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June 17, 2019

British Columbia Municipal Electrical Utilities
c/o Nelson Hydro
101-310 Ward Street
Nelson, BC
V1L 5S4

Attention: Ms. Marg Craig

Dear Ms. Marg Craig:

Re: FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC)

Project No. 1598996

Application for Approval of a Multi-Year Rate Plan for 2020 through 2024 (Application)

Response to the British Columbia Municipal Electrical Utilities (BCMEU) Information Request (IR) No. 1

On March 11, 2019, FortisBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-64-19 setting out the Regulatory Timetable for review of the Application, FortisBC respectfully submits the attached response to BCMEU IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

GENERAL

1. Please provide a best estimate of a rate-change forecast for the term of the MRP for FBC.

Response:

Please see Table C9-2 of the Application for details of FBC's indicative rate change forecast of 4 percent for 2020. FBC believes it would be premature to attempt to forecast rate changes for the remainder of the term of the MRP at this time. Future rate increases will depend on the details of the rate-setting framework approved in this proceeding and FBC's annual forecast items over the term of the MRP, which are not known at this time. FBC would therefore have to base any such forecast on numerous simplifying assumptions and the results could potentially be misleading to stakeholders.

EVALUATION OF THE CURRENT PBR PLANS

2. Please provide the operating and expense saving for the last 5 years under the Current PBR Plan in percentage values.

Response:

The following tables show FEI's and FBC's O&M formula savings including the Productivity Improvement Factor (PIF) and savings above the formula from 2014-2018 Actual and 2019 Projected in percentage values. The information is the same as that provided in Table B2-2 for FEI and Table B2-3 for FBC with the percentage values shown for each year.

FEI

Year	Actual (a)	Formula with 1.1% PIF (b)	Savings above the formula (c=b-a)	Formula O&M Savings above the formula Expressed in % (d=c/b)	Formula without 1.1% PIF (e)	Formula Savings related to 1.1% PIF (f=e-b)	Formula O&M Savings related to PIF Expressed in % (g=f/b)	Total Savings (Formula Savings + PIF Savings) (h=c+f)	Total Savings (Formula Savings + PIF Savings) Expressed in % (i=h/e)
2014	191.0	198.5	7.5	4%	200.7	2.2	1%	9.7	5%
2015	225.4	235.6	10.2	4%	240.4	4.8	2%	15.0	6%
2016	225.9	238.1	12.1	5%	245.6	7.5	3%	19.6	8%
2017	232.5	240.4	7.9	3%	250.7	10.3	4%	18.2	7%
2018	238.7	243.6	4.9	2%	256.8	13.2	5%	18.1	7%
2019P	246.9	248.9	2.0	1%	265.3	16.4	7%	18.4	7%

FBC

Year	Actual (a)	Formula with 1.03% PIF (b)	Savings above the formula (c=b-a)	Formula O&M Savings above the formula Expressed in % (d=c/b)	Formula without 1.1% PIF (e)	Formula Savings related to 1.03% PIF (f=e-b)	Formula O&M Savings related to PIF Expressed in % (g=f/b)	Total Savings (Formula Savings + PIF Savings) (h=c+f)	Total Savings (Formula Savings + PIF Savings) Expressed in % (i=h/e)
2014	52.0	52.7	0.7	1%	53.3	0.5	1%	1.2	2%
2015	51.9	53.0	1.1	2%	54.1	1.1	2%	2.2	4%
2016	51.8	53.6	1.8	3%	55.3	1.7	3%	3.5	6%
2017	52.5	54.1	1.6	3%	56.3	2.3	4%	3.9	7%
2018	53.8	54.8	0.9	2%	57.6	2.9	5%	3.9	7%
2019P	55.6	56.1	0.5	1%	59.6	3.5	6%	4.0	7%

3. Reference: Exhibit B-1, Section B2.3.5, pages B-18, B-44 - B-48, Exhibit B-1-1, Appendix C4-1: FEI 2014 – 2018 PBR Application proceeding, Exhibit B-1, page 17, Analysis of Strengths and Weaknesses

3.1.1 From a ratepayer perspective, would FortisBC accept that a productivity factor for FEI (1.1%) and FBC (1.03%) is a key positive aspect of the Current PBR Plans?

Response:

Please refer to the response to BCUC IR 1.6.3.

3.1.2 Has FortisBC in its review of Current PBR Plans in its consultations with any ratepayer stakeholder had any ratepayer stakeholder indicate that a productivity factor was not a desirable part of a PBR Plan from a ratepayer perspective?

Response:

From a ratepayer perspective, in its final argument submission in FEI's Annual Review for 2019 Rates proceeding, MoveUP commented that there are likely less realizable efficiencies for FEI to pursue in its next ratemaking plan which suggests a Productivity Factor (X Factor) may not be required.

On pages B-64 and B-65 of the Application, FortisBC noted MoveUP's position as follows :

> Also in its final argument, MoveUP commented and agreed that it is likely that there are less realizable efficiencies for FEI to pursue in its next ratemaking agreement:
>
> **Prospects Looking Forward: "Low-Hanging Fruit"**
>
> 9. The rationale for a further PBR term becomes much weaker in light of the decayed availability of realizable efficiencies. This is particularly the case given Fortis' own acknowledgement, in response to a series of MoveUP IRs, that (as we put it), the "low-hanging" efficiency opportunities were harvested early in the 2014-2019 PBR, and that significant further gains are getting thinner on the ground, and that there is little basis to expect that this trend would not continue into a second consecutive PBR cycle.

Further, as explained in the response to BCUC IR 1.17.5, the issue of the complexity of productivity growth studies was raised by CEC in its final argument in the 2014 PBR proceeding and discussed in the BCUC's Decision. For more information regarding FortisBC's proposed zero percent implied productivity factor, please refer to the responses to BCUC IRs 1.13.2 and 1.17.3.

3.1.3 Would FortisBC agree that the proposed MRP adjustments of:

a) a lack of productivity factor applied to formula O&M and growth capital (for FEI);

b) the removal of the 50% reduction to the growth factor for O&M and growth capital (for FEI);

c) the inclusion of positive only targeted incentives;

c) the addition of a two year ESM carryover; and

d) the inclusion of an innovation fund funded by ratepayers, reflect adjustments of an MRP which primarily improve the MRP for shareholders.

Response:

FortisBC does not agree that the proposed MRPs reflects adjustments which primarily improve the MRPs for shareholders. As explained in FortisBC's response to BCUC IR 1.19.8, the proposed MRPs have, for the most part, maintained the Current PBR Plan structure and other than the items described below maintain the same level of incentives and associated risks and rewards for the shareholders and the Utilities.

- For discussion regarding the MRP incentives and X-Factor recommendation, please refer to FortisBC's response to BCUC IR 1.6.3.
- For discussion regarding the elimination of the 50 percent multiplier, positive-only Targeted Incentives and the Efficiency Carryover Mechanism (ECM) (FEI assumes BCMEU is referring to a two year <u>ECM</u> carryover) and their associated risk and rewards for the Utilities and customers, please refer to FortisBC's response to BCUC IR 1.19.8.
- For discussion regarding the risk and benefits of the Clean Growth Innovation Fund please refer to FortisBC's responses to BCUC IRs 1.19.8 and 1.71.4.

3.1.4 Is it Fortis' view that the Current PBR model does not deliver sufficient benefit to shareholders and additional benefits to shareholders are required to move forward with a next generation PBR model as proposed in the application?

Response:

FortisBC's proposed MRPs are designed to respond to FortisBC's operating environment, our experience with the Current PBR Plans, and stakeholder feedback as discussed in detail in Section B of the Application. As stated on page B-30 of the Application, FortisBC's view is that the Current PBR Plans resulted in sizable benefits to both customers and the Utilities. However, FortisBC also identified weaknesses with the Current PBR Plans. In Section B2.2.3.5.2 of the Application, FortisBC noted the capital formulas and lack of specific mechanisms to promote innovation as the two major weakness of the Current PBR Plans. Furthermore, FortisBC discussed in detail its evolving operating environment in Section B1 of the Application, including government policies, customer expectations, an increased need for engagement, an increased need for maintenance and investment, and an increased need for innovation and adoption of new technologies. It is FortisBC's view that its proposed MRPs provide the appropriate response to its operating environment and make the necessary modifications to align the interests of customers and the Utilities for the long-term benefit of both.

RATE PLAN CONSIDERATIONS

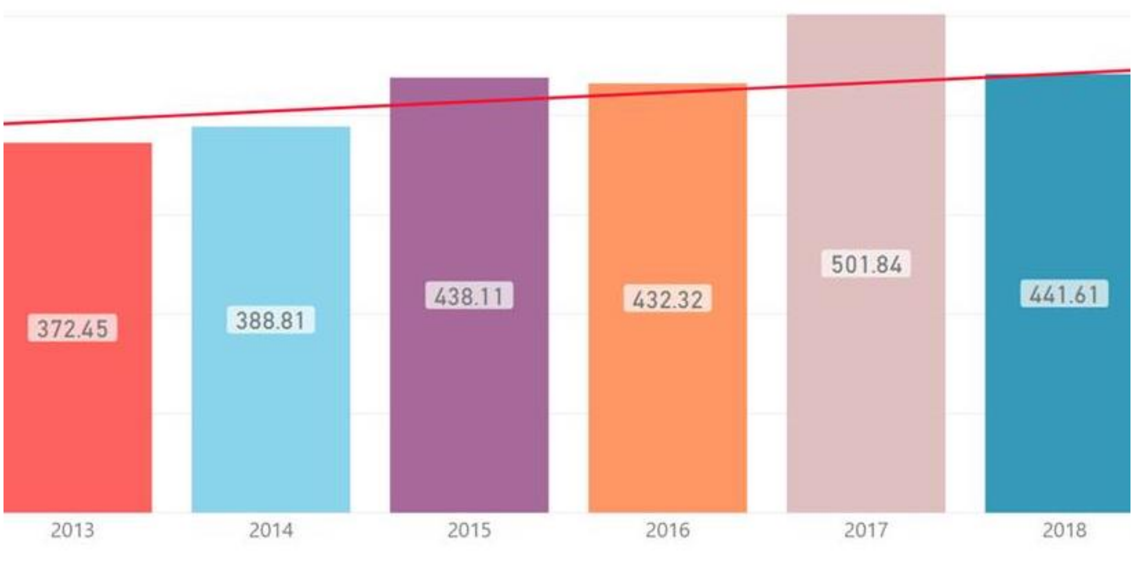
4. Reference: Exhibit B1, page B2, lines 25 – 26

4.1 Please provide the detail behind the statement that FortisBC has experienced "significant growth over the term of the Current PBR Plans".

<u>Response:</u>

The following examples illustrate the significant growth FortisBC has experienced over the term of the Current PBR Plan:

- **Customer Attachments** - FEI has experienced a record number of customer attachments in the new construction market and the conversion market year over year from 2014 to 2018, resulting in 66 percent more services installed in 2018 than in 2014. Through the term of the Current PBR Plan from 2014 to 2018 FEI has added nearly 90,400 new customers. Figure B1-1 on page B-13 of the Application describes the year over year customer attachments.
- **New Main and Service Pipe** – FEI has been adding new pipe at an average rate of over 400 kilometers per year. The following graph describes the incremental kilometers of pipe installed by year from 2013 to 2018.



- **Facilities** - FEI has added, upgraded or replaced close to 40 facilities including stations, and monitoring and controls to support the growth in assets and load brought on to the system by new and existing customers.

- **Load growth** - FBC is seeing load growth from Electric Vehicles and greenhouse operations related to the emerging cannabis industry. In addition, FBC has seen load growth of approximately 10 percent through increases in residential, commercial and industrial load.
- **System Control** - FBC is experiencing growing requirements related to Supervisory Control and Data Acquisition (Advanced Distribution Management System, and Advanced Metering Infrastructure (AMI)), Geographic Information System (secondary network model, AMI connectivity) and AMI (radio off customers). More protection and control devices, gang switches and motor operated devices are being deployed to manage customer outages.

4.2 What does FBC define as significant growth?

Response:

Please refer to the response to BCMEU IR 1.4.1.

5. Reference: Exhibit B1, page B11, lines 13 – 14

5.1 The Wholesale Customers have concerns with respect to an assertion there is "a high level of service through well-functioning channels". As an example, one wholesale customer waited approximately one year to receive an estimate to install two poles in its service territory. There is additional documentation of FBC taking a number of months to receive load profile data from FBC and other similar experiences of poor response.

5.1.1 Does Fortis agree that its level of service to wholesale customers should also be at "a high level of service through well-functioning channels"?

<u>Response:</u>

FBC continuously works with all customers to improve its level of service and agrees that wholesale customers should receive the same high level of service as direct customers.

Representatives from FBC will be discussing overall service and specific concerns with its wholesale customers at the British Columbia Municipal Electric Utility meeting in June. This direct feedback will help FBC to ensure it continually improves its levels of service with the wholesale customers.

SERVICE QUALITY INDICATORS

6. Has Fortis assessed the utilization of O&M cost per customer as a service quality indicator? Please discuss.

Response:

The measure of O&M cost per customer is already embedded in the proposed MRPs.

As explained by Ms. Roy at the May 1, 2019 MRP Workshop,[1] in response to a question from the BCMEU, O&M cost per customer is in fact what FortisBC will be measured on during the term of the proposed MRPs. O&M per customer is not identified as a service quality indicator because it is already part of the proposed MRPs and, indeed, the Current PBR Plans, although it was not specifically shown on a per customer basis. As shown in the Application as reviewed at the MRP Workshop, FortisBC saw a declining trend in O&M costs per customer over the term of the Current PBR Plans. In FortisBC's view, that is a key indicator that the Current PBR Plans worked as intended.

FortisBC believes O&M per customer is an important metric and is fundamental to the proposed MRPs, providing a common reference point to determine the level of O&M funding allowed and to evaluate performance by enabling a simple and transparent comparison of actual O&M costs per customer to that allowed. As a result, it is not necessary to also include it as part of the service quality indicators, which are focused on ensuring an adequate level of service for safety, responsiveness to customer needs and reliability.

[1] Transcript, page 65, lines 7-13 and 16-13.

7. Reference: PBR Workshop May 1, 2019, Slide 26 and Exhibit B-101, Appendix C5-2, pages 15 - 16

7.1 The interconnection utilization is an "informational metric". Please describe the use of "informational metrics" in the SQI category.

Response:

Informational SQIs are those that are useful for assessing performance but are not tied to specific benchmarks or thresholds. The use of these types of indicators serves to provide additional information and context in assessing whether there has been a serious degradation of service quality.

