EB-2018-0085

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determine payment amount for the output of certain generation facilities for the period of January 1, 2017 to December 31, 2021;

AND IN THE MATTER OF a motion by Ontario Power Generation Inc. pursuant to Rule 32 of the Ontario Energy Board's *Rules of Practice and Procedure* for an order or orders to vary the Decision with Reasons in EB-2016-0152.

COMPENDIUM AND BOOK OF AUTHORITIES OF THE SCHOOL ENERGY COALITION

March 22, 2018

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INDEX

Tab

1. OPG Argument-in-Chief, March 3 2017 (excerpt)
2. Exhibit A1-2-1 (excerpt)
3. Letter from OPG to Ms. Walli: dated February 22, 2017, Attachment A and B
4. *Decision and Order on Motion to Review* (EB-2011-0053 - Grey Highlands), April 21, 2011
5. *Decision and Order on Motion to Review* (EB-2013-0193 - Milton Hydro Motion to Review), July 4 2013
6. *Decision on Motion to Review Decision and Order* (EB-2013-0331 - NAN), January 16 2014
7. *Grey Highlands (Municipality) v. Plateau Wind Inc*., 2012 ONSC 1001
8. Final Argument of the School Energy Coalition (excerpt)
9. Final Argument of the Consumers Council of Canada (excerpt)
10. Final Submissions of the Association of Major Power Consumers in Ontario (excerpt)
11. Submissions of Canadian Manufactures and Exporters (excerpt)
12. Final Submissions of London Property Management Association (excerpt)
13. *Decision and Order* (EB-2014-0369 – Ontario Power Generation Motion to Review), January 28 2016
14. *Decision with Reasons* (RP-2004-0167/EB-2005-0188 - Natural Resource Gas Ltd. Motion to Review), October 6 2005
15. *Decision and Order* (EB-2009-0063 - Brant County Power Inc. Motion to Review), August 10 2010
16. *Decision and Order* (EB-2016-0225 - Milton Hydro Motion to Review), February 22 2018
17. *Decision on Motion* (RP-2005-0020/EB-2005-0361/EB-2006-0197/EB-2007-0016 – Erie Thames Powerlines), June 8 2007
18. *Decision and Order* (EB-2016-0085 – InnPower), March 8 2018
19. *Revised Decision and Order* (EB-2015-0072 – Grimsby Power), September 22 2016
20. *Decision and Order* (EB-2014-0073 – Festival), April 30 2015
21. *Decision and Order* (EB-2013-0130 - Fort Francis Power), August 14 2014
22. *Decision and Draft Payment Amounts Order and Procedural Order No. 10*, March 12 2018
23. *Union Gas Limited v. Ontario Energy Board*, 2015 ONCA 453
24. *Decision and Rate Order* (EB-2013-0119 – Chapleau PUC) March 13 2014
25. *Decision and Orde*r (EB-2013-0022 – Veridian), April 25, 2013

26. *Decision with Reasons* (EB-2007-0905 - Ontario Power Generation Inc.), November 3 2007 (excerpt)

27. Letter from Board Secretary, *Re: Applications for 2019 Electricity Rates*, dated December 7 2017, Attachment A

28. EB-2010-0008, Exhibit A1-3-1 (excerpt)

29. *Filing Guidelines for Ontario Power Generation Inc.: Setting Payment Amounts for Prescribed Generation Facilities* (EB-2011-0286), Revised November 11 2011

30. EB-2017-0049, Letter from Hydro One to Board Secretary, Re: Blue Page Update to Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application, dated June 17 2017

31. Letter from Board Secretary, *Applications for 2017 and 2018 Electricity* Rates, dated December 29 2015

32. *Decision with Reasons* (EB-2013-0416/EB-2014-247 - Hydro One Dx), March 12 2015 (except)

33. Exhibit A2-1-1, Attachment 3 (excerpt)

34. Exhibit G2-2-1 (excerpt)

35. O.Reg 353/15

36. Exhibit A1-7-1 (excerpt)

37. Stakeholder Consultation Session Notes: Second Information Session on Upcoming Applications, January 22 2015

EB-2016-0152

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Argument-in-Chief

Ontario Power Generation Inc.

May 3, 2017

As necessary, OPG expects that it would submit additional information to enable an assessment of its ROE performance to the OEB as part of its reporting, as well as a proposal on what corrective action, if any, may be required under off-ramp provisions.

13.0 IMPLEMENTATION

13.1 ISSUE 12.1

Primary: Are the effective dates for new payment amounts and riders appropriate?

OPG requests an effective date of January 1, 2017, in respect of the payment amounts associated with the prescribed hydroelectric and nuclear facilities (Ex. A1-2-1, p.1-2). Moreover, OPG requests recovery, by way of rate riders, of the difference between existing payment amounts and the payment amounts sought in this Application from the effective date to the implementation date.

