought should be directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived;
- Justification that the amounts to be incurred will be prudent. This means that the distributor’s decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not being funded by the expansion of service to include new customers); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

General Comments

In general, distributors initially expressed a preference for a multi-year capital plan review and approval approach in addition to the availability of a capital investment module. Some distributors maintained that the issue of unfunded capital arises when a distributor has to undertake programs or projects to meet requirements that may be in excess of what is allowed in the price cap formula, which implicitly considers a steady state growth rate in depreciation and returns, based on the historical costs of capital, and capital expenditures that are in effect equal to that annual depreciation expense. While these distributors were supportive of moving forward with a comprehensive price cap for 3rd Generation IR and were not advocating that distributors be held “whole” during the term for all capital expenditures, some distributors did advocate that distributors have a reasonable expectation of achieving their approved returns without being unduly penalized by having to significantly reduce their OM&A and/or capital programs. While some distributors expressed concern about the magnitude of the threshold in staff's revised proposal, they commented that the form of the mechanism is a major step forward in recognizing the business drivers necessitating such a module.

Participants representing groups of ratepayers generally expressed concern that staff's proposed approach may over-compensate distributors and result in over-earning during the IR term without clear requisite benefits to ratepayers. Many of these participants commented that CAPEX will be addressed in rebasing prior to IR, and they cautioned that any approach implemented with a capital module should only deal with incremental needs and that applications should have to include comprehensive evidence to support the claim.

One participant recommended that module treatment of capital investment should only be extended to two categories of “need” (lumpy spending and spending to improve productivity) and only to the amount that is not captured through the basic “inflation minus productivity” indexing rate adjustment components.

Another participant commented that the IR plan term should be three years to help reduce potential need for some form of special treatment of materially significant investment. This participant acknowledged that, to the extent that distributors find during the term of the IR plan that the formula is not sufficient to support incremental capital expenditures, they should have an opportunity to apply for the Board for relief; however, the onus would be on the distributor to demonstrate why its rates, derived using the formula, would not be sufficient to support the incremental capital investment. Under a three-year plan, this participant noted, such requests would be the exception, and not the norm.

A third participant urged the Board not to include an incremental capital module, and noted that PEG clearly indicated that there is no need for any explicit adjustment for capital in the indexing mechanism just because rate base is growing. This participant suggested that, if a distributor believes that it has significant incremental capital needs, the distributor should be encouraged to make a cost of service or multiple year cost of service filing. This participant also recommended that, if distributors are allowed to invoke the incremental capital module, then the X-factor proposed by PEG should be increased significantly to reflect that a significant amount of the capital has been removed from a comprehensive incentive rate mechanism, leaving a partial mechanism. Finally, if incremental capital is approved in rates, this participant expressed the view that distributors cannot expect to retain any excess earnings that they may achieve over and above that level.

Comments on Scope

One participant representing a group of ratepayers commented that the Board should not allow incremental rates where, for example, a distributor seeks to capitalize more of the costs of its existing labour force, or where a distributor says that its input costs for poles have gone up faster than inflation, or where a distributor says that it wants to prepare for future growth patterns, because these are all capital spending issues that should be handled within, and not outside of, the price cap budget provided.

Comments on the Materiality Threshold

In response to staff’s proposed 25% of capital budget threshold, distributors commented that linking an incremental capital module to a capital budget may be problematic because the base year capital budget is likely to vary significantly among distributors for a variety of reasons. They also commented that capital budgets could be distorted and/or not representative of future investment trends depending on investment cycles, the lumpiness of certain types of investments, and similar factors. Two participants commented that with the 25% of capital budget threshold the module could also be triggered even if rate base is declining (i.e., capital expenditures are less than depreciation expense).

Commenting that the proposed application requirements appear acceptable and not excessive, one distributor commented that the 150% depreciation threshold is appropriate and will address the most serious cases. However, some distributors, agreeing in general with the application requirements, commented that 150% depreciation is too high, and proposed the use of 125% above the depreciation expense from the approved base year. Another participant commented that the threshold of 150% may underestimate the degree of hardship for some, and encouraged the Board to allow applications for incremental CAPEX that will have significant influence on operations, regardless of the amounts.

One participant representing a group of ratepayers commented that the 150% of depreciation threshold is an improvement over the 25% of capital budget threshold. However, this participant expressed concern that, depending on what amount would actually be recovered through the module and subsequently what level of depreciation expense becomes the new benchmark for the threshold test, distributors may be encouraged to over spend on capital expenditures or accelerate their capital spending if they are near the threshold in order to use the module to increase revenue. This participant proposed that, if at the end of the IR term the actual CAPEX to depreciation ratio falls below 150%, any revenues collected through the application of the incremental capital module should be rebated to customers (with appropriate interest).

Another participant representing a different group of ratepayers commented that the use of an average is an improvement over staff's original proposal, but cautioned that it can still lead to perverse results with regard to the timing of expenditures (i.e., re-adjusting forecasted capital needs to be eligible for the module sooner). This participant recommended that application requirements include sufficient information to test this issue.

Commenting that the proposed 150% depreciation is too low, a fourth participant representing another group of ratepayers demonstrated the relationship between annual capital spending (affected by inflation) and the base depreciation levels already built into rate base. For example, this participant commented, for a distributor with zero growth (and therefore constant real dollar capital spending), at a 2% inflation rate (i.e., the Bank of Canada target inflation rate) and a 3.9% average depreciation rate (the current Ontario norm), the price cap mechanism naturally provides for capital spending of 150% of depreciation or more; and where a distributor has growth, it will have available, without any special treatment, substantially more than the 150% level. This participant expressed the belief that the threshold has to be at least 20% higher than the CAPEX spending provided for naturally by the price cap regime. Further, this participant stated that it is possible to estimate the amount of CAPEX generally allowed for by the price cap, tracked to growth rates, and thus to create a simple threshold formula that depends only on the approved depreciation level, and the distributor's growth rate.

Comments on Implementation Issues

While participants generally expressed a relatively common understanding of the overall intent of the capital module and how it might be implemented, they differed on views with regard to details.

Some distributors proposed specific considerations for implementation of a capital module that were generally consistent with staff's revised proposal, with the exception of a lower materiality threshold (125% depreciation included in base rates). Also, these distributors suggested that while they agreed that annual reporting on actual spend would be appropriate, no true-up would be required for the IR term unless there was evidence that there was a serious overstatement of capital requirements. In contrast, a participant representing a group of ratepayers noted that the application of the module would be based on forecast capital expenditures from the distributors and therefore a true-up should be used to reflect differences between the actual and forecast amounts, particularly if the actual expenditures, for whatever reason, do not hit the 150%

materiality threshold that they were forecast to hit. Two other participants commented that if an application addresses more than one year (looking forward) then forecasting accuracy (in terms of both capital spending and customer load) as well as the potential for variances between forecast and actual spending amounts become more significant matters and there is an increased need for ratepayer protection.

To mitigate the potential for unintended results with regard to the timing of expenditures, another participant recommended that, in addition to what was already identified in staff's revised proposal, the application requirements should also include a requirement that the distributor do the following: demonstrate that the incremental revenue requirement impact is not covered by the IR mechanism through the provision of forecasts for customer count, volumes and associated revenue, and revenue requirement associated with existing and proposed capital; and calculate the "rate adder" associated with the incremental revenue requirement. Another participant expressed support for a deferral account approach, consistent with the current mechanism in place to deal with smart meter expenditures, with amounts subject to a true-up upon rebasing based on the actual amounts spent. This participant noted that this could be captured through a rate rider rather than an adjustment to rates.

Policy and Rationale

The Board has determined that there will be an incremental capital module in 3rd Generation IR. Distributors with an amount of capital spending that exceeds the materiality threshold may best be accommodated through rebasing. However, on balance, as all participants acknowledged, some incremental capital investment needs may arise during the IR term and the Board notes that a clearly defined modular approach is generally accepted.

The incremental capital module described in this report is intended to address concerns over the treatment of incremental capital investment needs that may arise during the IR term.

While the module may provide for a broad scope for incremental capital needs, specific application must be made to provide for review and approval of stated need. Applications must be accompanied by comprehensive evidence to support the claimed need. The Board considers that the application requirements proposed by staff are reasonable.

For incremental capital expenditures to be considered for recovery prior to rebasing, amounts must satisfy the eligibility criteria set out in Table 5.

Table 5: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

As noted in the above table, **eligibility of a distributor to apply for rate relief through the module will be subject to a materiality threshold**. **However, the Board would be assisted by further consultation on the appropriate materiality threshold. The issue of the appropriate materiality threshold will therefore be included on the agenda for the August stakeholder conference (see Section 5).**

The Board has also determined that there will be annual reporting on actual capital spending and a prudence review at the time of rebasing. Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and the actual spending during the IR plan term. If the forecast costs

exceeded actual amounts spent, the difference will be returned to ratepayers. Cost overruns will be reviewed at the time of rebasing.
The Board agrees with the comments of all participants that capital expenditures mandated through government policy (e.g., smart meters) should continue to be dealt with outside of the IR plan.

With the exception of the value of the materiality threshold, the Appendix outlines the detailed requirements as they apply to 3rd Generation IR.

2.6 Treatment of Unforeseen Events

Z-factors are intended to provide for unforeseen events outside of management's control, and are a common feature of IR plans. In general, the cost to a distributor of these events must be material and its cost causation clear.

Issues and Options Raised in Consultation

The Discussion Paper acknowledged a number of issues related to Z-factor claims by electricity distributors, including the general view of distributors and other stakeholders that the current materiality thresholds are too low. The Discussion Paper identified the option of raising the two existing materiality thresholds for expenses and capital costs from the current 0.2 percent to 3 percent. During the May 6, 2008 stakeholder meeting, and in response to participant comments as summarized below, staff proposed the continuation of the current rules, with the exception of the scope of events that would qualify for Z-factor treatment and of the materiality threshold, and put forward a single threshold of 0.5 percent on total revenue requirement.

For 2nd Generation IR, Z-factors are limited to natural disasters and tax changes. One distributor questioned whether Z-factors need to be this limited. This distributor expressed the view that the eligibility criteria and the application filing, review and approval process requirements are adequate to discourage applications for relatively nominal amounts. Arguing that a specific materiality threshold is not needed, this distributor noted that the attention the Board, staff and intervenors give to a claim in an application would be proportionate to their respective concerns regarding the appropriateness and materiality of the claim.

As noted previously, some participants expressed concern over the issue of the treatment of tax changes under an IR plan that uses the GDP IPI FDD.

Some distributors recommended that the Board hold a consultation on the appropriate materiality threshold level and rules governing a Z-factor adjustment rather than applying an arbitrary 3% threshold level.

All participants representing ratepayer groups generally concurred that a single threshold which is indifferent to the type of costs incurred may be the most practical approach and that 0.5% of the total revenue requirement is reasonable. Further, they noted that this should apply to each event and not be a cumulative amount.

While generally agreeing with a move to a single threshold measure, another participant proposed refinements to the threshold test to address distributor diversity. This participant noted that, whatever formula is used to assess materiality, the actual dollar values for each distributor may not make sense if the distributor is very small or very large. Therefore, this participant proposed that for a distributor with a revenue requirement over $200 million the threshold would be fixed at $2 million, and for a distributor with a revenue requirement below $10 million the threshold would be fixed at $100,000.

Policy and Rationale

The Board has determined that the eligibility criteria are sufficient to limit Z-factors to events genuinely external to the regulatory regime and beyond the control of management and the Board.

With regard to the issue of tax changes, the Board will be informed by the decision in the EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation applications in which tax as a Z-factor is being considered. The Board will provide further guidance to electricity distributors subsequent to issuance of that decision.

The Board believes that a materiality threshold is important to provide distributors with guidance as to whether or not they should be applying to the Board for relief from a Z-factor event. **The Board has decided to set the materiality threshold based on the distributor's revenue requirement**.

Setting a single threshold of 0.5% of total revenue requirement may not make sense if a distributor is very small or very large. Staff's analysis presented at the May 6th stakeholder meeting indicated that staff's proposal would result in inordinately low threshold amounts for some small distributors (e.g., $1,600 for a distributor with a revenue requirement of $320,000) and inordinately high threshold amounts for some large distributors (e.g., over $2 million for a distributor with a revenue requirement of $525 million). Therefore, **the materiality threshold will be differentiated based on the relative magnitude of the revenue requirement** in order to maintain the concept of relative materiality across diverse distributors. Specifically, the materiality threshold will be as follows:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will permit the Board and any affected distributor to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

The Appendix outlines the detailed requirements as they apply to 3rd Generation IR.

2.7 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IR plan would be terminated or modified before its normal end-of-term date, usually because of extreme events that cannot be effectively addressed, or that should not be addressed, through Z-factor treatment or some other IR mechanism such as earnings sharing.

For the 2nd Generation IR mechanism, there are limited adjustments available to distributors. Therefore, an off-ramp is available where these adjustments proved insufficient for specific cost pressures (e.g., additional capital investment). Where this is the case, distributors are expected to file a comprehensive cost of service application and not to rely on the simplified filing requirements for the incentive mechanism.

Issues and Options Raised in Consultation

The Discussion Paper invited comment on a pre-defined off-ramp associated with excessive over or under earnings. At the May 6, 2008 stakeholder meeting, and in response to participant comments received as summarized below, staff proposed a less prescriptive approach in which a review may be initiated on a case-by-case basis on application.

While some participants supported the pre-defined off-ramp associated with excessive over or under earnings, others expressed the view that the use of off-ramps should be determined on a case-by-case basis where a distributor brings forward an application.

Some distributors recommended that the use of off-ramps be determined on a case-by-case basis where a distributor brings forward an application that proposes modifications to the adjustment mechanism or where the distributor is seeking a cost of service rebasing. One participant representing a ratepayer group also suggested that the distributor, its ratepayers, or Board staff should be able to invoke an off-ramp, and that the goal of providing for the off-ramp application should be to ensure that the IR plan and the distributor's circumstances are reviewed, not necessarily changed. In response, another participant stated it could not support this proposal because intervenors do not have access to the timely and detailed information needed to determine if a distributor should be compelled to come before the Board and explain why the IR plan should be terminated or continued.

Policy and Rationale

The Board has determined that the 3rd Generation IR plan will include a trigger mechanism with an **annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated**. In support of this approach, a distributor will be required make a report to the Board no later than 60 days after the company's receipt of its annual audited financial statements, in the event that the distributor falls short of or exceeds its ROE by 300 basis points. The report will be reviewed to determine if further action by the Board is warranted. Any such review would be prospective and could result in modifications to the IR plan, a termination of the IR plan or the continuation of the IR plan.

The Board believes this to be appropriate because of the uncertainty associated the various components of an IR plan. The Board intends this to be an early warning mechanism rather than necessarily terminating the IR plan, although that could be the outcome of any subsequent review.

The Board notes that most participants representing groups of ratepayers supported a pre-defined earnings-based off-ramp, especially in the absence of an earnings sharing mechanism. Several of these participants proposed an off-ramp as described above and which is similar to that agreed to in the settlements accepted in the two recent gas IR proceedings.

Implementation

The Board agrees that effective implementation of a prescriptive off-ramp will require timely release of distributor performance and financial data. Reporting requirements and review processes will be developed to support this mechanism.

2.8 Earnings Sharing

An earnings sharing mechanism ("ESM") provides ratepayers protection to the extent there is some level of uncertainty in the IR plan parameters. In addition, to the extent that a distributor is able to achieve significant efficiency gains during the IR plan period, it allows for ratepayers to share in those gains.

Issues and Options Raised in Consultation

Staff's Discussion Paper invited comments from participants on whether an ESM should be part of 3rd Generation IR and, if so, whether an asymmetrical ESM might be appropriate.

In light of comments received, as summarized below, staff proposed an asymmetrical mechanism during the May 6, 2008 stakeholder meeting. Under the proposal, amounts would be recorded each year during the IR plan term if a distributor's actual non-weather normalized earnings exceeded the calculated ROE by 200 basis points,[2] and would be shared equally (i.e., 50:50) at the time of rebasing. This proposal was intended to respond to the views expressed by various participants that certain elements of staff's composite proposal for the 3rd Generation IR framework may benefit from the counter-balance of an ESM. Specifically: the distributor's access to an incremental capital module; uncertainty associated with the estimation of the input price differential and productivity differential to implement in conjunction with the GDP IPI FDD; and some uncertainty in relation to the setting of appropriate stretch factors. This proposal was also based on a four year IR plan term.

Participants representing ratepayer groups continued to express strong support for earnings sharing. They commented that ratepayers do not have access to full information regarding a distributor's financial results and do not have the same ability as distributors to seek Z-factor relief. As such, they commented that the use of an ESM would provide a level of ratepayer protection during the IR plan. In general, these participants commented that ESM benefits should be shared annually, not at the time of rebasing. Another participant expressed the view that an ESM is an important component of any IR plan and that, to the extent that the Board were to decide to allow

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[2] ROE would be recalculated annually based on that year's application of the ROE formula and earnings sharing would be calculated as +200 basis points from that number.

for five year terms, an ESM would be an essential component of the IR plan. This participant expressed support for an asymmetrical earnings sharing mechanism given the fact that distributors can opt out of the IR plan at any point and apply for rates based on cost of service, and specifically proposed that if the term is five years the dead band should be 100 basis points and if the term is three years the dead band should be 200 basis points.

Two participants proposed menu approaches to the ESM that would be tied to the selection of productivity and/or stretch factors.

Another participant representing a ratepayer group, generally opposed to earnings sharing in IR plans, expressed the belief that an ESM is appropriate in 3rd Generation IR, and suggested that the asymmetrical ESM recently implemented for one of the gas distributors based on actual earnings and with a 200 basis point dead band, would be appropriate. However, this participant expressed the expectation that the need for an ESM could be reduced or eliminated in the next generation of IR for electricity distributors.

Some distributors commented that ESMs have the undesirable feature that they reduce the power of incentives for efficiency improvements, and cautioned that in considering such mechanisms, one should be mindful that, upon rebasing, consumers capture the benefits of efficiency improvements in perpetuity. This participant noted that, in the event that an ESM were to be implemented, it should be symmetrical and amounts should be cumulative over the term of the IR plan.

One participant commented that the need for an ESM, or an off-ramp for that matter, is very much dependent on the robustness of the IR mechanism. This participant provided as an example the critical short comings of the use of OM&A rather than total cost benchmarking in the application of the stretch factors. If the Board were to adopt this approach, this participant's view was that an ESM and an off-ramp would be required to mitigate the risk associated with this approach.

Some distributors commented that they accept the use of ESMs in IR plans that are in effect for more than five years, and recommended that under such plans if the achieved ROE from regulated activities was more than 300 basis points different from the Board's allowed ROE, then the computed overage/underage should be shared equally (i.e., 50:50) between the distributor and its ratepayers.

Policy and Rationale

The Board will not implement an ESM for 3rd Generation IR.

The Board has determined a relatively short plan term of three years for the 3rd Generation IR plan. During those three years, the IR plan will include an industry productivity factor as well as a stretch factor. Implicit in these factors are expected benefits that are shared with ratepayers, up-front throughout the IR term. In contrast, the ESM is designed to share benefits after-the-fact. This premise, supported by many participant comments, suggests that the only function of the ESM is a "safety net" should the productivity and stretch factors be too low. However, with a short plan term and confidence in these factors, the need for a safety net is largely reduced.

The Board is of the view that monitoring and reporting will capture any instances of a distributor earning super-normal profits. In such cases, a regulatory review, and potential off-ramp, can be triggered.

The Board also has concerns over the implementation of an ESM. The regulatory burden that this would place on distributors, intervenors, and the Board is significant. Once the framework for the over earnings calculations is established, the filings by the distributors would have to be tested for accuracy and prudence.

Therefore, in light of the short IR plan term, the availability of an off-ramp and the consumer benefit in the form of productivity and stretch factors for 3rd Generation IR, the Board has determined not to implement an ESM.

2.9 Service Quality

When the Board launched the Rate Plan, it also committed to implementing a regime of service quality requirements which would work to ensure that consumers continue to receive a high level of service from their distributors during the term of an IR plan.

On June 4, 2008, the Board issued amendments to the Distribution System Code which established a set of customer related service quality requirements with associated performance standards. These requirements include four previous service quality indicators (Connection of New Services, Appointments Met, Telephone Accessibility, and Written Response to Enquiries) and three new requirements (Appointment Scheduling, Rescheduling a Missed Appointment and Telephone Call Abandon Rate).

These service quality requirements and associated performance standards will come into effect in January 2009.

For the time being, the three existing system reliability indicators (SAIDI, SAIFI & CAIDI) will continue as reporting requirements. However, the Board's expectation is that system reliability requirements will eventually become mandatory.

2.10 Reporting Requirements

Reporting requirements and review processes will be developed as required to support the elements of the 3rd Generation IR mechanism that are described in this report.

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3 Implementation

A participant representing a group of ratepayers, building on a proposal by one of the distributors, recommended that in each rate order on rebasing, the Board panel structure the order so that annual adjustments, consistent with the IR plan as applied to that particular distributor, are included as part of the order. According to this participant, this approach could accomplish two things: first, where the Board accepts custom values based on specific application for any of the parameters in the IR plan, this approach would create a method by which that decision could be implemented; and second, it would also set the rates for each year of the IR plan term through a proper hearing on an evidentiary basis and any subsequent application by the distributor to re-open any of those years would be a reconsideration of the existing order (requiring an application to vary the existing order), not a fresh application. The Board sees merit in this suggestion and will give it further consideration.

3.1 How Adjustments Would be Determined

3.1.1 Continued Migration to Common Capital Structure

The Board will continue to include an adjustment to rates in 2009 and 2010 where applicable as outlined in its December 20, 2006 “Report of the Board on Cost of Capital and 2nd Generation IR for Ontario’s Electricity Distributors”, in order to transition distributors to the single deemed capital structure of 60% debt and 40% equity.

3.1.2 Conservation and Demand Management

The Discussion Paper noted that staff and the working group generally felt that the current Lost Revenue Adjustment Mechanism (“LRAM”) is appropriate until the completion of the consultations on rate design for electricity distributors since those consultations will look at related issues. The Discussion Paper invited comment on a revenue stabilization adjustment mechanism (“RSAM”), on a model that would include a CDM adjustment factor based on the CDM targets set by the Government of Ontario and/or the Ontario Power Authority, and on the option of maintaining the status quo vis-à-vis the Board’s current LRAM and shared savings mechanism (“SSM”) for electricity distributors.

Issues and Options Raised in Consultation

Most participants supported the continuation of the current LRAM and SSM. Some participants commented that a RSAM would involve a significant change in the risk profile of electricity distributors and/or their allowed return on equity, would require the production of load forecasts, and would shift the risk of volume fluctuations and deviations from forecast from the distributor to the ratepayers. In addition, alternative mechanisms do not appear to be practical at this point in time. One participant suggested that, going forward, if there is evidence that revenue erosion during the term of an IR plan is increasing, adjustment mechanisms may then be considered by the Board. As such, this participant concluded, this could be part of a longer term framework.

Distributors commented that they believed that in the short term distributors can make use of the existing lost revenue adjustment processes and that revenue-oriented IR alternatives could accommodate broader concerns around reductions in load and customer numbers.

Policy and Rationale

On March 28, 2008, the Board issued its “Guidelines for Electricity Distributor Conservation and Demand Management” which consolidate all of the Board’s policies in relation to CDM activities undertaken by electricity distributors. In those guidelines, the

Board noted that whether and how CDM funding may be included in the IR mechanism rate adjustment would be addressed in the appropriate forum.

As a result of these 3rd Generation IR consultations, the Board has determined that **CDM-related costs recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) will continue to be dealt with separately from the IR rate adjustment**.

This represents the status quo. The Board acknowledges that, should alternatives to the status quo be examined, these could have implications for electricity distributors and ratepayers. In the Board's view, these would best be dealt with as part of the consultations on rate design for electricity distributors (consultation EB-2007-0031).

3.1.3 Deferral and Variance Accounts

A set of authorized variance / deferral accounts are identified in the Board's Accounting Procedures Handbook. In its December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation IR for Ontario's Electricity Distributors", the Board indicated that, to the extent possible, it will limit reliance on the creation of new deferral accounts during the term of the 2nd Generation IR plan to well-defined and well-justified cases only. The Board will continue this practice for purposes of the 3rd Generation IR plan.

With respect to the disposition of commodity deferral and variance accounts, the Board is required to make an order at least every three months to determine whether and how the amounts recorded in such accounts (currently recorded in Account 1588 of the Uniform System of Accounts) shall be reflected in rates. With respect to non-commodity deferral or variance accounts, the Board is required to make an order at least annually.

In a letter dated February 19, 2008, the Board notified electricity distributors and other interested stakeholders that it intends to launch an initiative to develop policies and processes for the review and disposition of Account 1588. The Board indicated that it will consider the use of account disposition thresholds or “disposition triggers”. The Board also stated that it will consider whether to extend this initiative to deferral or variance accounts that are similar in nature to Account 1588, such as the Retail Settlement Variance Accounts (RSVAs) and the Retail Cost Variance Accounts (RCVAs).

The Board therefore expects distributors to deal with deferral and variance account disposition outside of the IR rate adjustment.

3.1.4 Adjustments to Revenue-to-Cost Ratios

On November 28, 2007, the Board released a report on the “Application of Cost Allocation for Electricity Distributors” which outlines the Board’s expectations on how electricity distributors are to adjust the revenue-to-costs ratios to bring them within the ranges stated in the report.

The cost allocation policies reflected in that report are to be followed by distributors whenever they apply for rates on a cost of service basis. In the event that further adjustments to one or more revenue to cost ratios have been specified by a prior Board Decision, then base rates will need to be adjusted accordingly prior to the application of the price cap index.

3.1.5 Application of the Price Cap Index

Consistent with the 1st Generation IR and the 2nd Generation IR mechanisms, the 3rd Generation IR price cap index will be applied uniformly across all customer classes and to both the Service Charge and the Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board.

The Board has determined that a distributor's allowance for taxes will continue to be adjusted by the price cap index. A distributor's allowance for taxes (whether PILs or actual taxes) currently includes provision for income tax and the Ontario capital tax. The Board does not think the tax allowance should be shielded from the index. This allowance should escalate in line with the other components of the revenue requirement reflected in base rates. As discussed in Section 2.6, the Board will in due course provide further guidance on the issue of treatment of material changes in tax rules during 3rd Generation IR.

The Board has determined that smart meter related matters **will continue to be dealt with separately from the IR rate adjustment and that the guidelines included in the Addendum will continue to apply.**

Also, consistent with practice to date in Ontario, the index will not be applied to specific service charges. The Board carried out a generic review on specific service charges in 2005,[3] and is currently carrying out further related consultations in respect of the provision of specific services and the application of associated charges (consultation EB-2007-0722). Until this work is complete, **the Board expects distributors to continue to use the currently established specific service charges and to deal with the need for new specific service charges outside of the IR rate adjustment.**

The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Allowances[4], Retail Service Charges or Loss Factors.

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[3] See chapter 11 of the 2006 Electricity Distribution Rate Handbook.
[4] Transformation and primary metering allowances and any other allowances the Board may determine.

A “de-construction” of 2008 rates will be carried out prior to adjusting base rates. After adjusting base rates with the price cap index, rate elements will be “re-constructed” to derive 2009 rates.

3.2 Rebasing Rules

Rebasing at the end of 3rd Generation IR will be based on a cost of service filing. Benchmarking evidence may be used within the scope of the cost of service proceeding.

Under the existing cost of service filing requirements, distributors are required to provide a detailed variance analysis between the Test Year and Bridge Year, and between the Test Year, the Historical Year and the last Board-approved Test Year. In response to concerns raised by distributors that significant upward pressure is anticipated on capital expenditures, the Board has determined that the distributor will be required to provide historical plant continuity information for each year of the IR plan term since the last Board-approved Test Year, and will revise the filing requirements accordingly. This information will inform the Board’s review and approval of the distributor’s rebasing application and the determination of appropriate capital expenditure levels for inclusion in base rates going forward.