In the Application, FBC has proposed the Customer Satisfaction Index, Average Speed of Answer, Generator Forced Outage Rate and the new Interconnection Utilization metric as informational indicators. FBC views the addition of the Interconnection Utilization metric targeted specifically at FBC's Wholesale Municipal customers as offering further information to assess the reliability of the system.

Please refer also to the responses to BCUC IRs 1.90.8 and 1.90.9 for discussion of the proposed process for examining the performance of SQIs and the implications under the proposed MRPs. The proposed process is the same as that being used for the Current PBR Plans.

7.1.1 Can there be any financial or regulatory impact on FBC if there is evidence of decline in service evidenced by an "informational metric"?

Response:

Unlike metrics with benchmarks and thresholds, under the process outlined in the Consensus Recommendation regarding performance ranges approved by Order G-14-15, the level of performance with respect to informational metrics does not have a direct impact on the earnings of the Utilities. The informational metrics provide supplemental information to be considered in determining whether a serious degradation of service quality has occurred that is due in whole or in part to the actions or inactions of the Companies.

FBC believes including Interconnection Utilization as an informational metric in the suite of metrics used to assess service quality provides greater visibility and an important avenue for the BCMEU to bring forward and discuss any system reliability concerns.

7.1.2 What level of deterioration would need to be demonstrated to cause a financial or regulatory impact?

Response:

Please refer to the response to BCMEU IR 1.7.1.1.

8. Reference: FBC Proposed Service Quality Indicators, Exhibit B-1-1, Appendix C5-2, pages 15-16, Municipal Wholesale Customer Service Quality - Table A: C5-2-16: "Results during the PBR Plan for Interconnection Utilization"

8.1 Please extend Table A C5-2-16 back to 2009 with a breakdown by the interconnection points identified in Table A: C5-2-15.

Response:

Please refer to the table below which provides a breakdown by interconnection points identified in Table A: C5-2-15. Note that the Interconnection Utilization values have been updated slightly for the years 2014, 2017 and 2018 to correct the way that outages affecting multiple points of interconnection were accounted for originally.

Point of Interconnection		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
City of Nelson	Rosemont Sub	100.00%	100.00%	99.98%	100.00%	100.00%	100.00%	100.00%	100.00%	99.97%	99.99%
	Coffee Creek Sub	99.71%	99.91%	99.92%	99.70%	99.87%	99.94%	99.40%	99.93%	99.42%	99.74%
City of Penticton	Huth Ave Sub (13kV)	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Huth Ave Sub (8kV)	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Waterford Sub	100.00%	100.00%	100.00%	99.99%	99.99%	100.00%	100.00%	99.98%	100.00%	100.00%
	Westminister Sub	100.00%	100.00%	100.00%	99.99%	99.97%	99.98%	99.92%	100.00%	100.00%	100.00%
	RG Anderson Sub	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	99.99%	100.00%	100.00%
City of Summerland	Summerland Sub	100.00%	100.00%	100.00%	99.91%	100.00%	99.99%	100.00%	100.00%	100.00%	99.95%
	Trout Creek Sub	100.00%	100.00%	100.00%	99.91%	100.00%	99.99%	100.00%	100.00%	100.00%	99.98%
City of Grand Forks	Ruckles Sub (DB1)	100.00%	100.00%	99.99%	99.99%	100.00%	99.97%	100.00%	99.99%	99.94%	99.90%
	Ruckles Sub (DB2)	100.00%	100.00%	99.99%	99.99%	100.00%	99.97%	100.00%	99.99%	99.94%	99.90%
	Donaldson Drive	100.00%	99.98%	100.00%	99.91%	99.99%	99.95%	100.00%	100.00%	100.00%	99.96%
Interconnection Utilization		99.98%	99.99%	99.99%	99.95%	99.98%	99.98%	99.94%	99.99%	99.94%	99.95%

9. Reference: FEI Service Quality Indicators, Exhibit B-1, Appendix C-4-2

9.1 Please file the OEB's Renewed Regulatory Framework for Electricity Distributors referenced on page 18 of Appendix C4-2.

Response:

Attachment 9.1 contains the requested Ontario Energy Board Report, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.

Also included in Attachment 9.1 is the Ontario Energy Board's Handbook for Utility Rate Applications, which provides additional updates and descriptions regarding the Renewed Regulatory Framework for Electricity Distributors.

10. Reference: Workshop – It was indicated in the Workshop that SAIDI and SAIFI values included the Customers of the Wholesale Customers as Indirect Customers: Transcript Volume 1, page 67, lines 6-10

10.1 Please provide an explanation as to how that occurs.

Response:

Wholesale customers that are affected by an outage due to loss of supply from FBC are represented in the FBC reliability statistics as a single customer for each point of interconnection. This is consistent with CEA guidelines for reporting SAIDI and SAIFI, which considers each individual meter point as representing a customer.

As an example, for a FBC transmission line outage that affects both FBC direct and wholesale customers, every FBC direct customer affected would be included in the SAIDI and SAIFI statistics while the wholesale customers would be included as a single customer for each affected point of interconnection.

11. Reference: Exhibit B1, Table A 1-7, Comparison and FBC Current and Proposed SQI's, page A-15

11.1 Please elaborate on how the SAIDI and SAIFI are normalized.

Response:

As stated on page 130 of FBC's Annual Review for 2019 Rates:

> FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms and wildfires.
>
> Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

11.2 Does Fortis use its reported SAIDI and SAIFI figures as it submits to the Canadian Electric Association?

Response:

Yes, the values that FBC reports to the BCUC are the same figures that are submitted to the CEA.

INNOVATION FUND

12. Reference: Workshop May 1, 2019, Slide 24

12.1 The anticipated annual funding levels for FBC will be $0.5 million per year. Is the basic charge rider per month, per individual meter?

Response:

The FBC Customer Charge will be increased by the approved amount of the Clean Growth Innovation Fund rate rider. Generally, a meter is associated with one customer account and receives a monthly or bi-monthly Customer Charge. For customers receiving a monthly bill the added charge will be $0.30 and for customers receiving a bi-monthly bill the added charge will be $0.60.

INCENTIVES

13. Reference: Exhibit B-1, Section C-3, pages C157 – C159, Exhibit B1-1, Appendix C8, page 2, Exhibit B3, Workshop Presentation, Slide 31

13.1 Please comment on why management would not already be motivated to pursue these opportunities if they were in the mutual interest of ratepayers and the shareholder?

Response:

Please refer to the response to BCUC IR 1.96.3.

13.2 To the extent management is motivated to pursue incentives above and beyond the normalized rate of return for the utility, to what extend are ratepayers at risk paying for efforts which may not be contributing to the optimum use of management time in the interest of ratepayers as opposed to achieving incentives of benefit to the shareholder?

Response:

Please refer to the response to BCUC IR 1.96.5.

14. Reference: Workshop May 1, 2019, Slide 33 "Passive Portfolio"

14.1 Please discuss in detail how the "passive portfolio" is established as it appears to have become the key base for determining whether any incentive will be paid under the Power Supply Example Targeted Incentives.

Response:

The passive portfolio is a calculation of total power purchase expense that would have occurred if FBC did not engage in any optimization activities, and relied strictly on its long-term resources to meet load in every hour. For a detailed example, please refer to the response to BCUC IR 1.102.2.

14.2 Please confirm that customers will bear the risk of any increase in power purchase expense above the forecast power purchase expense in the "passive portfolio".

Response:

For the MRP, FBC is proposing that any variance in power purchase expense, excluding the Company share of the Power Supply Incentive (PSI), will flow through to customers, consistent with the Current PBR Plan. The PSI does not increase this risk for customers, and any optimization activity that FBC undertakes will be subject to acceptance through FBC's Annual Electric Contracting Plan. Further, the passive portfolio is not used for ratemaking purposes, nor for setting a forecast for power purchase expense. The passive portfolio is only used as a basis to calculate the Eligible Mitigation Benefits for the PSI. FBC will continue to forecast power purchase expense based on the best available information at the time of the Annual Review, and any variance between approved and actual power purchase expense, with the exception of any PSI incentive payment, will flow through to customers by way of the Flow-through deferral account. Please also refer to the response to BCUC IR 1.102.25.

OTHER

15. Reference: Workshop May 1, 2019, Slide 37

15.1 Please describe what is meant by a "traditional and simplified earning sharing mechanism". What deficiency is FBC attempting to rectify by changing the existing earnings sharing mechanism?

<u>Response:</u>

"Traditional and simplified" refers to the mechanism by which the earnings sharing amount is determined. The Companies' traditional approach has been used for many years in BC, was proposed for the Current PBR Plans, and is also the accepted practice in other jurisdictions in North America. This traditional approach is a simple calculation, sharing the difference between achieved and approved ROE equally with customers. In contrast, the Current PBR Plans use a mechanism that is not used by other utilities in North America and is more complex, being based on separate calculations for certain components of earnings only.

The proposed MRPs, including the elimination of the dead band, an index-based approach to O&M, and FEI's unit-cost approach to Growth capital with a true-up, is designed to rectify the complexity of the current approach. The current approach shares earnings based on differences in O&M and the earnings impact of capital spending adjusted for actual customer growth, actual service line additions, and contained within a dead band. The current approach is complex, difficult to understand, and limits the incentive to manage capital spending.

PROPOSING A TRADITIONAL AND SIMPLE EFFICIENCY CARRYOVER MECHANISM

16. Reference: Workshop May 1, 2019, Slide 38

16.1 Please confirm that FBC is proposing continued earning sharing for a period of two years beyond the five year MRP term effectively providing seven years of earnings sharing opportunity to FBC.

Response:

Although the Efficiency Carryover Mechanism (ECM) continues for two years after the end of the proposed MRP term, the amounts that are calculated in those subsequent two years are half of the simple average surplus return on equity (after ESM sharing) from the last two years of the MRPs. Simply stated, the ECM for 2025 and 2026 is one quarter of the efficiency gains over the last two years of the MRP term (with a 50 basis point ceiling).

17. Reference: Workshop May 1, 2019, Slide 41

17.1 The proposed rate impact for FBC in 2020 is $15.5 million or 4.5%. Please comment on what the 2020 rate impact would have been if a cost of service filing had been filed by FBC. Would it have been greater, lesser or the same?

Response:

The rate projection in Section C9 of the Application is indicative only and will be updated in FBC's request for interim rates to be filed later in 2019 and again once a decision is received in this proceeding. However, FBC expects that the 2020 rate impact would not be materially different under cost of service.

18. Reference: Exhibit B-1, Section A1.3.2, Index – O&M, page A-5, line 12

18.1 Please provide further justification as to why FBC is using 2019 Base O&M versus 2018 or 3 year historic trends.

Response:

As noted in the Application in Section A1.3.2 Indexed-O&M: "The starting point for determining the O&M per customer is the 2019 Base O&M, which is the adjusted actual O&M expenditures for 2018 expressed over the average number of customers in 2018, escalated by the approved formula inflation factors for 2019". This means that the starting point is 2018 actual spending, which is consistent with one of the suggestions in this question.

FortisBC believes that the starting point should be the most recent year and not an average of a number of years, since the most recent year represents the current required spending to support business requirements, including current levels of inflation. If FortisBC had started from a three-year average, for example, then more adjustments would be required to arrive at an appropriate starting point for the upcoming five years that would reflect current levels of inflation and operational requirements.

To provide further clarity, FBC provides the following excerpt from page C-43 of the Application describing the process for developing the Proposed 2019 O&M Base.

> Using the 2018 actual expenditures as the starting point for the O&M Base, adjustments are then made to arrive at the 2019 Base. The adjustments are as follows:
>
> - Add back temporary O&M net savings included in the 2018 actual expenditures and the corporate and shared services adjustments that result from the updated studies included in Sections D4 and D5;
> - Multiply by the 2019 formula inflator as approved in the FBC Annual Review for 2019 Rates[2];
> - Adjust for approved 2019 exogenous factors, items held in deferral accounts in the Current PBR Plan that are now included in Base O&M, and items currently in O&M that will be recorded in a deferral account in this Proposed MRP (and vice versa); and
> - Add new incremental funding required for the upcoming MRP term.

[2] Financial Schedule 3, FBC's Compliance filing Order G-246-18 for Annual Review for 2019 Rates.

18.1.1 What are the “known and measureable changes” identified in line 18?

Response:

The reference to “known and measurable changes” identified in line 18 of Section A1.3.2 Indexed-O&M is in reference to the adjustment items noted in the discussion outlined in the response to BCMEU IR 1.18.1, including the add back of temporary savings, adjustment for exogenous factors, items held in deferral accounts, and new incremental funding required for the proposed MRP term.

Specific details for each of these adjustments for FBC are included in Table C2-14 of the MRP Application.

18.1.2 At lines 19 – 22, it is indicated that FEI’s and FBC’s proposed 2019 Based O&M are lower than the O&M levels prior to the start of the Current PBR Plans. Would Fortis agree that this indicates the inflation factor utilized in the Current PBR Plan was too high?

Response:

Not confirmed. The fact that the Companies’ inflation-adjusted 2018 Base O&M is lower than the O&M levels prior to the start of the Current PBR Plans indicates that the Companies’ O&M over the Current PBR Plan term (2014 – 2019) has increased at a rate lower than inflation, and that the proposed Base O&M includes the savings realized by FEI and FBC over the term of the Current PBR Plans.

Attachment 9.1

Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

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Table of Contents

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1 Introduction

The Ontario Energy Board regulates the rates of the 77 local electricity distributors that operate Ontario's local electricity delivery networks. These networks are essential to the seamless delivery of electricity from generators to end users. The cost of distributing electricity represents approximately 20% to 25% of the total electricity bill. Revenues collected from customers contribute to the ongoing operation and maintenance of the system as well as its expansion and modernization. Ontario's electricity distributors represent significant capital investments, with total assets of approximately $17 billion, and new investment of $1.9 billion in 2011. And while all distributors perform a similar service, their investment needs vary over time. Ontario's energy sector is evolving, as are the expectations of customers and the obligations placed on distributors as a result. The Board believes that our approach to regulation needs to evolve along with the sector.

The Board needs to regulate the industry in a way that serves present and future customers, and that better aligns the interests of customers and distributors while continuing to support the achievement of public policy objectives, and that places a greater focus on delivering value for money. A number of factors have prompted the Board's work on a renewed regulatory framework: government policy, aging infrastructure, customer concerns regarding rate increases, the increased maturity of the industry, and a need to harmonize and consolidate Board policies related to planning and rate setting.

