



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

OEB Staff Report

EB-2009-0084

**Review of the Cost of Capital for Ontario's
Regulated Utilities**

January 14, 2016

– intentionally blank –

Table of Contents

Table of Contents.....	i
1. Introduction and Summary.....	1
2. The Current Cost of Capital Policy	2
3. Cost of Capital Outcomes 2010-2015.....	4
3.1 Notional Debt	6
3.2 Multi-Year Applications.....	7
3.3 Bank Survey for the Short-term Debt Rate Calculation.....	8
3.4 Deferral and Variance Accounts	9
4. Conclusion.....	11
Appendix A: Review of Ontario Utilities (2010-2014).....	12
Achieved Returns for Rate-Regulated Utilities	16
Appendix B: Jurisdictional Review	20

1. Introduction and Summary

The purpose of this Report is to summarize OEB staff's review of the OEB's current cost of capital policy.

The OEB's current policy on the cost of capital was last updated in the [Report of the Board on the Cost of Capital for Ontario's Regulated Utilities \(EB-2009-0084\)](#) (the 2009 Cost of Capital Report) issued on December 11, 2009. This updated policy was developed to fully review the cost of capital approach, in light of anomalous results that the previous formulae gave following the global economic crisis in the late 2008 to early 2009 period.

In the 2009 Cost of Capital Report, the OEB committed to review its cost of capital methodology within five years. At that time the OEB noted that the periodic review would not necessarily result in resetting the base ROE or refining the formula.

In 2014, OEB staff commenced a review of the following:

- the results of the current policy flowing from the formulae for the return on equity and the short-term and long-term debt rates of the period since the inception of the new methodology at the end of 2009
- the actual financial results of rate-regulated utilities (natural gas distributors, electricity transmitters and distributors, and Ontario Power Generation's prescribed generation assets) based on recent available data (this is summarized in Appendix A)
- the performance of the existing policy in the context of the expected outcomes.

OEB staff also examined the cost of capital approach in the rest of Canada, the United States, the United Kingdom and Australia, to determine where the OEB currently fits with respect to both approach and results (i.e., allowed returns). Appendix B summarizes the jurisdictional review for information purposes.

Based on the results of this review, OEB staff has concluded that the methodology adopted in late 2009 has worked as intended. Movement in the parameters have followed macroeconomic trends and activity, and have not resulted in excessive or anomalous volatility. While there is more volatility observed in the financial performance of utilities, these are largely due to other reasons¹.

¹See Appendix A

2. The Current Cost of Capital Policy

This section provides a brief summary of the OEB's current cost of capital policy as documented in the 2009 Cost of Capital Report.

The financial crisis that occurred in late summer 2008 and continued into early 2009 provided a shock that necessitated a review by the OEB and all other Canadian regulators (the National Energy Board, the British Columbia Utilities Commission, and the Régie de l'énergie) which were using similar formulaic ROE approaches. While other Canadian regulators abandoned the formulaic approach as a result of the anomalous results arising based on the macroeconomic data in early 2009, the OEB concluded, following a consultative process, that the formulaic approach was still necessary to be able to continue regulatory oversight of over 80 utilities in Ontario. The 2009 Cost of Capital Report reaffirmed the economic, legal and regulatory principles underlying the treatment of cost of capital for rate-setting and summarized them in Section 4.0.

The OEB developed and documented the cost of capital policies so that the policies apply to both the natural gas and electricity sectors. While this updated policy reaffirmed and clarified many existing approaches, such as for the approach to capital structures for natural gas utilities, electricity transmitters and distributors and for Ontario Power Generation's (OPG) prescribed generation assets, new formulae were established for the ROE and the deemed long-term and short-term debt rates. In particular, the ROE formula introduced a second term, reflecting variability between long-term Government of Canada and A-rated corporate bond yields, as well as being fully recalibrated based on September 2009 data. The change in the formulae was to better reflect economic theory and to improve the chances of avoiding anomalous results as occurred in early 2009.

The OEB also committed to reviewing the annual formulaic results before issuing new parameters, and also committed to review the cost of capital policy in general within five years.

Table 1 summarizes the current methodology for calculating the cost of capital parameters.

Table 1: Current Cost of Capital Methodology²

	Electricity Distributors and Transmitters	OPG's prescribed generation assets	Natural Gas Distributors		
			Enbridge Gas Distribution Inc.	Union Gas Limited	Natural Resource Gas
Deemed Capital Structure	40% equity, 56% long-term debt, 4% short term debt	45% equity, 55% debt, on rate base adjusted for the lower of Asset Retirement Obligations or Unfunded Nuclear Liabilities (EB-2013-0321)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	40% equity, 56% long-term debt, 4% short term debt
Return on Equity (formula)	$ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (UtilBondSpread_t - 1.415\%)$, where ROE_t is the Return on Equity for year t , $LCBF_t$ is the Long Canada(30 year Government of Canada) Bond (yield) forecast for year t , and $UtilBondSpread_t$ is the spread between 30-year A-rated Utility Corporate Bond yields and Long Canada Bond Yields. The data for $LCBF_t$ and $UtilBondSpread_t$ are derived from Consensus Forecasts, and from Statistics Canada/Bank of Canada and Bloomberg LP data for the month 3 months in advance of the first effective date of the cost of capital parameters. Thus, for cost of capital updates effective January 1, September data are used.				
Long-term debt rate	Weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period. For electricity distributors and transmitters, a deemed long-term debt rate based on the following formula serves as a ceiling on affiliated debt at the time of issuance, on variable rate debt or on debt without a fixed term (e.g. Demand or Promissory Notes): $LTDR_t = LCBF_t + UtilBondSpread_t$				
Short-term debt rate	Formula: $STDR_t = AvgBA_t + AnnSpread_t$, where $AvgBA_t$ is the average 3-month Bankers' Acceptance rate for the month 3 months prior to the cost of capital update, taken from Statistics Canada/Bank of Canada, and $AnnSpread_t$ is the average estimate of the spread for 3-month Corporate loans over the overnight Bankers' Acceptance rate from a confidential survey with major Canadian banks, conducted annually.	Estimated short term debt cost. OPG and the natural gas distributors have methodologies that have been approved by the OEB in earlier decisions.			
Note	Preferred shares, if applicable, will be taken into account in the deemed capital structure and determining the weighted average cost of capital.				