4 Summary

The Board engaged many interested stakeholders in the discussion of an appropriate 3rd Generation IR for electricity distributors. This consultation has assisted the Board in developing the policies detailed in this report. The Board has appreciated the input from all stakeholders in determining the approach it should take. The Board has been particularly encouraged by the productive dialogue among the experts hired by the various participants.

The rate adjustments for the 2009 rate year will apply to distributors that were subject to rate rebasing in 2008. Distributors that have not yet applied for, or been subject to, rebasing, will continue to be subject to the 2nd Generation IR. For the 2010 and 2011 rate years the policy will continue to apply to the distributors whose rates were rebased in 2008 and will also apply to the additional distributors whose rates have been subject to rebasing in 2009 and 2010. The 3rd Generation IR mechanism elements are summarized in the following table.

Table 6: Components of the Board's 3rd Generation IR Policy

Inflation Factor	• Canada GDP IPI for final domestic demand – updated annually in March. Until Ontario data used to derive total factor productivity trend, values for the input price differential and productivity differential will be zero.
Productivity Factor	• Fixed at industry total factor productivity trend percentage per year for term of plan – all distributors subject to the same value.
Stretch Factors	• Differentiated based on distributor efficiency – updated annually in July. • Distributors will be assigned to 1 of 3 groups with stretch factors based on their efficiency as determined through comparative cost analysis.
Z-factors	• Will be on application (by next rate filing) subject to the three criteria of causation, materiality and prudence.
Incremental Capital	• Will be on application subject to the three criteria of materiality, need and prudence.

The Board will consider work to refine its empirical work on the electricity distribution sector, including total cost benchmarking, an Ontario TFP study, and input price trend research, in the context of its overall business planning process.

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5 Topics for Presentations at the Conference

This report sets out the Board's policies and approach to 3rd Generation IR and presents guidelines that the Board expects distributors to use in preparing their rate applications. This report also identifies three outstanding matters where the Board's determination may benefit from further consultation.

On June 13, 2008, the Board notified participants of a stakeholder conference that will be held the week of August 5, 2008. The August stakeholder conference will provide a forum for further discussion of the appropriate values for the productivity factor, the stretch factor, and the capital module materiality threshold. The Board will not entertain comments on any other issue at the conference.

The Board would be assisted by participants addressing the following questions in their presentations at the conference.

Productivity Factor

- What is the appropriate value for TFP trend?

Stretch Factor

- What are appropriate stretch factor values for each of the three groups?

Incremental Capital Module

- What is an appropriate capital expenditure to depreciation threshold value to determine materiality?

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Appendix: Filing Guidelines

These filing guidelines set out the Board's expectations for applications by distributors for rate adjustments on the basis of the 3rd Generation IR mechanism as set out in this report.

General

The implementation of the 3rd Generation IR mechanism will occur first with rate adjustments scheduled for May 1, 2009.

The price cap adjustment will be applied to the Service Charge and Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board. The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Specific Service Charges, Allowances[5], Retail Service Charges or Loss Factors.

The price cap adjustment will reflect inflation less the X-factor, and an adjustment for the transition to the common deemed capital structure of 60% debt and 40% equity.

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[5] Transformation and primary metering allowances and any other allowances the Board may determine.

Manager's Summary

Each application should include a completed Model and a brief Manager's Summary explaining all rate adjustments applied for. Any deviations should be thoroughly documented. Where necessary, support for applied adjustments, such as continuation of rate riders or for Z-factors, should be provided.

Incremental Capital Module

The incremental capital module has been incorporated into the 3rd Generation IR mechanism to address the treatment of incremental capital investment needs that arise during the IR plan term.

Eligibility Criteria for Incremental Capital Module Applications

The eligibility criteria for applications to recover amounts through rates to fund incremental capital investment needs are discussed in section 2.5 of this report, and are reproduced in Table 7 below for convenience:

Table 7: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

To be determined by the Board.

Filing Guidelines

The Board expects that applications requesting relief for incremental CAPEX during the IR plan term will be accompanied by comprehensive evidence to support the claimed need, and include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- A description of the underlying causes and timing of the capital expenditures including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, OM&A, return on rate base and PILs associated with the incremental capital), and a specific proposal as to the amount of relief sought;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were been derived;
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

Reporting Requirements

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. If the forecast costs exceeded actual amounts spent, the difference should be returned to ratepayers. Cost overruns will be reviewed at the time of rebasing.

Z-Factors

Z-factors are events that are not within management's control. A distributor will be expected to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor is expected to follow the guidelines listed below when applying to the Board to recover from ratepayers the amounts that the distributor has recorded. The Board may limit the recovery of certain amounts.

Eligibility Criteria for Z-factor Amounts

The eligibility criteria for applications to recover amounts in the Z-factor are discussed in section 2.6 of this report, and are summarized inTable 8 below. In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three criteria set out in Table 8.

Table 8: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The Board has determined that the following materiality thresholds will apply:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Filing Guidelines

Distributors are expected to submit evidence that the costs/revenues which were incurred / received meet the three eligibility criteria outlined above.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

Other Matters in Relation to Z-Factors and Incremental Capital Module

Distributors will be expected to file a proposal, including the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocations considered.

Distributors will also be expected to file a detailed proposal including justifications to recover, through a rate rider, the Board-approved incremental revenue requirement. The proposal should specify whether the rate rider will apply on a fixed or variable basis, or a combination thereof, and the time period for collection. A detailed calculation of the rate rider(s) should be provided for each year of the IR plan term.

Accounting Treatment

Eligible **Z-factor** amounts should be included in Account 1572, "Extraordinary Event Costs", of the Board’s Uniform System of Accounts of the Board’s Uniform System of Accounts contained in the Accounting Procedures Handbook for electricity distributors.

Eligible **Incremental Capital Module** amounts should be recorded in account 1508, Other Regulatory Asset, Sub-account Incremental Capital Expenditures.

Carrying charge amounts shall be calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for the respective quarterly period for deferral and variance accounts. These prescribed rates are reviewed and updated each quarter and published on the Board's web site.

TAB 25

Ontario Energy Board

EB-2007-0673

Supplemental Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

September 17, 2008

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1 Overview

On July 14, 2008, the Board issued its "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" (the "July 14, 2008 Report")[1]. That Report sets out the Board's policies and approach to 3rd generation incentive regulation ("3rd Generation IR").

When the July 14, 2008 Report was released, the Board had not yet determined the values for the productivity factor, the stretch factor, and the capital module materiality threshold. These were identified in the July 14, 2008 Report as the three outstanding matters that would benefit from further consultation prior to the Board making a determination on the values. Two Board Members, Mr. Paul Sommerville and Mr. Paul Vlahos, presided over a stakeholder conference held on August 5 – 7, 2008, to provide a forum for further discussion of these issues. At the end of the stakeholder conference, the Board Members indicated that they would report to the Board on the stakeholder conference, following which the Board would make a determination on the outstanding issues.

The participants at the stakeholder conference were:

Participants	Representing
Mr. Maurice Tucci Prof. Adonis Yatchew of the University of Toronto	Electricity Distributors Association ("EDA")
Ms. Susan Frank Ms. Paula Conboy, Ms. Lynne Anderson Ms. Julia Frayer of London Economics International, LLC ("LEI")	Hydro One, Inc. ("Hydro One") and the Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Powerstream Inc., Toronto Hydro-Electric System Limited And Veridian Connections Inc.) (the "CLD")

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[1] Available on the Board's website at http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf.

Participants	Representing
Mr. Peter Thompson	The Canadian Manufacturers & Exporters ("CME")
Ms. Julie Girvan	The Consumers Council Of Canada ("CCC")
Mr. David Macintosh	Energy Probe Research Foundation ("Energy Probe")
Mr. Randy Aiken	London Property Management Association ("LPMA")
Ms. Judy Kwik	The Power Workers' Union ("PWU")
Mr. Jay Shepherd	The School Energy Coalition ("SEC")
Mr. Bill Harper	The Vulnerable Energy Consumer's Coalition ("VECC")
Ms. Lisa Brickenden Mr. Allan Fogwill Ms. Marika Hare Mr. Bill Cowan Dr. Lawrence Kaufmann of the Pacific Economics Group, LLC ("PEG")	Board Staff

This Report sets out the Board's determination of the values for the productivity factor, the stretch factor, and the capital module materiality threshold for use in 3rd Generation IR. This Report also sets out the Board's determination on the issue of tax changes in relation to the Z-factor.

This Report is organized as follows. Each of the sections in Chapter 2 deals with an outstanding issue (i.e., the value for each of the productivity factor, the stretch factor, and the capital module materiality threshold) and is comprised of three subsections: the first briefly describes the issue, the second summarizes participants' comments, and the third sets out the Board's policy and rationale. Chapter 3 addresses the issue of tax changes in relation to the Z-factor. Appendix B to this Report contains an amended version of the filing guidelines that were set out in the Appendix to the July 14, 2008 Report. The amendments to the filing guidelines reflect the Board's determinations in this Report.

2 Values for Certain IR Plan Parameters

2.1 Productivity Factor

In the July 14, 2008 Report, the Board stated that while it is clear to the Board that participants support an index based approach for the derivation of an industry productivity trend to form the basis for the productivity factor for the incentive regulation ("IR") plan, the Board would be assisted by further consultation on the interpretation of the results in order to determine the appropriate value for the productivity factor.

The question to be addressed by participants at the stakeholder conference was: what is the appropriate value for the total factor productivity ("TFP") trend?

Issues and Options Raised in Consultations

The table in Appendix A summarizes the recommendations and supporting assumptions of Dr. Kaufmann, Prof. Yatchew, Dr. Cronin[2], and Ms. Frayer for the appropriate value for the productivity factor in 3rd Generation IR.

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") details the productivity study carried out (the "PEG Study") to arrive at PEG's recommended 0.88 percent value for the productivity factor in 3rd Generation IR. This value is based on U.S. data. Since there is insufficient Ontario data for setting a productivity factor for 3rd Generation IR, PEG used U.S. data after carrying out a comparative analysis to demonstrate that TFP growth for U.S. distributors is a reasonable proxy for contemporaneous Ontario distributor trends. Dr. Kaufmann submitted that he believed this a reasonable measure

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[2] Dr. Frank Cronin, retained by the PWU, did not attend the August stakeholder conference. He made his recommendations in written comments over the course of this consultation.

and that the methodology used to arrive at the recommended productivity factor can be easily applied to Ontario data in the future.

In relation to recent slow productivity growth evident in both the U.S. data and in the available Ontario data, Dr. Kaufmann noted that this has happened before as shown in the 1st generation performance-based regulation ("1st Generation PBR") productivity analysis (the "Cronin and King Study")[3] – slow productivity growth between 1988 and 1993 was followed by rapid productivity growth between 1993 and 1997. Given that experience, Dr. Kaufmann commented that he did not believe that he should assume that the recent slow TFP growth will necessarily continue in the future. As a consequence, PEG did not put any extra weight on the TFP growth of the last four years as did Prof. Yatchew.

The average annual productivity growth over the period 1988-2006 was 0.72 percent. The 0.88 percent value proposed by PEG is restricted to the period 1995-2006, a value that is based on a "start date analysis". Dr. Kaufmann explained that the purpose of PEG's start date analysis is to isolate the long-term trend as much as possible from systemic externalities, such as weather and the economy, so that TFP is not measured in a way that it is distorted by transitory impacts. Therefore, Dr. Kaufmann used statistical analysis to estimate the impact of heating degree days, cooling degree days, and unemployment rate on measured TFP growth. This analysis revealed that 1995 was most similar to 2006, the most recent year in the U.S. data set, and therefore was selected as the "start date" which was least likely to distort measured TFP growth due to transitory weather or economic conditions.

While Prof. Yatchew expressed a preference for the use of Ontario data to set a productivity factor for Ontario distributors, he accepted the PEG Study and the use of U.S. data and provided his advice on how to interpret the results for Ontario distributors.

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[3] Cronin, F.J., M. King and E. Colleran. PHB Hagler Bailly Consulting. Productivity and Price Performance for Electric Distributors in Ontario. Prepared for Ontario Energy Board Staff, July 6, 1999. Available on the Board's web site at http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/ppp1.html

Prof. Yatchew recommended a productivity factor of 0.55 percent which incorporates long-term average productivity growth of 0.72 percent and assigns greater weight to recent (2002-2006) slower productivity growth observed in both U.S. (0.41 percent) and Ontario data (0.01 percent estimated by PEG in the PEG IR Report). Noting that the Board took both recent and long-term patterns in productivity growth into account when it determined the policies and approach to 1st Generation PBR, Prof. Yatchew assigned a ⅔ weight to the long-term average and a ⅓ weight to the recent average, resulting in a point forecast figure of 0.55 percent as summarized in Table 1.

Table 1: Estimation of the 0.55%

Assigning a ⅔ weight to the long-term average and a ⅓ weight to the recent average:
0.49% = ⅔ 0.72% + ⅓ 0.01%
0.62% = ⅔ 0.72% + ⅓ 0.41%
0.55% ~ mid point between 0.49% and 0.62%

Prof. Yatchew commented that Dr. Kaufmann's productivity factor of 0.88 percent inappropriately restricts data to the 1995-2006 period and does not assign any additional weight to the more recent data. In his review of the PEG Study, Prof. Yatchew found no statistical evidence of systematic acceleration or deceleration in productivity growth throughout the sample period. He expressed concern with Dr. Kaufmann's "start-date analysis" in that he found no evidence of this approach in the mathematical statistics literature or in econometrics literature that would justify this kind of approach in this kind of setting. Prof. Yatchew suggested that if the Board wishes to move forward to create a predictable and evolving regulatory environment, the Board should not embed an algorithm for which he was unable to find support in academic literature. He proposed that the Board should include the entire 1988-2006 period to set the productivity factor for two reasons. First, Prof. Yatchew submitted that the "start-date analysis" fails because it searches for a single year that is most similar to the most recent year, rather than for a period that is likely to be representative of the future. Second, he noted that including the entire 1988-2006 period is based on the fundamental idea in statistics that larger samples deliver more precise estimates.

As noted in the July 14, 2008 Report, Dr. Cronin, in his written comments, recommended a productivity factor "menu" approach. Under that approach, distributors would be allowed to select from a menu of productivity factors, each with an associated allowed return on equity ("ROE"). Research during 1st Generation PBR found a ten-year mean growth rate of slightly more than 0.8 for TFP. Research subsequent to 1st Generation PBR found a mean ten-year growth rate of about 1.6 percent for TFP for most efficient firms[4]. On this basis, Dr. Cronin recommended that the "baseline" option in a menu should be a productivity factor of 0.8 percent with an associated allowed ROE of 8.5 percent. The proposed menu also included four other options, where increments of 0.2 percent in the productivity factor are associated with 100 basis point increments in the allowed ROE. The maximum productivity factor of 1.6 percent was therefore associated with a 12.5 percent allowed ROE.

Ms. Frayer submitted that the productivity factor should be measured using Ontario data for the industry and that results from other jurisdictions can be useful as checks but cannot substitute for Ontario-specific business circumstances. Specifically, Ms. Frayer commented that Ontario has many smaller distributors (the U.S. has typically much larger franchise areas in terms of geographical span and customers) and that Ontario distributors:

- with few exceptions, operate only electricity distribution businesses;
- face unique weather, have diverse customer bases, and have a distinct legacy of system configuration and network expansion because of government and municipal ownership which impacts input/output relationships and potential for productivity growth;
- have been under rate freezes, de facto price caps since the mid 1990s, while also processing corporatization changes and market restructuring; and

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[4] Cronin, F. and S. Motluk, "Leaders and Laggards: Examining Regulatory Applications of the Mamquist Productivity Index to Establish Secular Growth in Productivity." (forthcoming)

- will, in some cases, soon be in a dramatic capital expenditure (“CAPEX”) phase because of an aging asset base resulting from provincial mandates to electrify in the 1960s and 1970s.

Therefore, Ms. Frayer recommended using a 20-year average TFP growth measure of 0.58 based on the results of three different productivity studies: the Cronin and King Study (1988-1997), PEG’s projections for the “missing years” of 1998-2002 developed to facilitate PEG’s U.S.–Ontario industry trend comparisons[5] and LEI’s independent analysis of data filed under the Board’s Electricity Reporting and Record Keeping Requirements (“RRR”) (2003-2007). The three studies employ the index method to derive TFP growth; however, they include different measures for inputs quantities or values (e.g., labour, materials, and capital) and output quantities or values (e.g., throughput, customer numbers, and peak demand). In particular, the Cronin and King Study and the PEG Study used the monetary approach to account for capital quantities. In its five-year study, LEI chose to measure capital input quantity based on the physical length of distribution lines because of physical depreciation profile effects. That is, Ms. Frayer proposed that the carrying capacity of distribution lines does not decline consistent with accounting depreciation methods. Ms. Frayer submitted that economic theory, empirical evidence, industry experience and recent regulatory precedent all support the recognition of this approach when calculating the annual capital input quantity of electricity distribution assets and that accounting depreciation adjustments under the monetary approach bias the quantity of capital input. Ms. Frayer observed that over the most recent years, on average, TFP growth for the industry has been negative and submitted that this negative trend needs to be acknowledged and included in the analysis. LEI tested various weighting schemes for output which produced similar overall trends showing negative TFP growth. The value of 0.58 percent is an average

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[5] PEG developed four scenarios for TFP growth during the “missing years” between 1998 and 2002 in Ontario. PEG emphasized that they do not put forward any of these scenarios as accurate measures of TFP growth during that time. Rather, PEG is trying to bind the range of possible TFP growth rates for the Ontario industry over the entire 1988-2006 period, which will facilitate their comparisons with the U.S. industry over the same period. See PEG IR Report (p. 55).

of the percent change in the derived TFP index for each year over the 1988-2007 period and recognizes and incorporates recent negative trends in TFP growth.

Ms. Frayer explained that LEI did not include weather normalization because they wanted to present actual results subject to the actual operating conditions faced by distributors (i.e., they do not operate under weather-normalized conditions). Ms. Frayer submitted that, as a result, total factor productivity would be measured on the basis of actual figures, since that productivity will then form the productivity target which will affect actual revenues regardless of the weather in the future.

CME, in response to Prof. Yatchew's view that larger samples deliver more precise estimates, asked the consultants their views on what is the minimum period for statistical significance. In response, Ms. Frayer indicated her view to be seven to ten years, Prof. Yatchew suggested eight to ten years, and Dr. Kaufmann indicated that his view of the minimum period would be nine years.

In relation to the LEI study, most participants, as well as Dr. Cronin and Dr. Kaufmann, disagreed with the use of physical counts of capital in the calculation of TFP. Both of them recommended the customary use of monetary values. Dr. Kaufmann noted that when a utility sets its rates to recover depreciation and carrying costs associated with these capital goods, it does so with reference to the aggregated monetary values of these disparate assets net of their depreciation. He submitted that LEI's TFP study ignores this monetary valuation of assets in favour of a physical method for estimating capital stock. Since physical asset measures are not used to set rates at the outset of a plan, Dr. Kaufmann expressed concern over LEI's proposal to use a productivity factor to adjust distribution rates that, over time, bears no relationship to how those rates were originally set. Dr. Kaufmann also noted that the LEI TFP model assumes that there is no physical decay of distribution assets over time. He stated that there is no theoretical or empirical support for this assumption and cautioned that this is not an academic point but a practical one, because depreciation is a reality. CME submitted that the use of physical counts of capital is incompatible with the monetary approach that was used to derive the TFP trends for the periods 1988-1997 and 1998-2002 on which LEI relies, and the effect appears to materially distort the LEI trend downwards.

Most participants representing ratepayer groups supported Dr. Kaufmann's recommended 0.88 percent value for the TFP trend to be used as the base productivity factor for all electricity distributors in 3rd Generation IR. LPMA and Energy Probe commented that while Dr. Kaufmann's recommendation of 0.88 percent is "in the right ballpark", it is at the lower end of the range than should be considered for three reasons. First, Dr. Kaufmann has indicated that compared to values set in other jurisdictions in recent plans (generally one percent or higher), his 0.88 recommendation is on the low side. Second, the Board has endorsed the concept of a capital module. The inclusion of this module in IR should be reflected by a higher productivity factor to account for this deviation from the norm and for the relief that it may provide to distributors. Third, the three utility multi-factor productivity indices available from Statistics Canada show average growth rates of 0.86 percent, 1.07 percent and 1.08 percent over the period for which the data is available. Mr. Aiken noted that the Statistics Canada data on productivity numbers for utilities goes as far back as 1961. The average of these three rates is 1.00 percent. CME suggested the value be no less than 0.80 percent which is the mid-point between the average annual productivity growth in the U.S. electricity distributor data of 0.72 percent and the PEG-recommended 0.88 percent based on its "start date" analysis.

VECC expressed concern with the LEI study in that there was no weather normalization undertaken for the study period. VECC observed that weather normalization may not be critical when dealing with very long periods of time as the impacts will be somewhat smoothed out. However, VECC submitted that weather normalization is critical when dealing with a short period of time. During the timeframe in question, 2002-2007, VECC noted the extreme weather conditions in 2002 and how that influenced not only the operations of distributors but subsequent government policy decisions in Ontario. Further, VECC observed that while the term of the 3rd Generation IR plan is three years, the plan will actually be in effect over three tranches of distributors over a period of five years. Therefore, VECC disagreed that recent downward trends in productivity should be presumed to persist that long. VECC concluded that a value in the order of 0.72 to 0.88 percent may be the appropriate productivity factor. According to VECC, if the Board is concerned about the start/end date analysis, the Board could gravitate more towards the 0.72 value.

Hydro One and the CLD recommended that the value of the productivity factor be set within the range of 0.55 and 0.58 percent. The compound effect of declining load growth due to conditions such as a slowing economy and conservation and demand management activities, and rising costs due to conditions such as an aging work force, escalating fuel costs, changing accounting standards, and new environmental regulation requirements will make it a challenge to even achieve productivity within that range over the next three years.

Board Policy and Rationale

In the July 14, 2008 Report, the Board determined that X-factors assigned to individual distributors will consist of an empirically derived industry productivity trend (productivity factor) and stretch factor. The Board has not adopted a “menu” approach.

The Board notes that there was general consensus amongst the consultants on the following points:

- that estimating industry TFP trends is a common element in IR- based rate setting regimes;
- that the development of these trends in any given regulatory regime is highly dependent on the quantity and quality of data reflecting the experience of the utilities governed by the IR plan; and

- that the development of an Ontario-specific TFP trend for the 3rd Generation IR mechanism is hindered by a lack of data covering a sufficient period of time.

Accordingly, the proposals put forward by each of the consultants represented a compromise that was to some degree caused by this deficiency in data.

As noted above, PEG proposed a TFP value of 0.88 percent. This number was developed using U.S. utility data due to the absence of sufficient Ontario distributor data. While no detailed critique of the U.S. data set was undertaken by any of the other consultants, even PEG regretted having to resort to the use of non-Ontario data. It is also clear that some firms in the U.S. data set were vertically-integrated utilities and that their productivity profiles may be somewhat different than those of stand-alone distribution companies. While PEG's analysis controlled for this, it is noted that the results may still be somewhat skewed. In addition, PEG used a "start date analysis", described above, which was the target of some criticism by other consultants.

Ms. Frayer considered the use of U.S. data to be a significant shortcoming of the PEG proposal. In her view, the Ontario context is distinct and the use of U.S. data is unsound. Faced with the same data deficiency as the other consultants, she used a series of previous studies in combination with a unique approach to the consideration of capital as a component of the TFP trend calculation. She also argued for greater weight to be given to the more recent TFP trend to reflect the deceleration in growth in recent years in Ontario. In her view, the TFP value should be set at 0.58 percent.

Prof. Yatchew reluctantly accepted the use of U.S. data, but objected to the "start date analysis", which in his view is inappropriate and unprecedented. He also suggested, as did Ms. Frayer, that increased weight ought to be given to the most recent TFP trend. He proposed a TFP value of 0.55 percent.

In the Board's view, the data deficiencies noted by the consultants do not operate as an insurmountable obstacle to the development of an appropriate TFP value for 3rd

Generation IR. The Board accepts the use of U.S. data for the purposes of the derivation of the TFP trend for 3rd Generation IR. Use of this data set was supported by PEG and Prof. Yatchew. Ms. Frayer sought to circumvent the problem through a patchwork of studies that, in the Board's view, are not adequately demonstrated to be based on a series of consistent principles. Of greatest concern with Ms. Frayer's approach is the measurement of capital, which is inconsistent with the prior Ontario TFP studies and does not appear to have been adopted in any jurisdiction other than New Zealand. While the Board recognizes Ms. Frayer's efforts to construct an Ontario-specific TFP trend, the Board does not believe that the methodology advocated by Ms. Frayer is appropriate. The Board is optimistic that the current data deficiencies will recede as the Board accumulates data from the sector over the next several years. Within the next five years the data issue will have been resolved, and the development of an Ontario-specific TFP trend can proceed on a more solid footing.

The Board is not convinced that the "start date analysis" used by PEG, which limits the data sample to the period 1995-2006, is necessary or warranted. The Board agrees with Prof. Yatchew's statement that greater confidence can be derived from using the full data set, in this case representing U.S. data from 1988 to 2006.

Similarly, the Board is not persuaded that increased weight ought to be given to the most recent TFP trend. The merit of using the full data set is that the resultant TFP trend can be reasonably expected to reflect the ebbs and flows experienced over a relatively long period of time. To weight the most recent trend would undermine one of the virtues of using the full data set.

Accordingly, the Board has determined that the appropriate value for the TFP trend for 3rd Generation IR is 0.72 percent, the average annual productivity growth over the period 1988-2006 in the full set of U.S. electricity distributor data used by PEG. The Board is not convinced that the "start date analysis" is sufficiently well developed to justify limiting the sample. The Board believes that this value reflects a reasonable synthesis of the various points of view advanced in the course of the stakeholder consultations and of the Board's views on the relative merits of the approaches put forward by the various participants.

As indicated in the Board's July 14, 2008 Report, this value will be fixed for the term of the plan.

2.2 Stretch Factors

In the July 14, 2008 Report, the Board determined that it will use the results of two benchmarking evaluations to divide the Ontario industry into three efficiency "cohorts". The two evaluations will be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II. At the time of the release of the July 14, 2008 Report, the Board had not yet determined the stretch factor value to be assigned to each cohort.

The question to be addressed by participants at the stakeholder conference was: what are appropriate stretch factor values for each of the three groups?

Issues and Options Raised in Consultations

Table 2 summarizes participants' recommendations for the appropriate stretch factor values for each of the three groups in 3rd Generation IR.

Table 2: Summary of Stretch Factor Recommendations

	Efficiency Cohort/Group		
	I	II	III
	Statistically superior and in top quartile on OM&A unit cost comparison	*In middle two quartiles on OM&A unit cost comparison*	*Statistically inferior and in bottom quartile on OM&A unit cost comparison*
VECC	0.25%	0.50%	0.75%
CCC (two recommendations)	0.25%	0.50%	0.75%
	0.50%	0.50%	0.50%
LPMA and Energy Probe (two recommendations)	0.25%	0.50%	0.75%
	0.35%	0.50%	0.65%
SEC	0.00%	0.50%	1.00%
Ms. Frayer, LEI, on behalf of Hydro One and the CLD	0.00%	0.075%	0.15%
Prof. Yatchew, University of Toronto, on behalf of the EDA	0.00%	0.10%	0.20%
Dr. Kaufmann, PEG, Board staff's consultant	0.00%	0.25%	0.50%

As noted previously, Dr. Cronin recommended a productivity factor "menu" approach in his written comments. Dr. Cronin submitted that the menu would incorporate distributor diversity into the IR plan.