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.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board has developed a set of related policies to facilitate the achievement of these performance outcomes. The Board remains committed to continuous improvement within the electricity sector, The Board's policies for setting distributor rates as outlined below are supported by fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations.

The following are the three main policies:

- Rate-setting: There will be three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. Rate-setting is discussed in Chapter 2.

- Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. Planning is discussed in Chapter 3.

- Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. Performance measures and monitoring are discussed in Chapter 4.

In developing the policies in this Report, the Board has been guided by its objectives in relation to electricity, as listed in section 1(1) of the *Ontario Energy Board Act, 1998* (the "OEB Act"). These objectives are:

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

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.

The first two objectives, the protection of consumer interests and the promotion of economic efficiency and cost effectiveness within a financially viable industry, are the foundation of the renewed regulatory framework. These objectives are reflected in the outcomes set out above and are the main principles of the distribution rate-setting and performance measurement policies. They are also key considerations in the emphasis on pacing and prioritization of capital investment embodied in the planning policy.

The remaining three objectives of the Board in relation to electricity are reflected in the policies regarding infrastructure planning. Steps toward achieving these public policy objectives in respect of conservation and demand management, smart grid implementation and the expansion or reinforcement of the system to facilitate renewable generation are incorporated into the planning policy.

With the exception of regional infrastructure planning and smart grid, which apply to both distributors and transmitters, the policies set out in this Report apply to distributors only at this time. In due course, the Board will provide further guidance regarding how the policies in this Report may be applied to transmitters.

Policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year. Specifically, the new instruments for all three rate setting methods will be available to those seeking to rebase rates effective May 1, 2014.

The Board is committed to monitoring and evaluating the effectiveness of its policies. It will do so by identifying desired policy outcomes and requiring annual monitoring and reporting to measure success against those outcomes. The Board will develop the policy evaluation framework for the renewed regulatory framework after further work has been completed in relation to the distributor performance “scorecard”. More information on this policy evaluation framework will be provided later.

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2 Electricity Distribution Rate-Setting

2.1 Background

The Board has employed incentive regulation ("IR"), including formula-based and cost-based rate-setting, since it began regulating the rates of electricity distributors in 2001. Under its current approach to IR, the Board uses one year forecasted cost and revenue information to determine a base revenue requirement and the "base" rates that are set to recover that revenue requirement. In subsequent years, those base rates are adjusted annually according to a Board-approved formula that includes components for inflation and the Board's expectations of efficiency and productivity gains.

The Board's current IR plan for distributors ("3rd Generation IR") was established in 2008.[1] The core of the 3rd Generation IR plan is an "inflation minus X-factor" price-cap form of rate adjustment mechanism, which is intended to incent innovation and efficiency. The X-factors for individual distributors consist of an empirically derived industry productivity trend and differentiated stretch factors. Benchmarking, based only on operations, maintenance and administration ("OM&A") cost data, provides the basis for the annual assignment of stretch factors to distributors.

2.2 Evolving the Board's Approach to Rate-setting

As noted in Chapter 1, the maintenance and modernization of electricity distribution infrastructure will continue to exert cost pressures on customers. The Board's approach to rate-setting must continue to support a sustainable, financially viable and reliable

[1] The Board's 3rd Generation IR policy approach is set out in the "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" dated July 14, 2008. A Supplemental Report of the Board setting out the Board's determination of the values for the productivity factor, the stretch factors, and the capital module materiality threshold for use in the 3rd Generation IR plan was issued on September 17, 2008; and on January 29, 2009, the Board issued its "Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" which sets out the Board's determination on the model it would use to assign stretch factors to distributors.

electricity system. It must do so in a manner that is responsive to customers' concerns about affordability, by promoting increased efficiency which in turn can lower costs and provide for more predictable rates. It must also do so in a manner that better accommodates differing circumstances of distributors (for example, with respect to customer expectations, asset profile and investment needs) and facilitates the cost-effective and efficient achievement of expected performance outcomes. Finally, the rate regime must also recognize the inter-connected nature of the electricity system in Ontario, promote ongoing productivity improvements, encourage innovation, and support efficient regulation.

As part of the renewed regulatory framework consultation process, the Board issued a "straw man" model regulatory framework that identified at a high level certain potential changes to the Board's approach to rate-setting, including the pre-approval of multi-year plans, a focus on reliability, targeted rate-setting (treating OM&A and capital separately) to increase the pursuit of operating efficiencies, and greater flexibility in respect of the period between cost of service reviews.

Stakeholder Views

Stakeholder views on whether rate-setting should be targeted or comprehensive diverged significantly. Some distributors expressed strong support for targeted rate-setting. Those opposed argued that the capital and operating expenditures are too inter-related to be easily severed. Further, these stakeholders expressed concern that severing the two could create bias for one over the other resulting in sub-optimal investment, particularly in the absence of least-cost planning processes.

Stakeholder comment was generally in support of flexibility in the length of an IR term. Some stakeholders representing different business groups noted that aligning the IR plan term to match a 5-year planning horizon would be a sensible approach.

With respect to the current 3rd Generation IR plan, many stakeholders supported revising the inflation and productivity indices to better reflect circumstances faced by distributors in Ontario. Regarding the ICM some argued it is too restrictive while another commented it is sufficient because it is meant to be used in extraordinary circumstances rather than on a regular basis.

Many stakeholders commented on the need for flexibility in rate-setting to accommodate distributor differences, especially with respect to different capital spending needs. A menu approach – one that could include more than one type of rate-setting method (e.g., a simple index method and a multi-year approval-type method) – was identified by a few stakeholders as the preferred means of providing such flexibility. It was suggested that a distributor's ability to access certain rate-setting options should be linked to the distributor's benchmarked performance ranking.

Off-ramps and earnings sharing mechanisms were identified by some as necessary ratepayer protection mechanisms, particularly in longer term IR rate-setting.

The Board's Conclusions

The Board continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework.

Three alternative rate-setting methods will be available to distributors.

Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include "lumpy" investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.

The Board remains committed to the principles enunciated in its 3rd Generation IR report, and all three rate-setting methods are based on a multi-year IR mechanism. Each rate method will be supported by: the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations; and benchmarking. Rate applications will be supported by a five-year capital plan that includes consideration of regional infrastructure planning.

The Board believes that this more flexible approach to rate-setting will:

- enhance predictability necessary to facilitate planning and decision-making by customers and distributors;
- better align rate-setting with distributor planning horizons;
- facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and
- help to manage the pace of rate increases for customers.

The Board's rate-setting policy in this Report represents a further development of the approach adopted by the Board when it first established performance based regulation ("PBR") for electricity distributors in its January 18, 2000 Decision with Reasons:

> … PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-

> minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board."[2]

Going into PBR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for ratebase to be re-calibrated annually.

In implementing the new approach to rate-setting, the Board will use a rigorous performance reporting and monitoring process to ensure that, while distributors are responding to performance incentives, customer interests are being protected. As described in Chapter 4, a scorecard will be developed to measure distributor performance on four performance outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance. One measure that will continue to be considered by the Board is annual earnings. The Board's policy in relation to the off-ramp, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, continues to be appropriate. Each rate-setting method will include a trigger mechanism with 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. The Board will continue to require consistent, meaningful and timely reporting to enable the Board to monitor utility performance and determine if the expected outcomes are being achieved. This approach will, in turn, allow the Board 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. Customer

[2] Paragraph 2.0.14, p. 13, RP-1999-0034 Decision with Reasons, January 18, 2000

interests will also remain protected through regulatory processes that will continue to be open and transparent.

To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X factor.

With the introduction of these three rate-setting methods, the Board will review its existing rate-related policies for continued efficacy and to confirm whether and to what extent they can be integrated into any one or more of these rate-setting methods. The Board currently expects that existing policies will remain in place to support rate-setting in the future.

The key elements of the three rate-setting methods are set out in the following Table, and are described in greater detail below.

Table 1: Rate-Setting Overview - Elements of Three Methods

		4th Generation IR	Custom IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Productivity factor		
		Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting ("4th Generation IR"), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.

Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index ("Annual IR Index").

The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.

2.2.1 Description of the Three Rate-setting Methods

4th Generation IR

Building on the current 3rd Generation IR, the 4th Generation IR method includes certain enhancements to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. The 4th Generation IR method will be appropriate for distributors that anticipate that some incremental investment needs may arise during the term of the rate method.

Under this method, rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4th generation price cap index formula. The Board will retain a comprehensive price cap form of adjustment mechanism. The Board believes that the price cap approach, like that used in the Board's earlier IR plans, continues to be appropriate for most distributors.

The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years). This longer term will better align rate-setting and distributor planning, strengthen efficiency incentives, support innovation and help manage the pace of rate increases for customers.

A distributor on 4th Generation IR may request early termination and seek to have its rates rebased if it meets the Board's criteria for early rebasing.[3] As noted previously, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

As with current 3rd Generation IR, the allowed rate of change in the price of regulated services will be adjusted by the growth in an inflation factor minus an X-factor.

The Inflation Factor

Under price cap mechanisms, changes in price indices are reflected in allowed changes in output prices for regulated services (i.e., indices escalate the allowed prices).

The inflation factor could be established in one of two ways: either an industry-specific price index ("IPI") designed to track the inflation of the industry inputs, or a macroeconomic index. The Board has consulted with stakeholders on several occasions over the last ten years on inflation factors. The merits of, and concerns

[3] In keeping with the Board's approach as set out in its April 20, 2010 letter, a distributor that seeks to have its rates rebased earlier than scheduled must justify, in its cost of service application, why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remainder of the 4th Generation Plan term.

associated with, an IPI were summarized by the Board in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> …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 [Staff] 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.[4]

The Board has concluded it is now appropriate to adopt a more industry specific inflation factor for 4th Generation IR. Concerns regarding volatility will be mitigated by the methodology selected by the Board. The Board also will be guided by the following:

- the inflation factor must be constructed and updated using data that is readily available from public and objective sources such as, for example, Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices; and
- the component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific)

[4] At pp. 10-11.

X Factors

The Board described the components of an X-factor in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors 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 distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[5]

The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.

All distributors will be subject to the same productivity factor that will be set in advance for the purposes of the 4th Generation method. The Board will continue to use an index-based approach for the derivation of an industry productivity trend to form the basis for the productivity factor. The Board will update the industry productivity factor every five years (e.g., the update after 2014 would be in 2019).

The Board's approach in relation to the use and assignment of stretch factors under 3rd Generation IR will continue under 4th Generation IR. Distributors will continue to be assigned annually to one of three efficiency cohorts. The Board will make these

[5] At page 12.

assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.

Capital Spending

There will not be an ICM in the Custom IR method. Under this method, distributors will be expected to operate under their Board-determined multi-year rates.

Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

Annual IR Index

The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor.

Distributors, who apply under this method for 2014 rates or later, must have had a cost of service hearing in 2008 or later. The Board also expects that a distributor applying under this method will not be exceeding its approved annual ROE by more than 300 basis points.

Like other rate setting methods, a rate application under the Annual IR Index must also include a five year forecast of capital investments, except as noted in section 5.2 of this Report dealing with transitional issues. However, as indicated in Chapter 3, the scope and level of detail required in this plan will be proportional to the scope and magnitude of the proposed investments. As with all the rate-setting methods, annual reporting will be required from distributors on the Annual IR Index.

The prudence review associated with the disposition of Group 2 variance and deferral accounts makes their disposition generally incompatible with the design of the Annual IR Index. For that reason, a distributor that applies to have its rates set under the Annual IR Index is expected to limit requests for disposition of deferral and variance accounts to Group 1 accounts while it is on the Annual IR Index. If a distributor is seeking the disposition of any Group 2 accounts, that review and disposition will need to be the subject of a separate application.

Given the nature of the rate adjustments under this method, the Board does not believe that it is necessary to establish a fixed term for it, and a distributor whose rates have been set under it may apply to have its rates rebased and set under a different method at any time. As noted previously, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

Under the Annual IR Index rates will be adjusted annually by the growth in an inflation factor minus an X-factor.

Inflation Factor

The inflation factor determined for use in 4th Generation IR will also be used in the Annual IR Index.

X-Factor

Under the Annual IR Index, the Board will index rates by a percentage of the inflation factor so that annual adjustments under the Annual IR Index include recognition of expected productivity gains over time. This is particularly important given that there is no fixed term for this plan. To achieve this, the Board has determined that the X-factor for the Annual IR Index will be set after the Board's determination of the X-factor values for 4th Generation IR. The X-factor for the Annual IR Index will be the same as the highest X-factor set for 4th Generation IR in 2014, as updated every five years. This will ensure that the resultant rate adjustment under the Annual IR Index is equal to the lowest rate adjustment under 4th Generation IR. All distributors on the Annual IR Index will be subject to the same X-factor. When updated by the Board, the new X-factor will automatically be applied to all distributors that are then on the Annual IR Index.

Capital Spending

There will be no ICM in the Annual IR Index. The method presumes a largely steady-state or sustainment mode of operation by the distributor.

2.3 Decoupling

In 2010 the Board initiated a consultation process in relation to revenue decoupling mechanisms. The focus of that consultation was to examine the extent of revenue erosion due to, among other things, energy conservation efforts. The Board issued a consultant's report for stakeholder comment. That report contained a review of revenue decoupling mechanisms implemented in other jurisdictions and proposed options for consideration in Ontario.[6]

The Board indicated, when it initiated the renewed regulatory framework project in 2010, that the revenue decoupling consultation would proceed once there was substantial completion of the renewed regulatory framework policy initiative. The Board is of the view that it is now appropriate to resume the revenue decoupling initiative. Information regarding this initiative will be provided in due course.

2.4 Rate Mitigation

Rate mitigation has been a policy of the Board since 2000. At that time, the Board established a requirement that distributors *consider* mitigation where total bill increases for any customer class exceed 10%.[7] Since only consideration and not implementation of mitigation is required, this percentage is referred to as a "soft" threshold. The most recent articulation of the Board's mitigation policy confirmed the continuation of the "soft" 10% threshold for the filing of mitigation plans and provides guidance to distributors on preparing those plans.[8] In its mitigation plan a distributor may propose any, or no, mitigation mechanism as may be suitable in a particular circumstance.

[6] Lowry, Mark Newton, Ph.D., et al., Pacific Economics Group Research LLC. Review of Distribution Revenue Decoupling Mechanisms. March 19, 2010.
[7] January 18, 2000 Decision with Reasons in a proceeding to determine certain matters relating to the proposed Electricity Distribution Rate Handbook (RP-1999-0034).
[8] Report of the Board May 11, 2005 – 2006 Electricity Distribution Rate Handbook, p. 90.