The general IESO settlement process is described in Chapter Nine of the Market Rules. OPG understands that in order for revised payment amounts and riders to be implemented on the first of a given month, a final rate order establishing new payment amounts and riders would have to be issued by the 20th of the second month prior to the implementation month in order for the IESO to update its systems (Ex. I1-4-1).

In OPG's submission, the requested effective date for new payment amounts and rate riders are appropriate and should be approved by the OEB. As filed, the Application complied in all material respects with the OEB's filing guidelines and any directions provided in OPG's last payment amounts proceeding. On August 12, 2016, the OEB issued Procedural Order No. #1. Since then, OPG has met the deadlines established by the OEB and has worked diligently with all parties and OEB Staff to advance the Application in a reasonable and efficient manner, including reaching a settlement on a subset of issues (Ex. O1-1-1). OPG has done so while responding to over one thousand interrogatories and undertakings, and while marshalling evidence to support its requests from dozens of witnesses from across the company and, where appropriate, third party independent experts.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2017.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the *Ontario Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.

2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act"), for an order or orders approving a payment amount for hydroelectric generating facilities (the "regulated hydroelectric facilities") prescribed under Ontario Regulation 53/05 of the Act, as amended, ("O. Reg. 53/05") for the period from January 1, 2017 through December 31, 2017 and a payment rider for the regulated hydroelectric facilities for the period from January 1, 2017 through December 31, 2018.

3. Pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, OPG also seeks an order or orders approving payment amounts for nuclear generating facilities (the "nuclear facilities") prescribed under O. Reg. 53/05 for the period from January 1, 2017 through December 31, 2021 and a payment rider for the nuclear facilities for the period from January 1, 2017 through December 31, 2018.

4. OPG seeks an order declaring the current payment amounts interim effective January 1, 2017 for the regulated hydroelectric and nuclear facilities, if the order or orders approving

the payment amounts are not implemented by January 1, 2017 for the regulated hydroelectric and nuclear facilities.

5. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use the price-cap index methodology proposed in Ex. A1-3-2 for setting payment amounts for the prescribed hydroelectric generating facilities in the period from January 1, 2017 through December 31, 2021.

6. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use the methodology proposed in Ex. A1-3-2 to approve annual revenue requirements for the nuclear facilities for the period January 1, 2017 to December 31, 2021, and the rate smoothing methodology proposed in Ex. A1-3-3 to approve payment amounts for the nuclear facilities for the period January 1, 2017 to December 31, 2021.

7. OPG seeks approval of the cost of capital presented in Ex. C1-1-1.

8. OPG seeks approval for disposition of the audited balances in all of its deferral and variance accounts as of December 31, 2015, except the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Clearance of that account is subject to the completion of the generic proceeding on pension and OPEB costs (EB-2015-0040).

9. OPG seeks an order continuing established deferral and variance accounts as set out in Ex. H1-1-1.

10. OPG seeks an order establishing certain new deferral and variance accounts presented in Ex. H1-1-1.

11. Pursuant to section 78.1 of the Act, and pursuant to sections 5.5 and 6 (2) of O. Reg. 53/05, OPG requests that the OEB approve OPG's nuclear rate smoothing proposal as set out in Ex. A1-3-3, including the establishment of a deferral account and the portion of

the OEB-approved nuclear revenue requirement that is to be recorded in that deferral account for January 1, 2017 to December 31, 2021.

12. OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:
    - an update of the nuclear production forecast and consequential updates to nuclear fuel costs for the final two-and-a-half years of the five-year application period (July 1, 2019 to December 31, 2021); and
    - disposal of applicable audited deferral and variance account balances as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018.

13. To achieve the nuclear revenue requirements and disposition of the nuclear and hydroelectric balances in the deferral and variance accounts, and consistent with the price-cap index methodology for prescribed hydroelectric facilities, OPG is seeking payment amounts and riders as follows:
    - Effective January 1, 2017, $41.71/MWh for the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Where production is over or under the hourly volume, regulated hydroelectric incentive revenue payments will be consistent with the OEB's Payment Amounts Order for EB-2013-0321.

    - Approval for recovery of December 31, 2015 audited balances in the regulated hydroelectric deferral and variance accounts, except the Pension & OPEB Cash Versus Accrual Differential Deferral Account, of $211.3M and a disposition at a rate of $1.44/MWh for the output from the regulated hydroelectric facilities for the period January 1, 2017 to December 31, 2018.

- Approval of the following payment amounts for the nuclear facilities:

Effective Date	Payment Amount
January 1, 2017	$65.81/MWh
January 1, 2018	$73.05/MWh
January 1, 2019	$81.09/MWh
January 1, 2020	$90.01/MWh
January 1, 2021	$99.91/MWh

- Approval for recovery of December 31, 2015 audited balances in the nuclear deferral and variance accounts, except the Pension & OPEB Cash Versus Accrual Differential Deferral Account, of $1,162.4M and a disposition at a rate of $2.85/MWh for the output from the nuclear facilities for the period January 1, 2017 to December 31, 2018.