Dr. Kaufmann noted that determining the values of the incremental productivity gains that firms are expected to achieve under IR is a more forward-looking exercise than estimating a productivity factor which is typically derived using historical TFP trends. In practice, he advised, most stretch factor values approved in North America have been based on judgment and have varied from zero to one percent. For 3rd Generation IR, he submitted that relatively modest stretch factors may be more appropriate with the Board's early benchmarking application until the Board better understands distributors' comparative cost performance and potential for incremental productivity gains. Dr. Kaufmann noted that his recommendations acknowledge that distributors in Group I have been demonstrably superior performers and have limited potential to achieve incremental gains in excess of his recommended productivity factor. Further, he submitted, his recommendations are supported by benchmarking studies which find evidence of significant productivity differences, and thus potential for incremental productivity gains, among distributors in Groups II and III. The specific values that Dr. Kaufmann recommended for Groups II and III are reflective of Ontario precedents to date. Most distributors will be in Group II and have a stretch factor of 0.25 percent, which is equal to the value approved for all distributors in 1st Generation PBR, and the 0.5 percent value recommended for Group III is equal to the highest stretch factor approved to date in Ontario (in the incentive regulation plan approved for Union Gas Limited in proceeding RP-1999-0017).

Prof. Yatchew stated that Ontario distributors have been under a form of price-cap regulation for a period of time and have been engaged in a form of yardstick competition[6] for many years. These two factors, he argued, weaken the case for stretch factors in an Ontario electricity distributor IR plan. Prof. Yatchew also reiterated his concerns about the potential for “misclassification” of distributors to cohorts using the OM&A benchmarking studies and concern that the threat of misclassification may focus distributors on reducing OM&A costs rather than total costs, resulting in inefficient resource allocation (e.g., over-capitalization by utilities seeking to reduce OM&A costs; under-spending on OM&A; and sub-optimal decisions with respect to own vs. lease alternatives). He identified four sources of potential misclassification: the use of OM&A rather than total cost data; mismeasurement or omission of his recommended variables; statistical error which he measured at 20 percent; and the use of U.S. rather than Ontario data. Consequently, given that the Board has determined that non-negative stretch factors will be implemented, he recommended that the stretch factors be materially lower than those recommended by Dr. Kaufmann. He noted that his recommended stretch factors of 0.0 percent, 0.1 percent, and 0.2 percent for the three groups would result in X-factors of 0.55 percent, 0.65 percent, and 0.75 percent, and noted that the 0.65 percent value is substantially higher than recently observed productivity growth rates in the U.S. and in Ontario.

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[6] Prof. Yatchew described this *informal yardstick competition* as an industry-driven process during the many years that there were many distributors in this province. During that time, there was a systematic process for comparing performance amongst distributors. As distributors found better ways to do things, that information would be shared with others, because there was a relatively open public sector system for doing so.

Ms. Frayer also recommended lower stretch factor values than did Dr. Kaufmann for similar reasons to those put forward by Prof. Yatchew. She also reiterated her view that average performers should receive a zero stretch factor to represent their relatively neutral position to the projected TFP growth for the industry as a whole, and superior performers should receive a negative stretch factor to reflect their superior performance and their reduced ability to improve on that performance. Ms. Frayer took the approach that the stretch factor ought to be set in such a manner so that the maximum possible X factor (i.e., productivity factor plus stretch factor) component of the IR formula would be equal to the highest estimate for long term TFP growth (i.e., 0.73 percent) of four 20-year TFP analysis scenarios. She recommended basing the stretch factor values on implied lower and upper bounds from four 20-year TFP analysis scenarios comprised of the Cronin and King Study, the PEG Study (2-factor and 3-factor output) and the LEI study (2-factor and 3-factor output). The resultant “upper” bound, “median” and “lower” bound values (0.73 percent, 0.58 percent and 0.42 percent, respectively) form the basis for a recommended 0.15 percent maximum stretch factor. Given that the Board has determined that non-negative stretch factors will be implemented and also noting that small changes in the overall X-factor can create unreasonable financial burdens on distributors, Ms. Frayer recommended stretch factors of 0.0 percent, 0.075 percent and 0.15 percent on top of her recommended industry-wide productivity factor of 0.58 percent.

SEC observed that, in 3rd Generation IR, the stretch factor is of particular importance since there is no earnings sharing as part of the plan and rebasing to date has not demonstrated the theory that productivity gains achieved by distributors flow through to ratepayers forever thereafter. Acknowledging regulatory precedent and judgment, SEC submitted that “the right number” has to be meaningful in that it has to matter to the distributors. SEC noted that as part of the Board’s determination for the Z-factor threshold for 3rd Generation IR, the Board determined that 0.5 percent of distribution revenue requirement is material. SEC reasoned that if half of one percent is what matters enough to qualify a distributor for an adjustment to its underlying revenue requirement, then half of one percent is also what matters enough to influence a distributor's behaviour. In response to a suggestion that it might be possible to use the same stretch factor value for all three cohorts, SEC disagreed. SEC expressed concern that the Board would identify some distributors as being more efficient than others but that there would not be any consequence to it. Therefore, he recommended that the difference between the midpoint and either the bottom point or the top point should be 0.5 percent. In summary, SEC recommended stretch factors of 0.0 percent, 0.5 percent and 1.0 percent on top of Dr. Kaufmann's recommended industry-wide productivity factor of 0.88 percent.

While Dr. Kaufmann agreed with Prof. Yatchew that the theoretical rationale for stretch factors is that IR creates stronger incentives compared with cost-of-service regulation, he submitted that theory never says that stretch factors should only be implemented one time (i.e., in the first IR plan) and then be removed. Rather, he noted specific precedents in the U.S., Germany, and the U.K., as well as more general evidence from regulated industries to the effect that incremental productivity gains are sustained for more than a decade after regulatory reform (e.g., U.S. railroads, U.K. energy distribution).

All participants acknowledged that the stretch factor is based on judgment and that factors that could influence the Board's judgment include the term of the plan, the absence of an earnings sharing mechanism, and the inclusion of an incremental capital module. Participants also generally agreed that, in the long-term, when total cost benchmarking and the requisite data are available, the source of misclassification may be reduced to statistical error (which will always exist). Prof. Yatchew observed that part of the value of this process is that distributors that believe they are being treated inequitably will come forth with that information and hopefully improve the nature of the entire information set.

LPMA, Energy Probe, CCC and VECC recommended that the stretch factors be set at 0.25 percent, 0.50 percent, and 0.75 percent. LPMA and Energy Probe submitted that without an earnings sharing mechanism, the values for the stretch factors should at least be set relative to that which is evident in comparable IR plans. The recommended value for Group II is based on what Dr. Kaufmann indicated as the average stretch factor set in North America, and on what has been historically set in a Union Gas plan here in Ontario. With regard to Group I, LPMA and Energy Probe argued that the value should be greater than zero because there is no evidence to suggest that productive distributors will not or cannot continue to achieve additional gains. Their opportunity may be less, but LPMA and Energy Probe maintained that it is still greater than zero.

VECC commented that the stretch factor is in effect addressing three issues. First, the productivity factor reflects what a normal cost-of-service type application may result in, including the type of benefit a consumer might expect to see in terms of the resulting rates under a cost-of-service regime. If one accepts that there is greater opportunity for productivity improvements by distributors under IR, then according to VECC it seems reasonable to expect something in addition to that – the stretch factor. Second, there are a number of safety valves in the 3rd Generation IR design for distributors. Depending on a distributor's circumstance, the distributor may be eligible to apply for Z-factors, off-ramps, or revenue to support incremental capital. A distributor may also apply for a full cost-of-service review. With no earnings sharing mechanism, the stretch factor is in VECC's view also a safety valve for consumers. Third, the stretch factor is meant to recognize the fact that there are differences in terms of where distributors stand right now in terms of their level of efficiency, as reflected in the Board's decision to have three groupings. VECC concluded that the stretch factor for Group I should therefore be greater than zero. VECC recommended stretch factor values of 0.25 percent, 0.5 percent and 0.75 percent for the three groups.

With respect to Prof. Yatchew's concerns that 20 percent of the distributors, on average, will be misclassified as either being statistically superior or statistically inferior, CME observed that this would mean two out of the eleven distributors assigned to Group I may not belong there, and about two out of the eleven distributors assigned to Group III may not belong there. Consequently, CME proposed that the response to the misclassification concern should not be to reduce the stretch factor on average, but rather that it may be more appropriate to narrow the differences between the average stretch factor and the stretch factors for Group I and Group III. While CME did not recommend specific values, it recommended that the Group II stretch factor be set in the range of 0.25-0.50 percent. LPMA and Energy Probe, building on this idea, recommended that if the Board believes that some sort of mitigation against misclassification is required, then the stretch factor values could be set at 0.35 percent, 0.50 percent, and 0.65 percent for the three groups. CCC submitted that, if the Board were to accept the arguments about misclassification, CCC would support a stretch factor of 0.5 percent for all three cohorts.

Hydro One and the CLD noted that all participants seem to agree that benchmarking is in its infancy, that it needs to improve and that it will improve. These distributors acknowledged that there will likely be some misclassification, but that improvements will be made over time and therefore, they submitted, they support the Board's grouping approach. As to the values for the stretch factors, Hydro One and the CLD commented that, from their perspective, what is important is the combination of what is expected of them in terms of productivity plus a stretch factor because that is the number that needs to be achieved. Therefore, if the Board sets one high, perhaps it should set the other one low or vice versa – it is the combination that distributors are going to have to somehow manage to achieve. In summary, Hydro One and the CLD expressed a preference for the values 0.0 percent, 0.075 percent, and 0.15 percent for the three groups.

Board Policy and Rationale

It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the utility.

In the July 14, 2008 Report, the Board determined that stretch factors will be a feature of the IR mechanism, and that benchmarking will provide the architecture for their assignment to distributors. These determinations were not intended to be revisited during the August stakeholder conference. The Board acknowledges the concerns expressed regarding the current state of benchmarking in Ontario, but is not convinced that it needs to reconsider the benchmarking architecture for purposes of 3rd Generation IR.

The Board notes that all of the participants in the consultation agreed that the setting of stretch factors is a matter that calls for the exercise of judgment. As such, there are no hard and fast principles to guide the Board's determination of an appropriate value. The Board also notes that each of the participants urged the Board to take a conservative approach with respect to the stretch factor values in light of the fact that the Board's experience with benchmarking is in its early stages.

The Board is not convinced that the potential for misclassification raised by Dr. Yatchew is such that the Board needs to reduce the stretch factors so that they are of little or no materiality. As described in the July 14, 2008 Report, the three groupings have been developed using two distinct benchmarking evaluations. The two evaluations will be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II. The Board recognizes that the risk of misclassification cannot be ruled out. The Board intends to undertake further work on the model and will consult with stakeholders to identify whether it can improve the grouping approach and further reduce the potential for misclassification in the two OM&A benchmarking evaluations. It is also expected that the Board's knowledge of and facility with benchmarking will improve over the course of the 3rd Generation IR, and that any anomalies will be addressed in due course.

The Board also believes that it is important that the stretch factors be sufficient to influence distributor behaviour over the course of the plan. While the Board accepts that this is not the time to adopt large stretch factors, it does believe that they must be of such magnitude that they are likely to motivate distributors to change or maintain their status, as the case might be. The proposals put forward by Ms. Frayer and Prof. Yatchew would not, in the Board's view, be meaningful in that regard. The Board also believes that Ms. Frayer's approach would conflate the TFP and the stretch factor, effectively eliminating the consumer benefit element normally associated with the stretch factor.

As noted above, some participants argued that the best performers, or even average performers (i.e., those falling within Group I, or Group II), ought to enjoy a zero stretch factor. In fact, in earlier comments made within this consultation some participants argued for negative stretch factors for high performing distributors. At this time, the Board is not prepared to accept the premise there are no prospects for incremental productivity gains above the expected industry trend that should be shared with ratepayers – which a stretch factor of zero or less would connote. While these options may commend themselves in future IR plans, the Board does not think it appropriate at this time, and has adopted a modest but still meaningful stretch factor for Group I, and a higher stretch factor for Group II.

With respect to Group III (the poorest performers), the Board believes that the stretch factor value should not be so demanding as to be considered punitive. In the Board's view, the stretch factor approach ought to serve as an incentive for incremental productivity improvement and not as a punitive measure.

Accordingly, the Board has determined that the appropriate stretch factor values for each of the three groups are as follows:

Table 3: Stretch Factor Values

Group	Benchmarking Evaluations	Stretch Factor Value
I	Statistically superior and in top quartile on OM&A unit cost comparison	**0.2%**
II	In middle two quartiles on OM&A unit cost comparison	**0.4%**
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison	**0.6%**

These values will be in effect for the term of the plan. As indicated in the July 14, 2008 Report, each year the cohorts for the entire sector will be re-evaluated. This means that the stretch factor for a given distributor may change during the term of the IR plan if the distributor moves from one group to another.

The Board believes that the above stretch factor values reflect a reasonable synthesis of the various points of view advanced in the course of the stakeholder consultations and of the Board's views on the relative merits of the approaches put forward by the various participants.

2.3 Incremental Capital Module Materiality Threshold

In the July 14, 2008 Report, the Board determined that there will be an incremental capital module in 3rd Generation IR. Further, the Board determined that the eligibility of a distributor to apply for rate relief through the module will be subject to a materiality threshold. However, the Board stated that it would be assisted by further consultation on the appropriate materiality threshold.

The question to be addressed by participants at the stakeholder conference was: what is an appropriate CAPEX to depreciation threshold value to determine materiality?

Issues and Options Raised in Consultations

Board staff provided analysis that indicated that CAPEX to depreciation threshold values in the range of 170-190 percent may be appropriate. These threshold values are comprised of three parts:

- a 100 percent base depreciation value;
- an additional 20-40 percent for the annual 3rd Generation IR price cap index ("PCI") adjustment value (20 percent if PCI adjustment is one percent; 40 percent if PCI adjustment is two percent); and
- an additional 50 percent to adjust depreciation from historical to replacement dollars.

Board staff's 50 percent estimate for inflating depreciation expense to replacement dollars was derived as follows. An overall effect of inflation adjustment was estimated as 49.1 percent based on the published Ontario total values for depreciation expense, remaining book value of in-service plant and Statistics Canada inflation statistics. While an Ontario average was used to illustrate a single value as a threshold component for all distributors (~50 percent), staff noted that a table of depreciation escalators could be prepared for use with a variety of different average ages to reflect individual distributor age of plant.

Staff's threshold calculations did not attempt to adjust for customer or load growth. Staff noted that growth provides incremental funding for new capital and that this would be evident in a distributor's application to the Board and reviewed on a case-by-case basis.

While PEG did not make specific recommendations on the value of the threshold, Dr. Kaufmann emphasized that an implicit adjustment for CAPEX exists in the PCI because a historical level of CAPEX is built into the productivity factor. If a distributor has historically invested in more CAPEX, it will consequently have lower TFP growth, all else being equal, and that would translate into more rapid price escalation. Acknowledging that special CAPEX adjustments could be warranted if, for whatever reason, a distributor's future CAPEX differs in a significant way from what is reflected in historical industry-based trends, Dr. Kaufmann cautioned that the Board be careful to ensure that any such CAPEX adjustment does not allow double counting.

Ms. Frayer also acknowledged that some portion of rate base growth is already remunerated through the PCI; however, she submitted that the need for an incremental capital module arises because rate base is growing faster than the rates under the price cap regime, even if annual CAPEX stays at the same level over an IR plan term. Ms. Frayer explained that the annual PCI adjustment may not be sufficient for all distributors, depending on the depreciation profile and the capital additions profile for a particular distributor. Ms. Frayer commented that growth in rate base that is “unfunded” results in potential loss of capital carrying costs and potential for deteriorating ROE, despite distributors’ best efforts for cost cuts and/or delay in CAPEX. Ms. Frayer provided an illustrative analysis of incremental rate base and the need for rates – a rate adder of some sort or revenue adder – to cover that unfunded amount of incremental rate base. Based on the experiences of Hydro One and the CLD, expectations on inflation and LEI’s recommended productivity and stretch factors, Ms. Frayer proposed that a 2 percent growth in rate base is sufficiently material to have a significant influence on distributor operations. Given this, Ms. Frayer provided the following analysis. In 2007 the IR PCI adjustment was 0.9 percent. Assuming that 60 percent of a distributor’s revenue requirement is related to capital, she also assumed that 0.54 percent of the PCI adjustment (i.e., 60 percent of 0.9 percent) is available for capital-related costs, regardless of rate base growth. In contrast, on a rate rebasing basis, a 2 percent increase in rate base would result in about a 1.2 percent (i.e., 60 percent of 2 percent) increase in revenue requirement. Ms. Frayer noted that, in this example, the 2007 price cap would have fallen short on funding by 0.68 percent (i.e., 1.2 percent less 0.54 percent).

Ms. Frayer acknowledged the linkage between the CAPEX to depreciation ratio and rate base growth, and provided analysis to illustrate that linkage. Based on her analysis of RRR reported data for 2007, Ms. Frayer noted that there is a strong correlation between the two percent growth in asset base that she identified as material and substantial and a 125 percent ratio of CAPEX to depreciation expense. Therefore, Ms. Frayer recommended a 125 percent CAPEX to depreciation threshold.

CME and Board staff clarified with Ms. Frayer that her proposed value of 125 percent is derived based on estimated asset base growth, not load growth. Ms. Frayer commented that funding from the PCI, load growth, or other sources would be dealt with in the distributor’s application to the Board rather that factored into the threshold value.

Mr. Shepherd, representing SEC, also commented that an implicit adjustment for CAPEX exists in the PCI and reflected this in his proposed approach to deriving distributor-specific values for the materiality threshold. This distributor-specific proposal is in contrast to the proposals offered by Board staff and Ms. Frayer, both of which result in one value for the threshold.

Mr. Shepherd recommended a threshold of 200 percent plus or minus 50 percent of the distributor’s average three-year growth percentage, based on the following formula:

$$\textit{CAPEX potential under IR} = \frac{\mathrm{P} * \mathrm{R} * (\mathrm{d} + \mathrm{i} + (\mathrm{g} * 1.5))}{(\mathrm{d} + \mathrm{c})}$$

Where:

P = percent of revenue requirement that is capital driven (i.e., revenue requirement less OM&A);
R = revenue requirement of prior year;
d = depreciation expense as a percent of rate base (i.e., an average depreciation rate);
i = inflation factor in IR;
g = organic growth in revenue (i.e., change in load or customer numbers); and
c = interest + ROE + payments in lieu of taxes (PILs) as a percent of rate base.

(Implicit in the above formula is the annual reduction of cost of existing capital – the annual reduction in rate base reduces the cost of capital associated with old assets and provides additional funds to finance capital.)

Using RRR data, Mr. Shepherd adopted the following assumptions: P = 50% (2007 actual is 48.9%); d = 4% (2007 actual is 6.57%); and c = 8.7% (6% interest on 60%, 8.5% ROE on 40%, 33% combined income tax rate). For illustrative purposes, he adopted the Bank of Canada target rate of 2% for the value of inflation (i), and assumed R=1. Using these assumptions, Mr. Shepherd estimated that IR provides a distributor a CAPEX amount of approximately 25 percent of annual revenue requirement (i.e., g=0%) plus an additional 6 percent for each one percent of organic growth (i.e., g=1%). Translating this into CAPEX to depreciation expense terms, Mr. Shepherd estimated this to amount to approximately 148 percent of depreciation expense plus 36 percent for each one percent of organic growth. Mr. Shepherd provided further analysis to test this 148 percent threshold value against the RRR reported CAPEX in 2007 of 71 distributors. He indicated that 34 percent of those distributors reported CAPEX over the 148 percent of depreciation level, plus or minus growth, and that 66 percent reported CAPEX under that level. He further indicated that if the threshold were raised to 200 percent of depreciation, 14 percent of the distributors' reported CAPEX exceeded 200 percent of depreciation and 21 percent of the distributors' reported CAPEX was 100 percent below depreciation.

Mr. Shepherd submitted that qualifying for the capital module should be an" exception", not a "standard". This view was echoed by other participants. Mr. Shepherd noted that, regardless of the threshold, some distributors may under-spend during IR and that he is much more concerned with this than with the materiality threshold.

Mr. Aiken, on behalf of LPMA and Energy Probe for the purposes of this part of the consultation, proposed a formulaic approach to calculate an individual threshold for each distributor. The formula incorporates both the impact of the price cap and organic growth:

$$\frac{CAPEX}{d} = 1 + (\frac{RB}{d}) * (g + PCI * (1 + g)) \qquad (1)$$

Where:

RB = rate base included in base rates;

d = depreciation expense;

g = distribution revenue change based on load growth; and

PCI = price cap index (inflation less productivity factor less stretch factor).

(Mr. Aiken noted that the values for RB, d, and g, would be taken from the Board-approved base year rate decisions.)

Mr. Aiken arrived at this formula by first establishing a means of estimating the level of CAPEX that can be financed by increases in revenues due to the price cap formula and by load growth as follows:

$$CAPEX = d + RB * (g + PCI * (1 + g)) \qquad (2)$$

The premise of the above is that the approved base year revenue requirement covers OM&A costs and rate base costs (which include depreciation, interest on debt, return on equity and the associated taxes). Mr. Aiken noted that, similar to the other proposals, his proposal recognizes that the revenue generated under a price cap plan automatically generates more revenue for capital investment. Further, the revenue generated under a price cap plan is equal to the approved revenue requirement from the last rebasing year adjusted for the price cap index, as well as load growth.

Mr. Aiken provided various scenarios to illustrate how his proposed formula would reflect distributor diversity. In brief, distributors with relatively new asset stock (suggested by low depreciation relative to rate base) and therefore likely operating earlier in the asset replacement cycle, and distributors in higher growth areas (evidenced by the reported growth rate) and therefore earning faster growing revenue will both have higher CAPEX to depreciation ratios for purposes of this threshold test. Conversely, distributors in low growth areas or with aging assets will have lower CAPEX to depreciation ratios for purposes of the threshold test.

One area where Mr. Shepherd was critical of Mr. Aiken's model is that, in deriving a CAPEX to depreciation threshold, the model does not contain a capital efficiency factor. This could be rectified, Mr. Shepherd noted, by using the gross inflation factor, not netted for the X factor.

In response to staff's proposal and Ms. Frayer's proposal, Mr. Aiken submitted that a one-threshold-fits all approach is not appropriate for the incremental capital module due to the differing demands on distributors across the Province. Most other participants also supported a formulaic approach; however, Mr. Shepherd acknowledged that it may be more efficient for the Board to have a single threshold as opposed to a separately calculated threshold for each distributor. In relation to his own proposal, Mr. Aiken noted that the formula did not include an adjustment for historic inflation in the value of the assets; however, he commented that he would not be opposed to the inclusion of this in his approach.

Board staff carried out further analysis to estimate a more variable adjustment in its proposed approach as a function of the average number of years of the life of the plant. This was in response to Mr. Aiken's approach that recognizes distributor diversity. Staff provided a table of depreciation escalators that correlate with a variety of different average ages to reflect individual distributor age of plant. Staff calculated the cumulative Canadian CPI annual variation for the average number of years of plant. The average life of plant for each distributor was calculated by dividing the total value of the plant by annual depreciation. Using this revised inflation adjustment, the resultant threshold values ranged from 148 percent to 213 percent. Some participants observed that under staff's method, distributors with longer lived or older assets would have to exceed a higher materiality threshold than those with relatively new asset stock. However, Dr. Kaufmann observed that distributors that have older capital stock will have a lower value of reported depreciation because of the fact that the underlying assets were booked at historical cost, and submitted that if the Board does not adjust for that then those distributors will have a lower threshold. Staff noted that its proposed approach provided an empirical foundation for a threshold value which would ensure that the invoking of the capital module is an exception and not the norm.

Agreeing that invoking the module should be an exception and not a Y-factor pass through, CME submitted that to be eligible to apply and recover amounts under the capital module the CAPEX applied for must exceed the CAPEX to depreciation ratio plus a dead band, as determined by the Board. CME suggested a dead band of at least 10 percent. Mr. Shepherd noted that his proposal includes a dead band of plus or minus 50 percent of the average three-year growth percentage. Mr. Aiken suggested a dead band of 25 to 50 percent to be added directly to the threshold.

Prof. Yatchew expressed concern that if the incremental capital module does not provide adequate relief – and the threshold itself plays an important role in that – then there is a potential of incentives for distributors to front-end load their CAPEX into their test year, rather than to plan their expenditures on the basis of a more rational time distribution.

Board staff provided analysis based on RRR data that suggested that with a threshold equal to 150 percent, there would be more than 20 distributors eligible to apply and with a threshold equal to 200 percent, there would be about 10 distributors eligible. VECC observed that reviewing a capital module application may not be a simple process. It may require the review of productivity improvements inherent in capital spending and the setting of load forecasts. Therefore, VECC recommended that the Board keep this in mind when determining the threshold value. CCC observed that if in the first year the Board receives a large volume of capital module applications, then perhaps the threshold should be reconsidered.

In response to staff's 50 percent estimate for inflating depreciation expense to replacement dollars, Hydro One and the CLD estimated that adding this into the materiality threshold could translate into a decrease in ROE on an annual basis of up to 100 basis points for some distributors. Further, this impact could be cumulative over the three-year IR plan term. Therefore, Hydro One and the CLD did not support including the inflation adder to the materiality threshold, citing concerns that it would be the distributor that would have to fund this 50 percent factor that relates to capital spending. Hydro One and the CLD also observed that distributors need to reliably operate and sustain the businesses that they are licensed to conduct and submitted that if the capital module threshold, the productivity factor and the stretch factors are set too high then they may be compelled to make cost-of-service applications.

Board Policy and Rationale

The Board notes that there are clearly differences in perception as to the purpose of the incremental capital module. Ratepayer groups perceive the capital module as a mechanism aimed solely at addressing extraordinary or special CAPEX needs by distributors. The distributors, on the other hand, perceive the module as a special feature of the 3rd Generation IR architecture which would enable them to adjust rates on an on-going, as-needed basis to accommodate increases in rate base.

In the Board's view, the distributors' view is not aligned with the comprehensive price cap form of IR which has been espoused by the Board in its July 14, 2008 Report. The distributors' concept better fits a "targeted OM&A" or "hybrid" form of IR. This alternative IR form was discussed extensively in earlier consultations but was not adopted by the Board. The intent is not to have an IR regime under which distributors would habitually have their CAPEX reviewed to determine whether their rates are adequate to support the required funding. Rather, the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

A review of an application will test whether the applicant has passed the materiality threshold, and, if it does, will scrutinize the need for the requested incremental capital relief. Such scrutiny will entail reviewing the distributor's assumptions and planning and examining alternative options, and its overall CAPEX plan. If the application succeeds, in whole or in part, the Board will adjust rates to reflect a higher CAPEX as appropriate. It is important to note that the adjustment in rates will be linked solely to the costs of the incremental capital. Therefore, distributors should not perceive this activity as an opportunity to true up rate base for any other reason.

The incremental capital for which the Board may provide rate relief is the new capital sought in excess of the materiality threshold. The proceeding to consider an eligible distributor's application for rate relief would examine the reasonableness of the distributor's increased spending plan. If the application is approved, a rate rider would be established to reflect an amount sufficient to accommodate the portion of the approved incremental spending that exceeds the threshold amount. In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan.

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing.

With respect to the threshold itself, the Board believes that distributors should be able to determine whether or not they are eligible to apply with relative ease. Making that determination should not be an unduly cumbersome exercise. It should be formulaic and it should be relatively easy to populate with the required data.