2.4.1 Mitigation Policies under the Renewed Regulatory Framework

An objective for the development of a renewed regulatory framework is to ensure that distributors are encouraged to manage the prioritization and pace of network investments having regard to the total bill impact on customers. This prompted the Board to include the re-examination of its rate mitigation policy as part of the renewed regulatory framework consultation.

Stakeholder Views

There was broad support for the idea that distributors should consider mitigation when engaged in planning, ensuring that capital and OM&A expenditures are paced and prioritized in a manner such that costs are smoothed and minimized over the long term. Ensuring that the Board's approach to rate setting is designed such that rate increases are more gradual also received support from stakeholders. Conflicting views were expressed about whether the Board should consider total bill increases for rate mitigation purposes. A hybrid approach was proposed under which distributors would be required to consider anticipated total bill increases when planning investments. However, mitigation after the revenue requirement has been determined would only apply in relation to anticipated increases in distribution rates.

Stakeholder's comments reinforced that mitigation may not necessarily be appropriate in all circumstances. Some argued that the threshold should be "soft", thereby providing more flexibility in determining when the filing of a mitigation proposal is required. Other stakeholders, however, supported a firm and consistently-applied threshold, arguing that this will achieve greater predictability for both ratepayers (in relation to their electricity costs) and distributors (in relation to the regulatory process).

There was agreement among most stakeholders that, regardless of methodology, an empirical threshold should be developed. Proposals for a methodology on which to base the threshold include: a customer 'willingness to pay' survey or an 'economic tolerance' study; a factor of an inflation index such as the Consumer Price Index; and the establishment of criteria rather than relying on a specific figure.

In general, stakeholders were comfortable with continued use of conventional mechanisms but believed that alternative mechanisms should be further explored.

The Board's Conclusions

The Board has concluded that it will maintain its current policy with respect to rate mitigation. The implementation of the renewed regulatory framework should make the need for mitigation of large rate increases less likely as controls to address cost increases are integrated into the planning and rate-setting processes, and each distributor will be able to choose the rate-setting approach that best suits its particular investment profile. The Board will expect distributors to consider total bill increases when they engage in planning, an exercise that will be facilitated under the integrated approach to network planning described in Chapter 3, and to demonstrate to the extent possible the responsiveness of their planned capital and OM&A expenditures to the need for reasonably stable and affordable rates for customers. The Board is therefore of the view that changes to its rate mitigation policy are not necessary at this time. Once the Board and stakeholders have gained experience with the new rate-setting methods, the Board may revisit this issue if the need arises.

The Board further concludes that it is not necessary at this time to limit the mitigation mechanisms that distributors may want to propose. The Board will continue to evaluate proposed mechanisms on a case-by-case basis.

2.5 Implementation

Issues related to the inflation and productivity adjustment mechanisms have been explored in several different consultations over the last ten years. The Board has benefited from those consultations and has gained significant experience applying the results of those consultations. Consequently, the Board is of the view that the most expeditious way to reach a determination on these issues is through a Board-led stakeholder conference followed by written submissions. To inform the conference, new inflation, productivity and stretch factors, will be developed in consultation with stakeholders as part of the performance, benchmarking and rate adjustment indices work described in Chapter 4. The Board expects to issue its determinations on these issues in mid-2013.

Product	**Planned issuance**	**Process**
Determination of inflation & productivity factors, and stretch factors	June 2013	Stakeholder conference followed by written submissions
Revised Filing Requirements for cost of service rate applications (and IR adjustment if necessary)	June 2013	Consolidation of work from Network Infrastructure Investment Planning and Performance Measurement
Board determination on stretch factor assignments for 4th Generation IR	July 2013	As per current process

3 Distribution Infrastructure Investment Planning

Under the renewed regulatory framework, good planning is necessary to ensure that the Board's outcomes as set out in Chapter 1 are being achieved. The Board's approach to rate-setting described in Chapter 2 also depends on effective planning by distributors. The Board needs evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget. Distributor plans must therefore demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation with customers, municipalities and neighbouring distributors and transmitters where applicable.

3.1 An Integrated Approach to Distribution Network Planning

3.1.1 Planning as the Foundation for Rate-Setting

A number of Board planning requirements have evolved over time, and different regulatory instruments have been issued in response to specific regulatory needs. Figure 1 illustrates the Board's current regulatory framework. It sets out the relationships between a distributor's asset management and network investment planning processes, notes the Board's regulatory instruments that call for distributors to file certain network planning information, and identifies the information to be provided.[9]

The Board's filing requirements identify the planning horizon for different types of investment. Section 2.5.2.4 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "<u>CoS Filing Requirements</u>")[10] stipulates that, at a minimum, a three-year forecast of capital expenditures, covering the test year plus two

[9] Section 2 of the *Staff Discussion Paper on Distribution Network Investment Planning* summarizes the Board's current approach.
[10] Revised version issued June 28, 2012.

subsequent years, must be filed. The Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*[11] ("GEA Filing Requirements") state that "GEA Plans" should cover a five year horizon. The Board understands that distributors typically use five- to ten-year horizons for their own internal planning purposes. The GEA Filing Requirements are currently the only ones that integrate regional considerations and call for broader consultation

Stakeholder Views

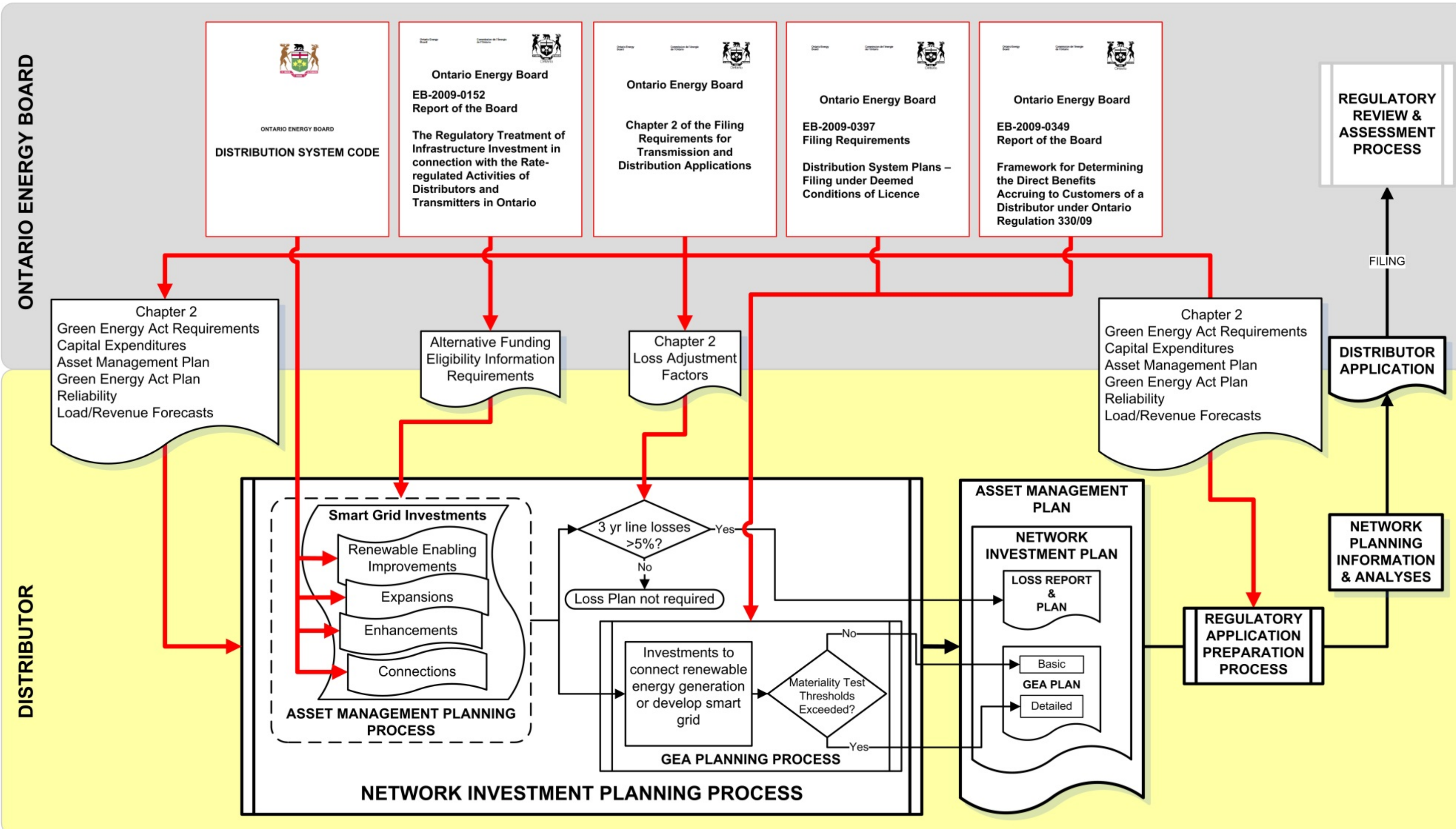
There was wide-spread stakeholder support for integrated network planning, although some stakeholders noted that certain investment drivers are inherently unpredictable. Stakeholders suggested that integrated planning would facilitate the identification and analysis of trade-offs amongst different investment options, promote sustainable least cost planning, and support optimized regional infrastructure planning.

Stakeholders generally agreed that a longer term view is needed in relation to investment planning, noting among other things that a multi-year approach better accommodates planning for large investments and allows greater scope to prioritize and pace investments and smooth rate increases. Reconciling long-term capital planning with shorter-term rate cycles and accommodating differences between transmission and distribution investments in terms of the time between planning and "in service" status were noted as challenges. Distributors largely favoured a planning horizon of three to five years as the minimum standard. Some stakeholders suggested that planning information be updated annually.

Several stakeholders underscored that the implementation of an integrated approach to planning must include the consolidation, simplification or standardization of the Board's various planning-related filing requirements.

[11] Revised version issued May 17, 2012.

Figure 1: Current Regulatory Framework for Distribution Network Planning



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The Board's Conclusions

The Board concludes that, in order to have distribution plans that support the Board's performance outcomes approach to rate-setting, an integrated approach to infrastructure planning is required. Under an integrated approach, all categories of network investments will be planned together, including investments for the renewal and expansion of networks and, where applicable, investments for the connection of renewable generation facilities, investments for smart grid development and implementation, and investments identified in the course of regional infrastructure planning exercises. An integrated approach to planning will provide a foundation for the setting of distribution rates and lead to optimized investments that support the achievement of the outcomes identified by the Board.

The Board will work to consolidate its various planning-related filing requirements. Harmonization and consolidation of these regulatory requirements can facilitate planning that will better support the achievement of the desired outcomes of the renewed regulatory framework. To the extent practicable, the terms and definitions used for asset management and investment planning information filings will be standardized to enhance clarity, consistency, and comparability. Also to the extent practicable, the Board will develop standardized requirements for capital plans and related filings.

Figure 2 provides a high level illustration of this approach, the main elements of which are discussed in later sections of this Chapter.

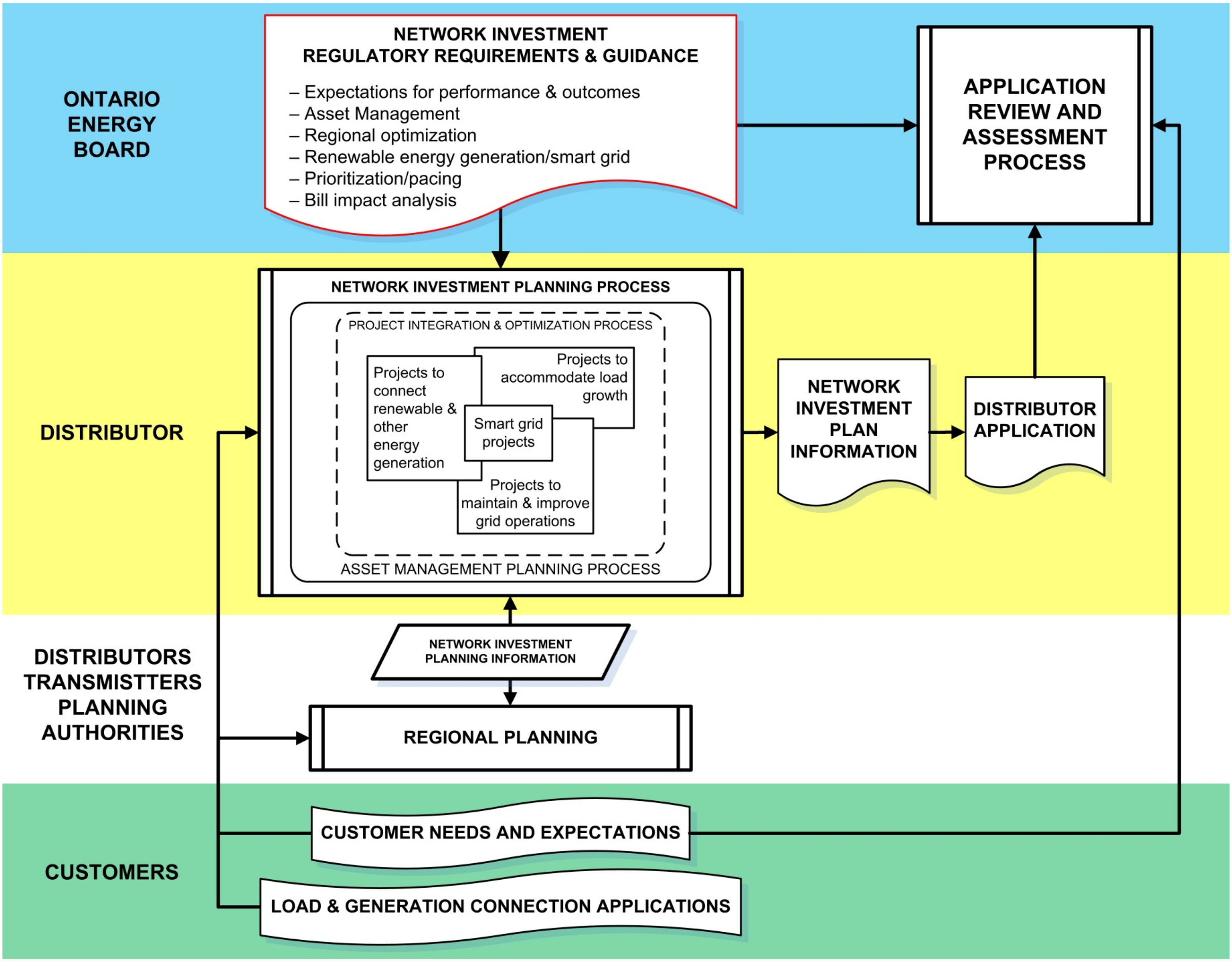
The Board further concludes that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles. This time horizon, along with the integrated approach to planning, will allow distributors to pace and prioritize projects with a view to the impact on the total bill for customers.