14. The Application will be supported by written and oral evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

15. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

16. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

17. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 24 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

(a)	The applicant:	Barbara Reuber Ontario Power Generation Inc.
	Mailing address:	H18 G2 700 University Avenue Toronto ON M5G 1X6
	Telephone:	416-592-5419
	Facsimile:	416-592-8519
	Electronic mail:	opgregaffairs@opg.com
(b)	The applicant's Counsel:	Charles Keizer Torys LLP
	Mailing address:	79 Wellington St. W. PO Box 270 Toronto Dominion Centre Toronto ON M5K 1N2
	Telephone:	416-865-0040
	Facsimile:	416-865-7380
	Electronic mail:	ckeizer@torys.com
(c)	The applicant's Counsel:	Crawford Smith Torys LLP
	Mailing address:	79 Wellington St. W.

		PO Box 270 Toronto Dominion Centre Toronto ON M5K 1N2
	Telephone:	416-865-0040
	Facsimile:	416-865-7380
	Electronic mail:	csmith@torys.com
(d)	The applicant's Counsel:	Carlton D. Mathias Ontario Power Generation Inc.
	Mailing address:	H18 A24 700 University Avenue Toronto ON M5G 1X6
	Telephone:	416-592-4964
	Facsimile:	416-592-1466
	Electronic mail:	carlton.mathias@opg.com

Dated at Toronto, Ontario, this 27th day of May, 2016.

Ontario Power Generation Inc.

Charles Keizer
Torys LLP

ONTARIO POWER GENERATION

Barbara Reuber
Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

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barbara.reuber@opg.com

February 22, 2017

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0152 – OPG Rate Smoothing Proposal

To make the increases resulting from its rate application more predictable and to reduce the average year-over-year impact on customer bills arising from its application for payment amounts for the period 2017-2021, OPG has identified a revision to O. Reg. 53/05, which if implemented would modify its rate smoothing proposal. This modified proposal was raised by the OEB and intervenors through the course of the proceeding. OPG has communicated this opportunity to the Minister of Energy (see Attachment A). The Minister has responded favourably (see Attachment B) and is pursuing the required amendments to O. Reg. 53/05.

OPG must await final promulgation of the regulatory change before it can file an amended proposal. Given the imminent start of the hearing in EB-2016-0152 and to facilitate an efficient process, OPG proposes to remove rate smoothing from the scope of Panel 2Aii Application Overview, Nuclear Rate-setting Framework, Business Planning and consider the issue at the end of the hearing through a rate smoothing panel. OPG will file an amended Ex. A1-9-1 which will identify the evidence related to rate smoothing that will be removed from Panel 2Aii and be considered by the rate smoothing panel.

Yours truly,

[Original signed by]

Barbara Reuber

cc: John Beauchamp (OPG) via e-mail
Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail

Attachment A

ONTARIO POWER GENERATION

Jeffrey Lyash
President & Chief Executive Officer

700 University Avenue Toronto, Ontario M5G 1X6

Tel: **416-592-2121** Fax: 416-592-2174
jeffrey.lyash@opg.com

February 17, 2017

The Honourable Glenn Thibeault
Minister of Energy
4th Floor Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Thibeault,

Ontario Power Generation (OPG) takes great pride in providing the lowest cost electricity in the Province and is committed to maintaining this position as a way to keep customer bills as low as possible. I am writing to propose an amendment to Ontario Regulation 53/05 that will permit OPG to submit to the Ontario Energy Board (OEB) a revised rate smoothing proposal that would significantly reduce the impact of OPG's rate application on customer bills.

As you are aware, OPG is in the midst of applying to the OEB for new payment amounts covering the period 2017 through 2021. This application advances several significant Provincial initiatives. In advancing these initiatives, OPG has been focused on the safe delivery of quality projects while controlling costs. To reduce the impact on customer bills, our rate application already contains a rate smoothing proposal but we believe that more can be done.

Coming out of discussions between OPG, the OEB panel, OEB staff and intervenors, we have identified an opportunity to further reduce the impact of our rate application. OPG's current submission is based on a smoothing of nuclear payment amounts as is required under Ontario Regulation 53/05. We propose that Ontario Regulation 53/05 be changed to smooth the total customer bill impact arising from changes in OPG's combined payments by adjusting the amount that OPG collects over time.

If this step were taken, subject to a final decision from the OEB, this would limit the increase on the average bills to 62 cents a month per year from the currently proposed $1.05, an average of a 40% reduction in the customer bill impact arising from OPG's application. If the Province is supportive of the implementation of a regulation change, OPG would modify its rate smoothing proposal in this current application to further reduce the impact on customer bills.

I also want to assure you that we understand the concerns of our customers and will look for ways in future rate applications to maintain our position as the low cost energy provider.