With rebasing at the end of 2nd Generation IR, and before commencing 3rd Generation IR, a distributor's rates include a CAPEX component. The adequacy of such CAPEX provision in rates during 3rd Generation IR depends on whether or not the need for CAPEX during 3rd Generation IR can be met through existing rates, as adjusted under the 3rd Generation IR regime and considering organic growth. There is no dispute among participants that the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping".

A constant theme in this and earlier consultations has been the notion that there is diversity among distributors in their needs for future CAPEX. The Board sees merit in an incremental capital module that considers the diversity among the distributors, as long as it can be implemented in a manner that is not unduly cumbersome. The Board has not observed any objections to this approach.

There was considerable support for the formula presented by Mr. Aiken on behalf of LPMA and Energy Probe. That formula incorporates both the impact of the price cap and of load growth on the level of CAPEX that can be funded without additional rate relief and does this on a distributor-specific basis, reflecting both distributor diversity and the differing positions of the distributors in the asset replacement cycle. The data required to perform the calculation is easily obtainable from the distributor's most recent rebasing and IR decisions.

There was a proposal that the price adjustment factor in the formula should be the gross inflation factor, not netted for the X (productivity) factor, to incorporate the expectation for a more efficient use of capital. The Board is not persuaded of the appropriateness of this approach as it goes beyond the need to address the more immediate pressures of incremental investing.

Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.

Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

Further details regarding this formula are set out in Appendix B to this Report.

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3 Tax Changes in Relation to the Z-factor

Some participants in this consultation expressed concern over the issue of the treatment of tax changes under an IR plan that uses the GDP IPI FDD as the inflation factor. The Board noted in the July 14, 2008 Report that it would be informed by the Board's decision in the EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation applications in which tax as a Z-factor was being considered.

The EB-2007-0606/615 decision was issued on July 31, 2008, and concluded that a 50/50 sharing of the impact of tax changes, as applied to the tax level reflected in the Board-approved base rates, is reasonable. Therefore, 50 percent of the tax reductions would be treated as a Z-factor and ratepayers would receive 50 percent of the tax benefits that will occur from 2008 through 2012.

For purposes of the 3rd Generation IR plan, the Board has not identified any reasons to adopt an approach different than that now in place for the gas distributors.

Therefore, for 3rd Generation IR, the Board has determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate. An approach similar to that adopted in the gas IR plans will be used to calculate the savings for purposes of the sharing. Additional details are set out in Appendix B to this Report.

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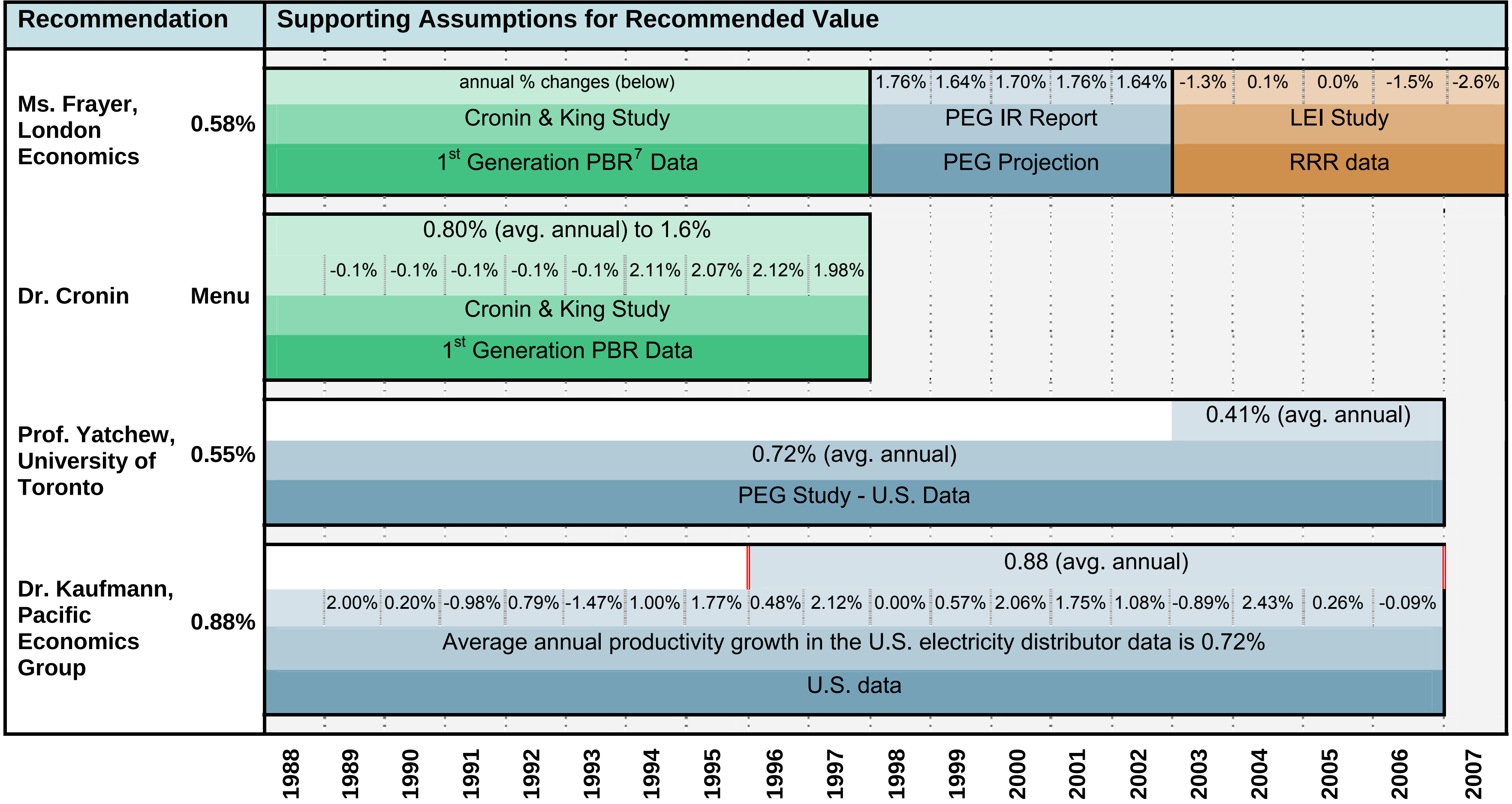
Appendix A: Summary of Productivity Factor Recommendations

Table 4: Summary of Productivity Factor Recommendations from Dr. Kaufmann, Prof. Yatchew, Dr. Cronin, and Ms. Frayer



Recommendation		Supporting Assumptions for Recommended Value																			
Ms. Frayer, London Economics	**0.58%**	annual % changes (below)										1.76%	1.64%	1.70%	1.76%	1.64%	-1.3%	0.1%	0.0%	-1.5%	-2.6%
		Cronin & King Study										PEG IR Report					LEI Study				
		1st Generation PBR[7] Data										PEG Projection					RRR data				
Dr. Cronin	**Menu**	0.80% (avg. annual) to 1.6%																			
			-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	2.11%	2.07%	2.12%	1.98%										
		Cronin & King Study																			
		1st Generation PBR Data																			
Prof. Yatchew, University of Toronto	**0.55%**																0.41% (avg. annual)				
		0.72% (avg. annual)																			
		PEG Study - U.S. Data																			
Dr. Kaufmann, Pacific Economics Group	**0.88%**									0.88 (avg. annual)											
			2.00%	0.20%	-0.98%	0.79%	-1.47%	1.00%	1.77%	0.48%	2.12%	0.00%	0.57%	2.06%	1.75%	1.08%	-0.89%	2.43%	0.26%	-0.09%	
		Average annual productivity growth in the U.S. electricity distributor data is 0.72%																			
		U.S. data																			
		1988	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**

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[7] The first generation electricity distribution performance-based regulation plan is detailed in the Board's January 18, 2000 RP-1999-0340 Decision with Reasons and is available on the Board's web site at http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Archived+OEB+Key+Initiatives/First+Generation+Electricity+Distribution+PBR.

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Appendix B: Amended Filing Guidelines

These filing guidelines supersede the filing guidelines set out in the Appendix to the July 14, 2008 Report.

Changes are highlighted for easy identification.

These filing guidelines set out the Board's expectations for applications by distributors for rate adjustments on the basis of the 3rd Generation IR mechanism.

General

The implementation of the 3rd Generation IR mechanism will occur first with rate adjustments scheduled for May 1, 2009.

The price cap adjustment will be applied to the Service Charge and Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board. The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Specific Service Charges, Allowances[8], Retail Service Charges or Loss Factors.

The price cap adjustment will reflect inflation less the X-factor, and an adjustment for the transition to the common deemed capital structure of 60% debt and 40% equity.

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[8] Transformation and primary metering allowances and any other allowances the Board may determine.

Manager's Summary

Each application should include a completed Model, provided by the Board, and a brief Manager's Summary explaining all rate adjustments applied for. Any deviations should be thoroughly documented. Where necessary, support for applied adjustments, such as continuation of rate riders or for Z-factors, should be provided.

Incremental Capital Module

The incremental capital module has been incorporated into the 3rd Generation IR mechanism to address the treatment of new capital investment needs that arise during the IR plan term which are incremental to the materiality threshold defined below.

Eligibility Criteria for Incremental Capital Module Applications

The eligibility criteria for applications to recover amounts through rates to fund incremental capital investment needs are discussed in section 2.5 of the Board's July 14, 2008 Report, and are reproduced in Table 5 below for convenience:

Table 5: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The materiality threshold for applications to recover amounts through rates to fund incremental capital investment needs is discussed in section 2.3 of this Report. The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + (\frac{RB}{d}) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);
d = depreciation expense included in base rates ($);
g = distribution revenue change from load growth (%); and
PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for “RB” and “d” are the Board-approved amounts in the distributor’s base year rate decision.

The value for “g” is the % difference in distribution revenues between the most current complete year and the base year. For example, for distributors that were rebased in 2008:

If a distributor applies in	then “g” will be the % difference between
2009	2007 actuals and 2008 Board-approved base
Jan-Mar 2010 Apr-Dec 2010	2007 actuals and 2008 Board-approved base 2008 Board-approved base and 2009 actuals
Jan-Mar 2011 Apr-Dec 2011	2008 Board-approved base and 2009 actuals 2008 Board-approved base and 2010 actuals

An Illustration:

Assumptions:	RB = $100 million; d = $5 million; g = 1.5% (0.015); and PCI = 0.75% (0.0075).
Calculation:	$1+(\frac{100,000,000}{5,000,000})*(0.015+.0075*(l+0.015))+0.20=1.65$
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to $8.26 million ($5 million * 1.65) before being eligible to apply to recover incremental amounts.

Filing Guidelines

The Board expects that applications requesting relief for incremental CAPEX during the IR plan term will be accompanied by comprehensive evidence to support the claimed need, and include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- A description of the underlying causes and timing of the capital expenditures including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, OM&A, return on rate base and PILs associated with the incremental capital), and a specific proposal as to the amount of relief sought;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived. This includes historical plant continuity information for each year of the IR plan term since the last Board-approved Test Year;

- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

Reporting Requirements

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing

Z-Factors

Z-factors are events that are not within management's control. A distributor will be expected to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor is expected to follow the guidelines listed below when applying to the Board to recover from ratepayers the amounts that the distributor has recorded. The Board may limit the recovery of certain amounts.

Eligibility Criteria for Z-factor Amounts

The eligibility criteria for applications to recover amounts in the Z-factor are discussed in section 2.6 of the Board's July 14, 2008 Report, and are summarized in Table 6 below. In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three criteria set out in Table 6.

Table 6: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The Board has determined that the following materiality thresholds will apply:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Filing Guidelines

Distributors are expected to submit evidence that the costs/revenues which were incurred / received meet the three eligibility criteria outlined above.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

Other Matters in Relation to Z-Factors and Incremental Capital Module

Distributors will be expected to file a proposal, including the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocations considered.

Distributors will also be expected to file a detailed proposal including justifications to recover, through a rate rider, the Board-approved incremental revenue requirement. The proposal should specify whether the rate rider will apply on a fixed or variable basis, or a combination thereof, and the time period for collection. A detailed calculation of the rate rider(s) should be provided for each year of the IR plan term.

Accounting Treatment

Eligible **Z-factor** amounts should be included in Account 1572, "Extraordinary Event Costs", of the Board's Uniform System of Accounts (the "USoA") contained in the Accounting Procedures Handbook for electricity distributors.

Eligible **Incremental Capital Module** amounts should be recorded in Account 1508, "Other Regulatory Asset, Sub-account Incremental Capital Expenditures", of the Board's USoA contained in the Accounting Procedures Handbook for electricity distributors.

Carrying charge amounts shall be calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for the respective quarterly period for deferral and variance accounts. These prescribed rates are reviewed and updated each quarter and published on the Board's web site.

Tax Changes in Relation to the Z-factor

The treatment of tax changes is addressed in section 1 of this Report. The Board has determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate. An approach similar to that adopted in the gas IR plans will be used to calculate the tax reduction for this purpose. The calculated annual tax reduction over the plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

The Model provided by the Board will include a schedule for distributors to complete that will calculate the amount to be shared and the resulting rate rider.

TAB 26

Ontario Energy Board

Commission de l’énergie de l’Ontario

Handbook
for
Utility Rate Applications

October 13, 2016

1. Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates. Rates are the key revenue tool for regulated utilities. Under legislation, regulated natural gas utilities and electricity distributors, transmitters and Ontario Power Generation (OPG)[1] are only permitted to charge for their regulated services through an order issued by the OEB. In making an order, the OEB must set rates or payments that are just and reasonable.

This Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications. The Handbook is applicable to all rate regulated utilities[2], including electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. It has been developed based on the OEB's policies and the experience gained through the processing of rate applications since the release of the *Renewed Regulatory Framework for Electricity* (RRFE)[3]. The OEB expects utilities to file rate applications consistent with this Handbook unless a utility can demonstrate a strong rationale for departing from it.

The Handbook contains the following sections:

- Background on the Renewed Regulatory Framework
- Legislative Mandate and Test
- Rate Applications and the Adjudicative Process
- The OEB's Review of the Key Components of Rate Applications
- Rate-Setting Options
- Rate-Setting Policies

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[1] OPG is the only generator subject to rate regulation by the OEB.

[2] This Handbook uses the term "utilities" to refer to all rate regulated entities unless specified otherwise.

[3] *Board Report: Renewed Regulatory Framework for Electricity Distributors,* October 18, 2012 (RRFE Report)

2. Background on the Renewed Regulatory Framework

The OEB established a new framework for electricity distribution rate regulation in 2012. The *Renewed Regulatory Framework for Electricity* is a foundational policy: it articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities. Key principles of the RRFE include the expectation for continuous improvement, robust integrated planning and asset management that paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

The OEB set out its goals for the RRFE as follows:

> The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.[4]

An important aspect of the RRFE is the evolution to an outcomes-based approach. The OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."[5] There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:

- Customer Focus: Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.

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[4] RRFE Report, p. 1.

[5] RRFE Report, p. 2.

- Operational Effectiveness: Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

- Public Policy Responsiveness: Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First[6] in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low income customers through programs such as LEAP and/or OESP[7], or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement. Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program.

- Financial Performance: Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.

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[6] Conservation First is a government policy referred to in the Long-Term Energy Plan.

[7] Low Income Energy Assistance Program (LEAP) and Ontario Electricity Support Program (OESP).

Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation).

Since the release of the RRFE Report, over half of Ontario electricity distributors have applied for rates under the RRFE. Enbridge Gas Distribution Inc. also applied using the principles of the RRFE. Based on its review of those rate applications, the OEB has now completed an assessment of the RRFE and the principles underpinning it. This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the *Renewed Regulatory Framework* (RRF) in this document and by the OEB going forward to reflect this transition.

3. Legislative Mandate and Test

The foundation for the OEB's public interest mandate is the *Ontario Energy Board Act, 1998*. The OEB Act sets out the objectives for the OEB's regulation of natural gas and electricity. The OEB balances these objectives in order to protect consumers, set demanding but fair performance expectations for utilities, facilitate the evolution of the sector, and support the policies of the Ontario government.

The OEB's authority to set rates for electricity distribution, transmission and payments for OPG[8] is set out in section 78 of the OEB Act. The key test is that the rates or payments must be "just and reasonable." The OEB reviews the information and proposals in a rate application in order to determine whether the proposals are reasonable for both consumers and the utility. For natural gas, the OEB's authority to set just and reasonable rates is in section 36 of the OEB Act.[9]

For all regulated utilities, the onus is on the utility to demonstrate that its rate (or payment amount) proposals are just and reasonable. If the OEB determines that the proposals are not just and reasonable, then it may set other rates (or payment amounts) which it determines are just and reasonable.

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[8] For OPG, Ontario Regulation 53/05 also defines the OEB's authority.

[9] Details of the legislative provisions are set out at Appendix 1.

4. Rate Applications and the Adjudicative Process

This Handbook applies specifically to rate applications, under any of the legislative sections identified above, which are intended to set rates for a multi-year period (Custom IR), or for the first year of a multi-year period (Price Cap IR or Revenue Cap IR). Under the RRF there are a variety of incentive rate-setting (IR) options which are discussed further in section 6 (Rate-Setting Options).

A comprehensive rate application has three main components: the business plan (along with supporting documentation and reports), historical and forecast information, and rate models that show the derivation of specific proposed rates based on the data.

- Business plan: The utility's plan for its business is foundational to the proposals included in its rate application. This includes the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them. The OEB expects the business plan to be informed by the utility's engagement with customers. The business plan is supplemented and supported by the associated plans, reports and documentation (including system plans[10], capital and operational plans, programs, benchmarking, external reviews, and customer engagement activities) which form the core of the rate application. This utility business plan may differ from the corporate business plan that may include matters that go beyond the scope of the OEB's review in a rate application.

- Historical and forecast information: Information filed in support of a rate application facilitates a thorough review of the utility's proposals and ensures continuity in the regulation of each utility over time. The filing of this information does not mean that the OEB will approve every aspect of what is filed in a rate application. The OEB assesses the utility's plans, and the resultant costs and revenue requirement, in order to consider the benefits to customers and a fair return for utilities in setting just and reasonable rates.

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[10] The term "system plan" is used in this Rate Handbook to refer generically to all types of plans that apply to the various sectors; that is "distribution system plan" for electricity and natural gas distributors, "transmission system plan" for electricity transmitters, and any nuclear and hydro-electric generation asset plan that OPG may file in the future.

- Rate models: The OEB has developed a set of rate models for electricity distributors which facilitates the review of rate applications and which distributors are required to use. These models are one of the tools the OEB uses to enhance the efficiency, consistency and accuracy of the review process.

To assist utilities, the OEB has developed filing requirements that identify the information that needs to be provided in an application. There are separate filing requirements for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. The OEB expects utilities to present rate applications that are complete and of high quality. A rate application is complete if it contains all of the information (data, reports and analysis) that the OEB has identified in the filing requirements. In addition to meeting the requirements from the filing requirements, high quality rate applications also address all of the regulatory policy considerations relevant to the company in a comprehensive, consistent and clear presentation that articulates the need for the utility's proposals and the value to customers.

In the past, the OEB used the regulatory process itself to augment a deficient application to ensure the information was complete and consistent. This approach added complexity and time to the process, increasing regulatory costs. In recent years, the OEB has conducted initial reviews of applications for completeness, to ensure that only applications which are substantially complete are allowed to proceed. A rate application must demonstrate on its face that it is of sufficient quality to support the OEB's rigorous review process. An application that does not meet this standard will not be processed; it will be returned for further work. This is one of the ways the OEB will ensure that utilities take full ownership of all aspects of the information and proposals included in their applications.

The OEB uses an open and transparent adjudicative process to review rate applications. The adjudicative process can involve a number of steps, depending on the type of application, to ensure that a utility's proposals are adequately examined and "tested" during the review. (Potential tools include interrogatories, technical and settlement conferences, and an oral hearing). The review involves stakeholders, including customer representatives and other groups. OEB staff ensures that the views of customers are considered in the application process by organizing community meetings to gather consumer views on the utility's proposals, using different media to notify customers that an application has been filed and facilitating the filing of letters of comment to the OEB from customers. The OEB is further augmenting its processes through the Consumer Engagement Framework to ensure customers have a stronger voice in the adjudicative process. The OEB uses the adjudicative process to ensure its review results in just and reasonable rates for customers. The OEB's approach to reviewing utility proposals within rate applications is discussed in the remaining sections of this Handbook.

5. The OEB’s Review of the Key Components of Rate Applications

One of the OEB’s primary goals is to ensure that utilities are delivering cost effective, efficient, reliable and responsive services to customers. The RRF is intended to elevate utility performance by creating incentives for superior performance. The RRF focuses on increased effectiveness and continuous improvement in meeting customer needs, including cost control and system reliability and quality objectives.

A utility’s proposals are expected to demonstrate the alignment of the utility’s strategic objectives with its current and future customers’ expectations for reliable and reasonably priced service. The utility is expected to integrate its business challenges, and what its customers are saying, to create a compelling business plan that directly links to proposals included in the rate application and the four performance outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance. In reviewing utility proposals, the OEB will analyze past performance but is even more concerned with future performance. The Ontario energy sector has gone through significant change, and even more change is expected in the future, particularly technology-driven change which has the potential to deliver significant benefits to customers.

The OEB will use a variety of tools to aid its review work, including trend analysis, cost benefit analysis, reviews of distributor due diligence processes (planning, risk management, governance, etc.), benchmarking and other analytical tools. The OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility’s spending proposals. If the OEB determines that a specific project or program has not been adequately justified, this may result in a reduction to the requested revenue requirement. It is the utility’s responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements, within the funding provided through rates. This provides the utility with the responsibility and flexibility to meet its obligations in ways which benefit customers and the utility.

In reviewing utility proposals in rate applications, the OEB's key considerations are:

- **A focus on cost effective delivery of outcomes that matter to customers**
- **Robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risks**
- **Performance assessments which analyze the level of continuous improvement and a utility's ability to plan and execute plans**

The following key components are addressed in this section:

- Business plan
- Customer engagement
- Planning
- Outcomes and performance metrics
- Performance scorecards
- Benchmarking
- Operations, Maintenance and Administration (OM&A) and Compensation Expenses
- Bill Impacts
- Mergers, Acquisitions, Amalgamations and Divestitures (MAADs)
- Non-Regulated Activities and Affiliate Transactions

Business Plan

A utility's business plan for its regulated activities is fundamental to the evaluation of the proposals in its rate application. The business plan (which is included in the Executive Summary of the application) should describe the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the rate application and the plan to meet them, and how customers will benefit. It forms the "story" that underpins the rate application as a whole and its constituent parts. The business plan should address the utility's circumstances and challenges, integrate its customers' expectations, set performance commitments, and demonstrate how the results will be achieved. This business plan is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews and customer engagement) which form the core of the rate application.

The business plan should demonstrate that the utility's goals are appropriately aligned with the needs and preferences of its customers and the objectives of the RRF, and that the utility is well positioned to deliver on its goals. This information will allow the OEB to understand the impacts of the business plan on key areas of the application such as customer service, system reliability, costs and customer bills.

In reviewing a utility's proposals in a rate application, the OEB will consider whether the business plan demonstrates how the utility's objectives are:

- **Translated into outcomes**
- **Relate to what is being sought in the application**
- **Align with the objectives of the RRF**
- **Align with customer preferences and expectations**

Customer Engagement

Customer engagement is foundational to the RRF. Enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. Today's customers are more informed and more active participants in their energy services. They should have a say in shaping utility plans, particularly given the customer's role in conservation efforts and the customer-focused nature of future technological innovation. Customers should also help determine the pace of utility investment.

Each type of utility will have a variety of customers to include in engagement activities. For example, natural gas utilities have end-use customers and transportation customers. Electricity distributors have end-use customers, generators, and sometimes other embedded distributors. Electricity transmitters have customers which are distributors, generators, and large end-use customers. Ontario Power Generation has an indirect relationship with end-use customers. Although the types of customers vary, the principles presented here are applicable to all utilities. The OEB expects utilities to adapt these principles to their particular circumstances.

Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate those interests and preferences into their plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs. Existing processes and customer interactions should also inform the customer focus element of the utility's proposals. For example, reliability complaints could inform investment program priorities, such as targeting poor performing feeders for upgrades, or the use of smart grid technology to reduce the duration of outages.

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities. The application must also demonstrate how the utility has reflected customer input in the development of its plans. The OEB will evaluate whether the utility's application is reflective of, and appropriately informed by, customer needs, expectations and preferences and whether the utility is positioned to deliver on its plans in a way that will provide value to customers.

In reviewing customer engagement, the OEB will consider:

- **The forms of customer engagement used, their quality and effectiveness**
- **The quality of the utility's analysis of customer input**
- **Whether and how customer input has informed the utility's planning**
- **Whether and how the utility's plans deliver benefits which address customer needs and preferences**

The OEB is not specifying how customer engagement should be done or how customer feedback should be received. It can take many forms, and the OEB expects utilities to consider a range of approaches, using both existing and new processes. A customer satisfaction survey is a tool to gauge how a customer views the past performance of its utility, but it is not a tool that engages customers on future plans and therefore is not sufficient to meet the OEB's expectations for appropriate engagement to inform the utility's plans. Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity. The OEB will consider the adequacy of customer engagement in assessing whether it has been demonstrated that a proposal provides value to customers. If the OEB determines that customer engagement has not been adequate, then the OEB may conclude that a program or project is not adequately justified, in whole or in part, and this could result in a reduction to the requested revenue requirement.

Planning

Robust planning is one of the foundations of the OEB's RRF. The utility's business plan sets the context for the proposals in a rate application (as part of the Executive Summary of the application). The utility's system plan is an important component of the application and complements and supports the specific capital and operational plans and programs, and the associated budgets, which form the utility's overall business plan.

A utility's core business in serving customers is asset management, and strong asset management is essential to delivering reliable and quality energy services that customers value. Strong planning will help drive operational effectiveness, and the utility system plan will be an important component of the utility's business plan which supports the rate application. The capital intensive nature of the energy sector and long life of most assets means that investment brings with it the likelihood of rising costs as aging and fully depreciated assets are replaced with new assets. Therefore it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates. Utilities are expected to develop plans that deliver lower cost solutions over the long-term through a Conservation First approach, integration with regional plans, and consideration of the evolution of the sector, including innovation and new technologies. Utilities are expected to engage customers and incorporate their expectations into their planning.

The OEB's comprehensive policies for electricity distributor system planning, and filing requirements are set out in *Chapter 5 of the Filing Requirements for Electricity Rate Applications*. The planning principles, as set out in the next section, are applicable to all rate-regulated utilities. However, other utilities (natural gas utilities, electricity transmitters, and OPG) would include different types of initiatives in their plans. For example, a natural gas utility would need to incorporate the cap and trade program in its system plan. The discussion below is presented in the context of electricity distribution system plans, but is intended to provide guidance to electricity transmitters, natural gas utilities, and OPG.

Electricity Distribution System Plans

The OEB requires electricity distributors to file a distribution system plan (DSP) every five years, regardless of the rate-setting method chosen. The DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The asset management process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus. The asset management process needs to be informed by an asset condition assessment such as equipment testing results, maintenance and usage history, historical failures or system weaknesses. Information is also required on the consequences of the failure of assets (such as how many customers will be affected, the type of customers and the time to restore the system) to appropriately prioritize plans. The capital expenditure plan sets out and justifies a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance and operations expenditures.

A DSP must contain sufficient information to allow the OEB to assess whether and how a distributor has planned to deliver value to customers, how the plan supports the effective management of the assets, and how a distributor is seeking to control the costs and related rate impacts of proposed investments. The asset management plan underpinning the DSP should be directly linked to the proposed budget, to demonstrate that the proposed capital expenditures have been determined through the necessary optimization and prioritization process.