² Table 1 provides a summary of the cost of capital methodology as it currently applies to rate-regulated utilities in Ontario. This reflects the 2009 Cost of Capital Report and subsequent OEB letters and decisions. Subsequent letters and decisions have changed the timing for updates and the capital structure for rate-setting purposes for some utilities; the basic methodology determined in the 2009 Cost of Capital Report is unchanged.

3. Cost of Capital Outcomes 2010-2015

From early 2010 (for rates effective May 1, 2010) to now, the OEB has applied the formulae and policies as documented in the 2009 Cost of Capital Report. Some minor changes to the approach have been effected. For example, the confidential survey of major Canadian banks used for the short-term debt calculation is now done in September to accommodate issuance of the update for January 1 of each year. The OEB determined that the update would normally be done once annually, with the January 1 update to apply to rates set through a cost of service application in that calendar year³. Macroeconomic conditions and their impact on cost of capital are monitored throughout the year, and any major changes could trigger an updated calculation.

In OEB staff's view, the revised formulae have worked as intended. The range of the ROE has been from 8.93% to 9.85%, with most results being close to the middle of the range and with moderate fluctuations. The formulae have operated as expected by economic theory. The prolonged period of low interest rates, the slow but steady recovery from the 2008-9 financial crisis and the specification and calibration of the formulae in the 2009 Cost of Capital Report are all significant factors.

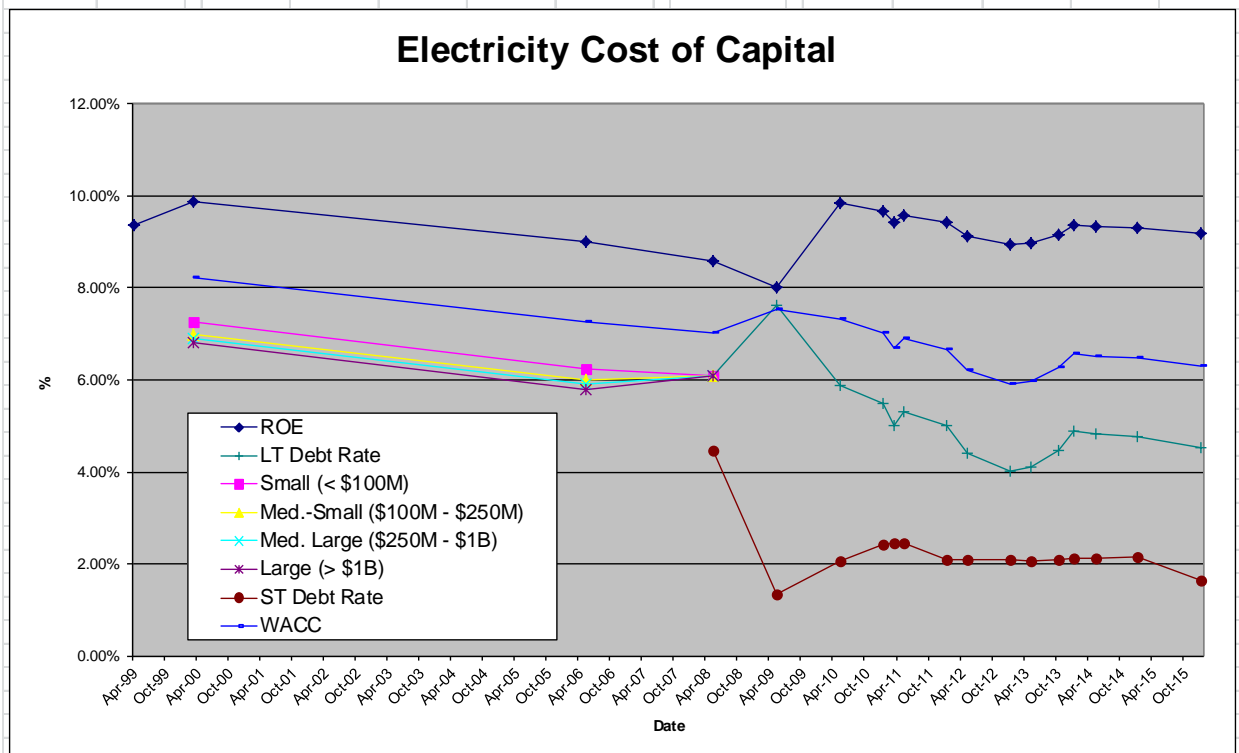
As noted in each letter issued by the OEB on the cost of capital parameter updates since early 2010, the OEB reviews the formulaic updates, and approves them subject to its assessment that the formulaic updates are reasonable with respect to current and forecasted (for the coming test year) macroeconomic conditions. To date, the OEB has approved the formulaic updates as calculated.

³ [OEB Letter on the Updated Cost of Capital Parameters for 2014, November 25, 2013](#)

Table 2 summarizes the results from 2010 to 2016.

Table 2: Summary of Cost of Capital Parameters

Date	Return on Equity	Long-term Debt Rates					Short-Term Debt Rate	Weighted Average Cost of Capital (WACC)				
		All Utilities	Small Utilities (< \$100M)	Small to Medium Utilities (\$100M - \$250M)	Medium to Large (\$250M - \$1B)	Large Utilities (> \$1B)		All Utilities	Small Utilities (< \$100M)	Small to Medium Utilities (\$100M - \$250M)	Medium to Large (\$250M - \$1B)	Large Utilities (> \$1B)
Previous Methodology - Ontario Hydro Services Company (now Hydro One Networks)												
Apr-99	9.35%											
Mar-00	9.88%		7.25%	7.00%	6.90%	6.80%		8.21%	8.57%	8.30%	8.09%	7.88%
May-06	9.00%		6.25%	6.00%	5.90%	5.80%		7.26%	7.63%	7.35%	7.14%	6.92%
May-08	8.57%	6.10%	6.10%	6.10%	6.10%	6.10%	4.47%	7.02%				
May-09	8.01%	7.62%					1.33%	7.52%				
May-10	9.85%	5.87%					2.07%	7.31%	New Methodology			
Jan-11	9.66%	5.48%					2.43%	7.03%				
Mar-11	9.43%	5.02%					2.46%	6.68%	Used for OPG Decision EB-2010-0008			
May-11	9.58%	5.32%					2.46%	6.91%				
Jan-12	9.42%	5.01%					2.08%	6.66%				
May-12	9.12%	4.41%					2.08%	6.20%				
Jan-13	8.93%	4.03%					2.08%	5.91%				
May-13	8.98%	4.12%					2.07%	5.98%				
Oct-13	9.16%	4.48%					2.08%	6.26%				
Jan-14	9.36%	4.88%					2.11%	6.56%				
May-14	9.33%	4.82%					2.12%	6.52%				
Jan-15	9.30%	4.77%					2.16%	6.48%				
Jan-16	9.19%	4.54%					1.65%	6.28%				



As part of this review, OEB staff also examined four issues regarding the operationalization of the policy that have arisen since 2009, and OEB staff's conclusions are summarized below.