There is some urgency to this request given that we are to start the hearing portion of this application in late February. I am happy to answer any questions you may have and look forward to a favourable response

Sincerely,

Jeff Lyash

Attachment B

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

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900, rue Bay
Toronto ON M7A 2E1
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Téléc. : 416 327-6754

Ontario

FEB 2 1 2017

MC-2017-321

Mr. Jeffrey J. Lyash
President and CEO
Ontario Power Generation
700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lyash:

Thank you for your letter dated February 17, 2017, outlining Ontario Power Generation's (OPG) suggested changes to *Ontario Regulation 53/05* under the *Electricity Act, 1998*. These proposed changes would help to smooth the recovery of costs associated with OPG capital investments, taking into account the overall impact on customer bills.

According to your letter, OPG's current application would have resulted in an average $1.05 per month impact on customer bills, on an annual basis for the 2017 to 2021 application period, if accepted by the Ontario Energy Board (OEB). OPG's current proposal would reduce average bill impacts to $0.62 per month on an annual basis; a 40 per cent reduction relative to OPG's current application. This aligns with the province's objectives of reducing costs for electricity customers in Ontario.

I would ask that you work with the Ministry of Energy staff in order to enable this change on an expedited basis, recognizing the urgency in finding ways to provide relief for customers and the timing of OPG's application. Please ensure that all changes are designed to mitigate cost impacts to electricity customers. I trust the OEB will review this application, in accordance with its objectives to protect the interest of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

Your proposal demonstrates leadership on the part of OPG staff, management and Board of Directors to keep the interests of Ontario ratepayers at the forefront of your corporate mission. I am also pleased to learn that this proposal was a result of the established OEB intervener process, which encourages dialogue and collaboration between all interested parties.

Sincerely,

Glenn Thibeault
Minister

EB-2011-0053

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF the *Electricity Act, 1998* S.O. 1998, c. 15 (Sched. A) (the "*Electricity Act*");

AND IN THE MATTER OF an application by Plateau Wind Inc. for an order or orders pursuant to section 41(9) of the *Electricity Act* establishing the location of Plateau Wind Inc.'s distribution facilities within certain road allowances owned by the Municipality of Grey Highlands;

AND IN THE MATTER OF a Motion by the Municipality of Grey Highlands, pursuant to Section 42 of the Board's *Rules of Practice and Procedure*, for a review by the Board of its decision EB-2010-0253 dated January 12, 2011;

AND IN THE MATTER OF Rules 42-45 of the Board's *Rules of Practice and Procedure*.

BEFORE: Karen Taylor
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER ON MOTION TO REVIEW

BACKGROUND

On January 12, 2011, the Board issued its Decision and Order in Board File No. EB-2010-0253 (“Decision”),in relation to an application by Plateau Wind Inc. (“Plateau”) under subsection 41(9) of the *Electricity Act, 1998* regarding the location of Plateau Wind Inc.’s distribution facilities within certain road allowances owned by the Municipality of Grey Highlands (“Grey Highlands”). The Board determined the location of Plateau’s distribution facilities within certain public rights-of-way, streets and highways owned by Grey Highlands.

On February 16, 2011, Grey Highlands filed a Notice of Motion with the Board seeking an Order of the Board (the “Motion”) for the following:

1. To review and overturn the Decision of January 12, 2011 wherein the Board determined that the Applicant was a “distributor” for the purposes of section 41 of the *Electricity Act*.
2. As a result of the foregoing, an Order declaring that the Ontario Energy Board has no jurisdiction to determine the location of Plateau’s facilities within the road allowances owned by the Municipality.
3. An Order staying the original decision until such time as a determination on the motion has been issued.

Grey Highlands submitted that the findings of the Board raise a question of the correctness of the Decision on the following grounds:

a. The Board erred in its interpretation and application of Section 4.0.1of Ontario Regulation 161/99, which was an error of law;

b. The Board erred in the determination of its jurisdiction, which was an error of law;

c. The Board erred in the interpretation of the definitions of “renewable energy generation facility”, “distribution systems” and “distribute” in the Electricity Act which was an error of law;

d. The Board erred in determining the location of the structures under section 41(9) of the Act based on an erroneous conclusion (at paragraph

> 44 of the Decision that "the two parties [the Municipality and the Applicant] had reached a mutually acceptable agreement with respect to the location, construction, operation and maintenance of the Distribution Facilities within the Road Allowances". The foregoing constitutes a mixed error of fact and law.