The OEB has consolidated, streamlined, and strengthened its planning policies into an integrated approach. Under this integrated approach, all network investments will be planned together, including network renewal and expansion, connection of renewable generation facilities, smart grid development and implementation, conservation, and investments arising from regional planning processes.

The DSP is expected to have the following characteristics:

- Consolidated and stand-alone (i.e. not presented through separate parts across an application)
- Includes all assets, both system assets and general plant
- Underpinned by an asset condition assessment
- Linked directly to the proposed budget
- Integrates considerations of conservation, smart grid, renewable generation connection, regional planning, and any relevant public policies
- Demonstrates how the utility has planned to deliver value to current and future customers
- Demonstrates how the plan supports the effective management of the assets
- Demonstrates how the plan is optimized (by considering alternatives, including different capital program options, maintenance or operating solutions, the use of conservation to defer investments, the use of new and emerging technologies, etc.) and how projects are prioritized and paced to recognize potential rate impacts

In a cost of service proceeding the OEB will consider the entire five year DSP as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the DSP. The OEB has established a policy for the funding of capital for electricity distributors on the Price Cap IR option.[11] Requests for funding under these mechanisms must meet all of the same requirements for capital spending

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[11] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

as would be in a cost of service or Custom IR application. Any Incremental Capital Module that involves a significant increase to a capital budget may need to be supported by a DSP along with customer engagement analysis.

In reviewing the utility system plan, the OEB will consider the following:

- **Have the criteria outlined in Chapter 5 of the *Filing Requirements for Electricity Rate Applications* been addressed?**
- **Does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and corresponding capital and operational plans and budgets?**
- **How has the plan addressed the information and preferences gathered from the utility's customer engagement work?**
- **Does the plan deliver quantifiable benefits for customers?**
- **Does the plan support the achievement of the utility's identified outcomes, and the outcomes of the RRF (customer focus, operational effectiveness, public policy responsiveness, and financial performance)?**
- **Has the company controlled costs through optimization, prioritization and pacing?**
- **Has the plan appropriately integrated conservation, renewable generation connection, regional plans, smart grid, and any relevant public policies?**

Outcomes and Performance Metrics

The RRF is an outcomes-based approach. A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes. These outcomes are linked to performance metrics, which will be used to show whether the outcomes have been achieved. Utilities are expected to consider cost trends, benchmarking of comparable utilities, and learnings from their customer engagement in setting outcomes and performance metrics.

Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives. The outcomes should be based on the utility's business plan and should identify outcomes at the key program level that flow directly from the cost proposals. The outcomes should demonstrate the value proposition for customers and/or public policy goals. Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers and not a line by line review of expenditures. The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing.

Performance metrics are generally quantitative measures which will be used to assess whether the outcomes have been achieved; however qualitative measures may also be considered. Performance metrics ensure that the outcomes are measurable. For the pole line example noted above, the outcome could be increased reliability for that particular feeder.

The OEB has established a set of performance metrics for electricity distributors through its Performance Scorecard. In a rate application, the electricity distributor must identify metrics for its identified outcomes, which will often be in addition to those scorecard measures.

Other utilities (natural gas utilities, electricity transmitters and OPG) should establish performance metrics which are directly linked to the identified outcomes related to their business plans. These performance metrics will generally be part of the set of performance measures the utility has proposed for a performance scorecard (discussed further in the next section).

In reviewing a utility’s proposed outcomes and performance metrics, the OEB’s key considerations are:

- **A focus on strategy and results, not activities**
- **The need to demonstrate continuous improvement**
- **Outcomes which are demonstrated to be of value to customers**
- **Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement**

Performance Scorecards

Customers expect continuous improvement in the utility services delivered to them. Utilities must demonstrate their performance through effective and transparent reporting. As part of the RRF, the OEB has developed performance measures and standards for electricity distributors in four areas: customer focus, operational effectiveness, public policy responsiveness, and financial performance.[12] This Performance Scorecard brings greater transparency to utility performance and

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[12] *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach*, March 5, 2014

enhances the ability to assess performance over time and to compare performance across utilities.

In its rate application, an electricity distributor should discuss its performance for each of the Performance Scorecard measures over the last five years, and explain the drivers for its performance. The OEB's review of a utility's proposals will consider the utility's past and target performance against the four RRF outcomes. The electricity distributor is also expected to discuss its plans for continuous improvement. It is expected to identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan.

All other utilities (natural gas utilities, electricity transmitters, and OPG) are expected to propose a scorecard (including the performance metrics linked to the proposed outcomes) to measure and monitor performance and, where appropriate, enable comparisons between utilities. The format should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. After the OEB has set approved scorecards for one or more electricity transmitters and natural gas utilities, those scorecards will provide additional guidance to other utilities filing applications. However, a utility is also encouraged to propose other performance categories and measures that it believes would be meaningful for its operations as an Ontario utility.

The proposed scorecard should include data for at least five years. A utility may propose measures for which five years of data is not yet available if it commits to collecting and reporting the data through the course of the plan. Furthermore, the lack of historical data should not be a barrier to the setting of new measures, especially if these are important to monitoring a utility's future performance e.g. a measure on system utilization could report on how a utility is managing its assets. The OEB may undertake further work to make enhancements to any scorecard proposed through an application as the OEB continues to develop its approach to performance assessment, and to maintain a level of consistency for scorecards between utilities.

In reviewing the proposed performance scorecard, the OEB's key considerations are:

- ***Whether the measures capture key factors of utility performance***
- ***Whether the scorecard enables assessments over time and appropriate comparisons with other utilities***
- ***Whether the utility has set reasonable targets for its performance metrics***

Benchmarking

Benchmarking will be used by the OEB to review a utility's proposals, including at the program level[13]. Utilities are expected to provide benchmarking analysis which supports their proposed plans and programs and demonstrates continuous improvement.

The OEB currently conducts total cost benchmarking for electricity distributors. An econometric model is used to generate efficiency rankings and assign electricity distributors to one of five groups based on their total cost performance, including both capital and OM&A costs. These results are used to set the productivity stretch factors for the incentive rate-setting mechanism (IRM) applications, and will also be a consideration in assessing a utility's cost trend performance. An electricity distributor is expected to provide a forecast of its efficiency assessment using the model for the test year. This provides the OEB with a directional indicator of efficiency.

Utilities are generally not required to present total cost benchmarking analysis as part of their applications, unless they have been ordered to do so through an OEB decision. Two other types of benchmarking are required in rate applications:

- External benchmarking to analyze specific measures or specific programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group
- Internal benchmarking to assess continuous improvement by the utility over time

Benchmarking need not be limited to unit cost benchmarking (e.g. the capital cost of a billing system per customer or the cost of cable or pipe per km). Performance benchmarking in areas such as reliability or other outcomes may also be appropriate. What is important is that the utility explains how it has interpreted the benchmarking and what actions it has taken as a result of it.

With the Custom IR rate setting options, a utility can customize the rate setting mechanism for their specific circumstances. Given this flexibility, the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term. When determining what areas to benchmark, a utility should consider the following potential criteria:

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[13] Such as cost per pole replacement or billing costs per customer

- Key areas where the utility's performance is considered particularly strong or particularly weak
- Areas where expenditures are a key driver for the revenue requirement
- Areas that have been targeted for specific programs
- Areas where the OEB has expressed concern in past decisions
- Areas related to performance metrics and/or performance scorecard measures
- Linkages to customer engagement analysis

Utilities are expected to present objective, well researched benchmarking information, supported by a high quality and thorough analysis (using either third party or internal resources) that can be rigorously tested.

In reviewing benchmarking, the OEB will consider:

- **The structure of the benchmarking and the comparators used**
- **The quality of the benchmarking**
- **The linkages between the results of the benchmarking and the proposals in the rate application**

OM&A and Compensation Expenses

Under the RRF, the OEB has adopted an outcomes-based approach to regulation. As a result, the review of OM&A expenses will focus on the examination of outputs and programs, and whether there is evidence of continuous improvement, rather than the discrete line items or inputs to the OM&A budgets.

In addition, because employee compensation costs are already reflected in the proposed capital and operational programs, a detailed presentation of compensation is not necessary for the OEB's consideration of the proposed program costs to achieve the expected outcomes. The OEB does expect a utility to provide a description of its compensation strategies and policies (e.g. how salary scales are set and reviewed, how target salaries are compared to external benchmarks, performance pay structures, and the board of directors oversight process) and to clearly explain the reasons for all material changes to head count and compensation, and the outcomes expected from these changes. A utility should demonstrate clearly the linkages between its compensation strategies and policies and utility performance. Additional requirements for particular utilities may also arise from specific OEB directions in prior proceedings.

In reviewing a utility's proposed expenses for OM&A and Compensation, the OEB's key considerations are:

- **Have the costs been paced at the rate of inflation, and if not, what is the rationale for increased costs**
- **If the rationale for increased costs is customer or load growth, what is the relationship between increased costs and that growth**
- **A focus on strategy and results, not activities**
- **The need to demonstrate sustainable continuous improvement**
- **The outcomes that are expected from the proposed expenses**

Bill Impacts

The OEB is sensitive to customer concerns about energy bills. Customers are entitled to reliable service at reasonable rates. The OEB has adopted a number of policies to drive further efficiencies and to ensure utilities are focussed on providing value to customers. Customer needs and expectations, the pacing and prioritization of investment, and utility performance over time and in comparison to peers are all factors that the OEB considers, and are intended to drive effectiveness and continuous improvement. Utility proposals and plans ultimately translate into customer rates and bills. Rate changes and bill impacts are a particular focus of customers, and of the OEB. The OEB will hold utilities accountable to justify the bill impacts of their proposals; effective cost control will be expected.

Importantly, each utility can choose the rate-setting approach that best suits its particular needs. A utility is expected to tailor its proposals to meet the requirements of increased investment along with the requirements for enhanced productivity, cost control, and continuous improvement to create an appropriate rate profile.

In reviewing proposals in rate applications, the OEB will assess:

- **How the utility has considered total bill impacts in its planning**
- **How the utility has demonstrated the responsiveness of its expenditure plans to the need for stable and reasonable rates for customers**
- **Whether the pacing and prioritization of planned work is appropriate in light of the bill impacts of carrying out necessary investments**
- **What the bill impacts are for only those components of the bill that are within the control of the utility (no pass-through items)**
- **Whether any mitigation is warranted**

Mergers, Acquisition, Amalgamations and Divestitures (MAADs)

The OEB has issued a *Handbook to Electricity Distributor and Transmitter Consolidations*[14] that makes clear that rate setting is generally not a consideration in reviewing a consolidation through a merger, acquisition, amalgamation or divestiture. In the first cost of service or Custom IR application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction, including a rate harmonization plan and/or customer rate classifications post consolidation.

This will include consideration of:

- **The treatment of any premium above book value paid as part of a consolidation (no premium is to be recovered from customers).**
- **The savings that have been generated through the consolidation.**
- **Whether there were any inducements or incentives beyond the purchase price to encourage a shareholder to agree to the consolidation and if so whether there is any intent to recover the costs of those inducements or incentives from customers. Any costs incurred will be reviewed to ensure that the costs incurred are delivering the best value to customers.**
- **Whether the rate harmonization plan includes a detailed explanation and justification for the implementation plan, and an impact analysis. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. Regardless of the option adopted, the OEB will assess whether the proposed harmonized rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.**

Non-Regulated Activities and Affiliate Transactions

As noted previously, the business plan filed with the rate application is not necessarily the corporate business plan for the utility. There may be aspects of the corporate business plan that are not relevant to the OEB’s review of a rate application. The OEB will consider non-regulated activities and transactions with affiliates in the context of their effect on the regulated rates to customers to ensure there are no cross subsidies that negatively affect these regulated customers.

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[14] January 19, 2016

Depending on the corporate structure of the utility, this could include an assessment of:

- **The reasonableness of the costs allocated to non-regulated activities within the regulated utility**
- **The costs to be charged to the regulated utility from an affiliate**
- **The revenues forecast to be received from an affiliate for services provided by the regulated utility**
- **Whether these activities affect the quality of services to be delivered to the customers of the regulated utility**
- **Whether non-regulated activities will affect the financial viability of the regulated utility, or introduce a significant enough risk that it affects debt financing costs**

6. Rate-Setting Options

The OEB's approach to rate regulation has evolved over time to create better incentives to drive utilities to improve their efficiency in a way that benefits both customers and shareholders. Performance-based regulation under the RRF is the framework for rate-setting. This is consistent with broader trends amongst regulators around the world to shift rate regulation from a process of simply recovering costs to one of driving improved utility performance through incentives.

The OEB has developed a set of rate-setting options[15] to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. Each of the methods also includes incentives and benefits for customers related to continuous improvement and productivity.

Electricity Distributors

To support the move to an outcomes based approach, the OEB recognized the need to provide flexibility in rate setting options to give utilities the necessary tools to develop business plans that meet their needs. The RRFE established three incentive rate-setting (IR) methodologies for electricity distributors: Price Cap IR (previously known as 4th Generation IR), Custom IR, and the Annual IR Index.

- Price Cap IR: Under this methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula specific to each year. For electricity distributors, the formula includes an industry-specific inflation factor and two factors for productivity. One productivity factor is a fixed amount for industry-wide productivity and the other is a stretch factor, which is set each year based on the level of productivity the electricity distributor has achieved.

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[15] There are rate setting options under the RRF that take into consideration actual or forecast costs, including both cost of service and custom incentive rate-setting; also called rebasing applications. Other rate-setting options, such as revenue cap and price cap incentive rate-setting, decouple the rates from costs.

- Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.

- Annual IR Index: Under this methodology, rates are subject to the same annual adjustment formula as those under Price Cap IR. Utilities under the Annual IR Index are not required to periodically set base rates using a cost of service process, but they are required to apply the highest stretch factor. This approach is the most mechanistic of all rate applications. These utilities are required to provide five-year distribution system plans as a reporting requirement every five years, and like all other distributors will continue to report their performance using the OEB's Performance Scorecard. This will allow the OEB to determine whether the planning process and level of investment is adequate and whether service levels remain appropriate.

Electricity distributors may choose from any of these three methodologies. There are no eligibility requirements for any of these methods, but the rate application must meet the requirements of the rate-setting option. Those requirements are set out in the OEB's RRFE Report, in the filing requirements and in this Handbook.

Electricity Transmitters

Electricity transmitters may choose either Custom IR or a Revenue Cap IR. The Revenue Cap IR methodology is similar to the Price Cap IR option discussed previously for distributors. Individual rates are not set for each transmitter. The revenue requirement for each transmitter is approved by the OEB and this is used to set uniform transmission rates that apply throughout the province. Therefore, instead of a Price Cap IR option, a transmitter can propose an incentive mechanism for adjusting its revenue requirement in a similar manner.[16]

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[16] As set out in Chapter 2 of the *Filing Requirements for Electricity Transmitter Applications*, electricity transmitters will be permitted a final cost of service proceeding as a transition mechanism, and that proceeding will incorporate certain elements and principles of the RRF (including customer engagement, benchmarking, and a transmission system plan).

Natural Gas Utilities

Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

Ontario Power Generation

The OEB established expectations that payments for OPG will be based on Price Cap IR for the hydroelectric business and Custom IR, based on the RRFE principles, for the nuclear business. The OEB may set out its expectations for future applications in its next decision and order for OPG.

Specific Considerations for Custom Incentive Rate setting

The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended. A Custom IR application is by its very nature custom, and therefore no specific filing requirements have been established. However, any utility filing a Custom IR application should be informed by the cost of service filing requirements and this Handbook. The sections that follow set out the OEB's minimum standards for certain key elements of Custom IR applications.

There is no threshold test or eligibility requirement for a Custom IR application. The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards:

- Term: A Custom IR must have a minimum term of five years. The OEB has determined that this term supports a longer term approach to planning to smooth expenditures and pace rate increases, strengthens efficiency incentives and supports innovation. Longer terms can be proposed with appropriate mechanisms for consumer protection as discussed below.

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed below) and earnings sharing but could include other approaches specific to a utility’s circumstances.

For electricity distributors, the OEB has established an off-ramp that involves a threshold above the distributor’s approved return on equity at which a regulatory review may be triggered.[17] An electricity distributor can propose an alternative threshold that provides greater protection for customers. Other utilities may propose an off-ramp that takes into consideration the OEB’s objective of protecting customers from excess earnings.

The OEB does not require a Custom IR to include an earnings sharing mechanism, except in the context of deferred rebasing periods as part of electricity distributor consolidation[18]. While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred. The requirement for a custom index ensures that benefits are shared immediately with customers through productivity commitments.

If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

If a Custom IR application does not meet all of these requirements, the OEB may impose a reduced term, reject the application or determine that an application is incomplete and will not be processed until the requirements are met.

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[17] This policy was reaffirmed in the RRFE Report.

[18] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015

7. Rate-setting Policies

The OEB has a number of accounting and rate-setting policies that are applicable to rate applications. Appendix 3 includes summaries of these policies. The OEB expects to update this appendix as more policies are developed. Utilities and stakeholders should consult the relevant policy documents (which are available on the OEB website) for detailed information.

Appendix 1: Excerpts from the *Ontario Energy Board Act, 1998*

This appendix sets out the key legislative provisions related to rate setting for natural gas and electricity.

Statutory Objectives

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

1.1 To promote the education of consumers.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer’s economic circumstances.

4. To facilitate the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

Board objectives, gas

2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.

2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

3. To facilitate rational expansion of transmission and distribution systems.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

Natural Gas Rate Setting

Order of Board required

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

Order re: rates

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.

Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

Burden of proof

(6) Subject to subsection (7), in an application with respect to rates for the sale, transmission, distribution or storage of gas, the burden of proof is on the applicant.

Electricity Distribution and Transmission Rate Setting

Orders by Board, electricity rates

Order re: transmission of electricity

78. (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.

Order re: distribution of electricity

(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract.

Rates

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.

Burden of proof

(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.

Ontario Power Generation Payment Setting

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. .

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section.

Appendix 2: Glossary of Terms

Advanced Capital Module

The Advanced Capital Module (ACM) is an evolution of the Incremental Capital Module (see below). The ACM improves the regulatory efficiency for the review and approval of proposed incremental capital expenditures. An ACM proposal is made during a cost of service application to identify, based on the 5-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth. Reviewing ACM projects as part of a cost of service application allows for testing of the need, pacing and prioritization of projects as part of the more comprehensive review that occurs in processing a cost of service application. However, rate riders to fund ACM projects only come into service when the assets enter service during the IRM period.

Annual Index Rate-setting

The Annual Index Rate-setting method is a variation on the Price Cap IR method that is suitable to utilities with very stable investment expectations; these will typically be experiencing little growth and where investments are largely stable and to replace existing assets at end-of-life. A utility under the AIR has rates adjusted by the Price Cap IR method, but where the stretch factor is set at the highest amount. However, a utility under the AIR does not have to periodically rebase rates through a comprehensive cost of service review unless and until its circumstances change.

Capital Expenditures

Capital expenditures are amounts spent by a utility to acquire or enhance fixed assets, such as land, buildings, and major equipment. When the asset is ready to be used, the expenditure is added to rate base as a capital addition. The expenditure is then recovered through rates over the life of the asset.

Capitalization Policy

Capitalization policy is the accounting policy used to determine whether money spent in a given year should be treated as a capital expenditure or as an operating, maintenance and administrative expense. If the amount is determined to be part of capital expenditures, then the amount is added to rate base (capitalized) and recovered gradually over time.

Conditions of Service

Electricity and natural gas distributors are required by the OEB to describe their customer-facing operating practices in a Conditions of Service document. This document includes topics such as connection policies, security deposits, and opening or closing accounts. Each distributor must ensure that its Conditions of Service is public and readily available to customers.

Conservation and Demand Management

Activities and programs which are designed to reduce electricity use are known as Conservation and Demand Management, or CDM.

Cost Allocation

Cost allocation is the process of dividing a utility's total costs amongst different customer classes as fairly as possible. The objective is to allocate costs in a way that reflects how each customer class uses the utility's services. Once the costs are allocated to each customer class, the rates are set to recover those costs.

Cost of Capital

The cost of capital is the cost associated with the debt and equity which are used to finance a utility's business. The OEB sets the level of debt and equity in the capital structure. The OEB also sets the cost of debt (long-term and short-term) and the return on equity, based on market conditions and the risks utilities face. The cost of capital is included in rates, but a utility could earn a higher or lower return on equity, depending upon its performance.

Cost of Service

Cost of service is the total cost for a utility to provide service to its customers. A cost of service application is a detailed presentation of a utility's costs. The OEB reviews a cost of service application and decides the rates that a utility will charge its customers. The OEB examines the utility's operating, maintenance and administrative expenses and capital expenditures, as well as the expected number of customers and total amount of energy delivered. The cost of service does not include the commodity costs of the energy (natural gas or electricity); those costs are treated separately.

Customer Class

A customer class is a group of customers who use a similar amount of energy, or use energy in a similar way (for example, residential customers). A utility's total costs are divided among the customer classes to set rates. The cost to serve each customer in a particular class is similar, and therefore it is fair for all customers in a class to pay the same rate.

Custom Incentive Rate-setting (Custom IR)

While the Price Cap IR option, along with options such as ICMs and ACMs should be adequate for most utilities, some utilities may find that their circumstances, such as high growth or significant capital investments, may not be accommodated adequately through the standard approach. Utilities with significant operating and capital expenditure needs may apply for a multi-year (minimum five years) Custom IR plan where rates are set for all years of the plan term.

Deferral and Variance Accounts

Variance accounts track the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower, then the extra money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the extra amount through future rates. A deferral account tracks the cost of a project or program which the utility could not forecast when the rates were set. When the costs are known, the utility can then request permission to recover the costs in future rates.

Demand Meter

A demand meter measures the maximum amount of electricity used in a set period of time, for example 15 minutes. The largest commercial and industrial customers have demand meters.

Demand Side Management

Activities and programs which are designed to reduce natural gas use are known as Demand Side Management or DSM.

Depreciation and Amortization

Depreciation and amortization are standard accounting practices. Depreciation is applied to tangible assets, like buildings, poles and computers, as a way to recover the cost of the asset gradually. Over the lifetime of a tangible asset, a portion of the total cost is treated as depreciation expense each year and recovered through rates. Amortization is like depreciation, but it is used to recover the costs of intangible assets like licences and goodwill.

Distribution - Electricity

Distribution is the final stage in the delivery of electricity from generators to customers. Distributors take electricity from the high voltage transmission system and convert it to lower voltages (below 50kV). Distributors then use equipment such as lines, poles, and meters to deliver the electricity to customers. The OEB licenses and sets the rates of electricity distributors.

Distribution – Natural Gas

Distribution is the final stage in the delivery of natural gas from producers to customers. Distributors take natural gas from the high pressure transportation system and reduce the pressure. Distributors then use equipment such as pipelines, compressors and meters to deliver natural gas to customers. The OEB sets the rates of natural gas distributors.

Distribution Rates

Distribution rates are the charges that recover a distributor’s own costs of providing distribution service, including operations, maintenance and administrative expense, depreciation, taxes, interest, and return on equity. A distribution rate typically includes a monthly fixed charge and a volumetric rate (a cost per unit of electricity used). The OEB approves the rates that a distributor can charge.

Feed-in Tariff (FIT)

Feed-in Tariff (FIT) is an Ontario government program offered to encourage development of renewable energy generation. Wind, water, biomass, biogas, landfill gas and solar generators are eligible for the FIT program. FIT participants enter into a long-term contract to sell electricity to the province at a guaranteed fixed price. The price is designed to cover project costs including a return on the investment.

Generation

Generation is the production of electricity from a fuel source. In Ontario, most electricity is generated at nuclear, hydroelectric, natural gas, wind, solar, and biomass facilities. Generation facilities are connected to the Ontario grid which delivers electricity to customers. Some generators are connected to the high voltage transmission system; others, typically smaller ones, are connected to the lower-voltage distribution system.

Incentive Regulation

The OEB sets rates using incentive regulation. Incentive regulation is a set of tools or methods which encourage utilities to become more efficient in ways that will benefit customers through better service and lower rate increases. The shareholders of the utilities also have the opportunity to benefit from efficiency improvements through higher earnings.

Incremental Capital Module

The Incremental Capital Module (ICM) is a capital tracker mechanism which allows for funding of significant capital investments for discreet projects during the period of incentive regulation between cost of service applications to rebase rates. Any qualifying ICM capital project must satisfy a materiality threshold to determine that the incremental capital amounts are beyond the normal level of capital expenditures expected to be funded by rates, including the effect of customer and load growth. An ICM request is requested and approved as part of a Price Cap IR application.

Interval Meter

An interval meter measures electricity use and transmits the data at regular intervals, for example each hour. Mid-size commercial and industrial customers have interval meters.

Licensed service territory

An electricity distributor’s licensed service territory is the area in which the distributor has exclusive authority to distribute electricity. Every electricity distributor in Ontario must be licensed by OEB, and the licence identifies the service territory. For example, Toronto Hydro-Electric System Limited is licensed to distribute electricity within the City of Toronto.

Loss Factor - Electricity

A small amount of electricity is used up through the process of moving electricity from generators to customers. A loss factor is an adjustment to rates to recover the cost of this electricity which is consumed during delivery. The loss factor is approved by the OEB.

Meter

A meter measures natural gas or electricity use, and the data is used to bill customers. A standard meter measures the amount of electricity or natural gas consumed on a cumulative basis. These meters are read periodically, for example bi-monthly.

MicroFIT

MicroFIT projects are very small renewable electricity generation projects, with capacity under 10 kilowatts. An example of a microFIT project is a rooftop solar installation on an individual house. The owner of the microFIT project is paid a fixed price for each unit of electricity generated during the contract period (typically 20 years). MicroFIT is part of the Feed-in Tariff (FIT) program which includes larger renewable electricity generation projects (see definition of Feed-in Tariff).

Monthly Service Charge

The monthly service charge is a fixed amount each month, regardless of usage. This charge is designed to recover the fixed costs of providing distribution services which do not vary with usage. Meters, poles, and wires are some examples of fixed costs. The monthly service charge is one part of a customer’s total bill; other parts of the bill may vary with usage.

Operating, Maintenance and Administrative Expenses

Operating, maintenance and administrative expenses are the costs associated with running a utility on a day to day basis. Examples of these costs include employee salaries, tools and equipment, and office expenses. Operating, maintenance and administrative expenses do not include costs associated with investment in assets, such as depreciation or interest payments.

Payments in Lieu of Taxes (PILs)

Most Ontario electricity transmitters and distributors do not pay Canadian corporate income tax. Instead, they make payments in lieu of taxes (PILs) to the Ontario government. PILs are calculated in the same way as corporate income taxes and are recovered through rates.

Price Cap

Price cap refers to the mathematical formula used to set how much a utility's rates can increase in a year when the utility is not having a full review of its rates. The formula ensures that a utility's rates will increase at a rate which is less than inflation. For most electricity distributors, rates are set for one year using a full review, and are then set for four years using a price cap formula.

Price Cap Incentive Rate-Setting

The Price Cap Incentive Rate-setting (Price Cap IR) is the standard formulaic method by which distribution rates are annually adjusted during the incentive rate-setting period between cost of service applications. The formula adjusts current rates for the following year by inflation in input prices (costs of production or service) less expected productivity improvements including a stretch factor (or consumer productivity dividend). The Price Cap IR is the standard rate-setting method for most electricity distributors between cost of service applications.

Rate Adder

A rate adder is an amount added to the base rate to provide advance funding for a special project which has been mandated by the OEB. When the project is completed and the final cost is approved by the OEB, the money collected through the adder will be deducted from the total cost. This adjusted total cost will then be recovered or refunded over time through rates.

Rate Base

Rate base is the total dollar value of all the assets used by a utility to provide energy service: wires, poles, meters, IT equipment, etc.

Rate Rider

A rate rider is an amount which is added to or subtracted from the distribution rate to recover or refund a specific amount of money for a temporary period, generally a year or less. Once the period ends, the rate rider stops.