3.1 Notional Debt

In the OEB's [Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications](#), the OEB clarified the treatment of "notional" debt (that portion of deemed debt exceeding a utility's actual debt). This concept is shown in the following examples, where notional debt is used as the "plug" to true up actual debt to the allowed debt thickness for rate-setting purposes.

	<u>Actual</u>		<u>Deemed for Rate-setting</u>	
	Amount	%	Amount	%
<i>Debt</i>	\$11,250,000	45%	\$11,250,000	45%
			\$3,750,000	15% Notional
Total Debt	\$11,250,000	45%	\$15,000,000	60%
Equity	\$13,750,000	55%	\$10,000,000	40%
Total Rate Base	\$25,000,000	100%	\$25,000,000	100%

	<u>Actual</u>		<u>Deemed for Rate-setting</u>	
	Amount	%	Amount	%
<i>Debt</i>	\$17,000,000	68%	\$17,000,000	68%
			-\$2,000,000	-8% Notional
Total Debt	\$17,000,000	68%	\$15,000,000	60%
Equity	\$8,000,000	32%	\$10,000,000	40%
Total Rate Base	\$25,000,000	100%	\$25,000,000	100%

Notional debt can arise for a number of reasons such as the difference between actual capital assets and regulatory rate base due to the addition of an allowance for working capital.

Divergence from the deemed capital structure is generally under the control of the utility as it may relate to timing for debt financing for planned capital investments, as well as the interests of shareholders, such as reinvesting retained earnings.

Notional debt can be either positive (i.e. deemed debt is greater than actual debt) or negative (where deemed debt is less than actual debt). Since the factors which cause

notional debt to arise are largely under the control of the utility, the OEB has determined in a number of cases that notional debt should attract the weighted average cost of actual long-term debt rate rather than the deemed long-term debt rate issued by the OEB.⁴ An exception to this is where a utility is 100% equity financed and has no current debt or recent history of debt financing. In such a circumstance, the OEB has noted that the deemed long-term debt rate should apply as a ceiling.

OEB staff notes that this discussion of notional debt is a clarification of existing policy and practice, and should be considered in conjunction with the established policy on the treatment of long-term debt in section 4.4.1 of the 2009 Cost of Capital Report.

3.2 Multi-Year Applications

Subsequent to the adoption of the current cost of capital policies in the 2009 Cost of Capital Report, the OEB has continued to evolve its approaches to the regulation of natural gas and electricity distributors. A key document issued by the OEB was the [Report of the Board on a Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach](#), issued on October 18, 2012.

The Renewed Regulatory Framework for Electricity (RRFE) established a multi-year Custom Incentive Rate-setting (Custom IR) option. With Custom IR, a utility proposes a five-year plan for rate-setting to appropriately recover the costs that it would forecast for investment in and operation of its assets to serve customers, while also factoring in both incentives and productivity improvements. There is a great deal of flexibility in the design of Custom IR plans.

While the RRFE report focussed on the electricity distribution sector, many of the concepts are pertinent to other sectors. Multi-year plans have been approved for transmitters, gas distributors and OPG.^{5,6}

The issue with respect to cost of capital for a Custom IR application pertains to whether and how the cost of capital parameters are updated beyond the first year of the Custom IR plan. The current data availability (i.e. from *Consensus Forecasts*) and formulaic methodology can provide a cost of capital forecast one year ahead. Forecasting error increases the further out the forecast goes.

⁴ OPG's Prescribed Payments for 2011-12 Decision with Reasons EB-2010-0008, pages 124-125, Hydro One Networks Inc. Decision with Reasons, EB-2008-0272, pages 51, 54-55, Hydro One Remote Communities Decision with Reasons, EB-2008-0232, page 12, London Hydro Inc. Decision with Reasons, EB-2008-0235, pages 36-37

⁵ Enbridge Gas Distribution for the period 2014 to 2018 (EB-2012-0459)

⁶ OPG structured their previous three cost of service applications as two year plans (EB-2007-0905, EB-2010-0008, EB-2013-0321).

Three approaches have been approved to date by the OEB in various forms to set cost of capital parameters for outer years in multi-year cost of service or Custom IR applications:

- Updates for each year
- Forecast of future parameters
- No updates to parameters for certain years beyond year 1

OEB staff also notes that the issue of the treatment of cost of capital for multi-year plans has been considered in other jurisdictions. Of particular insight is Ofgem's RIIO approach. Ofgem's RIIO approach for a multi-year plan (eight years for electricity distributors) sets the ROE at the outset of the plan, expressed in real terms. The (real) debt rate is updated annually. More importantly, inflation is also updated annually under the RIIO approach; this means that all cost of capital parameters, in nominal terms, are updated (formulaically) on an annual basis.

The OEB's policy on setting the cost of capital parameters was established in such a manner as to accommodate annual updates. That said, OEB staff recognizes that different Custom IR or multi-year cost of service applications will represent different consequences for ratepayers and different attributions of risk for the utility. Accordingly, whether or not to set annual cost of capital parameters using the current formula will depend on a distributor's circumstances as well as on the design and operation of an approved Custom IR or multi-year plan. In addition, volatility in macroeconomic conditions, which would also translate into changes in the cost of capital parameters, would also be a driver.

OEB staff is of the view that the OEB should not prescribe any one approach at this time but that this matter should be considered in the broader context of the OEB's planned review of rate setting policies in support of infrastructure planning and investment decisions.

3.3 Bank Survey for the Short-term Debt Rate Calculation

The calculation of the deemed short-term debt rate relies on one unique source of data, namely a confidential survey conducted with major Canadian banks. Each year the OEB requests their estimates of the spread over the 3-month Bankers' Acceptance Rate that they would charge credit-worthy (A-rated) Corporate customers such as utilities for 3-month commercial loans. This determination was made because no comparable data was identified.