In Procedural Order No. 1 issued March 11, 2011 the Board determined that it would proceed with the Motion by way of a written hearing to determine the threshold question of whether the matters should be reviewed before conducting any review on the merits of the Motion. In determining the threshold question the Board noted that it considers the grounds for the motion in relation to the grounds set out in Rule 44.01 (a). In Procedural Order No. 1 the Board stated the following:

> Rule 44.01 of the *Rules of Practice and Procedure* states that a motion for review must set out grounds that raise a question as to the correctness of the order or decision in question, which grounds may include the following: (i) error in fact; (ii) change in circumstances; (iii) new facts have arisen; and (iv) facts that were not placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

The Threshold Issue

Under Rule 45.01 of the Board's *Rules of Practice and Procedure,* the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits. Section 45.01 of the Board's Rules of Practice and Procedure (the "Rules") provides that:

> In respect of a motion brought under Rule 42.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

The threshold question was articulated in the Board's *Decision on a Motion to Review Natural Gas Electricity Interface Review Decision*[3] (the "NGEIR Decision"). The Board, in the NGEIR Decision, stated that the purpose of the threshold question is to determine whether the grounds put forward by the moving party raised a question as to the

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[3] May 22, 2007, EB-2006-0322 / 0388/ 0340, page 18

correctness of the order or the decision, and whether there was enough substance to the issues raised such that a review based on those issues could result in the Board varying, cancelling or suspending the decision.

Further, in the NGEIR Decision, the Board indicated that in order to meet the threshold question there must be an "identifiable error" in the decision for which review is sought and that "the review is not an opportunity for a party to reargue the case".[4]

In demonstrating an error, the moving party must show that the findings are contrary to the evidence, the panel failed to address a material issue or something of a similar nature. The alleged error must be material and relevant to the outcome of the decision. The review is not an opportunity to reargue the case. A motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and there is no purpose in proceeding with the motion to review.

SUBMISSIONS AND FINDINGS

a) Interpretation and application of Section 4.0.1of Ontario Regulation 161/99

The first ground of the Motion submitted by Grey Highlands is that the Board erred in its interpretation of section 4.0.1 of Ontario Regulation 161/99 which exempts certain distributors from the requirements of the *Ontario Energy Board Act, 1998* including the requirement to obtain a licence. Grey Highlands submitted that the Board, in relying on section 4.0.1 of the Regulation, failed to give consideration to its original submissions on the totality of the statutory and regulatory regime that applies to a "distributor".

Plateau submitted that Grey Highlands has failed to identify any error or change in fact or circumstances that would present sufficient grounds, within the context of Rule 42.01 of the Board's *Rules of Practice and Procedure,* to raise questions as to the correctness of the Board's original Decision. Specifically, Plateau submitted that Grey Highlands not only failed to provide evidence of any error in fact, change in circumstance or new evidence but also, this first ground of review is immaterial to the outcome of the Decision. In addition, Plateau submitted that the Motion makes incorrect, misleading claims that have no bearing on the correctness of the Decision.

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[4] NGEIR Decision*,* at pages 16 and 18

Board Findings

The Board finds that Grey Highlands' submissions on this ground are a restatement of legal arguments it made in its original submissions in the section 41(9) application and on which the Board ruled in its Decision. As such, it has failed to demonstrate any of the factors or considerations enunciated in Section 42.01 of the Board's Practice Direction, or the NGEIR decision. Motions for Review are not an opportunity to merely re-state the position of the Moving Party. The Moving Party must provide convincing argument that the original Decision was incorrect on grounds that are additional to those urged on the original panel.

b. The Board erred in the determination of its jurisdiction and its interpretation of the definitions of "renewable energy generation facility", "distribution systems" and "distribute" in the *Electricity Act* which was an error of law;

The second and third grounds submitted by Grey Highlands in support of its Motion are interrelated and allege that the Board erred in the determination of its jurisdiction to hear the application and incorrectly interpreted definitions in the *Electricity Act.* Grey Highlands submitted that in the absence of any electricity or any source from which Plateau proposes to "distribute" electricity there can be no "distribution system" and accordingly there can be no matter for resolution pursuant to section 41 of the *Electricity Act*.

Plateau, in its submission, argued that the grounds raised do not pass the threshold test as Grey Highlands is arguing the same position it put forward in the main proceeding and argued that the evidence in the original proceeding ought to have been interpreted differently. In its view Grey Highlands has failed to identify any error or change in the facts or circumstances that could give rise to a different interpretation or any material issue not considered by the Board.

Board Findings

As with the first ground, the Board notes that Grey Highlands' submission in support of these grounds is substantially a restatement of its submissions in the original application. Grey Highlands argues that the evidence in the original application should have been interpreted differently but does not present any error or change in facts or circumstances indicating that the original application should have been decided differently. At the heart of Grey Highlands' submissions is the notion that the defined terms "distribution system", "generation facility", transmission system" and "renewable energy generation facility" are mutually exclusive such that, if the subject Distribution Facilities are part of a 'renewable generation facility' then they are not also a 'distribution system' and Plateau is not a 'distributor' that can avail itself of section 41(9) of the *Electricity Act.*

The Board finds, as did the panel in the original Decision, that there is nothing in the applicable legislation and regulation that would support such a restrictive, mutually exclusive interpretation of the definitions in the *Electricity Act* or indicate that a "strict construction" of section 41 of that Act is proper, or would yield the interpretation Grey Highlands argues for in its Notice of Motion.