Revenue Requirement

The revenue requirement is the total cost for a utility to provide energy service. It includes the cost of salaries, equipment, capital projects, depreciation, taxes, interest and a return on the equity invested by shareholders. The revenue requirement is used to set rates for customers.

Revenue Sufficiency/Deficiency

The revenue sufficiency or deficiency is the total amount by which a utility's revenue needs to decrease or increase from the current level to earn the revenue requirement. When the OEB sets new rates for a company, it compares the total revenue the company would earn using the current rates to the total revenue the company is entitled to earn. If there is a revenue sufficiency, it means the company would recover too much revenue under the current rates, and therefore rates need to be reduced. If there is a revenue deficiency, it means the company would not recover enough revenue under the current rates, and therefore rates need to be increased.

Revenue-to-Cost Ratio

The revenue-to-cost ratio is the relationship between the revenues from a particular customer class and the costs to serve that customer class. The ratio can be expressed as a decimal value, such as 0.90, or given as an equivalent percent value, such as 90%. For this example, a 90% revenue-to-cost ratio would mean that the customer class is paying 90% of the costs that the distributor incurs to serve that class. The revenue-to-cost ratio is one of the factors the OEB considers when setting rates. The goal is to have each class pay for the costs of serving it.

Service Reliability

Service reliability refers to the level of continuous service a utility provides without interruption or an outage. The OEB sets measures and standards which track the type and duration of outages for each utility.

Service Quality Indicators

Service quality indicators measure the level of customer service a utility provides. Examples of service quality indicators include meeting scheduled appointments, billing accuracy, and telephone response time. The OEB sets standards for key service quality indicators and monitors performance. Service quality indicators are not related to the number or duration of power outages (see definition for service reliability).

Smart Grid

The smart grid uses advanced information technology to improve communication to and from individual parts of the electricity system. The smart grid constantly monitors the system, making it more efficient. It can also detect and fix problems more quickly, thereby increasing reliability.

Smart Meter

A smart meter measures electricity consumption continuously, and transmits the data electronically. This data is used to charge for electricity according to the time of day (time-of-use rates). Residential and small commercial customers in Ontario have smart meters.

Specific Service Charges

Specific service charges are for certain extra services such as special meter reads, late payment interest, and legal letters. Each specific service charge is based on the cost to provide the service and is only charged if a customer uses the service. The costs to provide these services are not included in distribution rates, but they still must be approved by the OEB.

Tariff of Rates and Charges

The Tariff of Rates and Charges is a public document that lists the OEB-approved rates and charges for utility service. Utilities must use these rates and charges to bill their customers. Rates are listed for each customer class, along with other charges for a variety of specific services.

Transformer

A transformer is the equipment used to change the voltage of electricity. Most customers use electricity at low voltage, but electricity is transmitted over long distances at high voltage because it is more efficient. A transformer is used to reduce voltage before it is delivered to customers. A transformer can also be used to increase voltage, for example where an electricity generator is connected to the transmission system.

Transmission - Electricity

Transmission is an intermediate step in the delivery of electricity from generators to customers. Transmitters take electricity from generators and transmit it via high voltage transmission lines to distributors, where it is converted to lower voltages and provided to customers. The OEB licenses and sets the rates of electricity transmitters.

Transportation – Natural Gas

Transportation is the intermediate stage in the delivery of natural gas from producers to customers. Transporters take natural gas from the producers and transport it in high pressure pipelines to natural gas distributors who then deliver it to customers at lower pressures. The OEB sets the natural gas transportation rates for companies that operate only in Ontario.

Unmetered scattered load

Unmetered scattered load is a class of customers that use small amounts of electricity but have no meter. Examples include traffic lights, bill boards, bus shelters, and railway crossings. Rates for these customers are set on the basis of estimated consumption.

Volumetric Rate

A volumetric rate is a rate applied to each unit of electricity or gas that a customer uses. As a result, the more energy a customer uses, the higher the total charge. Some parts of the customer's bill are based on volumetric rates, for example the Electricity line. Other parts of the bill are fixed no matter how much energy is used.

Weather Normalization

Weather normalization is a mathematical adjustment to past energy usage data. This adjustment removes the impact of annual variations in weather to show what the usage would have been under normal (or long term trend) weather conditions. Utilities weather normalize data to better understand how other variables, such as energy efficiency, price, building structures and new technology impact demand. This helps utilities understand trends in energy consumption and develop more reliable forecasts.

Working Capital Allowance

The working capital allowance is the cash a utility needs in order to pay its operating, maintenance and administrative expenses during the time between when the utility spends money to provide service and when it receives payment from its customers. The working capital allowance is included in a utility's rate base.

Appendix 3: Rate-setting Policies

Accounting Standards

Utilities will use International Financial Reporting Standard (IFRS) as the basis for their regulatory accounting unless the OEB has approved another standard or the utility is eligible for Accounting Standards for Private Enterprises (ASPE)[19]. If an accounting standard other than IFRS is used and if the accounting standard relies on the approval of a regulator for the determination of certain costs (for example, capitalization of costs), then this must be disclosed to the OEB in the rate application.

Capital Funding Options

During the IRM period, it is expected that a utility should manage both its capital and operating expenses to service current and new customers while maintaining its financial viability and delivering productivity improvements, in line with the “inflation less productivity” Price Cap IR adjustment. However, capital investments can be “lumpy”. To preserve the efficiency of the IRM process and avoid early rebasing or inefficiently timed capital investments aligned with the cost of service rebasing application, the OEB has provided for capital tracker mechanisms (e.g. the Incremental Capital Module and the Advanced Capital Module developed for electricity distributors). These allow for approval and funding recovery of qualifying capital investments during the IRM period between cost of service rebasing where material capital investments that are beyond what is normally funded through rates can be reviewed and approved without requiring an early rebasing. The ICM was established in 2008 as part of the 3rd Generation IRM, but it and the ACM have evolved as a result of the OEB’s review. The OEB’s policies on the ICM and ACM are documented in two OEB reports.[20]

Natural Gas Demand Side Management (DSM) Costs

Natural gas distributors may apply to the OEB for funding to support the design and delivery of broad-based DSM plans. The OEB’s policy document for gas utility DSM plans (the DSM Framework[21]) provides the basis for any application that seeks approval of amounts related to DSM programs. Natural gas distributor DSM plans are made up of individual programs for certain customers and are aimed to reduce overall natural gas

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[19] *Report of the Board: Transition to International Financial Reporting Standards*, July 28, 2009 and *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011.

[20] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

[21] EB-2014-0134

consumption and increase the efficiency of equipment and technologies that use natural gas. OEB-approved DSM funding, which is used to support program design, delivery, implementation, marketing and administration, is approved by the OEB under Section 36 and is recovered by the gas utility from its customers through distribution rates.

Electricity Conservation and Demand Management (CDM) Costs

Electricity distributors may apply to the OEB for CDM funding for the purpose of deferring the capital investment for specific distribution infrastructure. The OEB's policy document for electricity distributor CDM (the CDM Requirement Guidelines[22]) provides guidance for electricity distributors seeking approval of any such proposal. Electricity distributors may pursue activities such as electricity conservation and energy efficiency programs, demand response programs, energy storage programs and programs aimed at reducing distribution losses. The primary goal of these activities must be for the purpose of deferring the capital investment for specific distribution infrastructure. Any OEB-approved funding is provided under Section 78 and is recovered by the electricity distributor from its customers through distribution rates. For all other CDM related programs, including general customer-focused electricity conservation and energy efficiency programs, electricity distributors must enter into contractual agreements with the IESO. These programs are not funded through distribution rates

Cost Allocation

Cost allocation is the process used to determine how a distributor's total revenue requirement will be attributed to each customer class. The guiding objective is to allocate costs to the customers that cause the costs to be incurred. Although highly technical in nature, cost allocation also requires significant judgement.

The OEB's cost allocation policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors.[23] The OEB has established principles and approaches which address many of the issues which arise during the cost allocation process. Electricity distributors are encouraged to include cost allocation proposals which conform to the OEB's established policies. An electricity distributor (or any other party to a proceeding) may propose an alternative approach, but must provide sufficient evidence and analysis to support a determination that the alternative is a superior approach in the circumstances.

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[22] EB-2014-0278

[23] *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*, March 31, 2011.

Natural gas utilities, electricity transmitters, and OPG should support their cost allocation proposals with appropriate rationale, based on the OEB's historical approach to cost allocation issues for these utilities. Natural gas utilities, where applicable, must provide information on its regulated and unregulated storage operations and a description of the allocation of costs between regulated and unregulated storage.

Cost of Capital

Utilities have the opportunity to recover their cost of capital through their rates. The OEB sets the cost of capital using a formula-based approach, which has streamlined the regulatory process considerably.[24] The same approach is used for all utilities, and the results are predictable, stable and fully transparent. The general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically 5-years.

A utility applying for cost of capital under the OEB's policy is not required to provide supporting evidence for its return on equity proposal. The onus is on other parties to provide evidence to demonstrate that the policy should not apply. Support must be provided for debt costs proposals. A utility (or any other party to a proceeding) may propose alternative approaches, but must provide sufficient evidence and analysis to support a determination that the alternative is appropriate in light of the utility's circumstances.

Depreciation

Depreciation is the return of invested capital over the useful lives of these assets. Depreciation is a significant component of a utility's revenue requirement. While the calculation of depreciation expense can be a relatively mechanistic exercise resulting from assets in service and forecast to be in service, it relies on an appropriate study of the useful lives and componentization of the utility's assets[25]. This study will form an important supplementary part of the utility system plan. A utility can use a third-party for its depreciation study, but is not required to do so unless ordered by the OEB.

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[24] *Report of the Board on the Cost of Capital for Ontario`s Regulated Utilities*, December 11, 2009 and OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016 and associated OEB cover letter.

[25] Information that the OEB expects electricity distributors to consider is contained in the OEB's letter regarding *Depreciation Study for Use by Electricity Distributors, Consultant Final Report EB-2010-0178 – Transition to International Financial Reporting Standards* and the associated report by Kinectrics Inc. titled Asset Depreciation Study for the Ontario Energy Board, July 8, 2010 and the OEB's letter regarding *Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013*, July 17, 2012.

Regardless of how the work is completed, the study must be supported by high quality evidence and a thorough analysis that can be rigorously tested.

Natural Gas System Expansion

The OEB has issued specific guidelines for natural gas utilities' transmission and distribution system projects. The OEB's *Report on the Expansion of Natural Gas System in Ontario*, the E.B.O. 134 Report, forms the basis of the filing requirements on the economic feasibility tests to be applied to leave to construct applications for pipeline transmission projects. A natural gas utility must provide information of transmission projects in its capital plan and provide an assessment of the potential impacts of the proposed natural gas pipeline(s) on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of costs, rates, reliability and access to supplies.

The OEB issued its *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188) in January 1998. This report provides the criteria under which the OEB assesses the overall economic feasibility of distribution system expansion projects. A key principle of the guidelines is that existing ratepayers should be held harmless from rate impacts resulting from the cost of new connections. A utility as part of its capital plan must provide an assessment of all its distribution system expansion projects as per the *E.B.O. 188 Guidelines* and demonstrate that existing customers will be held harmless from the proposed distribution system expansion projects. This policy is currently under review by the OEB under proceeding EB-2016-0004.

Rate Design

Once costs are allocated to a particular customer class, rate design is the process used to develop the specific structure of rates to recover those costs. Although highly technical in nature, rate design also requires significant judgement and the consideration of broader rate setting principles in order to ensure fairness for customers and public interest outcomes.

The OEB's rate design policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors. The OEB has established principles and approaches which address many of the issues which arise during the rate design process. The OEB has also developed specific approaches to a number of specific rate design issues. One recent example is the change to residential rate design. The OEB's policy to re-design residential electricity distribution rates to be a fixed charge will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services. It is also a fairer way to recover the costs of providing electricity distribution service.[26]

Rate Mitigation

The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities. For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers[27].

Rate-setting Policies for Consolidations

On March 26, 2015 the OEB issued its *Report of the Board: Rate-Making Associated with Distributor Consolidation*. To encourage consolidations, the OEB established a policy that consolidating entities could defer rebasing for up 10 years. For electricity distributors deferring rebasing beyond five years, an earnings sharing mechanism (ESM) is required above ±300 basis points. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

Under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the OEB's reports.

To encourage consolidation, the OEB also extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.

On January 19, 2016 the OEB issued the *Handbook to Electricity Distributor and Transmitter Consolidations* (the MAADs Handbook). The MAADs Handbook provides

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[26] *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015.

[27] The OEB's August 14, 2014 Decision on the quarterly rate adjustment mechanism process for natural gas distributors (EB-2014-0199), determined that advance notification to customers would be required going forward and a mitigation plan must be filed if a 25% or greater change is anticipated on the commodity portion of a typical residential system supply customer's bill.

guidance to applicants and stakeholders on how the OEB will review applications for consolidation.

Working Capital Allowance

The (cash) working capital is the amount of cash that the utility requires to cover cash outlays in advance of when it recovers these amounts from customers. The working capital allowance is the allowance for this minimum amount of cash, reflected as capital not otherwise available for investment in assets that is factored into the determination of rate base.

The cash working capital requirements or working capital allowance is traditionally determined through a study that examines cash outlays and cash receipts and the leads and lags between the outlays and receipts.

For electricity distributors, the OEB currently allows for a working capital allowance of 7.5% of total operating expenses plus the cost of power[28] A distributor may propose an alternative which must be supported by a lead-lag study. Natural gas distributors, transmitters and OPG use utility-specific working capital allowances based on studies.

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[28] The OEB letter regarding the *Allowance for Working Capital for Electricity Distribution Rate Applications*, June 3, 2015, provided an update to the OEB's policy for the calculation of the allowance for working capital for electricity distribution rate applications.

TAB 27

3 PROPOSED ICM PROJECTS

This Decision considers whether Alectra Utilities should be able to charge customers rate riders to fund specific incremental capital projects during the IRM term or deferred rebasing period.

The OEB's policy for the funding of incremental capital is set out in the *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 (ACM Report)[8] and the subsequent *Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report* (Supplemental Report) (collectively referred to as the ICM policy). The OEB provided further policy direction for the availability of incremental capital modules following a merger in the *Report of the Board Rate-Making Associated with Distributor Consolidation* (MAADs policy)[9] and in the *Handbook to Electricity Distributor and Transmitter Consolidations* (MAADs Handbook).

Alectra Utilities' application included a request for incremental funding for five ICM projects, three within the PowerStream RZ and two within the Enersource RZ.

The OEB first addresses the overall eligibility for ICM funding and the criteria that must be met for incremental capital project funding. The OEB then assesses each of the five projects.

3.1 Overall Eligibility for ICM Funding

As set out in the OEB's ICM policy, the ICM is a funding mechanism available to electricity distributors whose rates are established under the Price Cap IR regime, as described in Section 3.3.2 of the Filing Requirements.[10] The OEB's ICM policy does not make ICM funding available for typical annual capital programs.[11] It is also not available for projects that do not have a significant influence on the operations of the distributor.[12] The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the Price Cap IR rate-setting plan which are incremental to a

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[8] EB-2014-0219

[9] EB-2014-0138

[10] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 3 Incentive Rate-Setting Applications*, July 12, 2018 ("IRM Filing Requirements")

[11] Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219, September 18, 2014, page 13

[12] *Ibid*, p. 17

materiality threshold.[13] The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed Distribution Supply Plan. It is not limited to extraordinary or unanticipated investments.

In order to qualify for ICM funding, a request must satisfy the eligibility criteria of materiality, need and prudence, as set out in section 4.1.5 of the ACM Report. Changes to the materiality threshold were made in the Supplemental Report.[14]

Materiality

There are two materiality tests related to ICM applications. The first test is the ICM materiality threshold formula, which serves to define the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor".[15]

Alectra Utilities calculated the materiality thresholds for the two rate zones as follows:

- Enersource RZ has a maximum eligible incremental capital amount of $36.8 million, which means that its proposal to recover $10.7 million through the ICM for this rate zone is within the OEB's acceptable range.
- PowerStream RZ has a maximum eligible incremental capital amount of $22.1 million, which means that its proposal to recover $20.9 million through the ICM for this rate zone is within the OEB's acceptable range.

No party took issue with Alectra Utilities' calculation of the ICM materiality threshold for each rate zone.

The OEB adopted a second, project-specific materiality test in the ACM Report. The project-specific materiality test is as follows:

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project

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[13] *Ibid*, p. 4
[14] Supplemental Report, p. 19
[15] ACM Report, p. 17

> expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[16]

Alectra Utilities' application stated that each capital project was eligible for ICM funding, as each project was discrete and material.

OEB staff submitted that all of the projects met the second project-specific materiality test except for the PowerStream RZ – Barrie TS Feeder Relocation project. OEB staff indicated that this project represents 0.8% of the Alectra Utilities' total capital budget and in the OEB's decision on Alectra Utilities' 2018 ICM requests[17], the OEB did not approve projects of similar size, as they were not significant compared to the overall capital budget.

AMPCO, BOMA, CCC, EP, and SEC submitted that the Enersource RZ - Rometown Area Overhead Rebuild project and the PowerStream RZ – Barrie TS Feeder Relocation project were minor expenditures in comparison to the overall capital budget, and Alectra Utilities should be able to fund these projects through its normal capital budget.

EP also submitted that the PowerStream RZ – Bathurst Road Widening Relocation project was a minor expenditure in comparison to the overall capital budget.

SEC noted that the Enersource – Leaking Transformer project had high levels of spending in 2019 and less in the three subsequent years. SEC submitted that if Alectra Utilities balanced the spending over the four years, Alectra Utilities would be able to manage the program within its existing capital budget.

Alectra Utilities noted that the OEB has not defined the project-specific materiality threshold. Alectra Utilities submitted that there is no justification for the definition of project-specific materiality argued by OEB staff and intervenors. Alectra Utilities further submitted that it is unrealistic to expect Alectra Utilities to absorb a disallowance of $12.8 million for non-road allowance projects this year, in addition to the $27.4 million from 2018 ICM projects.

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[16] ACM Report, p. 17
[17] EB-2017-0024

Findings

The OEB accepts Alectra Utilities' calculations for the ICM materiality threshold based on the OEB's ICM formula in the ACM Report. This includes:

- Enersource RZ – maximum eligible incremental capital amount of $36.8 million
- PowerStream RZ – maximum eligible incremental capital amount of $22.1 million

This does not mean that all capital spending up to the maximum eligible incremental capital amount is eligible for incremental funding. The OEB has established other criteria so that the ICM does not become just a capital budget top-up to the ICM materiality threshold.

The OEB's findings on the project-specific materiality threshold can be found in the Eligibility of Individual Projects for ICM Funding section of this Decision.

Need

The ACM Report indicated that need must be established by meeting the following criteria:

- passing the Means Test
- the amounts must be based on discrete projects, and should be directly related to the claimed driver
- the amounts must be clearly outside of the base upon which the rates were derived.[18]

Under the Means Test, if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, then the funding for any incremental capital project would not be allowed. Alectra Utilities submitted that based on the accounts of its predecessor utilities, it had satisfied the Means Test in each rate zone.

No party took issue with Alectra Utilities passing the Means Test.

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[18] ACM Report, p. 17

Findings

The OEB finds that Alectra Utilities has passed the Means Test.

The question of need is further addressed in the Eligibility of Individual Projects for ICM Funding section of this Decision.

Prudence

The ACM Report specifies that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[19]

Findings

The assessment of each proposed ICM project follows in the Eligibility of Individual Projects for ICM Funding section. The OEB has not found any of the planned capital spending imprudent. The question is whether each project is eligible for incremental funding while rates are being set through an IRM mechanism.

3.2 Eligibility of Individual Projects for ICM Funding

Enersource RZ – Rometown Area Overhead Rebuild Project: $3.2 million

Alectra Utilities proposed ICM funding of $3.2 million to rebuild the assets in the Rometown area. Alectra Utilities stated that through enhanced overhead system inspections it had identified a number of overhead system areas that have deteriorated and require renewal. In contrast to the 2019 Pole Replacement Program, Alectra Utilities indicated that this Rometown project targets a defined system area with known substandard assets.

AMPCO, BOMA, CCC, EP, SEC and OEB staff submitted that the project should not receive ICM funding. These parties submitted that the project should be funded through Alectra Utilities' Overhead Distribution Sustainment investments, which include ongoing work programs such as the Pole Replacement Program, Overhead Switch Sustainment Program, and Overhead Rebuild Program. Specifically, OEB staff submitted that the

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[19] ACM Report, pp. 18-19

TAB 28

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0018** **Alectra Utilities Corporation**

VOLUME: **Technical Conference**

DATE: **October 8, 2019**

MR. WASIK: No, Mr. Oakley, but I would offer that there is a process we use with respect to addressing the cables.

And so all of the cables that we plan to address through this DSP are in areas where there has been failures or multiple failures.

So these cables have already been repaired and have already been addressed. We've got to the point where the backlog of the deteriorated cables is so bad that we're having a difficult time keeping up with addressing all those areas.

So most, if not all, of the projects that we have identified for cable replacement are in situations where rehabilitation or repair is no longer a viable option and the appropriate option is to replace it, and we've provided that analysis in each of the business cases for the cable replacements.

MR. OAKLEY: Okay, thanks.

If we could move along to G-Staff-26D.

MR. WASIK: One moment. I'm with you, Mr. Oakley.

MR. OAKLEY: Okay. Could you confirm that once you know the type of the cable, its installation configuration, like whether duct or direct buried, and if it has ever been injected, the only other cable condition factor Alectra considers is age. So age is really the unknown or the variable once you kind of know where the cable is and what it is made of?

MR. WASIK: So that previous reference that I showed you, in terms of our cable replacement approach, does look like -- does look at the type of cable, how it has been installed, the number of outage events it also includes.

So we also take into account the previous history of performance of that cable and the number of failures when considering prioritizing, identifying which areas to first focus on.

So in addition to age we do -- and the demographic of the cable we also do look at the previous location -- the previous failures, as well as the location, in terms of the number of customers and the various criticality of the cable to the system.

MR. OAKLEY: Okay, thanks. And just given that, could you confirm that Alectra and its predecessors would have had all that information for the respective underground cable fleets -- this is prior to amalgamation even -- so the required cable replacement rates for the forecast should have been known and anticipated for years prior to the amalgamations?

[Witness panel confer]

MR. WASIK: So Mr. Oakley, as we explained in the DSP, we have applied this particular process in Alectra uniformly. Relative to the predecessor utilities, some of this information was used, and so we were aware that there is a growing volume of underground cable that is coming due for renewal and we have planned properly to prepare and get ready to address that incoming increase, in terms of the number of cables.

TAB 29

G-Staff-89

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix E, Page 9

Kinetrics Inc. (Kinetrics) gave Alectra Utilities recommendations to improve its ACA methodology and practices as part of its ACA assurance review.

a) Please provide the timing and implementation plan for incorporating Kinectrics' recommendations into Alectra Utilities' harmonized ACA program.

b) Please quantify how implementing the Kinectrics recommendations will impact Alectra Utilities' future capital expenditure plans.

c) Please confirm that:

  i. Alectra Utilities does not have asset degradation curves; and

  ii. Alectra Utilities' adopted scoring approach is commonly used by utilities with limited failure statistics.

Response:

a) Alectra Utilities has begun to implement the recommendations included in Kinectrics' 2018 Asset Condition Assessment Assurance Review. The recommendations in the Report include: continued improvements in ACA model development; continued investment in collecting more data for each asset category; and leading the development of internal ACA systems and capabilities. Alectra Utilities has implemented plans to develop an Asset Data Register that will enable Alectra Utilities to capture, store and process asset failure information and diagnostics. The implementation of the Asset Data Register commenced in 2019, and will continue in 2020 in coordination with the implementation of Alectra Utilities consolidated Enterprise Resource Planning ("ERP"), Geographic Information System ("GIS") and Outage Management System ("OMS"). The full implementation of the Asset Data Register, will enable Alectra Utilities to gather necessary failure information in order to develop degradation curves for the utility. The Asset Data Register will also provide a centralized repository of data necessary to increase Data Availability Index ("DAI") required for the Asset Condition Assessment process.

b) Alectra Utilities cannot speculate nor quantify the changes, if any, that the continuous improvements which Kinectrics has recommended would impact future Asset Condition

Assessments completed by Alectra Utilities or future capital investment plans. In the 2018 ACA Assurance Review Report Kinectrics has stated, "…Alectra's ACA is aligned with good utility practices. The processes, methodologies, and results are appropriate in serving as the basis of identifying system sustainment needs."

c) i) Alectra Utilities clarifies that it has asset degradation curves that are based on a continuous function rooted in the assumption that asset failures increase with age. In the 2018 ACA Assurance Review, Kinectrics states: *"Where utility-specific empirically derived asset degradation curves are unavailable, this provides a good representation of service life."* Kinectrics continues to state that: *"In the absence of Alectra-specific statistics, use of the OEB TUL and Max UL values is reasonable, given that they are based on surveys of multiple utilities in Ontario, including some of the Alectra legacy utilities."* Alectra Utilities does confirm that at the time of the 2018 ACA development, it did not have Alectra Utility-specific degradation curves as the company formed in 2017 and continues to integrate systems, processes and standards.

ii) Alectra Utilities is in the process of developing a utility specific degradation curve. Further, as identified in response to c) i), Alectra Utilities utilizes an asset degradation curve based on a continuous function given by the Gompertz-Makeham Model, and applied with the Typical Use Life and End of Useful Life from the Ontario Energy Board's "Asset Depreciation Study".