OEB staff notes that this bank survey is the most resource and time-intensive aspect of the annual cost of capital update. All correspondence is done in confidence, and only

the OEB staff directly involved in calculating the formulaic updates handle the information.

The process has worked well to date. There has been generally good cooperation and participation by the banks. Since inception at the beginning of 2010, all participating banks have fully participated in all years except one, when one bank did not respond.

Given that the deemed short-term debt is a relatively small number, and is applied to only 4% of the rate base, the impact is relatively small. OEB staff will continue to assess whether there are alternative data sources that are cost effective and require a less intensive process.

In light of the above, and given that the process has worked well so far notwithstanding the issues noted above, and that there has been no concerns expressed by the industry or other stakeholders about the process or the results, OEB staff sees no basis for changing the data sources for the deemed short-term debt rate at this time.

3.4 Deferral and Variance Accounts

In setting the cost of capital, the regulator takes into account the risk of the utility (relative to the market and, more importantly, firms and sectors of similar business risk).

Deferral and Variance Accounts (DVAs) do not exist as such for unregulated firms (although DVAs may proxy certain operations in selective competitive markets where a pass-through of costs may reflect market design and operation).

The OEB, and many economic regulators, have used DVAs for many years. DVAs have become a common tool to deal with:

- Pass-through costs
- Recognition of costs and revenues between cost of service reviews
- Mitigation of impacts of major costs and expenses
- Changes in accounting and tax policies
- Government and regulatory policies, such as conservation and demand management, or smart meters

In many instances, a DVA may be established for a specific purpose and duration, after which it disappears. In other instances, such as with the Retail Settlement Variance Accounts for commodity and transmission pass-through for electricity distributors, the DVA is perpetual. In general, DVAs will serve to reduce the business risk of the regulated firms. The DVAs for the pass-through of electricity commodity and transmission costs ensure that the utilities essentially face no risk (or reward) on the

commodity charges (except for possible bad debt of defaulting customers unable to pay or due to errors by the utility).

When considering the establishment of a new DVA, the OEB does not in the normal course consider the impact on the overall risk profile of the subject utility. However, there have been instances where the OEB has expressed concern with shifting risk to ratepayers (thus reducing the risk to the utility and its shareholders)⁷.

In reviewing proposals for adjustments to the portfolio of DVAs, and in particular new DVAs, the OEB could consider whether the determination would materially impact the business risk and hence the cost of capital. Any change could be effected through changing the deemed capital structure.

However, one drawback of this approach is that it may require significant evidence to be filed by the utility on the impact on its cost of capital. And, in some instances, utilities file standalone Accounting Order applications which normally are limited to a review of materiality, causation and the likely event that the subject cost will be prudently incurred. Adding a review of the impact on the firm's cost of capital would likely convert this type of application from a minor one into a major proceeding.

The 2009 Cost of Capital Report was developed in a similar environment to the current one with respect to the number and nature of existing DVAs. OEB staff is of the view that the use of DVAs and the relationship to business risk should be a consideration when reviewing rate setting policies in the future.

⁷ EB-2012-0459, pg. 38-40. In its decision on Enbridge's Custom IR application the OEB denied a request for a DVA for the GTA Project, and accepted, with certain thresholds, DVAs for Relocation Mains and Replacement Mains projects. These different determinations were made on the basis that the GTA project, going in service in 2015, had largely known costs while the other projects, with longer time horizons, had less certainty over the term of their rate plan.

4. Conclusion

OEB staff is of the view that the current cost of capital policy has worked as it was intended. Movement in the parameters have followed macroeconomic trends and activity, and have not resulted in excessive or anomalous volatility. While there is more volatility observed in the financial performance of utilities, these are largely due to other reasons as discussed in Appendix A.

Appendix A: Review of Ontario Utilities (2010-2014)

In addition to reviewing the updated parameters over the 2010-2014 period, OEB staff also reviewed the actual results achieved by the rate regulated utilities.⁸ To ensure comparability between utilities and what was approved in cost of service applications, the reviews were based on the deemed capital structure. The results are presented in Appendix A.

Natural Gas Distributors

Natural Gas Distributors have generally achieved returns above the OEB-issued ROE in most years. The earnings sharing mechanisms in the IRM plans of Union Gas and Enbridge have acted to limit overearnings. It is worth noting that, with exception of NRG in 2011, and Enbridge and Union Gas in 2013, natural gas distributors were either under IRM or had no rate changes. For the most part, their ability to achieve and exceed the allowed ROE was independent of the new cost of capital methodology.

Electricity Transmitters

With the exception of one small transmitter (Niagara West Transformation Corporation), Ontario's three electricity transmitters were able to achieve ROEs on a deemed capital structure basis above the allowed ROE for 2013 and 2014. The achieved ROEs on a deemed capital structure basis indicate that these utilities are generally able to meet or exceed a market-based rate of return.

Ontario Power Generation

Ontario Power Generation (OPG) has had payment amounts for prescribed generation assets subject to OEB oversight since 2008. A review of OPG's ROE results, as filed and updated in 2015 for the period 2010-2014, is anomalous in OEB staff's view.

The ROE results in 2010-2012 show achieved ROEs in the high 4% to low 5% range, significantly lower than the approved ROEs. The achieved ROE is 0.46% for 2013 and 6.31% for 2014. OPG rebased its rates for 2011-2012, and again for 2014-2015, but

⁸ Due to changes in reporting requirements, consistent data is not available for all years. For electricity transmitters, reporting to the OEB only commenced in 2013.

rates were unadjusted for 2010 and 2013 as OPG did not file an application for new or adjusted rates for those years⁹.

OPG's summary analysis is derived from more detailed filings, which are necessary to understand OPG's regulatory treatment. Actual rate base and capital structure differ significantly from the regulatory treatment to set payment amounts. In particular, OPG has future asset obligations related to the future retirement and decommissioning of its nuclear generating facilities (Pickering, Darlington and the Bruce GS leased to Bruce Power). Also, significant projects and regulatory assets (Niagara Tunnel, work on refurbishment projects for both Pickering and Darlington Nuclear GS) were ongoing over this period. The treatment of other regulatory amounts for deferral and variance accounts and for other adjustments (e.g., Hydroelectric Incentive Mechanism) factors into the calculations.