Accordingly, this panel finds that the Decision and Order in the original application did not err in law in its findings with respect to its jurisdiction or interpretation of the definitions considered in the original application.

c. The Board erred in determining that Plateau and Grey Highlands had reached a mutually acceptable agreement

The fourth ground set out in the Notice of Motion is an alleged error of fact arising from paragraph 44 of the Board's Decision of January 12, 2011 which reads as follows:

> [44] *The Board notes Plateau's evidence that,* ***during the course of negotiations between Plateau and the Municipal Staff*** *regarding a road use agreement,* ***the two parties had reached a mutually acceptable agreement with respect to the location, construction, operation and maintenance of the Distribution Facilities within the Road Allowances (the "Proposed Road Use Agreement")*** *and that the Proposed Road Use Agreement was subsequently rejected by the Grey Highlands Council without apparent explanation.* (emphasis added)

Grey Highlands argues that the Board's Decision and Order on the location of Plateau's distribution facilities was based on "an erroneous statement of fact" that "the two parties had reached a mutually acceptable agreement". Grey Highlands essentially argues that the Municipal Staff and the CAO were not authorized by Grey Highlands' Council to enter into a Proposed Road Use Agreement.

Plateau argues that Grey Highland's has taken the above noted paragraph of the Decision and Order out of context. The position of Plateau is that paragraph 44 explicitly discusses and agreement between Plateau and the Municipal Staff of Grey Highlands and this agreement resulted in the preparation of a proposed road use agreement.

Board Findings

The Board finds that it is clear that the “two parties” referred to in the above-noted paragraph are “Plateau and Municipal Staff” and accordingly the Board does not find that the Decision and Order contained an error of fact. Furthermore, the Board referenced the agreement between Plateau and Municipal Staff, not for the purpose of finding, as a fact, that there was a binding agreement between Plateau and Grey Highlands, but rather that there was consensus as between Plateau and Municipal Staff as to the proposed *location* of the Distribution Facilities. On a section 41(9) application the Board the only issue before the Board is the location of the Distribution Facilities. The only evidence before the Board on that specific issue of location was that presented by Plateau (and which had previously been acceptable to Municipal Staff). Plateau’s evidence on this issue was never challenged by Grey Highlands at any time.

The Board has decided to dismiss the Motion without a hearing, pursuant to Section 45.01 of the Board’s *Rules of Practice and Procedure*. In the Board’s view, for the reasons outlined above, the Motion does not meet the requirements of Rule 42.01 of the *Rules of Practice and Procedure* or the established Threshold Tests required for further consideration of the motion to review. Accordingly, the Board finds that the Motion of Grey Highlands is without merit, and that the Board did not err in its Decision of January 12, 2011.

Grey Highlands Reply Submission

The Board finds it necessary to discuss one other issue raised by Grey Highlands in its Reply Submission. Specifically, Grey Highlands takes issue with the Board’s application of the Threshold Question and Test for a Rule 42.01 Motion. Specifically Grey Highlands state that: “If the Threshold Test” referenced by Plateau was intended to apply to this review proceeding, the Board should have indentified and made reference to such test in its procedural order. Procedural Order No 1 dated March 11, 2011 makes no reference to the specific nature or content of the threshold test that it would engage or apply.”

The Board notes that, as set out above, Procedural Order No. 1 specifically asked parties for submissions on the threshold question and stated the following: “In determining the threshold question the Board considers the grounds for the motion in relation to the grounds set out in Rule 44.01 (a)". As such, the Board finds that the threshold test was clearly articulated and, in any event, the Board's findings in this proceeding confirm that there is no reason to doubt the correctness of the Decision and Order.

COST AWARD

Plateau submitted that the Motion is frivolous and vexatious and that, therefore, the Board should make an order requiring that Grey Highlands reimburse Plateau for all of its costs associated with the Motion. including all legal fees and disbursements that Plateau has incurred, and will incur, in responding to the Motion.

Section 30 of the *OEB Act* endows the Board with broad powers to make orders respecting costs. It is open to the Board in an appropriate case to order any person or party to pay all or part of another person's or party's costs of participating in a proceeding before the Board. This would include an order requiring a person or party to pay the costs incurred by the Board itself in conducting the proceeding.

Elsewhere in this Decision the Board has concluded that the Motion brought by Grey Highlands was without merit.

The Board finds that, but for one factor, this is a case where it would be appropriate to require Grey Highlands to pay the costs of the Applicant and the Board associated with this Motion. In the Board's view such an order would be a reasonable one.

However, as noted, there is one factor which operates to make the issuance of such an order in this case unreasonable.

It has not been the Board's practice to make such orders in the past. In the absence of past practice, the Board is not inclined to impose such an order here and now.

Henceforth, however, parties bringing motions should be cognizant of this possibility.

This is not meant in any degree to discourage meritorious motions or motions that while unsuccessful in the result contain substantive legal, policy, regulatory, or factual grounds. Motions are an important regulatory instrument which have not infrequently allowed for the correction of error of whatever kind.