This planning horizon should also enhance cost predictability for both the distributor and its customers.

All distributors will therefore be required to file network investment planning information for five forecast years (where the initial or test year is the first forecast year) as part of any application for the rebasing of their rates under 4th Generation IR, or for the setting of their rates under the Custom IR method. Distributors using the Annual IR Index method will also be required to file a plan at intervals to be specified by the Board. The scope and level of detail required in the plan will depend on the scope and magnitude of the capital investments the plan is intended to support.

The Board will also monitor and measure plan implementation and plan achievement as discussed in Chapter 4.

Figure 2: Integrated Approach to Distribution Network Planning



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3.1.2 The Board's expectations for asset management and investment planning

Since 2009, the Board has required distributors to file an asset management plan if available. Where no asset management plan is available, the distributor must file information outlining its approach to the planning and prioritization of capital projects.[12]

Stakeholder Views

There was a general recognition that greater standardization of asset management plans in terms of concepts, definitions and key plan elements is needed to reduce costs, facilitate regulatory review and enhance regulatory predictability.

Stakeholders suggested different approaches for addressing uncertainty in the context of a multi-year planning horizon and for avoiding the adverse impact that deferred investments can have on customer rates. A "best practice" approach to asset management planning was suggested as a means of ensuring that investments are adequately supported and justified in distributor asset management plans.

The Board's Conclusions

The Board concludes that further development and rationalization of the Board's filing requirements should be undertaken to assist the production of planning information to better support distribution rate setting. The Board will further engage stakeholders in the development of standard requirements for asset management and capital plans. The standard requirements will facilitate the testing of the plans and ensure that the Board's expectations are clear to utilities and other stakeholders.

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[12] *CoS Filing Requirements*, section 2.5.2.4.

3.1.3 Tools and methods to support proposed investments

The Board's filing requirements identify minimum requirements with respect to the quantitative data and qualitative information that is to be provided by distributors as part of their filings. The onus, however, remains on a distributor to provide the data, information and analyses necessary to justify the forecasted costs that are the basis for the distributor's proposed rates. Filings must enable the Board to assess whether and how a distributor has sought to control costs in relation to its proposed investments through the appropriate optimization, prioritization and pacing of investment expenditures.

There is a need, therefore, to consider whether specific qualitative and quantitative analyses should be required to assist the Board in its review and consideration of distributor investment plans. Whether and how experts might be used to assist in the assessment of distributor investment plans and planning processes was also noted for consideration.

Stakeholder Views

Some stakeholders endorsed the involvement of independent third party experts in the assessment of distributor planning processes and filings. It was noted that this is currently a practice in the United Kingdom, and that some Ontario distributors already routinely use third party experts for plan evaluation purposes.

Stakeholder proposals for tools and methods to support and justify distributor investments included specific quantitative analyses and verifiable or authoritative qualitative information. A variety of data and quantitative analyses were suggested.

Stakeholder views varied on bill impact estimations and associated tools. Some stakeholders were supportive of a requirement that distributors consider forecasts of the 'total bill' when developing their spending plans, identifying this as essential to the pacing and prioritization of investment in a manner that controls year-over-year rate increases and to reducing the need for mitigation at the time of Board approval. Others noted that some costs on the total bill are outside of a distributor's control, and that increases in these costs should not result in automatic offsetting adjustments to distribution investment spending.

The Board's Conclusions

As indicated in the Introduction to this Report, the Board's first two statutory objectives are key considerations for the policies described in this Chapter. Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan. The Board recognizes that factors beyond a distributor's control may add complexity and uncertainty to any effort to estimate bill impacts on customers. However, a distributor must exercise control over the pace of its own capital spending, as this factor can be an important element in the total cost of electricity to customers. To aid distributors in this essential task, standardized methods and tools should be developed for use by distributors in the preparation of their plans. In addition, the Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor).

The Board will further engage stakeholders on the identification and development of qualitative and quantitative approaches and tools to be used by distributors to support their investment proposals, including methodologies to assist in prioritizing and pacing proposed investments in consideration of the total bill impact on customers. The output of any methodology will need to be transparent, robust and reproducible, and include forecast information from independent and authoritative sources where these are publicly available.

3.2 Regional Infrastructure Planning

3.2.1 Background

Regional planning has been undertaken for many years in Ontario. However, until recently most distributors focused almost exclusively on the delivery of electricity to their own load customers. The *Green Energy and Green Economy Act, 2009* has created an increased need for coordinated planning among distributors and transmitters, and also among neighbouring distributors, on a regional basis. The development and implementation of the smart grid will also require regional coordination. [13]

3.2.2 Integration of Regional Considerations

Some Ontario utilities are already engaged in regional or otherwise coordinated planning exercises or discussions. In the context of the Board's conclusion that more integrated planning is needed in the renewed regulatory framework, the question is whether a more structured approach to regional infrastructure planning is required.

Stakeholder Views

Many stakeholders were supportive of a more formal approach to regional planning as a means of addressing key concerns with the current approach. In their view, the current approach is not sufficiently inclusive (in particular, ratepayer interests are under-represented) and a more formal approach would address this issue and ensure participation by all distributors. Other stakeholders, however, were of the view that the current approach is adequate.

[13] The Minister's Directive referred to later in this Chapter identifies regional coordination as a policy objective to guide the Board in the development of guidance to the industry on the development and implementation of the smart grid.

There was general agreement that any regional planning process should be a “one-step” process, with the Ontario Power Authority (“OPA”), the relevant transmitter and the relevant distributors involved in developing a single regional plan. There was also general agreement on the need for all potential solutions, including distribution and transmission infrastructure, distributed generation and conservation and demand management (“CDM”) solutions, to be considered in the context of a new regional planning process.

Some stakeholders suggested that regional plans should be approved by the Board, whether separately or in the context of a rate or leave to construct proceeding.

The Board’s Conclusions

The Board concludes that infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into utility planning processes, which will, in turn, help promote the cost-effective development of electricity infrastructure in the Province. The effective use of regional infrastructure planning and the inclusion of regional considerations in distributors’ and transmitters’ plans will also be key in ensuring that the development and implementation of the smart grid in Ontario is carried out on a coordinated basis and that smart grid investments are made at the system level (distribution or transmission) that will best serve the interests of the region.

Distributors and transmitters will therefore be expected to file evidence in rate and leave to construct proceedings that demonstrates that regional issues have been appropriately considered and, where applicable, addressed in developing the utility’s capital budget or infrastructure investment proposal. The Board does not expect that a formal regional infrastructure plan will be required in all instances to satisfy this filing requirement. While the Board will consider regional infrastructure plans in its regulatory processes, the Board will not formally approve these plans.

The Board believes that effective regional infrastructure planning will be best achieved by allowing relevant stakeholders a further opportunity to build on their practical experience and on the input received through this consultation to date. The Board will convene a stakeholder working group to prepare a report that sets out the details of appropriate regional infrastructure planning processes, that designs the outputs of the planning process and that identifies any changes to the Board's regulatory instruments that may be needed to support the process. The Board expects the following to be reflected in that report:

- The Board expects regional infrastructure planning to be more structured, and therefore lead responsibility must be assigned. The Board believes that there is merit in having this responsibility lie with the appropriate transmitter. The transmitter will work with the OPA to identify where CDM or distributed generation options may represent potential solutions.

- Regions that will form the foundation for the process will be identified, such that all distributors will have an understanding of the regions within which they reside. The Board sees merit in having predetermined regions that are based on electrical system boundaries, and suggests that the Independent Electricity System Operator's electrical zones be used as a starting point.

- Protocols will be in place for the sharing of information among relevant parties.

- Distributors will be expected to participate in regional infrastructure planning processes.

Following receipt of that report, the Board will determine whether any changes to its regulatory instruments are required.

3.2.3 Facilitating the Implementation of Regional Infrastructure Planning through Amendment of Board Codes

Two issues relating to cost responsibility for transmission connection assets have been identified as potential impediments to the implementation of regional infrastructure planning and the execution of regional infrastructure plans.

The first issue (the "Otherwise Planned and Refund" issue) is centered on sections 6.3.6 and 6.2.24 of the Transmission System Code ("TSC"). As a general rule under the TSC, cost responsibility for transmission connection assets lies with the transmission customer, who may be required to make a capital contribution before the asset is built. Section 6.3.6 of the TSC creates an exception by stating that a capital contribution is not required for connection facilities that are "otherwise planned" by the transmitter. Section 6.2.24 of the TSC contemplates that, where a customer has made a capital contribution for the construction of a connection facility and that capital contribution includes the cost of capacity not needed by the customer, the customer is entitled to a refund of a portion of the capital contribution if that capacity is later assigned to another customer. However, that entitlement to a refund ends five years after the connection facility comes into service.

The second issue (the "Transmission Asset Definition" issue) pertains to the definition of certain transmission connection assets and the cost responsibility consequences that flow from that definition. Specifically, the question is whether certain line connection assets are more appropriately treated as network assets for cost responsibility purposes.

Stakeholder Views

Otherwise Planned and Refund Issue

Stakeholders generally agreed that changes to the current TSC cost responsibility rules for line connection assets are required to facilitate regional infrastructure planning and the ultimate execution of regional plans. Stakeholders were also broadly supportive of a shift away from the current emphasis on a ‘trigger’ pays model in relation to new or upgraded line connection investments.

It was noted that section 6.3.6 of the TSC can act as a disincentive to joint planning between the transmitter and distributors and that there are ambiguities in relation to when or how that section applies, as previously acknowledged by the Board.[14]

Some stakeholders identified that the effect of the five-year sunset proviso in section 6.2.24 of the TSC is that later-arriving customers that benefit from a connection asset are able to avoid contributing to the cost of that asset. It was noted that this can create an inappropriate incentive for a distributor to delay requesting additional capacity until after the five year period expires.

The Transmission Asset Definition Issue

Stakeholders were generally supportive of redefining line connection assets. Among the concerns noted with the current cost responsibility regime is that it does not take into account the evolutionary nature of the transmission system and that, in some

[14] In its September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), the Board stated that *“[T]here can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other….That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required.”*

cases, a distributor is responsible for the costs associated with line connection assets that perform functions beyond simply supplying the distributor.

However, stakeholders were divided on the scope of the proposed redefinition. Some stakeholders suggested that line connection assets be defined as network assets in all cases. Others proposed that line connections be so defined only in cases where such line connection assets provide other functions beyond supplying a distributor, citing the example of Dual Function Lines.[15]

It was also noted that line connection assets are not currently classified in a consistent manner. In particular, in about 50% of the cases 115/230 kV auto-transformers are currently classified as network assets (and the costs recovered from all Ontario ratepayers), while in the remaining 50% of the cases they are classified as line connection assets (and the costs recovered from only the triggering distributor and its customers). It was further noted that all distributors in a region benefit from a 115/230 kV auto-transformer, and that it is essentially impossible to determine the extent to which each transmission customer benefits from such an asset.

The Board's Conclusions

Otherwise Planned and Refund Issue

The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard.

[15] The definition of certain line connections as Dual Function Lines was approved by the Board in Hydro One's EB-2006-0501 transmission rate proceeding. It addressed the Board's concerns associated with the Line Connection pool in the RP-1999-0044 transmission rate proceeding, where the Board stated that it expected the definition of the Line Connection pool to be reconsidered in Hydro One's next cost allocation and rate design proceeding.

The reference to “otherwise planned” in section 6.3.6 of the TSC implies that a transmitter is expected to plan investments without the input of transmission customers, including distributors. This is incompatible with the Board’s approach to regional infrastructure planning set out above. The Board will therefore initiate a process to propose the removal of section 6.3.6 of the TSC.

The Board also concludes that the five year limit on the requirement to provide a refund to the initial transmission customer or customers that provided a capital contribution may be creating unintended effects. The Board will therefore also propose amendments to section 6.2.24 of the TSC regarding the five-year sunset provision.

These TSC amendments would apply on a go forward basis only (i.e., only to initial customers that make a capital contribution after the amendment comes into force).

Transmission Asset Definition Issue

The Board concludes that no redefinition is required in relation to transformation connection assets for the purpose of facilitating regional infrastructure planning. However, the Board also concludes that the redefinition of certain line connection assets in a manner that better reflects the function that each asset performs will facilitate the implementation of regional infrastructure planning, and should also place distributors (and therefore all Ontario customers) on a more level playing field in terms of cost responsibility. To the extent that line connection assets are defined based on function, distributors (and their customers) will be responsible only for the costs associated with upgrades to assets that are used solely to supply a distributor or group of distributors (i.e., where such distributors are the sole beneficiaries). The end result will be somewhat akin to ‘partial’ province-wide pooling with the uploading of some transmission assets from the line connection pool to the network pool. At the same time, all distributors will remain responsible for the costs associated with some line connection assets. This approach should maintain cost discipline.

The Board has concluded that all 115/230 kV auto-transformers and the associated switchgear should consistently be defined as network assets. The rationale for classifying this subset of transmission assets as network assets was previously explained by the Board as follows:

> These unique system elements in some instances accommodate loads that are beyond a customer's requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) …. In particular, use of autotransformers is seen as a means to optimize use of the transmission system as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.[16]

The Board will further engage stakeholders in the identification of all line connection assets that perform one or more functions beyond supplying the distributor and in developing criteria to be used to assess new assets and future upgrades to existing assets for redefinition purposes. That consultation will take into account the function the asset performs, reflect the 'beneficiary' pays principle and consider the frequency with which line connection assets should be reviewed to ascertain the function they provide for the purpose of future transmission rate proceedings.

Once the stakeholder consultation has been completed, the Board expects to propose amendments to the relevant provisions of the TSC with a view to integrating the new treatment of all applicable line connection assets, and will proceed with any other changes to its regulatory instruments as may be required to give effect to those amendments.

These changes are expected to apply on a go forward basis only (i.e., to new line connection assets or to upgrades to existing line connection assets that are built after the amendment comes into force). This approach will avoid retroactive changes in cost allocation and the associated rates. As a consequence, the Board notes, only future

[16] September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), pages 24-25.

line connection upgrades have the potential to affect the execution of regional infrastructure plans.