TAB 30

AMPCO-60 Attach 1
Asset Renewal Rate

						Sustainment Strategy								
Asset Class	Population in ACA	# in very poor & poor condition in ACA	# at or Beyond End of Useful Life (EUL)	# in very poor & poor condition & at of Beyond End of Useful Life (EUL)	Data Availability Index % in ACA	Baseline Pace Quantity Per Year	Moderate Pace Quantity Per Year	Slow Pace Quantity Per Year	Historical Asset Quantity Replaced 2014 to 2018	Forecast Asset Quantity Per Year 2020 to 2024	Forecast Quantity Per Year 2020 to 2024 in very poor & poor condition	Forecast Quantity Per Year 2020 to 2024 beyond EUL	Forecast Quantity Per Year 2020 to 2024 in very poor & poor condition & beyond EUL
Padmount Transformer	79487	1700	797	85	95.0%	600	400	300	3669	550	550	317	317
Polemount Transformer	32123	1015	409	173	92.0%								
Vault Transformer	13345	283	752	43	80.5%								
Padmounted Switchgears	3389	586	65	60	94.7%	117	78	59	324	83	83	16	16
Overhead Switches	3889	330	147	147	100.0%	66	44	33	394	44	44	28	28
Overhead Conductors	16400	380	102	102	100.0%	76	51	38	2.1	0	0	0	0
Wood Poles	105569	8547	702	511	68.7%	1709	1140	855	4545	892	892	4	4
Concrete Poles	25340	1292	644	644	88.0%	258	172	129					
Primary XLPE Cables	21638	3156	1710	1647	100.0%	631	421	316	591	437	135	135	135
Primary PILC Cables	410	17	2	2	100.0%	3	2	2		0	0	0	0
Primary EPR Cables	91	0	0	0	100.0%	0	0	0		0	0	0	0
Station Assets													
Power Transformers	295	34	2	0	77.0%	N/A	N/A	N/A	9	0.4	0	0	0
Circuit Breakers	1271	406	30	24	72.6%	N/A	N/A	N/A	169	7.6	5.8	0	0
Station Switchgear	356	36	13	1	85.2%	N/A	N/A	N/A	38	1.8	0.6	0	0

TAB 31

G-Staff-69

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 107-110 of 438

Alectra Utilities provides the following tables on SAIDI and SAIFI metrics:

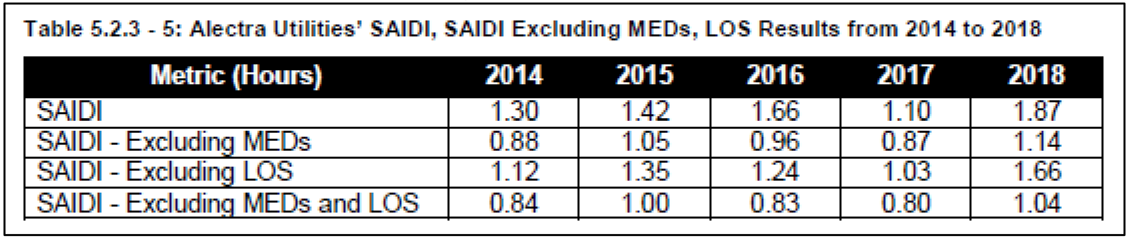


Table 5.2.3 - 5: Alectra Utilities' SAIDI, SAIDI Excluding MEDs, LOS Results from 2014 to 2018

Metric (Hours)	2014	2015	2016	2017	2018
SAIDI	1.30	1.42	1.66	1.10	1.87
SAIDI - Excluding MEDs	0.88	1.05	0.96	0.87	1.14
SAIDI - Excluding LOS	1.12	1.35	1.24	1.03	1.66
SAIDI - Excluding MEDs and LOS	0.84	1.00	0.83	0.80	1.04

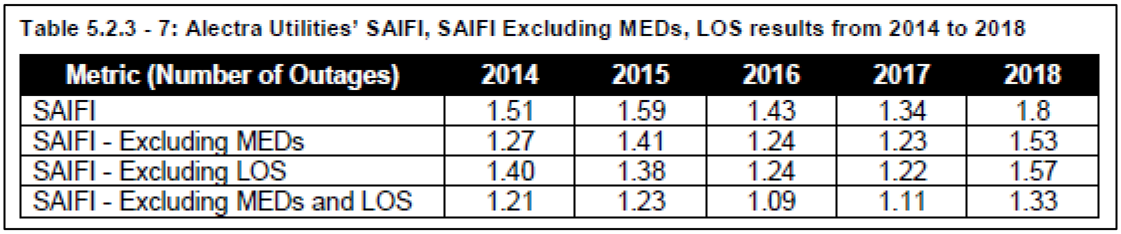


Table 5.2.3 - 7: Alectra Utilities' SAIFI, SAIFI Excluding MEDs, LOS results from 2014 to 2018

Metric (Number of Outages)	2014	2015	2016	2017	2018
SAIFI	1.51	1.59	1.43	1.34	1.8
SAIFI - Excluding MEDs	1.27	1.41	1.24	1.23	1.53
SAIFI - Excluding LOS	1.40	1.38	1.24	1.22	1.57
SAIFI - Excluding MEDs and LOS	1.21	1.23	1.09	1.11	1.33

Regarding the two tables, Alectra Utilities states:

> **Figure 5.2.3 - 2 and Table 5.2.3 - 5 illustrate an increasing system average interruption duration trend at Alectra Utilities (including its predecessors) since 2014. The five year SAIDI measure indicates a 16% increase on annual average system outage duration that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the 2018 SAIDI measure indicate a 8% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities.**

Additionally:

> **Figure 5.2.3 - 3 and Table 5.2.3 - 7 illustrate a trend of increasing system average interruption frequency at Alectra Utilities (including its predecessors) over the five year period from 2014 to 2018. The five year SAIFI measure indicates a 6% increase on annual average system outage frequency that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the SAIFI measure also indicate a 6% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities.**

a) **The 2018 reported SAIFI and SAIDI figures are higher than the previous years shown in the table. If a start date of 2014 and end date of 2017 are used, all reliability trends appear to be improving. In which year did the alleged trends in deteriorating reliability begin?**

b) **What factors caused the 2017 SAIDI and SAIFI measures to be low, and what factors caused the 2018 SAIFI and SAIDI measures to be high (relative to the 5 year average)?**

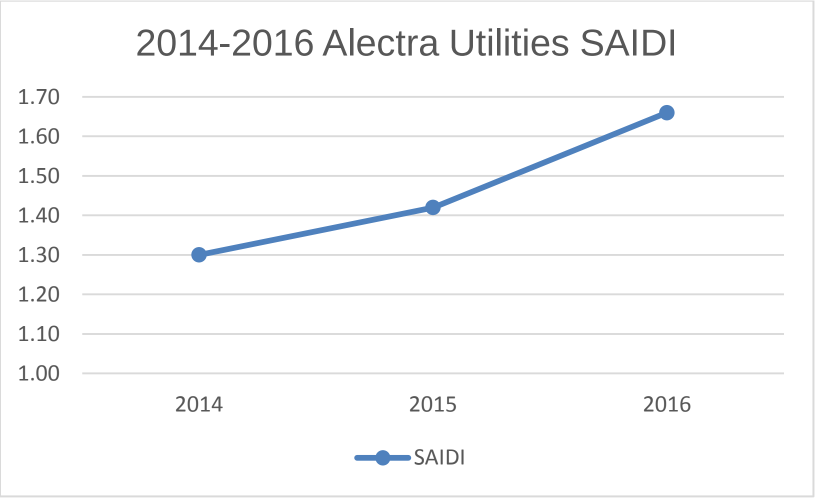
c) How does Alectra Utilities account for the variance in reliability metrics around the multi-year mean and the alleged signaling of an upwards trend?

d) Please provide 10 years of historical SAIFI and SAIDI data for Alectra Utilities and its predecessor utilities.

Response:

a) Alectra Utilities presents Figure 1, below, which provides the SAIDI results from 2014 to 2016. Based on the trends identified over this period, the deteriorating trends in reliability began in 2014 and continued through to 2016. Alectra Utilities' customers experienced better than average SAIDI results in 2017 and substantially worse than average SAIDI result in 2018.

Figure 1 - Alectra Utilities 2014-2016 SAIDI



b) Figure 2, below is a comparison of cause codes for 2017 and 2018 against the five-year average based on the number of customer interruptions (SAIFI).

Figure 3, below, provides a comparison of Customer Hours of Interruption (SAIDI) for 2017 and 2018 against a five year average.

Figure 2 and 3 clearly illustrate that outages as a results of Defective Equipment, Adverse Weather, Tree Contacts, Loss of Supply, as well as Unknown outages are higher in 2018 than 2017, as well as the 5-year reliability average.

Figure 2 -Number of Customer Interruptions 2017 and 2018 versus 5 Year Average

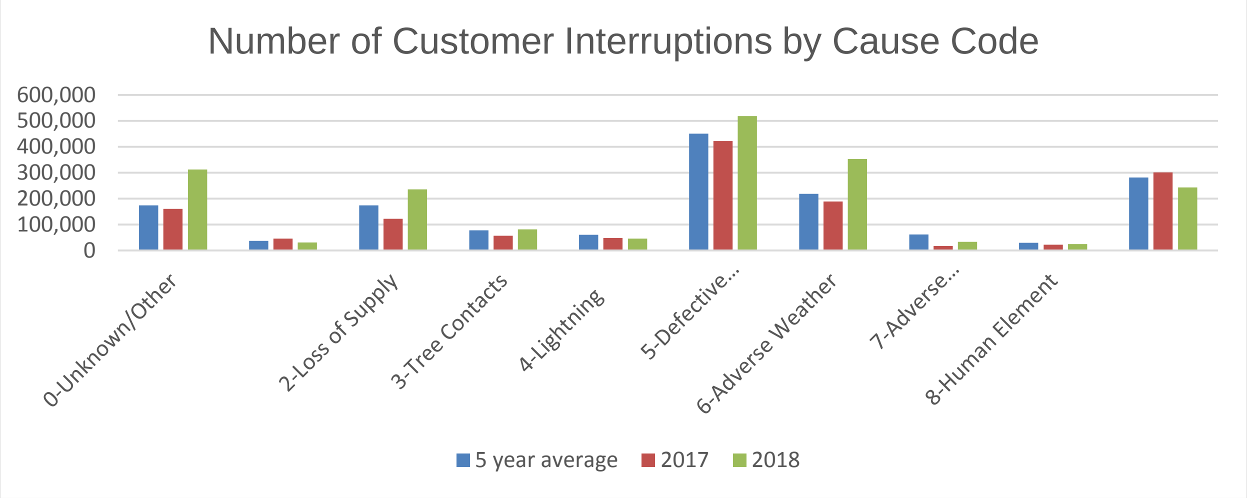
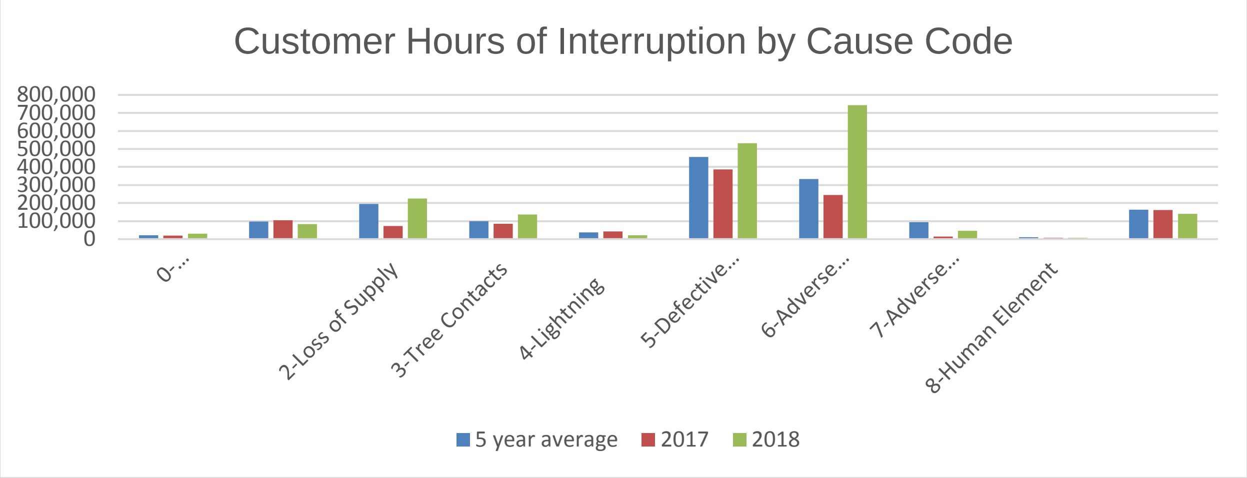


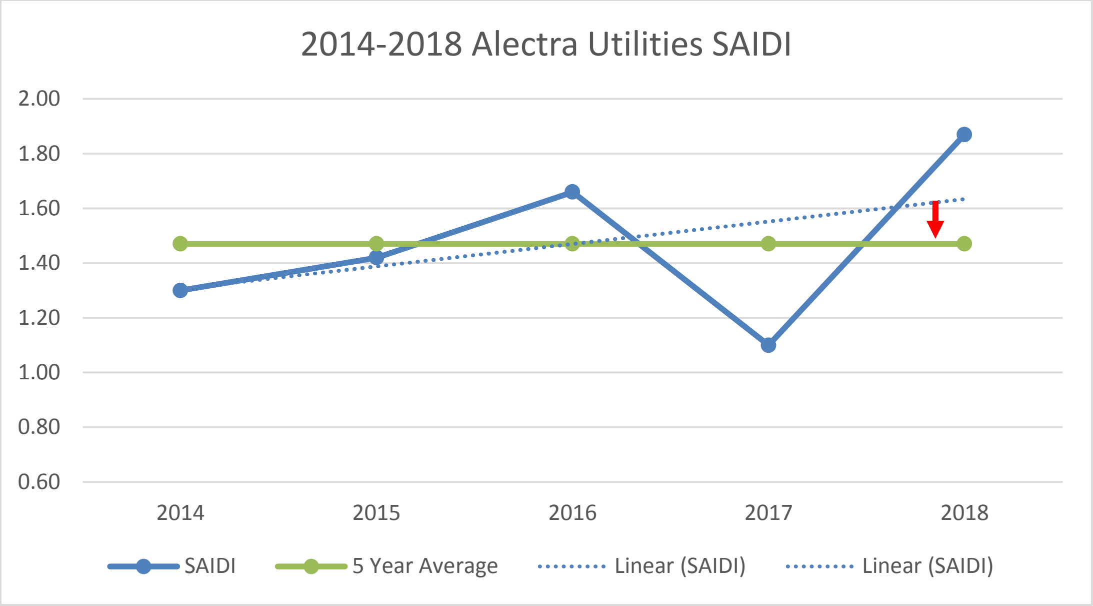
Figure 3 - Customer Hours of Interruption 2017 and 2018 versus 5 Year Average



c) Alectra Utilities reviewed the 5-year mean against the trend line prediction as provided in Figure 4, below. As described in Section 5.2.3, subsections C.1.1 and C.1.2 (Exhibit 4, Tab 1, Schedule 1, Page 107 to Page 111), through the implementation of capital investments proposed in the DSP, Alectra Utilities seeks to maintain reliability levels to historical (i.e. 5-year average) SAIDI and SAIFI levels.

For customers experiencing poor reliability beyond the system average, Alectra Utilities has established plans to address the deteriorated and failing distribution assets in order to improve reliability to a minimum of overall historical system levels, which reflects the needs, priorities and preferences of customers. As provided in response to part a), Alectra Utilities' customers have been experiencing a negative trend in worsening reliability. Alectra Utilities has assessed the root causes of the negative trend in reliability and has established plans reverse this trend by addressing the leading causes of outages (i.e. defective equipment and adverse weather).

Figure 4 - 2014-2018 Alectra Utilities SAIDI



d) The ten-year historical SAIDI of Alectra Utilities and its predecessors is provided in Table 1, below. The ten-year historical SAIFI of Alectra Utilities and its predecessors is provided in Table 2, below. For years prior to 2014 this data is based on the historical OEB Scorecards of Alectra Utilities' predecessor utilities.

Table 1 - SAIDI Hours for Alectra Utilities and Predecessor Utilities (2009-2018)

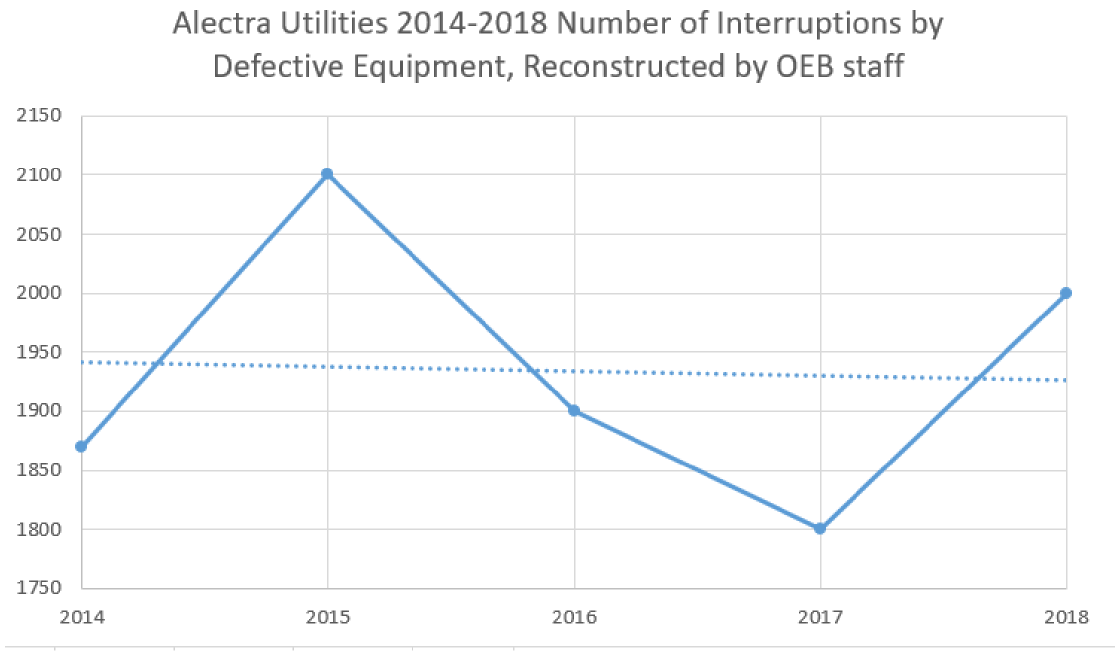
SAIDI - Hours										
Territories	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alectra Central South	0.57	0.55	0.72	0.70	5.34	0.67	0.72	0.81	0.71	1.72
Alectra Central North	0.72	0.46	0.68	0.76	10.46	0.57	0.72	0.45	0.48	0.72
Alectra West	0.69	1.15	2.23	1.45	4.97	2.18	1.77	1.64	1.47	2.96
Alectra East	1.59	0.54	1.05	1.16	10.67	1.45	1.99	2.74	1.44	1.95
Alectra South West	0.21	0.33	1.70	1.34	3.37	0.75	0.57	1.08	0.47	0.50
Alectra Utilities						1.30	1.42	1.66	1.10	1.87

Table 2 - SAIFI Hours for Alectra Utilities and Predecessor Utilities (2009-2018)

SAIFI										
Territories	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alectra Central South	0.92	1.10	1.54	1.71	2.72	1.13	1.64	1.13	1.20	1.94
Alectra Central North	1.03	0.76	1.05	1.27	3.64	0.95	1.22	0.72	0.70	0.94
Alectra West	1.12	1.55	1.74	1.95	2.09	1.91	1.92	1.98	1.86	2.85
Alectra East	1.07	0.80	1.00	1.70	2.49	1.71	1.52	1.41	1.35	1.48
Alectra South West	0.50	0.75	1.51	2.50	3.95	1.30	1.53	2.19	1.30	1.20
Alectra Utilities						1.51	1.59	1.43	1.34	1.80

TAB 32

Figure 1 – Alectra Utilities 2014-2018 Number of Interruptions by Defective Equipment, Reconstructed by OEB Staff to Include Linear Trendline[1]



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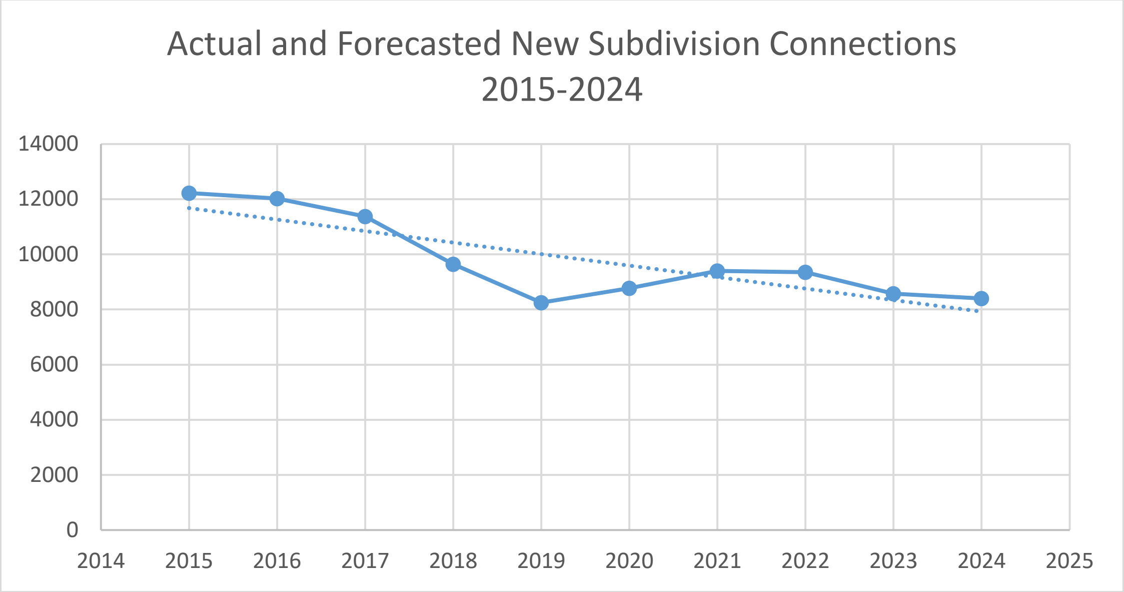
[1] Data is taken from Figure 1 in G-Staff-70 a)

TAB 33

Figure 1 – Alectra Utilities Actual and Forecasted New Subdivision Connections[1]



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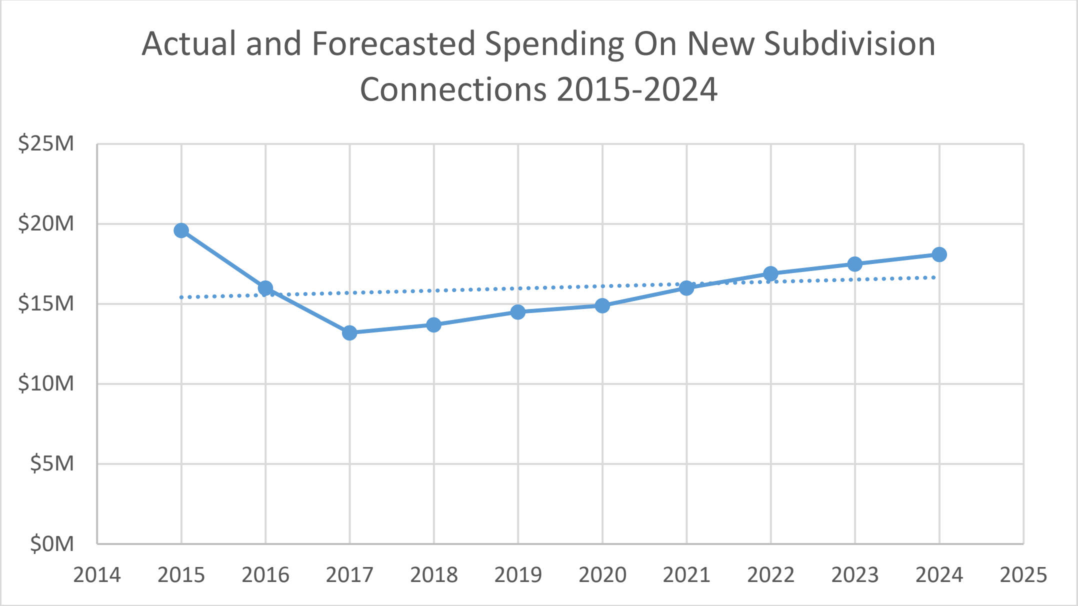
[1] Data is taken from Exhibit 4, Tab 1, Schedule 1, Appendix A02, Table A02 - 9

TAB 34

Figure 1 – Historical and Forecasted Spending on New Subdivision Connections 2015-2024[1]



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[1] Data is taken from Exhibit 4, Tab 1, Schedule 1, Appendix A02, Table A02 - 14

TAB 35

EP-24

Reference: Exhibit 04, Tab 01, Schedule 01, Page 8

Question:

a) **When did Downtown Mississauga start intensifying?**

b) **Is Alectra claiming that it needs "secure funding" to connect 6 buildings?**

c) **If the answer to (b) is yes, please provide a numerical analysis to support the claim that demonstrates that rates paid by the owners or occupants of the 6 buildings are inadequate to fund the connection.**

Response:

a) Major intensification started to occur in 2006 with the Provincial approved of the Places to Grow Act: the Growth Plan for the Greater Golden Horseshoe, which established the boundaries for urban growth and established Mississauga and City Centre as Urban Growth Centre with a target of 200 residents and/or jobs per hectare by 2031. The City center started to see major high-density residential development starting in 2010 and now has the second highest number of high density development in GTA.

b) Alectra Utilities has not claimed that it needs to secure funding to connect 6 buildings, rather, the six buildings referred to are an example of the rapid development and intensification occurring which requires Alectra Utilities to invest in its distribution system which includes feeders and stations necessary to support the downtown development needs as well as existing customers in that area. These investments enable Alectra Utilities to fulfill its obligations as a licensed distributor and provide normal and contingency supply in the growing areas and ensure reliability to existing customer in these areas of intensification.

c) Please see response to part b).

TAB 36

G-Staff-25

Reference: Exhibit 4, Tab 1, Schedule 1, Page 3 of 438

Regarding deterioration of underground cables, Alectra Utilities states:

> **A recent specific example underlying these trends is the York Hill/Hilda neighbourhood in Vaughan, which was scheduled for underground cable replacement in 2019 however from June 22 to July 13, 2018, approximately 250 customers starting experiencing an outage approximately once every three days during this period. Cables which Alectra Utilities repaired would fail again within a short duration. Alectra Utilities was ultimately forced to replace the cable in the area on an emergency basis at a higher cost and with greater disruption, causing further impacts to the affected customers.**

a) What were the initial causes of the failures, and were the subsequent causes of failures different from the initial causes?

b) Were the failures in close proximity to one another? Please provide details.

c) Were the cable segments that experienced these failures all of the same age?

d) Did Alectra Utilities do any additional analysis on the retired cable once it had been removed from service? If yes, what were the findings?

e) Did the performance of the cable correspond with the expected performance that Alectra Utilities models in its asset management program?

f) Please quantify the difference in cost of replacing the cable in 2018 rather than the estimated cost of the planned replacement in 2019.

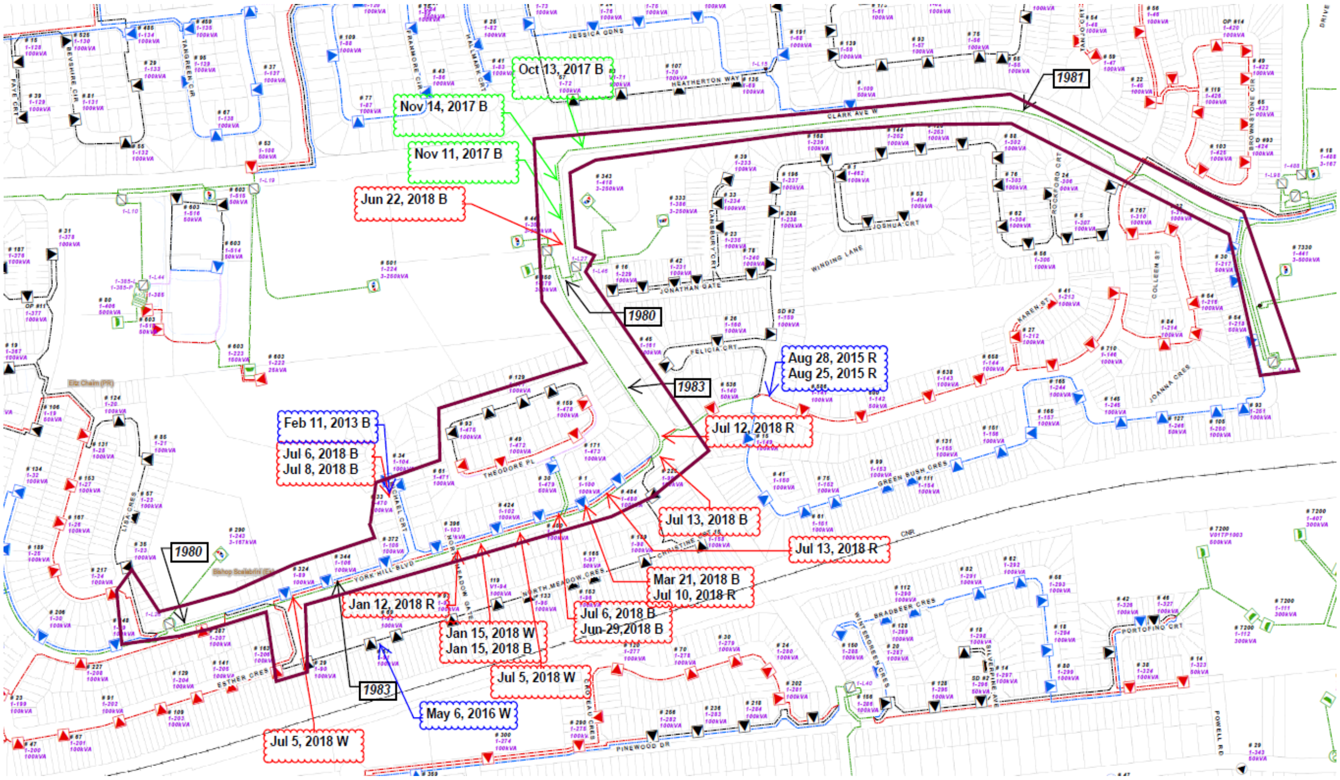
g) Please compare the actual outage duration in 2018 versus the estimated outage duration had the replacement taken place as planned in 2019.