This approach is meant to discourage motions, which represent no reasonably arguable grounds or a substantial re-argument of points rejected by the panel with cogent reasons in the first instance. In appropriate cases the Board may deny a party its own costs, or require it to pay the costs of other parties or the Board, or both. Where the moving party is a regulated entity, the Board may order that the shareholder pay such costs, without recourse to the ratepayer.

The Board expects the incidence of such orders to be infrequent. The standard for qualification is high. But the Board considers the possibility of such orders to be a necessary element of its governance of its own processes.

THE BOARD THEREFORE ORDERS THAT:

1. The motion to review is dismissed and Board Decision EB-2010-0253, dated January 12, 2011 is confirmed.

DATED at Toronto, April 21, 2011

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2013-0193

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a Motion by Milton Hydro Distribution Inc. pursuant to the Ontario Energy Board's *Rules of Practice and Procedure* for a review by the Board of its Decision and Order in proceeding EB-2012-0148 dated April 4, 2013.

BEFORE: Paula Conboy
Presiding Member

Ellen Fry
Member

Marika Hare
Member

DECISION AND ORDER ON MOTION TO REVIEW

July 4, 2013

INTRODUCTION

On April 25, 2013, Milton Hydro Distribution Inc. ("Milton Hydro") filed with the Ontario Energy Board (the "Board") a Notice of Motion to Review and Vary (the "Motion") the Board's Decision and Order dated April 4, 2013 in respect of Milton Hydro's 2013 IRM rate application, EB-2012-0148, (the "2013 IRM Decision"). The Board assigned the Motion file number EB-2013-0193.

The Board has determined the threshold question of whether the matter in the Motion should be reviewed on its merits, as provided for in section 45.01 of the Board's *Rules* *of Practice and Procedure* (the “threshold question”). For the reasons set out below the Board has determined that the matter should not be reviewed.

The Board issued its Notice of Motion to Review and Procedural Order No. 1 on May 14, 2013. The Board granted intervenor status and cost award eligibility to the Vulnerable Energy Consumers Coalition (“VECC”), which was the only intervenor in Milton Hydro’s 2013 rate application.

Milton Hydro submitted additional material in support of its Motion on May 22, 2013. Board staff and VECC filed their submissions on June 3, 2013. Milton Hydro filed a reply submission on June 10, 2013.

BACKGROUND

On September 14, 2012 Milton Hydro filed an IRM application for the 2013 rate year. The application sought approval for changes to the rates that Milton Hydro charges for electricity distribution, to be effective May 1, 2013.

In its 2013 IRM application, Milton Hydro requested the recovery of lost revenues of $107,762 using the Lost Revenue Adjustment Mechanism (“LRAM”). Milton Hydro’s LRAM claim included lost revenues for 2010 CDM programs persistent in 2011 and 2012.

On April 4, 2013, the Board issued its 2013 IRM Decision. As part of that decision, the Board denied the LRAM claim. The following is a key portion of the Board’s reasons for doing so:

> Page 42 of Milton Hydro’s evidence for 2011 rates states: “Milton Hydro’s revenue forecast is based on the **forecasted** kWh, KW and customer counts for the 2010 Bridge Year and 2011 Test Year” (emphasis added).
>
> There is no mention in this portion of the evidence that the load forecast was based on actual customer consumption and demand. This in fact, would be inconsistent with a “forecast”, which anticipates future loads, not actual loads from previous years. Milton Hydro, as an early implementer of CDM programs, should have been aware of the approximate potential forecast loss for 2011 as a result of conservation initiatives, even without the OPA report. Without an explicit

> statement that the 2011 forecast did not include the impact of CDM, which there is not, the Board finds that the 2011 forecast must have taken load loss as a result of CDM into consideration. Therefore, the Board finds that no LRAM is available for 2011 or 2012 to account for the persistent impact of CDM programs implemented in 2010[1].

Milton Hydro's Motion seeks to vary the 2013 IRM Decision to accept the LRAM claim that the Board denied.

POSITIONS OF PARTIES

Milton Hydro submitted that the Board erred in fact in failing to take into consideration the evidence presented by Milton Hydro in its 2011 cost of service application. Milton Hydro stated that the evidence clearly showed that it did not include 2010 CDM results in its 2011 cost of service load forecast.

Board staff submitted that regardless of whether Milton Hydro explicitly identified an absence of CDM impacts in its load forecast in the application, the Board in its rebasing decision approved the total forecast as complete, given that there was no language to the contrary. The Board in over 25 LRAM decisions has determined that in the absence of an explicit statement to the contrary in a decision or settlement agreement, the load forecast is deemed to be just and reasonable for rate-making purposes and final in all respects. The 2008 CDM Guidelines state that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. Board staff therefore submitted that there is no error in fact and that the threshold question for review has not been met.