Pooling

During the consultation process, stakeholders provided insight into the relative merits of implementing changes to the Board's cost responsibility regime that are of a more transformative nature than those discussed above. Specifically, stakeholders commented on the potential to move to the regional or province-wide pooling of transmission connection facility costs, in whole or in part. The Board has concluded that a shift to province-wide pooling carries with it the risk of cross-subsidization, the potential for transmission overbuild and an inappropriate cost shifting between regions in the province. Regional pooling would only address those risks to some extent, and would be too complex to implement as regions may change over time and a number of distributors would be included in more than one regional pool. Moreover, the Board is satisfied that a move to any form of pooling of costs is neither necessary nor desirable at this time for the purpose of facilitating regional infrastructure planning and the execution of regional plans, given how the Board is addressing the cost responsibility issues discussed above.

3.3 Development of the Smart Grid

3.3.1 Background

With the coming into force of the *Green Energy and Green Economy Act, 2009*, several provisions were added to the OEB Act in relation to the development and implementation of a smart grid in Ontario. The Board now has a statutory objective to facilitate the implementation of a smart grid on Ontario, and it is a deemed condition of license for all licensed electricity distributors and transmitters to plan for and make smart grid investments as directed by the Board.[17]

On November 23, 2010, the Minister of Energy issued a Directive to the Board requiring it to provide guidance to licensed electricity distributors and transmitters (among possible others) regarding the Board's expectations in relation to smart grid activities. In developing that guidance, the Board is to be guided by certain parameters for three objectives for the smart grid, namely, customer control objectives, power system flexibility objectives and adaptive infrastructure objectives. The Board is also to be guided by 10 policy objectives of the government, including policy objectives pertaining to efficiency, customer value, interoperability, and privacy.

3.3.2 Smart Grid Planning and Innovation

Planning for smart grid development and implementation by electricity distributors and transmitters will be an integral part of the broader network investment planning exercise, and the Board's guidance with respect to smart grid activities will be provided in a Supplemental Report of the Board. Moreover, the Board expects that smart grid development will be coordinated on a regional basis in furtherance of the government policy objective set out in the Minister's Directive to the effect that smart grid implementation efforts should involve regional coordination in order to achieve economies of scope and scale.

Smart grid investments are eligible for the application of the "alternative" mechanisms identified in the "*Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors* (EB-2009-0152)". As noted in Chapter 4, the Board intends to explore further opportunities to embed the

[17] Paragraph 4 of section 1(1) and section 70(2.1) of the OEB Act, respectively. The *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* referred to earlier in this Chapter speak to electricity distributor planning activities in respect of smart grid demonstration projects, studies, planning exercises, education or training, and establish deferral accounts for costs associated with these activities.

facilitation and recognition of technological innovation in the renewed regulatory framework. Smart grid development and implementation activities will be a central focus of that effort, given that grid-enhancing advanced technology systems and equipment are at the heart of the smart grid.

3.3.3 Treatment of Smart Grid Investments for Rate-setting

Under the integrated approach to planning described in this Report grid-enhancing advanced information and exchange systems and equipment (which are commonly referred to as smart grid) are considered integral to all utility investment. Under this approach, no distinction is made for regulatory purposes between “smart grid” and more traditional investments undertaken by distributors and transmitters – more advanced technologies are so integrated with other activities that such distinctions are not productive.

This approach to smart grid investments and activities will best support the achievement of the objectives of the renewed regulatory framework. It facilitates more fully integrated planning, and will promote economic efficiency and the better alignment of expenditures with cost recovery so as to minimize ‘total bill’ impacts. It is also more efficient from a regulatory perspective.

3.3.4 Demarcation of Utility Role: “Behind the Meter” Activities

One of the objectives of the smart grid set out in the Minister’s Directive is customer control. Parameters for that objective include enabling access to data by authorized parties, enabling consumers to better control their consumption and providing consumers with opportunities to participate in small-scale renewable generation. The Board considers that the achievement of this customer control objective will require that “behind the meter” services and applications be available to customers. The issue of behind the meter services is closely linked to that of access to meter data. Access to meter data is key in facilitating the provision of behind the meter services and applications. The Board's regulatory framework for smart grid development and implementation should therefore facilitate data access and the implementation of behind the meter services and applications.

The question that arises is the role of distributors in the provision of behind the meter services and applications. Currently, there are private (i.e., unregulated) businesses that provide these services and applications, and that do so without Board oversight. Some distributors also provide such services on a non-utility basis as part of a CDM program. One example is the Peaksaver program offered on behalf of the OPA.

Stakeholder Views

Few stakeholders commented on this issue. One stakeholder proposed that there should be no restrictions on the provision of behind the meter services. Another maintained that distributors should be allowed to provide behind the meter CDM services, but also stated that the "demarcation should be the meter". Input was also received from the Smart Grid Working Group.

The Board's Conclusions

The Board anticipates that distributors will continue to be engaged in the provision of behind the meter services and applications that fall within the parameters set out in section 71(2) or section 71(3) of the OEB Act. In so doing, they are engaging in a non-utility activity. That activity must be accounted for separately from utility activities and be undertaken on a full cost recovery basis (in other words, not covered in rates). There is no element of natural monopoly in the market for behind the meter services and, therefore, the Board has concluded that customer control would be best served by the forces of market competition. The Board expects that this policy conclusion will assist distributors in planning and organizing their and their affiliate's activities.

3.3.5 Other Issues

Following the receipt of the Minister's Directive, Board staff consulted with the Smart Grid Working Group to produce a Staff Discussion Paper, which was issued in November 2011, and in that paper identified a number of key issues, including cyber-security, privacy, interoperability, customer access and the recognition of types of benefits flowing from smart grid in applications. Issues not addressed in this Report will be addressed in the Supplemental Report of the Board on Smart Grid.

3.4 Implementation

The Board will establish two new stakeholder working groups to accomplish activities dealing with distribution network planning and regional infrastructure planning. The Board will also reconvene its previously established smart grid working group. The principal tasks of these working groups will be:

- An Integrated Approach to Network Planning: To revise the Board's filing requirements for distributors and transmitters and issue guidance in accordance with the Board's conclusions in the Report. The development of an integrated set of revised filing requirements will include those related to distribution network planning, smart grid planning and regional planning.

- Regional Infrastructure Planning: To develop guidance regarding the implementation of the Board's conclusions in the Report related to moving to a more structured approach to regional infrastructure planning, as well as the appropriate redefinition of certain line connection assets and TSC cost responsibility rule changes to remove barriers related to regional plan execution.

- Development of the Smart Grid: To develop the regulatory documents to implement the Minister's Directive and the Board's conclusions in the Report.

The main products and timelines for these working groups are outlined in the table below. Further detail is provided in the remaining sections of this chapter.

	Product	**Planned issuance**	**Process**
Network Planning	Consolidated capital plan filing requirements	February 2013	Staff proposal on asset management and capital planning filing requirements Working group meetings Staff proposal on integrated filing requirements Working group meetings
Integrating Regional Planning	Consolidated capital plan filing requirements	February 2013	Working group meetings Working group report to Board (regional infrastructure planning process, filing requirements) Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements
	Amendments as necessary to TSC and DSC	April 2013	Working group meetings Working group reports to Board (asset redefinition, regional infrastructure planning process) Notice of proposed code amendments
Smart Grid	Supplemental Report of the Board	January 2013	Working group meetings Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements

3.4.1 Distribution network investment planning

The Board's filing requirements in relation to distributor asset management and investment planning information will be enhanced, and the Board will release Consolidated Capital Plan Filing Requirements in February 2013.

In order to implement the Board's requirements for integrated infrastructure planning, the Board will identify tools and methods to support proposed infrastructure investments in distributor applications, including the demonstration of how the distributor has optimized, prioritized and paced investments to take into consideration the total bill impact on customers.

3.4.2 Facilitating effective regional infrastructure planning

The Board will determine the regional infrastructure planning related information needed to support rate and leave to construct applications, and this will be incorporated into the Board's Consolidated Capital Plan Filing Requirements.

Key elements that need to be addressed in order to facilitate the move to a more structured regional infrastructure planning process include the following:

- The information a distributor should be required to provide to the transmitter for regional infrastructure planning purposes and the frequency at which it should be updated;
- The appropriate evaluative criteria to compare potential solutions;
- The circumstances under which the OPA should participate;
- The form in which broader consultation should take place before a regional plan is finalized; and
- Appropriate regional boundaries and the criteria to be used to establish them.

A Working Group Report to the Board will be produced, as well as a staff proposal for consolidated filing requirements. The Board expects that the section of the Report addressing regional infrastructure planning process matters will also provide input for the Board's consideration in relation to any other key elements that the working group believes should be addressed in order to facilitate the move to a more structured regional infrastructure planning process.

3.4.3 Facilitating the implementation of regional infrastructure planning

As noted in this Report, the Board believes that changes to the cost responsibility regime necessary to facilitate regional infrastructure planning will require the development of a set of criteria based on the function(s) that line connection assets perform. These changes will be effected through a notice and comment process to amend the relevant TSC sections.[18] Given the interconnected nature of these cost responsibility changes related to the redefinition of line connection assets and those involving TSC cost responsibility rule changes discussed above (i.e., "Otherwise Planned and Refund Issue"), the Board will address all of the proposed amendments in one notice and will propose the same implementation date for all amendments. This code amendment process will also address amendments to the TSC that may be required in relation to the regional infrastructure planning process matters discussed above.

The proposal for Code amendments will also be informed by a Working Group Report to the Board in relation to criteria for line connection asset redefinition and identifying the assets that meet those criteria. The Board expects any amendments made to the Codes will come into force in mid-2013.

3.4.4 Smart grid guidance

The Board will issue a Supplemental Report providing the Board's guidance on smart grid, including the integration of smart grid development into the overall regional and

[18] The redefinition of certain line connection assets may also require proposed amendments to other regulatory instruments of the Board.

network planning filing requirements. The Board expects to issue the Supplemental Report on smart grid policy in January 2013, and to integrate the smart grid work into the Consolidated Capital Plan Filing Requirements.

4 Performance Measurement and Continuous Improvement

The renewed regulatory framework is a comprehensive performance-based approach to regulation that promotes the achievement of performance outcomes that will benefit existing and future customers. The framework will align customer and utility interests, continue to support the achievement of important public policy objectives, and place a greater focus on delivering value for money.

The achievement of the performance outcomes will be supported by specific measures and targets and annual reporting. Distributor performance will be compared year over year, both to prior performance and to the performance of other distributors. To facilitate performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes.

Under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers.

4.1 Monitoring Distributor Performance

Under the rate-setting approach described in Chapter 2, the Board will be setting rates under longer-term plans and allowing distributors to select the rate-setting method that best meets their needs and circumstances. Distributors will be required to undertake longer-term integrated planning that captures all categories of network planning, including those reflecting regional needs, as discussed in Chapter 3.

The Board has standards and measures for performance in place today;[19] however, the Board needs to assess whether these continue to be appropriate in light of the performance outcomes defined by the Board and the new rate setting methods. The Board also needs to consider the consequences that might flow from performance that does not meet the standards.

Benchmarking will become increasingly important, as comparison among distributors is one means of analyzing whether a given distributor is as efficient as possible.

Stakeholder Views

There was general stakeholder support for meaningful, empirically-based standards, performance measures and regulatory mechanisms, provided that the implementation costs do not outweigh the value for customers. Desirable characteristics that were identified included: focus on what customers value; promoting alignment of distributor and customer interests; and ability to accommodate differences within the distribution sector.

Stakeholder suggestions for objectives to underpin the development of distributor customer service and cost performance standards and measures included furthering market development; revealing infrastructure investment planning effectiveness or cost performance; facilitating price transparency for customers; and improving existing customer service standards.

A number of stakeholders acknowledged the cost performance incentives that are inherent in incentive regulation. Caution was expressed about implementing direct financial incentives until Board-approved measures are in place. Stakeholders were divided on process incentives; some were supportive of streamlined regulatory processes for high-performing distributors while others were opposed to limits being

[19] These are identified in the *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors.*

placed on the review of applications based on the quality of evidence or the applicant's past performance.

The Board's Conclusions

Performance Outcomes and the Electricity Distributor Scorecard

The Board is establishing performance outcomes that it expects distributors to achieve in four distinct areas:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board concludes that a scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. The scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons, which are critical to the Board's rate-setting approach under the renewed regulatory framework. Distributors will be required to report their progress against the scorecard on an annual basis.

A sample of a possible scorecard based on a simple sub-set of the Board's current standards and measures (such as the service quality requirements in the *Distribution System Code*) is provided below. The sample is provided for illustrative purposes only, as the Board has not yet determined content of the scorecard to be used. The Board expects that the scorecard will evolve as appropriate standards and measures are developed to assess distributor performance against the identified outcomes.

Figure 3: Sample Scorecard

Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance
services provided in a manner that responds to identified customer preferences	*continuous improvement in productivity and cost performance; and delivery on system reliability and quality objectives*	*delivery on obligations mandated by government (specific legislation or via directives to the Board)*	*financial viability maintained; and savings from operational effectiveness are sustainable*
• Customer complaints • Connection statistics • Connection of New Service • Reconnection • Telephone Accessibility • Appointments Met • Written Response to Enquiries • Emergency Response • Telephone Call Abandon Rate • Appointments Scheduling • Rescheduling a Missed Appointment	• Distribution Losses • System Average Interruption Frequency Index (SAIFI) • System Average Interruption Duration Index (SAIDI) • Customer Average Interruption Duration Index (CAIDI) • Momentary Average Interruption Frequency Index (MAIFI)	• Electricity Conservation (Kwh) • Peak Demand Reductions (kW)	• Current Ratio • Debt Service Capability • Interest Coverage • OM&A Cost per Customer • Return on Equity

Standards and Measures

The Board will engage stakeholders in further consultation on the standards and measures to be included in the distributor scorecard. The standards and measures must be suitable for use by the Board in monitoring and assessing distributor performance against expected performance outcomes, in monitoring and assessing distributor progress towards the goals and objectives in the distributor's network investment plan, in comparing distributor performance across the sector and identifying trends, and in supporting rate-setting.

The Board has established a set of objectives to guide the consultation. Standards and measures should:

- be aligned with, and reflect a distributor's effectiveness in achieving, the performance outcomes listed in Chapter 1;
- be reflective of customer needs and expectations;
- encourage year-over-year performance gains;
- reveal current performance and signal future performance;
- reflect a distributor's effectiveness in prioritizing and pacing investment (with regard to total bill impacts) and implementing its capital plan;
- be measureable by each distributor, and be aligned with their reporting for their own internal purposes to the extent possible;
- consider the characteristics of a distributor's service territory; and
- be practical.