Electricity Distributors

The bulk of the rate-regulated utilities in Ontario are electricity distributors, currently over 70 in number. These vary greatly in size and operational characteristics. The smallest municipally-owned distributor serves about 1200 customers, while Hydro One Networks serves over 1.2 million distribution customers. Hydro One Networks serves a mix of urban and rural parts of the province, while most other electricity distributors serve largely urban and suburban areas.

The OEB had established a multi-year approach to rate-setting whereby rates are rebased through a cost of service application, followed by several years under formulaic price cap adjustments. This approach was replaced with three rate-setting options starting with 2014 rates under the RRFE, and therefore the new approaches are not substantially reflected within the historical period analyzed in this Report.

OEB staff conducted a review of achieved ROE (based on the deemed capital structure) for the period 2011-2014¹⁰. The results show a high degree of variability with the achieved ROE range from (17.50%) to 41.81%. For a number of utilities, the results

⁹ OPG's 2013 Audited Financial Statements note the following:

ROE decreased in 2013 primarily due to lower net income and a higher average shareholder's equity, excluding accumulated other comprehensive income (AOCI). The lower net income was primarily due to lower earnings from the Regulated – Nuclear Generation segment.

Nuclear production of 44.7 TWh in 2013 decreased by 4.3 TWh primarily due to extensions to planned outages at the Pickering and Darlington Nuclear generating stations.

¹⁰ While distributors have been reporting under the *Reporting and Record-keeping Requirements* since 2000, there have been numerous changes in the reporting requirements, and the quality and completeness of the data is less in earlier years. Also, it is in 2011 when distributors reported the achieved ROE on the deemed capital structure on a consistent basis; earlier reported ROEs on an actual basis could be misleading because of variability in actual capital structures (from the deemed structure and between distributors).

swing widely from one year to another. Further analysis has provided some explanation of these widely anomalous results.

In many cases, utilities showing the greatest volatility are smaller distributors. Due to smaller size, they often cannot realize economies of scale and may be more vulnerable to external events, such as storms which affect the distributor's complete service area and for which significant recovery efforts are required.

Another key factor in the observed volatility is the nature and timing of the disposition of certain regulatory assets and liabilities. The smart metering initiative is one major contributor to this. Smart meter deployment and operationalization has been one of the largest projects undertaken by most distributors. It occurred over a number of years, averaging around three years for most distributors, but taking up to eight or nine years for others. Due to regulations and uncertainty at the inception of the program, the OEB provided funding to distributors through a funding adder and used deferral and variance accounts to track costs and funding adder revenues.

Distributors subsequently applied for disposition and recovery (or refund) of any under- or over-collection. While this approach was successful in accomplishing its intended purpose, it also had unintended consequences from a financial reporting perspective when amounts approved for disposition moved from being regulatory assets and liabilities to being normal distribution costs and revenues. At the point that transfers are made, there can be a temporal mismatch between costs and revenues.

Another timing issue is the lost revenue adjustment mechanism adopted so that lost revenues are not a disincentive for distributors to deliver conservation programs. Revenues lost in one period due to the effects of conservation programs are recovered in a future period.

Financial performance is dependent on how well the utility manages its costs under this regime and its resources to adequately meet customers' needs, as well as reflecting exogenous factors such as weather and socioeconomic conditions.

Given all of these factors, the volatility observed is not overly surprising, even if the outliers may be indicative of other issues specific to individual utilities. The data may not necessarily point to concerns with the cost of capital methodology itself but may, as noted above, reflect as much the distributors' abilities to manage the challenges and opportunities faced in terms of the regulatory regime as well as their individual and macroeconomic environmental, operational, and financial conditions.

The following table provides summary statistics from OEB staff's analysis.

Achieved ROE based on Deemed Capital Structure

	2011	2012	2013	2014
Average	7.94%	6.88%	9.39%	10.30%
Median	8.49%	7.92%	9.02%	9.48%
Minimum	-7.59%	-17.50%	-13.11%	0.05%
Maximum	21.25%	41.81%	29.9%	31.78%

The average is unweighted, meaning that there is no accounting for the size of each distributor. The median, or middle value, might be a better measure of the industry situation. While the median values for 2011 and 2012 are below the OEB-issued ROE for that year, the 2013 and 2014 values are slightly above that issued (8.93% for January 1 and 8.98% for May 1, 2013, and 9.36% for 2014).

The differences between the OEB approved and the actual results can be attributed to the following:

- 1) Approximately 20-25% of electricity distributors rebase in any given year
- 2) Disposition of certain deferral and variance accounts can cause significant impacts on income, particularly due to temporal differences in revenue and cost recognition
- 3) Variations in costs and revenues from the forecasts factored into the base rates, largely related to customer numbers, customer consumptions and loads, revenue sources, cost factors, as well as weather, macroeconomic conditions and conservation (whether based on programs or natural)
- 4) The utility's ability to manage its costs leading to under or over spending, and demand pressures
- 5) The effectiveness of a utility's planning to smooth out investments.