Response:

a) The causes of failure at the York Hill/ Hilda neighbourhood included both cables and splices failures as the initial and subsequent causes.

b) Alectra Utilities has provided Figure 1 below to show where and when the cable and accessory failures occurred.

Figure 1 - Cable and Accessory Failures in the York Hill/Hilda Area



c) The cables were not all the same age, but of similar vintage, installed between 1980 and 1983.

d) Alectra Utilities did not perform additional analysis of the retired cables. The failed cable was consistent with segments previously analyzed by Alectra Utilities (and its predecessors).

e) The cable performance was between the Typical Useful Life (“TUL”) and End-of-Useful Life (“EUL”) of non-tree retardant direct buried cables.

f) In addition to the $3.8MM in capital investment required for emergency replacement of the cable, the work completed in at York Hill/Hilda in 2018 also required an additional $0.208MM in operating and maintenance cost related to excavation and repair of the deteriorated cable, prior to Alectra Utilities determining that the cable was no longer dependable and required replacement. A significant amount of effort was also required by the customer service and corporate communications group to address the increasing frustration and anger from the customers. In addition, Alectra Utilities had to reallocate capital from other projects in order to accommodate the emergency replacement, causing further disruption and rescheduling of work.

g) The 2018 CMI before Alectra Utilities intervened and replaced the cable was 427,537 minutes of interruption. Should Alectra Utilities not intervened and replaced the cable in the area, Alectra Utilities projects that the outages would have continued and increased in duration for the remainder of 2018. The forecasted reliability improvement in the business case for 2019 was 560,845 CMI, hence Alectra Utilities estimate of reliability improvement of the cable investment project as planned at York Hills and Hilda was very reasonable.

TAB 37

SEC-51

Reference

Presentation Day Transcript 1:55

Please provide evidence that reactive replacements on average cost three or four times more than planned replacements.

Response:

Alectra Utilities compared the costs of cable failures from 2014-2017 with planned cable replacements and found that reactive cost were 3.21 times higher then planned. Additionally, analysis of 2017 pole replacements under both reactive and planned scenarios identified that reactive pole replacement costs 1.96 times higher then planned. This analysis did not include indirect costs associated with reactive replacement, such as the cost impact of diverting labour resources from planned work to respond to unplanned reactive replacement work. If indirect costs were included, the reactive replacement compared to proactive replacement would be substantially higher.

Further, Alectra Utilities retained Vanry & Associates (‘Vanry”) to complete an assurance review of the 2020-2024 DSP. Vanry states in its report (Exhibit 4, Tab 1, Schedule 1, Appendix D) that:

> *“…in North American distribution sector that reactive replacement work is more costly than proactive replacement work by anywhere from 2 to 6 times.”*

TAB 38

JT1.5

Reference:

To prepare a description of the variance calculation between the revenue requirement for in-service capital additions and the amount collected by the rider for the CIVA proposal.

Response:

While the wording of this undertaking is unclear, for completeness, Alectra Utilities has prepared this response considering the issues raised by OEB Staff, found on pages 126-136 of the Technical Conference Day 1 Transcript from October 7, 2019. Those issues relate to the calculation of M-factor riders and annual billing determinants, and the interaction of those riders with the Capital Investment Variance Account ("CIVA").

In Alectra Utilities' proposal, the purpose of the CIVA is to track any variances between the forecast M-factor project revenue requirement and the actual revenue requirement of those projects over the 2020-2024 period, and to allow a future OEB panel to approve a return of any excess revenue to customers or recovery of any incremental revenue associated with those projects to Alectra Utilities.

During the Technical Conference, OEB Staff observed that billing determinants are updated annually for the most recent historical year, as part of a Price Cap-IR application. Alectra Utilities agrees. OEB Staff have proposed that the M-factor riders be calculated annually, as part of Alectra Utilities' annual Price Cap-IR application.

Alectra Utilities still seeks the OEB's approval of the full five-year M-factor project revenue requirement in this proceeding, as well as the related riders for each of the five years, by rate zone and rate class. In addition, consistent with the recommendation from OEB staff, Alectra Utilities suggests that a review of the calculation of the annual M-factor riders, by rate zone be included in the mechanistic Price Cap-IR application, such that the rider in each of 2021 to 2024 can be updated with the most recent billing determinants. For instance, in the application that Alectra Utilities files for 2021 electricity distribution rates, it would include a request to update its calculation of 2021 M-factor riders for the latest billing determinants available at the time (i.e., 2019 billing determinants). Any M-factor riders from prior years, in this example the ones that would already have been set to commence in 2020, would not be changed.

Alectra Utilities requires the M-factor in order to have flexibility on the timing/ implementation of M-factor projects. Given the annual fluctuations in billing determinants and potential variations in M-factor project costs, it is almost certain that the revenue collected through the M-factor riders will diverge, to some degree, from the M-factor revenue requirement approved by the OEB in this proceeding. Any such variances will be resolved through CIVA true-up riders that the OEB may establish in a subsequent proceeding, after it determines the appropriate treatment of any CIVA balance.

TAB 39

G-Staff-17

Reference 1: Exhibit 2, Tab 1, Schedule 3, Page 5 of 21
Reference 2: OEB Handbook for Utility Rate Applications, October 13, 2016, Page 27

On page 5 of 21, in describing the impetus for the M-factor, Alectra Utilities states that it "… has capital expenditure needs materially in excess of the level that which is presently funded in existing rates." Additionally, Alectra Utilities notes that the Custom IR option is not available during its deferred rebasing period, but that its "…evolving capital needs are analogous to those distributors whose capital programs have been funded through custom IR frameworks, accepted by the OEB."

The OEB's Handbook for Utility Rate Applications notes that: "The ICM and ACM mechanisms for funding capital for electricity distributors… are not available for utilities setting rates under Custom IR."

a) If M-factor funding is approved, please confirm that Alectra Utilities will not be seeking ICMs during the remainder of this DSP term (2020-2024).

b) If Alectra Utilities does intend to seek ICMs during this DSP term (2020-2024), please explain why this is appropriate given the nature of the M-factor and the similarities with the Custom IR option as described by Alectra Utilities.

c) If yes to a), please explain Alectra Utilities' plans in the event of large unforeseen capital spending needs.

Response:

a) Alectra Utilities confirms that if M-factor funding is approved, Alectra Utilities will not be seeking ICMs during the remainder of this DSP term.

b) Please see response to part a).

c) In order to mitigate risk for customers, and to address uncertainties in its future investment needs, Alectra Utilities is requesting approval to establish the following two capital related variance accounts. First is a symmetric Capital Investment Variance Account ("CIVA") to track the difference between the capital funding provided through M-factor riders and the actual M-factor capital investments during the term of the Distribution System Plan ("DSP"). Customers will be refunded for overall under-investment; any prudent spending above the level funded through M-factor riders will be recovered by Alectra Utilities. The second variance account is the Externally Driven Capital Variance Account ("EDCVA"), which would capture the difference between the revenue requirement in rates associated with externally-driven capital expenditures related to regional transit projects and capital works required by road authorities. Details of both variance accounts are provided in Exhibit 2, Tab 1, Schedule 4.

TAB 40

5.4.3 JUSTIFYING CAPITAL EXPENDITURES

5.4.3.1 OVERALL PLAN

A Overview

Alectra Utilities' capital expenditure plan demonstrates its measured and targeted approach to investment, which is guided by the company's strategy of prudently renewing its existing assets, investing in new assets only where necessary, investing in technology as a means to reduce the need for system expansion, and investing in new assets to meet customer and regulatory requirements. While Alectra Utilities will, over the 2020-2024 planning period, make capital investments in relation to each of the OEB's four investment categories to address its system needs and having regard to the priorities expressed by its customers, the focus during this period will be on (i) System Renewal investments to address deteriorated and failing infrastructure, as well as safety and reliability risks, and (ii) System Access investments to ensure system capacity to accommodate expected growth and new developments. Table 5.4.3 - 1 provides a summary of Alectra Utilities' planned investments over the 2020-2024 period.

Table 5.4.3 - 1: Summary of Capital Investments – 2020-2024

	Planned Expenditures ($MM)				
	2020	**2021**	**2022**	**2023**	**2024**
System Access	$66.5	$66.9	$63.2	$67.1	$70.2
System Renewal	$139.0	$142.0	$154.0	$156.1	$177.2
System Service	$38.0	$36.9	$36.0	$42.4	$37.2
General Plant	$39.4	$34.4	$35.1	$30.2	$24.7
Total	**$282.9**	**$280.2**	**$288.3**	**$295.8**	**$309.3**

This section provides

i. a summary of how historical and planned capital investments are allocated among the OEB's four investment categories (Section B),

ii. a discussion of the key investment drivers underlying the capital expenditure plan (Section C),

TAB 41

CAPITAL FUNDING MECHANISM ("M-factor")

Alectra Utilities is requesting approval for capital funding based on a rate-adjustment mechanism that reconciles the capital needs set out in the DSP with the capital-related revenue in rates, and associated 2020 to 2024 capital riders for each RZ, as follows.

Overview

Underlying the OEB MAADs Policy and Handbook is the notion that amalgamations are in the public interest because they lead to efficiencies and future rates that are lower than otherwise would occur with no amalgamation. The OEB has expressed that it is in the public interest to have amalgamated utilities operate as one as soon as possible:

> "The OEB remains of the view that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers." [Handbook, p. 13]

Having amalgamated in 2017, Alectra Utilities is in transition and moving from individual utilities to an integrated utility operating as one company both from an OM&A and capital planning basis.

Through the rebasing deferral period, there is an integration of operations to achieve efficiencies and OM&A savings, which is part of the underlying regulatory and policy rationale for consolidation and the deferred rebasing period of 10 years. The other key element of the transition from separate utilities to consolidated operations is capital planning integration. Alectra Utilities, as a newly formed company, has moved to integrate capital planning across its company and service territory, to use one planning platform and to allocate resources and personnel in the execution of the capital plan across the company.

Alectra Utilities is in the unique circumstance of being the first utility arising from a consolidation of multiple utilities to file a five-year DSP in the midst of its rebasing deferral period rather than at its conclusion, as required by the OEB in Alectra Utilities' 2019 EDR Application Decision.[18] This circumstance is unique not just because Alectra Utilities is the first utility to do so, but also because of the rate making implications of presenting such a plan during the rebasing deferral period. While the DSP is based on a system wide consideration of Alectra Utilities' capital investment

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[18] Decision and Order, April 6, 2018, EB-2017-0024, p. 2.

TAB 42

> typical annual capital programs. It is also not available for projects that are not significant to the operations of the distributor. Where the OEB has not approved a project for incremental funding, this should not be interpreted as the OEB saying that it is not prudent to complete the project.[23]

Over the five-year term of the DSP, Alectra Utilities plans to invest approximately $768MM in System Renewal. These investments are needed to be responsive to customer expectations that Alectra Utilities maintain the reliability of its system. The DSP provides detailed evidence on the prudence of the planned investments, including the need to execute them over the 2020 to 2024 period, in order to prevent reliability from declining further. These investments cannot be funded under the current ICM. The funding deficiency is not sustainable over time and is to the detriment of Alectra Utilities' customers.

In recent years, Alectra Utilities has been required to defer a significant amount of System Renewal investments to accommodate other mandatory expenditures. In particular, the utility has been required to defer renewal investments to accommodate large System Access projects. In 2015, System Access investments comprised 18% of the overall capital investments made by the company's predecessor utilities. This increased to 30% as of 2019 as a result of significant investments required in road authority projects. Decreasing reliability in that same period is due in part to the deferral of renewal investments. The M-factor will provide Alectra Utilities with the flexible funding basis necessary to execute both mandatory work and critical system renewal during the 2020 to 2024 period. The M-factor will allow Alectra Utilities to renew the assets that are leading to declining reliability, safety and other performance issues, while continuing to provide the utility with a reasonable opportunity to realize the synergies that underpinned its creation.

2. Regulatory- and Cost-Efficiency

Funding capital investments through the M-factor creates significant efficiencies for the OEB and for the utility. By establishing a mechanism to fund prudent capital expenditures based on a DSP over a five-year period, annual incremental capital proceedings are avoided. There would be a cost saving and OEB resources could be redirected to address other matters before the Board. Without an M-factor, Alectra Utilities will need to continue to file significant applications with the

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[23] EB-2017-0024, Decision and Order, April 6, 2018, p. 30.

TAB 43

5.7.3 XLPE (Cross-Linked Polyethylene) Cables

5.7.3.1 Asset Class Demographics

Alectra’s distribution system has 21,638 km of primary underground XLPE cable. XLPE cables are three types each having different expected useful lives as follows:

- **Non Tree Retardant cables (NON TR)**:
  Vintage 1988 or older; TUL 30 years; EUL 40 years
- **Tree Retardant Direct Buried cables (TR-DB)**:
  Vintage 1989-1993; TUL 35 years; EUL 45 years
- **Tree Retardant or Strand Blocked In-Duct cables(TR-ID):**
  Vintage 1994 or newer; TUL 40 years; EUL 55 years

Figure 24 shows the age demographics of XLPE cables in Alectra’s distribution system.

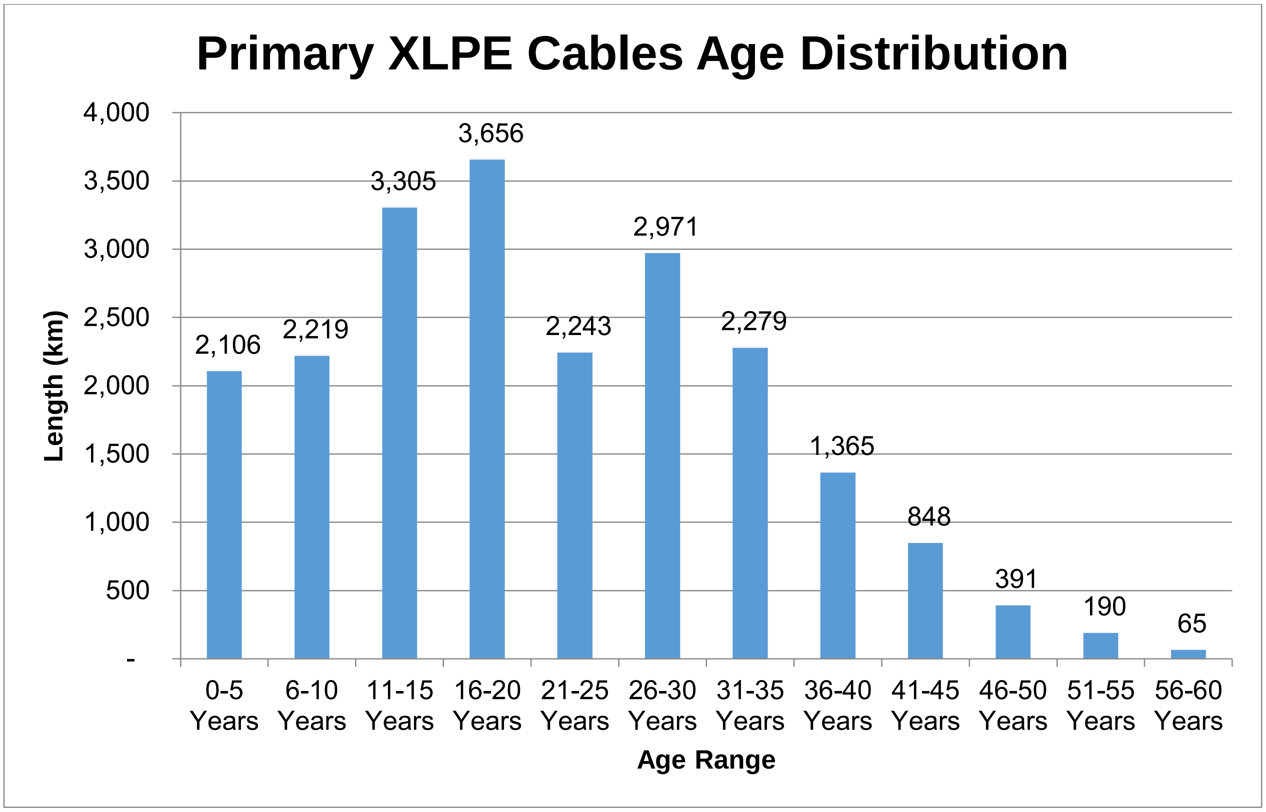


Figure 24 Primary XLPE Cables Age Distribution

5.7.3.2 Health Index Formula and Results

Health index of primary XLPE cables is calculated using age. The TUL and EUL used in the age score for each type are based on industry averages and Alectra's experience. The scoring method is based on the Gompertz-Makeham function where TUL and EUL correspond to 80% and 1% score respectively.

Health index is scored according to the curves shown in Figure 25.

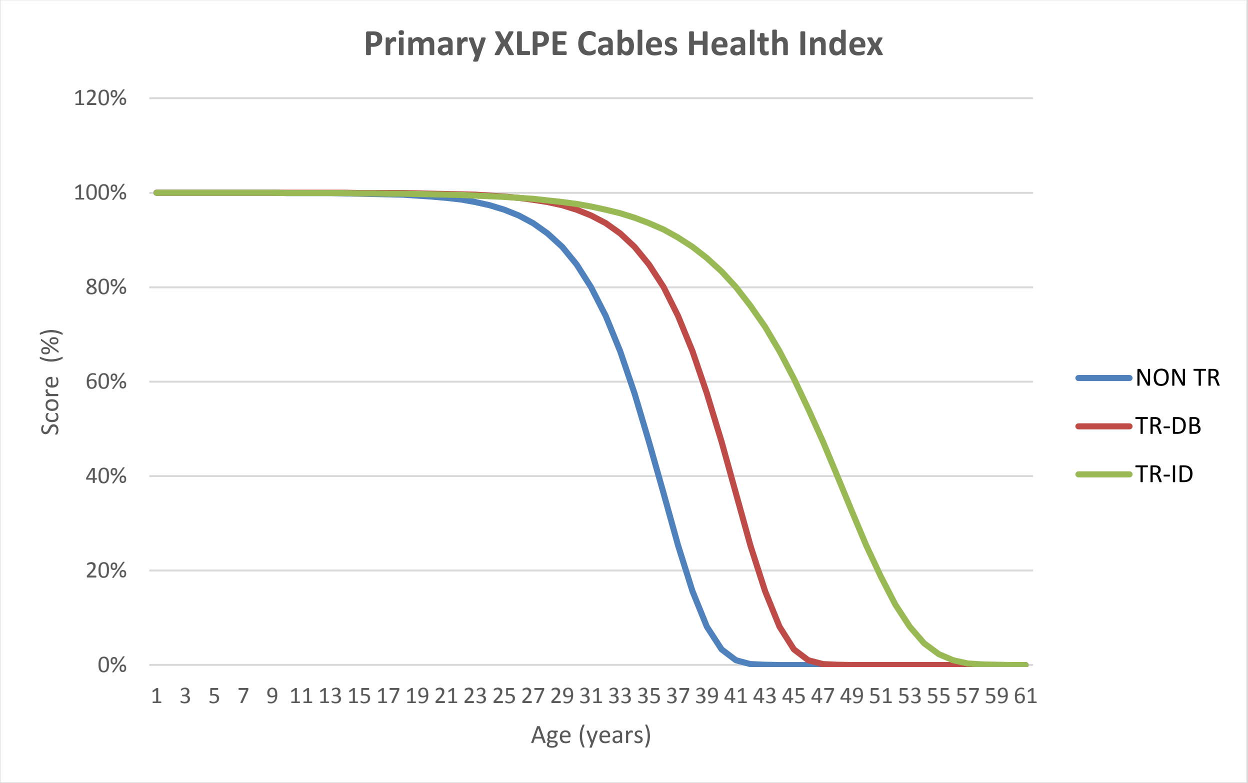


Figure 25 Primary XLPE Cables Health Index as a function of age

Health Index is computed as a function of age (i.e. percentage score) as shown in Table 18.

Table 18 XLPE Cable Health Index Parameters and Weights

Input	Input Weight	Scoring Method
Age	100%	Percentage Score

TAB 44

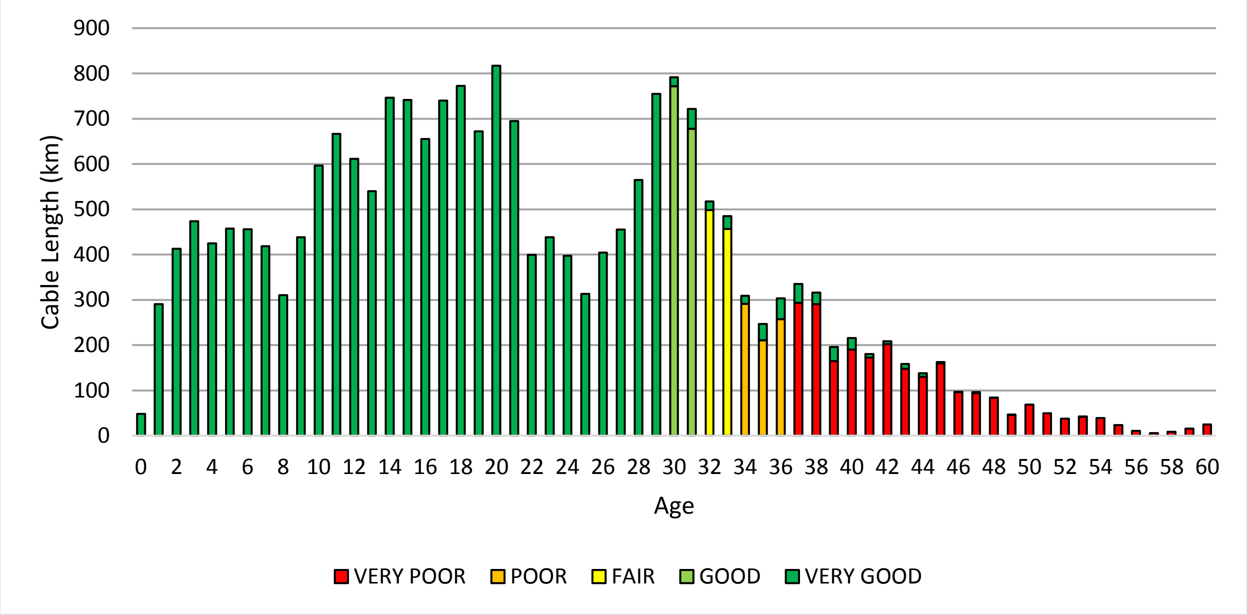
Alectra Utilities urgently needs to increase spending not only to halt the increasing trend, but also to reverse it and reduce the number of cable failures to return customers back to historical reliability levels. Without the proposed expenditures, cables will continue to degrade and Alectra Utilities expects reliability to decline further as deteriorated cables begin to fail at greater rates, having been stressed from historical faults.

Increased Expenditures Needed to Address Aging Cable Population

In addition to the significant amount of cable that is currently in very poor condition, Alectra Utilities must also plan to address a wave of cable that will deteriorate in the coming years.

As illustrated in Figure A10 - 7, there is a direct correlation between the age and condition of XLPE cable.[99]

Figure A10 - 7: XLPE Cable by Condition



The proposed investments focus on Area 1 and Area 2 as shown in Figure A10 - 8. All of the cable in Area 1 is in very poor condition and cannot be rejuvenated. Most of the planned cable replacement expenditures target this group of cable. The cables in Area 2 are in a range of conditions, but they will quickly slide into very poor condition if not addressed in the near term.

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[99] Health Index for cables are based cable type (including installation) and cable age. For example, Non-Tree Retardant XLPE direct buried cable has a different failure curve then Tree Retardant XLPE cable in a conduit.

TAB 45

Table A02 - 11 and Table A02 - 12 respectively provide population and employment increases in percentage, which further provide insight into the growth patterns within Alectra Utilities' service territory and where customer connections activities are forecasted to take place. The data displayed in Table A02 - 11 indicates a decrease in the rate of growth in the various areas from 2021 to 2041, however, the rates during the DSP horizon are expected to be constant as shown. Population and employment increases lead to new subdivision construction and ICI developments.

Table A02 - 11: Population Increases (in %) by Cities/Regions

City/Region	Population (% Increase from Previous Five Years)[72]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	17%	12%	6%	19%	9%	8%	7%	7%
City of Hamilton	3%	3%	3%	12%	6%	6%	5%	5%
York Region	22%	16%	7%	12%	8%	8%	8%	7%
City of Guelph	8%	6%	8%	9%	9%	8%	7%	6%
Simcoe County	12%	10%	8%	4%	8%	7%	7%	7%
City of St. Catharines	1%	0%	1%	3%	4%	6%	6%	5%

Table A02 - 12: Employment Increases (in %) by Cities/Regions

City/Region	Employment (% Increase from Previous Five Years)[73]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	14%	12%	9%	8%	5%	5%	5%	5%
City of Hamilton	7%	7%	8%	9%	5%	6%	7%	8%
York Region	20%	17%	13%	12%	7%	7%	7%	7%
City of Guelph	8%	1%	10%	8%	5%	6%	3%	4%
Simcoe County	17%	8%	9%	6%	4%	3%	7%	7%
City of St. Catharines	5%	-9%	4%	5%	3%	5%	5%	7%

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[72] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)

[73] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)

TAB 46

deteriorate, Alectra Utilities will have no option but to replace them. However, since most of these cables are in conduit, the replacement will be less expensive than for older cables. A secondary benefit includes the installation on newer generation strand filled cable which is expected to have a longer operating life than earlier generation cable.

Similar to Area 1 and Area 2 cable accessories are also replaced this is because the components are not reusable and therefore must be replaced.

2.4 Options Analysis

Alectra Utilities has considered three different investment strategies to manage the aging and deteriorating underground cable infrastructure within its service area. These include the following:

- Strategy 1: Accelerated pace (Improve cable reliability by 8%)
- Strategy 2: Moderate pace (Maintain cable reliability at 2018 level)
- Strategy 3: Reduced pace (Allow cable reliability to worsen by 10%)

The expenditures proposed reflect Strategy 1: investing at an accelerated pace.

In the second phase of customer engagement, Alectra Utilities received strong support for underground system renewal; 73% of residential customers that participated in the second phase of customer engagement indicated support for the recommended or accelerated pace of the renewal. Preference to proceed with underground renewal investments was also received from business customers (65% of small business, 97 of 137 mid-sized business and 10 of 13 large users) prefer the recommended or accelerate pace. Based on the need of investment and strong customer preference for underground system renewal, Alectra Utilities has incorporated into plans the accelerated pace for underground cable renewal. Alectra Utilities must address the cables in Area 1 and Area 2 now to be prepared for the wave of cables in Area 3 shown in Figure A10 - 8. If Alectra Utilities does not deal with Areas 1 and 2 now, then it will have no ability to manage the larger volume of assets in Area 3.

<u>Strategy 1: Accelerated pace (Improve reliability by 8%):</u>

Strategy 1 would address all cables in Areas 1 and 2 by 2028. Figure A10 - 9 illustrates the overall breakdown of cables identified for intervention under this strategy between cable replacement and rejuvenation respectively.