4.2 The Role of Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking. Expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework policies.

Stakeholder Views

There was general support for the continued development and use of benchmarking tools, with further empirical work on the distribution sector identified as a priority. It was noted that the cost of this exercise should not exceed its value, recognizing that there may be limits to the practical use of cost comparison and benchmarking information. Among suggestions offered for the further use and development of benchmarking tools were the use of external data, benchmarks and productivity trends to establish boundaries within which distributors should operate; the more rigorous implementation of benchmarking in rate proceedings; and the adoption of a “balanced scorecard” approach to benchmarking to reflect customer and distributor diversity.

The Board’s Conclusions

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4th Generation IR and the Annual IR Index, and will inform the Board’s review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor’s rates are set, the distributor will continue to be included in the Board’s benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.

4.3 Regulatory Mechanisms

The Board is committed to ensuring optimal performance and value for customers, and will continue to enhance its regulatory mechanisms where necessary to achieve this goal. In initiating the performance-based approach, the Board will maintain its existing regulatory mechanisms, subject to certain refinements. Specifically, the X-factor will be refined as discussed in Chapter 2 and the "publication of distributor results" mechanisms referred to above (among possible others) will be integrated into the electricity distributor scorecard.

The Board's incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board's current policies as set out in the *Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors*, the Board expects that new approaches may be required.

In addition, appropriate consequences should flow from unsatisfactory performance against the Board's standards, in order to maintain the integrity of the Board's outcome-based approach and its approach to rate-setting.

Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- The establishment of an "efficiency carry-over" mechanism;
- Development of incentives to;
  - reward superior performance;
  - encourage innovation;
  - encourage asset optimization; and
- Potential consequences for inferior performance.

The development of these regulatory mechanisms will be aligned with the standards and measures referred to above.

4.4 Implementation

To establish the outcome based framework and provide for effective monitoring of distributor performance, the Board will:

- define the standards and measures that will be applicable to distributors;
- establish benchmarking models (through further empirical work);
- establish the reporting requirements applicable to distributors, including the format of the performance scorecard; and
- determine the regulatory mechanisms that will be used in conjunction with those standards and measures (in due course).

A stakeholder working group will be established to provide staff with expert assistance and to help staff review and evaluate proposals regarding performance standards, measures, and the development of benchmarking. This will also include consideration of rate adjustment indices (i.e., inflation and X factors). Staff and consultant reports will be issued for comment.

With respect to benchmarking, the objective is to establish total cost benchmarking for the 2014 rate year. Further work will involve comprehensive benchmarking (i.e., model(s) that combine standards for utility customer service and cost performance) to be applied in subsequent rate years.

The end result of this work will be a Supplemental Report of the Board expected to be issued in mid-2013. Regulatory instruments such as the Reporting and Record Keeping Requirements will be amended as necessary to implement the Supplemental Report.

Work carried out in this consultation to develop total cost benchmarking will provide the foundation for the development of the Board's approach to comprehensive benchmarking. The overall approach and timeline for such additional work will be issued after the substantial completion of work planned for implementation for the 2014 rate year.

	Product	Expected issuance	Process
Standards and measures	Supplemental Report of the Board, including distributor scorecard	June 2013	Staff proposal Stakeholder meeting Working group meetings Board staff report to the Board (for comment) Stakeholder meeting Written comments
	Amendments to RRR if needed	July 2013	Notice and comment
Benchmarking	Supplemental Report of the Board (same document as above), plus consultant report on approach to total cost benchmarking	June 2013	Validation of data by distributors Consultant Concept paper Stakeholder meeting Working group meetings Consultant report (for comment) Stakeholder meeting Written comments

4.4.1 Issues to be addressed in relation to standards, measures and regulatory mechanisms

Working with stakeholders, the Board will consider the following areas in the context of developing a scorecard and performance standards, and measures to facilitate annual monitoring of distributor performance.

Assessing performance outcomes:

- confirm the standards and measures that best reflect a utility's effectiveness and/or continuous improvement in achieving the performance outcomes.

Effective planning & implementation:

- establish measures that best reflect a distributor's effectiveness with respect to:
    - planning - prioritizing and pacing investment with regard to total bill increases to consumers;
    - plan implementation – progress in achieving targets against the capital plan; and
    - plan achievement – achievement of the goal(s)/outcome(s) originally committed to in an approved capital plan

Regulatory reporting:

- establish the electricity distributor scorecard to effectively organize how utilities report on their performance to the Board.

Regulatory Mechanisms:

In due course, the Board will further engage stakeholders to consider the appropriate form and implementation of:

- an "efficiency carry-over" mechanism; and
- performance incentives to reward achievement of utility plan objectives, and/or encourage and reward implementation of truly innovative technologies to address system and customer requirements.

4.4.2 Issues to be addressed in relation to benchmarking

The use of OM&A data to benchmark distributors for stretch factor assignment purposes in the 3rd Generation IR plan is the foundation for a more comprehensive (e.g., total cost) benchmarking approach. Work to develop the more comprehensive benchmarking model(s) will also create the dataset necessary to estimate Ontario TFP trends.

The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the utility customer service and cost performance outcomes, including total cost benchmarking and an Ontario TFP study. This work will inform the Board determination on inflation and X factors for rate-setting.

The Board will also determine how to make expanded use of benchmarking for assessing distributor performance as well as to inform rate setting. In particular, the Board will establish how its standards for utility service and cost performance and various empirical tools and benchmarking will further inform (a) utility planning processes, (b) utility applications to the Board, and (c) the Board's review processes.

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5 Implementation and Transition

5.1 Implementation

As noted throughout the Report, additional work is required in each of the three policy areas to implement the Board's renewed regulatory framework. The policies set out in this Report are integrated and therefore will be implemented in a coherent sequence and in a manner that allows them to interact effectively. The complete listing of activities planned over the next several months is included in Appendix B.

As outlined in the implementation section of previous chapters, the Board will establish three stakeholder working groups to provide staff with expert assistance and to review and advise staff on proposals regarding the implementation tasks. The first working group will focus on performance, benchmarking and rate adjustment indices. The second group will address outstanding matters with respect to network investment planning, and the third will work on development of regional infrastructure planning processes. In addition, the Smart Grid Working Group will be reconvened. The stakeholder members of the working groups will be selected by the Board. By sharing certain members in common, working group efforts will be coordinated and mutually informed on an on-going basis.

Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies. The Board expects that the policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year.

5.2 Transition

The Board expects that the three new rate setting methods will be available for the 2014 rate year. At that time, distributors may select the appropriate rate setting method for their utility.

The Board has established a transition plan to facilitate the early adoption of the three new rate-setting methods. The Board is aware that the preparation of a rate application can be a lengthy and resource-intensive effort. In devising the implementation and transitional measures described in this Report, the Board is attempting to balance the interest in having the new rate-setting methods available to most distributors for the 2014 rate year with the recognition of the time needed to prepare applications under the new methods. A set of tables have been provided below that represent the transition options that distributors have based on their current status in the 3rd Generation IR plan, and the timing of their rate year.

Option 1 – 4th Generation IR

Transition to full 4th Generation IR will depend on when a distributor is next scheduled to rebase under cost of service.

Option 1a – Distributor completes remaining term of 3rd Generation IR

Those distributors who are within the term of their current 3rd Generation IR (in other words are scheduled to rebase for January 1, 2015 rates or later) will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR term. The adjustment mechanism will be the same as that used for 4th Generation IR. Filing requirements for these annual adjustment applications will be available for January 1, 2014 rates.

The Board discourages distributors who are not currently scheduled to be rebased for 2014 rates from filing applications for early rebasing under the 4th Generation IR method. The Board will continue to apply the criterion regarding early rebasing enunciated in its letter of April 20, 2010: that is, that a distributor must clearly demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM period.

Option 1b – Distributor Rebases under 4th Generation IR

Complete filing requirements (including Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements) will be available for rebasing applications under 4th Generation IR for May 1, 2014 rates. In order to provide some additional time to prepare applications, these rebasing applications may be filed by October 1, 2013. When a distributor rebases using the 4th Generation filing requirements, the total term will be 5 years.

For distributors scheduled to rebase for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available:

1) Rebase under 3rd Generation IR filing requirements (in other words, without the 5 year capital plan) and remain under IR for 4 years total (rebasing plus 3 years) with rates adjusted annually using the 4th Generation IR annual adjustment
2) Delay rebasing by one year - rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years.

Option 2 - Move to the Annual IR Index

Distributors may file for rates under the Annual IR Index at any time. Filing requirements for the Annual IR Index will be available for January 1, 2014 rates. Distributors on the

Annual IR Index method will be required to file five-year capital plans in accordance with the Consolidated Capital Plan Filing Requirements on a periodic basis, and perhaps as soon as with applications for May 1, 2014 rates. This timing will be confirmed when the Board issues the Consolidated Capital Plan Filing Requirements.

Option 3 - File a Custom IR application.

Distributors may file for a Custom IR as soon as the Consolidated Capital Plan Filing Requirements are available. This option will not be available for January 1, 2014 rates, but will be available for purposes of setting May 1, 2014 rates or later.

Distributors may make a Custom IR application any time within a 3rd or 4th Generation IR or Annual IR Index term. The Board will permit an exception to the early rebasing test for distributors applying under the Custom IR method in advance of their normal rebasing date. The Board's view is that the Custom IR method should be available as soon as possible for distributors with prolonged elevated investment needs. One of the Board's main concerns with early rebasing is the opportunity it affords distributors to avoid the efficiency incentives in the annual adjustment mechanism. The Board is satisfied that the Custom IR process will be sufficiently rigorous that an assessment of the adequacy of past and future productivity levels can be made and the results of that assessment can be incorporated into the distributor's future rates.

The Board anticipates that there could be a significant case load for the determination of 2014 rates as a consequence of the implementation of the new framework. Delays may occur. Any distributor intending to apply under the Custom IR method for 2014 rates is encouraged to speak with Board staff at an early point to discuss scheduling.

The Board does not intend to publish filing requirements for the Custom IR method (other than the Consolidated Capital Plan Filing Requirements) at this time, although much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers. Consistent with the conclusions set out in this Report in relation to the Custom

IR method, the onus will be on the applicant to specify and substantiate its preferred approach to multi-year rate-setting. After the Board has gained some experience with these types of applications it may publish filing requirements for Custom IR applicants.

Figure 4: Transitional Measures for Rates for May 1, 2014 or Later

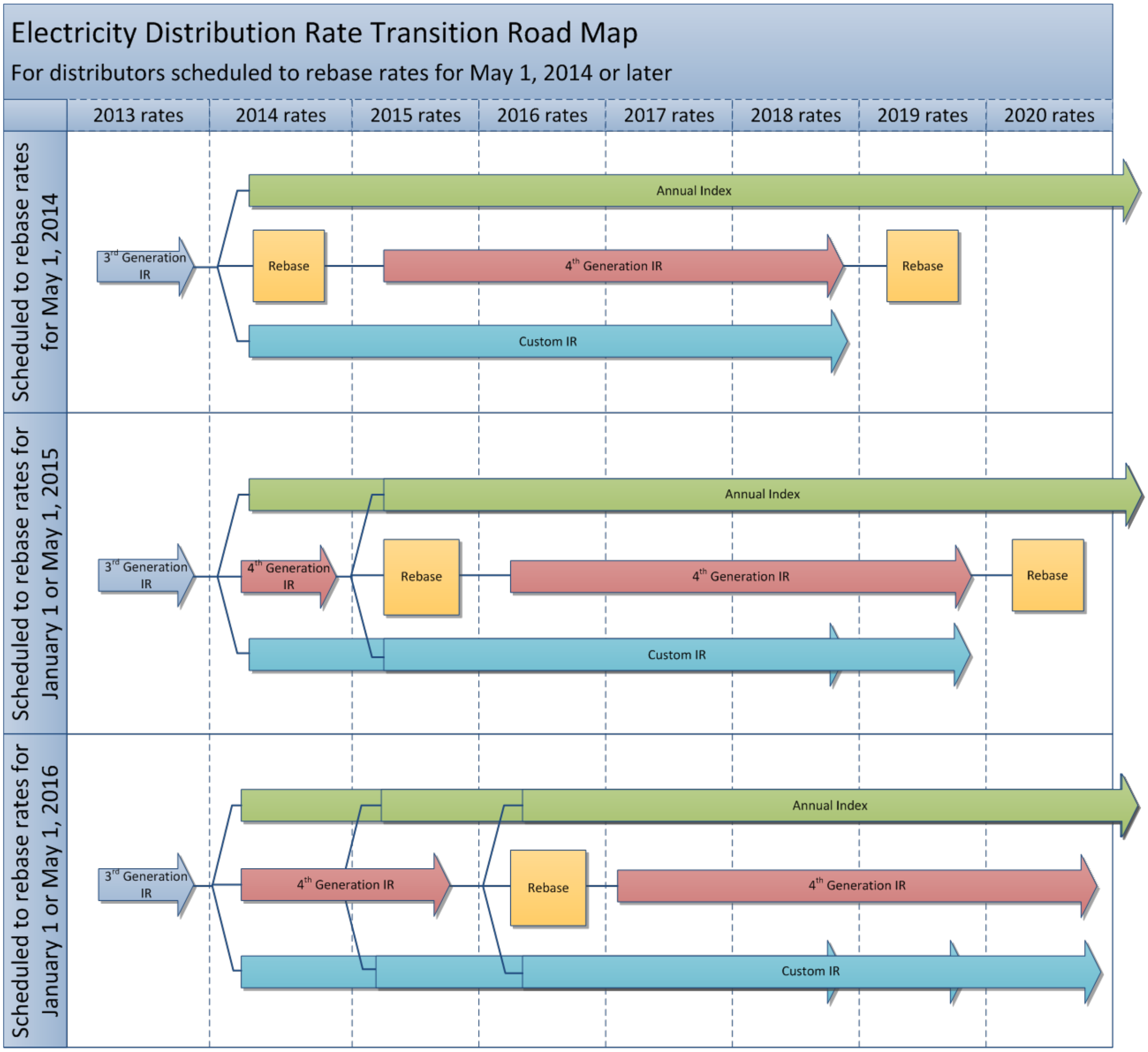
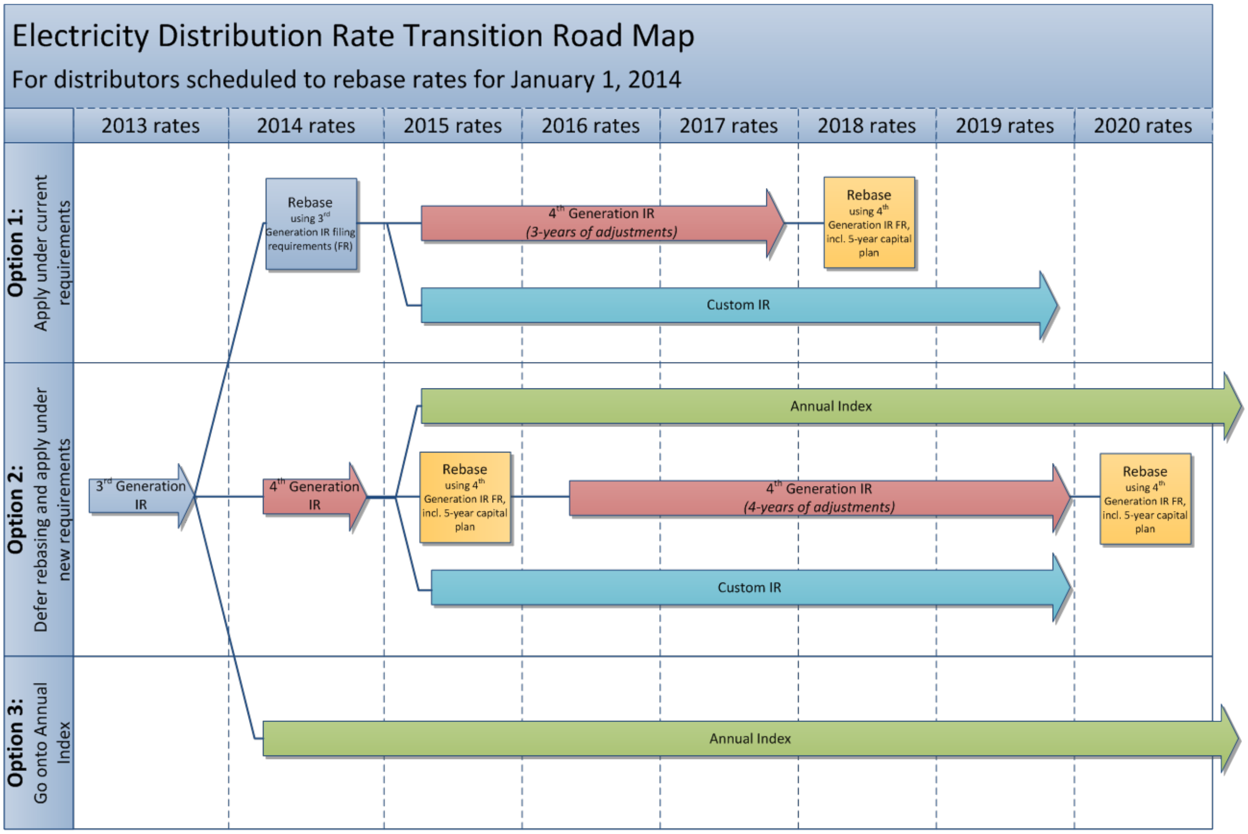