Achieved Returns for Rate-Regulated Utilities

1. Electricity Distributors

		Achieved ROE% on Deemed Capital Structure			
	Company_Name	2011	2012	2013	2014
1	Algoma Power Inc.	10.50%	11.44%	7.06%	8.38%
2	Atikokan Hydro Inc.	-5.31%	-2.52%	11.28%	28.33%
3	Bluewater Power Distribution Corporation	9.20%	9.70%	11.40%	10.17%
4	Brant County Power Inc.	8.60%	6.90%	6.90%	9.84%
5	Brantford Power Inc.	7.50%	3.20%	11.60%	11.15%
6	Burlington Hydro Inc.	11.40%	11.37%	8.15%	15.26%
7	Cambridge and North Dumfries Hydro Inc.	9.57%	9.78%	7.80%	8.32%
8	Canadian Niagara Power Inc.	7.21%	9.42%	6.71%	8.31%
9	Centre Wellington Hydro Ltd.	3.34%	2.99%	10.40%	10.96%
10	Chapleau Public Utilities Corporation	5.43%	-17.50%	19.84%	16.88%
11	Collus PowerStream Corp.	2.26%	0.10%	8.40%	11.21%
12	Cooperative Hydro Embrun Inc.	6.26%	10.28%	8.43%	4.35%
13	E.L.K. Energy Inc.	4.07%	11.90%	9.20%	19.22%
14	Enersource Hydro Mississauga Inc.	8.65%	6.58%	9.46%	9.43%
15	Entegrus Powerlines Inc.	N/A	7.61%	7.61%	10.20%
16	EnWin Utilities Ltd.	8.49%	3.48%	13.04%	9.62%
17	Erie Thames Powerlines Corporation	4.41%	8.43%	11.8%	10.63%
18	Espanola Regional Hydro Distribution Corporation	-0.56%	-13.19%	29.9%	28.00%
19	Essex Powerlines Corporation	10.83%	8.15%	11.20%	9.73%
20	Festival Hydro Inc.	11.71%	9.75%	10.50%	8.18%
21	Fort Frances Power Corporation	0.48%	-17.2%	14.47%	0.05%
22	Greater Sudbury Hydro Inc.	6.07%	11.79%	19.00%	14.04%
23	Grimsby Power Incorporated	2.35%	12.04%	7.20%	5.89%
24	Guelph Hydro Electric Systems Inc.	8.41%	8.00%	7.29%	12.48%
25	Haldimand County Hydro Inc.	10.39%	7.60%	12.90%	13.74%
26	Halton Hills Hydro Inc.	9.14%	13.30%	14.97%	12.91%
27	Hearst Power Distribution Company Limited	21.25%	41.81%	27.17%	24.31%
28	Horizon Utilities Corporation	8.19%	12.49%	9.01%	7.50%
29	Hydro 2000 Inc.	9.12%	-17.49%	7.40%	31.78%
30	Hydro Hawkesbury Inc.	20.35%	7.69%	1.00%	12.48%
31	Hydro One Brampton Networks Inc.	11.16%	10.72%	10.64%	9.45%
32	Hydro One Networks Inc.	8.80%	8.72%	8.00%	6.26%
33	Hydro Ottawa Limited	7.86%	9.41%	7.80%	8.06%
34	Innpower Corporation	8.58%	1.96%	6.70%	5.82%
35	Kenora Hydro Electric Corporation Ltd.	1.25%	7.00%	9.50%	8.14%
36	Kingston Hydro Corporation	6.26%	10.34%	9.03%	9.98%
37	Kitchener-Wilmot Hydro Inc.	11.02%	10.91%	8.94%	10.87%
38	Lakefront Utilities Inc.	8.64%	11.4%	9.20%	6.50%
39	Lakeland Power Distribution Ltd.	6.52%	9.73%	10.70%	12.50%
40	London Hydro Inc.	6.80%	4.90%	11.22%	9.10%
41	Midland Power Utility Corporation	9.93%	6.00%	10.00%	13.51%
42	Milton Hydro Distribution Inc.	8.90%	8.15%	10.60%	10.29%

		Achieved ROE% on Deemed Capital Structure			
Company Name		2011	2012	2013	2014
43	Newmarket-Tay Power Distribution Ltd.	9.48%	9.39%	11.10%	8.88%
44	Niagara Peninsula Energy Inc.	6.03%	7.23%	6.71%	4.89%
45	Niagara-on-the-Lake Hydro Inc.	11.00%	7.46%	3.84%	10.85%
46	Norfolk Power Distribution Inc.	7.81%	5.17%	10.30%	2.99%
47	North Bay Hydro Distribution Limited	10.15%	9.08%	8.88%	7.17%
48	Northern Ontario Wires Inc.	10.65%	2.48%	-13.11%	8.99%
49	Oakville Hydro Electricity Distribution Inc.	6.78%	5.49%	6.03%	9.94%
50	Orangeville Hydro Limited	7.23%	7.80%	6.21%	9.47%
51	Orillia Power Distribution Corporation	9.93%	11.60%	11.7%	12.11%
52	Oshawa PUC Networks Inc.	12.40%	10.18%	6.47%	6.41%
53	Ottawa River Power Corporation	10.58%	11.60%	5.90%	6.31%
54	Peterborough Distribution Incorporated	7.24%	4.35%	12.40%	8.15%
55	PowerStream Inc.	10.09%	8.55%	9.98%	9.49%
56	PUC Distribution Inc.	8.16%	4.99%	7.00%	5.47%
57	Renfrew Hydro Inc.	8.39%	5.36%	4.50%	2.92%
58	Rideau St. Lawrence Distribution Inc.	2.04%	4.47%	12.1%	6.76%
59	Sioux Lookout Hydro Inc.	9.67%	9.22%	12.3%	6.38%
60	St. Thomas Energy Inc.	7.31%	1.31%	0.00%	9.36%
61	Thunder Bay Hydro Electricity Distribution Inc.	7.24%	7.74%	6.34%	5.99%
62	Tillsonburg Hydro Inc.	-1.32%	-2.65%	6.50%	6.63%
63	Toronto Hydro-Electric System Limited	9.73%	7.62%	7.10%	7.41%
64	Veridian Connections Inc.	10.00%	9.00%	8.10%	10.61%
65	Wasaga Distribution Inc.	17.30%	11.91%	2.90%	4.98%
66	Waterloo North Hydro Inc.	10.04%	7.41%	8.70%	7.26%
67	Welland Hydro-Electric System Corp.	5.74%	6.73%	10.50%	9.98%
68	Wellington North Power Inc.	-7.59%	1.66%	4.35%	5.74%
69	West Coast Huron Energy Inc.	17.62%	10.79%	9.40%	14.84%
70	Westario Power Inc.	4.34%	7.83%	8.50%	11.90%
71	Whitby Hydro Electric Corporation	12.15%	12.35%	14.54%	13.89%
72	Woodstock Hydro Services Inc.	8.35%	11.84%	13.28%	11.83%

	2011	2012	2013	2014
Average	7.94%	6.88%	9.39%	10.30%
Median	8.49%	7.92%	9.02%	9.48%
Minimum	-7.59%	-17.50%	-13.11%	0.05%
Maximum	21.25%	41.81%	29.9%	31.78%

2. Electricity Transmitters

Source: Achieved ROE from Electricity Transmitters under Reporting and Record Keeping Requirements Section 3.1.4.

Transmitter	2013		2014	
	Achieved Return on Equity	Approved ROE from last Cost of Service	Achieved Return on Equity	Approved ROE from last Cost of Service
Canadian Niagara Power Corporation ⁽¹⁾	16.30%	9.88%	13.58%	9.88% ⁽¹⁾
Entegrus Powerlines Inc.	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Five Nations Energy Inc. ⁽²⁾	Not Submitted	9.50%	Not Submitted	9.50% ⁽²⁾
Great Lakes Power Transmission LP ⁽³⁾	11.51%	8.93%	11.42%	9.36% ⁽³⁾
Hydro One Networks Inc. (Transmission) ⁽⁴⁾	12.90%	9.16%	13.10%	9.36% ⁽⁴⁾
Niagara West Transformation Corporation ⁽⁵⁾	3.70%	7.00%	-3.00%	7.00% ⁽⁵⁾

(1) Approved 2009 ROE from Decision EB-2001-0034

(2) Approved 2012 ROE from Decision EB-2009-0387

(3) Approved 2014 ROE from Decision EB-2012-0300

(4) Approved 2014 ROE from Decision EB-2012-0031

(5) Approved 2014 ROE from Decision EB-2010-0345

3. Ontario Power Generation

Source: Achieved ROE from OPG filings with respect to EB-2010-0008 Reporting and Record Keeping Requirements. Please note that in 2014, the debt to equity ratio was changed from 53:47 to 55:45.

Year	2010	2011	2012	2013	2014
Achieved ROE	5.16%	4.81%	4.53%	0.46%	6.31%
Approved ROE	8.65% ⁽¹⁾	9.43%	9.55%	9.55% ⁽²⁾	9.36% ⁽³⁾

(1) Approved 2010 ROE from Decision EB-2007-0905

(2) Approved 2012 ROE from Decision EB-2010-0008

(3) Approved 2014 ROE from Decision EB-2013-0321

4. Natural Gas Distributors

Year	2010 ROE		2011 ROE		2012 ROE		2013 ROE		2014 ROE	
	Approved	Achieved	Approved	Achieved	Approved	Achieved	Approved	Achieved	Approved	Achieved
Natural Resource Gas ⁽¹⁾	9.85%	Not available	9.20%	9.98%	9.12%	7.16%	8.98%	6.29%	9.36%	Not available
Union Gas ^{(2) & (3)}	8.54%	10.91%	8.54%	10.38%	8.54%	11.03%	8.93%	10.67%	8.93%	10.69%
Enbridge Gas Distribution ^{(4) & (5)}	8.39%	10.071%	8.39%	8.908%	8.39%	7.628%	8.93%	10.414%	9.36%	10.460%
		Equity Thickness 36%		Equity Thickness 36%		Equity Thickness 36%		Equity Thickness 36%		Equity Thickness 36%

(1) Source: EB-2014-0274

(2) Achieved ROE% shows Actual ROE Before Earnings Sharing

(3) Source:

Approved: 2010-2012 ROE EB-2007-0606; 2013-2014 EB-2013-0202

Achieved: 2010 ROE EB-2011-0038; 2011 ROE EB-2012-0087; 2012 ROE EB-2013-0109; 2013 ROE EB-2014-0145; 2014 ROE EB-2015-0010

(4) Achieved ROE% shows Normalized Actual ROE Before Earnings Sharing

(5) Source:

Approved: 2010-2012 ROE EB-2007-0615; 2013 ROE EB-2011-0354; 2014 ROE EB-2012-0459

Achieved: 2010 ROE EB-2011-0088; 2011 ROE EB-2012-0055; 2012 ROE EB-2013-0046; 2013 ROE EB-2014-0195; 2014 ROE EB-2015-0122

Appendix B: Jurisdictional Review

OEB staff conducted a jurisdictional review of the cost of capital in Canada, the United States, the United Kingdom and Australia. These jurisdictions were selected because they are likely the most comparable to Ontario, both in terms of energy sector structure and operation, and in terms of regulatory approach.

Canada

Other Canadian regulators are the most relevant for comparison purposes. From the mid-1990s, several provincial regulators, including the OEB, adopted formulaic approaches for updating the ROE based on the National Energy Board's RH-2-94 formula; however, with the exception of the OEB, all Canadian regulators moved away to some degree from their formulaic approaches following reviews as a result of the 2008-2009 financial crisis. Three provincial regulators – the British Columbia Utilities Commission (the BCUC), the Régie de l'énergie du Québec (the Régie) and the Alberta Utilities Commission (the AUC) subsequently conducted proceedings to review the cost of capital.

In all three proceedings, the OEB's approach from the 2009 Cost of Capital Report was considered. The BCUC and the Régie adopted variations of the OEB's ROE formula, but added a floor such that the ROE would not be updated if the risk-free rate (the Long Canada Bond (yield) forecast) was below a pre-set value; this was to reflect economic theory and to prevent anomalous results. The Régie subsequently cancelled the formula as the first update produced a lower result, while the BCUC did not update the ROE formulaically as the floor value was not exceeded.

Other Canadian regulators are relying on more traditional approaches, determining the cost of capital based on evidence in individual rate applications. There is a range of allowed ROEs. In 2014, the Régie increased the allowed ROE for Hydro Québec to 8.20% from 6.19%, while, at the other extreme, some natural gas distributors in the Maritime provinces have allowed ROEs of 10.90% to 11%. However, for the most part, allowed ROEs are in the range of 8.5% to 9.75%, and the OEB's formula produces results close to the median.

Along with the Régie, the AUC has employed a traditional approach in recently reviewing its cost of capital applicable to regulated gas and electricity utilities. In October 2012, the AUC initiated a 2013 generic cost of capital proceeding.

The AUC final decision was issued on March 23, 2015.¹¹ The AUC adopted an ROE of 8.3% for 2013 to 2015 inclusive.^{12,13} The exact derivation of this number is not provided, but it is observed that it is close to the average of the estimates provided by the expert witnesses for the Alberta utilities and for intervenors.^{14,15}

OEB staff notes that the methodology is still largely similar to that of the current OEB approach (e.g. 50 basis points for transaction costs and an approach largely based on CAPM¹⁶). Timing differences account for a portion of the difference in results.

The AUC decided not to retain a formulaic approach going forward given that, among other reasons, current market conditions may not be reflective of a typical risk-return relationship for an investor¹⁷.