Figure 5: Transitional Measures for Rates for January 1, 2014



Appendix A: Summary of Consultation Activities to Date

Unless otherwise indicated by a prefacing identifier, all five inter-related initiatives were addressed in coordinated consultation activities.

Date	Issue / Document
Oct 27-10	The Board issued a letter announcing its intention to develop a Renewed Regulatory Framework for Electricity. • Letter
Dec 17-10	The Board issued a letter a letter initiating a consultation process to develop three key elements to a Renewed Regulatory Framework for Electricity. • Letter
Jan 13-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Ontario Energy Board is initiating a consultation with stakeholders on the implementation of Smart Grid. The Board invites all interested parties to participate in this consultation - a Smart Grid Working Group (SGWG). Nomination to participate in the working groups is due January 24, 2011. • Letter
Jan 27-11	Board staff has posted material for the Stakeholder Conference to be held on February 2nd. • Instructions on How to Join the Stakeholder Conference via WebCast (for those not attending in person) • Draft Agenda • Presentations o Overview o Distribution Network Investment Planning (EB-2010-0377) o Rate Mitigation (EB-2010-0378) o Defining and Measuring Performance of Electricity Distributors and Transmitters (EB-2010-0379)
Jan 31-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board received the following Smart Grid Working Group Submissions: • Accenture • Association of Major Power Consumers in Ontario • Bell Canada • Bluewater Power Distribution Corporation • Building Operators and Managers Association • Cambridge and North Dumfries Hydro Inc. • Capgemini

Date	Issue / Document
	• Certicom Corp. • Chatham-Kent Hydro • Cornerstone Hydro-Electric Concepts • David O'Brien • Direct Energy Marketing Ltd. • Electrical Safety Authority • Electricity Distributors Association • Elenchus Research Associates • Elster Metering • Enbala Power Networks • Enbridge Gas Distribution Inc. • Energate - 1 o Energate - 2 o Energate - bio • Energent Inc. • Energy Aware Technology Inc. • Enersource • Erie Thames Powerlines • Festival Hydro Inc. • GE Digital • General Motors of Canada • Honeywell • Horizon Utilities • Hydro One Networks Inc. • Hydro Ottawa Ltd. • IBM • Independent Electricity System Operator • Just Energy • Kinectrics Inc. • London Property Management Association • Measurement Canada • Metering Support Services Canada Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc. • Ontario Sustainable Energy Association • PowerStream Inc. • Regen Energy - 1 • Simpleafy • Society of Energy Professionals • Telvent • Thunder Bay Hydro Electricity Distribution Inc. • Toronto Hydro-Electric System Ltd. • Utilismart Corporation • Utilities Kingston • Veridian Connections Inc.
Feb 14-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): Board staff today issued a letter on the selection of Smart Grid Working Group members • Letter

Date	Issue / Document
Apr 1-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board initiated a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters. • Board letter on Regional Planning and participation
May 4-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): Stakeholder Meeting • Agenda
Jun 3-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has issued Meeting Notes from the Stakeholder Meeting on Regional Planning. • Meeting Notes
Nov 8-11	The Board has issued a set of staff discussion papers and supporting consultant reports for the initiatives set out below. Details on the consultation process are set out in the cover letter. • Cover Letter • Distribution Network Investment Planning • Approaches to Mitigation for Electricity Transmitters and Distributors • Defining and Measuring Performance of Electricity Transmitters and Distributors • Developing Guidance for the Implementation of Smart Grid in Ontario • Regional Planning for Electricity Infrastructure • FAQs: Renewed Regulatory Framework for Electricity
Nov 8-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper
Nov 8-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper

Date	Issue / Document
Nov 23-11	The Board's letter dated November 8, 2011, invited interested stakeholders to participate in a two-day Information Session on the staff discussion papers and consultant reports issued that day. The session will be held on December 8 and 9, 2011. The purpose of this informal session is to give participants an opportunity to ask clarifying questions to better understand the documents. Today, Board Staff posted details regarding stakeholder participation at that session. • Details on Staff Information Session **Questions in Advance Encouraged** To facilitate an efficient and useful session, participants are encouraged to send written questions in advance to Board staff at RRF@OntarioEnergyBoard.ca. Please provide document references, if any, with your questions. Questions provided in advance will be used by staff to help kick off the session.
Dec 6-11	Board staff posted a draft agenda for the two-day Information Session planned for December 8 and 9, 2011. • Draft Agenda

Dec 9-11	Board staff posted the questions that participants of the two-day Information Session provided in writing.
	
	• Canadian Manufacturers & Exporters
	  o December 2, 2011 Letter
	  o Questions
	  o Brief
	• Consumers Council of Canada
	• Electrical Contractors Association of Ontario
	• Just Energy Ontario LP
	• Low-Income Energy Network
	• Ontario Power Authority
	• Pollution Probe
	• Power Workers' Union
	• School Energy Coalition

Dec 12-11	Board staff posted material shown at the December 8 – 9 Information Session. • Power Advisory 'Bill Impact Estimation Model' presentation
Feb 6-12	The Board has issued a letter providing an update to interested stakeholders on the consultation process for its initiative to develop a renewed regulatory framework for electricity distributors and transmitters. • Letter • Attachment A - "straw man" model Regulatory Framework

Date	Issue / Document
Feb 22-12	The Board has issued a letter inviting interested stakeholders to a Stakeholder Conference, scheduled for **March 28 – 30, 2012**, as part of the Board's consultation process to develop a renewed regulatory framework for electricity distributors and transmitters. **Please note, participants are asked to register in advance by e-mail to RRF@ontarioenergyboard.ca by 4:30 p.m. on March 9, 2012**. • Letter
Mar 2-12	Regional Planning for Electricity Infrastructure (EB-2011-0043): In the Board staff information session on the Renewed Regulatory Framework for Electricity held on December 8/9, 2011, clarification of the Ontario Power Authority's ("OPA") current regional planning process was requested. In response, the OPA provided a description of their regional planning process. • Description of the OPA's regional planning process
Mar 20-12	Board staff posted a draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Draft Agenda

Mar 21-12	Board Staff has posted materials from a series of Executive Roundtable Meetings held by the Chair during February and March 2012.
	
	• Presentation
	• List of Attendees
	• Meeting Notes:
	  o Consolidated Notes from Executive Roundtables with Distributor
	  o Consolidated Notes from Executive Roundtables with Consumer Groups
	  o Notes from Executive Roundtable with Agencies & Transmitters
	  o Notes from Executive Roundtable with Academics, Finance Industry, Consultants & PWU

Mar 23-12	Board Staff has posted the presentations filed by participants for the Stakeholder Conference to be held March 28-30.
	
	• Travis Allan, Counsel for Retail Council of Canada
	• Tom Brett, Counsel for Building and Office Managers Association
	• Jake Brooks, Executive Director, the Association of Power Producers of Ontario
	• Bob Chow, Director – Transmission Integration, Ontario Power Authority
	• Frank Cronin, Consultant to Power Workers Union
	• John Cyr, Counsel for Northwestern Ontario Associated Chambers of Commerce & Northwestern Ontario Municipal Association
	  o Presentation
	• Susan Frank, VP & Chief Regulatory Officer of Regulatory Affairs, Hydro One Networks
	  o Regional Planning
	  o Investment Recovery
	• Robert Frank, Counsel for Electrical Contractor Association of Ontario
	• Marion Fraser, Director, Ontario Sustainable Energy Association
	• Rene Gatien, President & CEO, Waterloo North Hydro Inc.

Date	Issue / Document

	• Jack Gibbons, Consultant to Pollution Probe
	• Elise Herzig, President & CEO, Ontario Energy Association
	• Brennain Lloyd, Coordinator for Northwatch
	• Colin McLorg, Manager – Regulatory Policy & Relations, Toronto Hydro
	• Jack Robertson, Vice President & General Manager, Elster Metering
	• Andrew Roman, Counsel for Medium Size Distributors Group
	• Bruce Sharp, Consultant to Canadian Manufacturers & Exporters and co-sponsored by Consumers Council of Canada, Vulnerable Energy Consumers Coalition, School Energy Coalition, and Federation of Rental-housing Providers of Ontario
	  o Aegent OEPIF: unit price increase details
	  o Aegent OEPIF: unit price increase pie charts
	  o Aegent OEPIF: residential increases
	• Jay Shepherd, Counsel for School Energy Coalition
	• John Loucks, Vice-President - Corporate and Member Affairs, Electricity Distributors Association
	• George Vegh, Chair, Distribution Regulation Review Task-Force
	• Adonis Yatchew, Consultant to Electricity Distributors Association

Mar 27-12	Board staff posted an updated draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Updated Draft Agenda • Attachment to Draft Agenda
Apr 5-12	The Board has issued guidance to stakeholders on issues where comments would be particularly helpful to the Board in developing a renewed regulatory framework for electricity distributors and transmitters. **Interested stakeholders are invited to file written comments by April 20, 2012** in accordance with the filing instructions set out in the letter below. • Letter
Apr 9-12	Board staff posted transcripts from the March 28-30 Stakeholder Conference. • Transcripts
Apr 24-12	Board staff has posted the written comments received by the Board by April 20, 2012. • View Comments (+)

Appendix B: Summary of Planned Consultation Activities

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
2012						
October	Stakeholder working groups established to address distribution network investment planning, smart grid, and regional planning issues			Stakeholder working group established to address both performance- and benchmarking-related issues		
	A web-cast on the "Report of the Board: A Renewed Regulatory Framework for Electricity" and next steps will be held					
November	**Staff proposal** issued in relation to asset management and capital planning filing requirements	Working group meetings			**Summary of data points and time series** needed for empirical analysis issued for distributor validation	
				Staff proposal on standards, measures, and scorecard issued	**Consultant concept paper** on empirical analyses *(including consideration for inflation and productivity)* and benchmarking issued	
December	Working group meetings		**Working Group Reports to the Board** issued: (1) Asset Redefinition; (2) Regional Planning Process	A stakeholder meeting to inform and generate ideas prior to convening the working group		
				Working group meetings on standards, measures and scorecard		
2013						
January		**Supplementary report of the Board** issued: Smart grid policy		Working group meetings (continued)	Distributor validation of data points and time series due	
	Staff proposal for consolidated capital planning filing requirements issued					
	Working group meetings					

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
February	Working group meetings (continued)		**Proposed amendments to the Transmission System Code** issued **If needed, proposed amendments to the Distribution System Code** issued		Working group meetings on empirical analyses *(including consideration for inflation and productivity)* and benchmarking	
	Application filing requirements and guidelines issued setting out consolidated capital planning provisions					
March				**A Board Staff Report to the Board** on standards, measures and scorecard issued for comment	**Consultant report** on methodology, data analysis, calculations, and results in relation to the preferred approach to benchmarking issued *(consideration for inflation and productivity will inform a Stakeholder Conference in April)*	
April			**Amendments to the Transmission System Code** issued	Stakeholder meeting on performance and benchmarking related issues		Stakeholder conference on appropriate values for inflation and productivity factors
May				Written *comments due on staff report and the preferred approach to benchmarking and results*		
June				**Supplemental Report of the Board** issued describing the standards, measures and scorecard reporting associated with utility outcomes for customer service and cost performance **Consultant final report** setting out the approach to total cost benchmarking that will be used by the Board issued		**Board determination** on inflation, productivity factor, and stretch factors issued **Application filing guidelines** issued setting rate application provisions
July				**If needed, proposed amendments to the Electricity Reporting & Record Keeping Requirements** issued		**Board determination on stretch factor assignments** issued

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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

[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.

[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.

[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.

[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.

[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

[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

[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:

[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.

[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.

[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]

[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.

[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.

[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.

[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

[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.

[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.