Following this decision the AUC reviewed the cost of capital for 2016 and decided to retain the results for 2013-15 on an interim basis for 2016 and subsequent years until changed¹⁸. The AUC indicated its intention to initiate a 2016-17 generic cost of capital review, but only after consultation with parties on approaches for streamlining the process.¹⁹

United States

In the United States, energy is regulated at both the Federal and state levels. OEB staff undertook a jurisdictional review of approved ROE levels based on public reports and summary studies.

Public Utility Reports publishes a survey that covers cost of equity capital determinations by state public utility commissions. The report covering the period September 2013 to September 2014 displayed results ranging from 7.16% to 10.80%,

¹¹ Decision 2191-01-2015

¹² Alberta Utilities, Commission, Decision 2191-01-2015, March 23, 2015, para. 277.

¹³ Analysis indicates that, at least going back to 2011, the AUC has assessed utilities as being less risky than has the OEB. The 2011 ROE of 8.75% was 83 bps below the OEB's issued ROE of 9.58%. The OEB's 2013-2015 ROEs of 8.98%, 9.36% and 9.30% average to 9.21%, a differential of 91 bps.

¹⁴ Ms. Kathy McShane for the utilities, and Dr. Laurence Booth and Dr. Dennis Cleary for intervenors.

¹⁵ The decision also contained other findings which, although related, are peripheral and do not significantly impact the review. Some slight revisions were made to deemed equity thicknesses for certain utilities, but as these are in the range of about 35% to 45% they are comparable to Ontario utilities. The AUC also determined that there was no conclusive evidence that the adoption of PBR (IRM in Ontario) affected (increased) the risk of utilities, a finding consistent with the OEB's approach for many years.

¹⁶ Capital Asset Pricing Model

¹⁷ Decision 2191-D01-2015, page 87

¹⁸ Decision 20371-D01-2015, issued July 8, 2015

¹⁹ The recent AUC decisions highlight a distinction between the AUC's approach and other regulators whereby the cost of capital is being set, in part, on a retrospective basis; while the OEB's methodology is set prospectively. Prospective setting of the cost of capital is common in other jurisdictions (CRTC, Ofgem) and is more consistent, in OEB staff's view, with business and investor decisions.

while the most recent report covered the period September 2014 through September 2015 and displayed a range from 8.3% to 12.00%. However, most allowed ROEs during both time periods were in the range from about 9.50% to 10.25%.

Another resource reviewed was the quarterly summaries prepared by the Edison Electric Institute (EEI). The EEI is the association representing investor-owned utilities in the United States and it funds certain research.

The EEI reports have the advantage of summarizing recent decisions, but also tracing the movements in the average allowed ROEs back over time. For 2015 Q2 and Q3, the EEI documented that the average allowed (or approved) ROE in decisions was 9.73% and 9.4% respectively. The EEI reports note that these were record lows, and consistent with a downward trend extending over more than three decades of data. The latest report also notes that two commissions noted the significant decline in capital market costs when rejecting higher requested ROEs.

OEB staff notes that the most recent “record low” is 21 basis points above the OEB’s most recent ROE (set for 2016 rates at 9.19%) and 47 basis points above the OEB’s low of 8.93% (set for January 1, 2013 rates) since the implementation of the 2009 Cost of Capital Report.

It has often been observed that allowed ROEs in the United States are higher than is the case for Canada. Ofgem in the United Kingdom has made similar observations. A detailed analyses has not been conducted on the reasons for these differences as part of this review. However, this issue was discussed in detail the last time the OEB reviewed its cost of capital policy.

United Kingdom

The RIIO (Revenues = Incentives + Innovation + Outcomes) model now in use is a combination multi-year cost of service and incentive regulation approach. In late 2013, Ofgem initiated a review of the cost of capital as a result of a Competition Commission review of a Northern Ireland decision by that jurisdiction’s regulator. As a result of the process, Ofgem ordered a reduction in the ROE by 30 basis points for electricity distributors. As a result, Western Midland Power has an approved ROE of 6.4% while other “slow-tracked” electricity distributors have allowed ROEs of 6.0% for the start of RIIO-ED1 in 2015. It is worth noting that Ofgem expresses the ROE in real terms; when expected inflation of 2.6% is factored in, the approved ROE is about 9.38% for Western Midland and 8.97% for other distributors. Under the RIIO approach, the base ROE (in

real terms) is set at the outset of the RIIO term (i.e., 8 years for electricity distributors), while the (real) debt rate and inflation are updated annually²⁰.

Australia

The Australian Energy Regulator (AER) has adopted a regulatory approach influenced by and very similar to Ofgem's RIIO. This approach was developed over several years, with a number of policy documents issued in December 2013 and rates under the new approach effective in early 2015. The AER's approach is quite rigorous in terms of applying economic theory as well as considering legal and regulatory principles. OEB staff observes that the AER approach, developed independently and documented in an extensive guideline, shares much in common with the OEB's own approach. While concerned with size-related risk, the AER has determined that a common deemed capital structure of 40% equity and 60% debt would apply to all natural gas and electricity utilities. The allowed ROEs for 2015 are comparable in nominal terms to the OEB's formula but would be, akin to the United Kingdom, somewhat lower in real terms due to higher inflation. Two differences are noted:

1. An allowance for tax expense is developed and considered as part of the cost of capital issue generally, in contrast to the approach in Ontario (and North America generally), where the tax expense is calculated separately based on applicable tax policy and rates.
2. The cost of debt is a 10-year trailing average of benchmark rates, rather than being a weighted average of actual (including new debt forecasted for the test year) common in North America. The AER approach seems to reflect their circumstances, where the relatively short existence of utilities as corporations and the prevalence of arrangements to hedge interest rate risk means that the 10-year trailing average may reasonably proxy the average debt rate for most utilities.

²⁰ In economic regulation in the United Kingdom, inflation is measured via the Retail Price Index (RPI), a published government statistic. In Appendix 2 of the letter from Ofgem in December 2013 initiating its review of the cost of capital for electricity distributors' first RIIO plan, Ofgem noted that the Bureau of Labour Statistics had studied and concluded that the RPI was subject to an upward bias (in contrast to the Consumer Price Index, similar to the CPI measures used in North America). Nonetheless, Ofgem determined in its decision (17 February 2013) that the RPI would continue to be used. 2.6% is the forecasted amount for the 2015-2022 period, but will be updated as part of the annual rate adjustments. In the updated RIIO models issued by Ofgem in late 2015 for March 2016 rate changes, an updated RPI of 2.8% is used but is subject to change.