VECC submitted that Milton Hydro's application and the Board's decision in the 2011 cost of service proceeding do not explicitly state that there was no CDM allowance for 2010 in the load forecast. On that basis VECC submitted that the 2013 IRM Decision did appropriately take into consideration the facts presented in Milton Hydro's 2011 cost of service application and there was therefore no error in fact. Accordingly, VECC also submitted Milton Hydro's Motion does not meet the threshold question and Milton Hydro's motion to vary should be denied.

[1] EB-2012-0148, Decision and Order at page 10

In its reply, Milton Hydro submitted that the Motion does meet the threshold test. Milton Hydro submitted that its evidence makes it obvious that 2010 actual data is not used and therefore the persistence of 2010 OPA CDM programs is also not included. Milton Hydro further submitted that it had identified an error in the Board's decision. In its view, the decision is contrary to the evidence provided in Milton Hydro's Cost of Service Application.

THE THRESHOLD TEST

Under section 45.01 of the Board's *Rules of Practice and Procedure* (the "Rules"), the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

The Board has considered previous decisions in which the principles underlying the threshold question were discussed, namely the Board's Decision on a *Motion to Review Natural Gas Electricity Interface Review Decision* (the "NGEIR Review Decision") and the Divisional Court's decision *Grey Highlands v. Plateau.*.[2]

In the NGEIR Review Decision, the Board indicated that "the review [sought in a motion to review] is not an opportunity for a party to reargue the case".

In the *Grey Highlands v. Plateau* the Divisional Court agreed with this principle. The court dismissed an appeal of the Board decision in EB-2011-0053 where the Board determined that the motion to review did not meet the threshold test. The Divisional Court stated:

> The Board's decision to reject the request for review was reasonable. There was no error of fact identified in the original decision, and the legal issues raised were simply a re-argument of the legal issues raised in the original hearing.[3]

BOARD FINDINGS

In the 2013 IRM Decision, the Board considered fully the evidence filed by Milton Hydro concerning its LRAM claim. This is illustrated by the portion of the 2013 IRM Decision

[2] EB-2006-0322/0388/0340, May 22, 2007 at page 18 and EB-2011-0053, April 21, 2011 ("Grey Highlands Decision"), appeal dismissed by Divisional Court (February 23, 2012)
[3] *Grey Highlands (Municipality) v. Plateau Wind Inc*. [2012] O.J. No. 847 (Div. Court) (*"Grey Highlands v. Plateau"*) at para 7

quoted above in the “Background” section. Milton Hydro had a full opportunity in that proceeding to argue its position concerning its LRAM claim.

Milton Hydro is now asking the Board to reconsider the conclusion that it reached in interpreting the evidence in the 2013 IRM Decision after considering the arguments of the parties in that proceeding. Accordingly, the Board considers that this Motion is an attempt by Milton Hydro to reargue its case. Therefore, the Board, in considering the threshold question provided for in section 45.01 of the *Rules* has determined that the matter in the Motion should not be reviewed on its merits, and dismisses the Motion.

COST AWARDS

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claim no later than **7 days** from the date of issuance of this Decision.

2. Milton Hydro shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of this Decision.

3. VECC shall file with the Board and forward to Milton Hydro any responses to any objections for cost claims within **28 days** from the date of issuance of this Decision.

4. Milton Hydro shall pay the Board’s costs incidental to this proceeding upon receipt of the Board’s invoice.

All filings to the Board must quote file number **EB-2013-0193,** be made through the Board’s web portal at, https://www.pes.ontarioenergyboard.ca/service and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the board’s web portal should be filed in accordance with the Board’s Practice Directions on Cost Awards.

DATED at Toronto, July 4, 2013

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2013-0331

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Order by the Ontario Energy Board dated August 28, 2013 which approved rates and other charges to be charged by Hydro One Remote Communities Inc. for electricity (EB-2012-0137)

AND IN THE MATTER OF Rules 8.02, 42, 43, 44, and 45 of the Ontario Energy Board's *Rules of Practice and Procedure*.

BEFORE: Christine Long
Presiding Member

Paula Conboy
Member

Emad Elsayed
Member

DECISION ON MOTION TO REVIEW DECISION AND ORDER

On September 11, 2013, the Nishnawbe Aski Nation ("NAN") filed a Motion to Review and Vary (the "Motion") the Board's Decision in Hydro One Remote Communities Inc. ("Remotes") application for changes to the rates that Remotes charges for electricity, to be effective May 1, 2013 (EB-2012-0137). In the Decision, the Board approved a 3.45% rate increase, based on the average of approved rates for Ontario distributors from 2010 to 2011, in accordance with Regulation 442/01.

The Threshold Question

Under Rule 45.01 of the *Rules of Practice and Procedure,* the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits. The Board issued Procedural Order No. 1 on October 11, 2013, making provision for submissions on the threshold question. Submissions were received from NAN, Remotes, and Board staff, together with a reply submission from NAN.

In its submission, Board staff noted that the threshold question was first articulated in the Decision on a Motion to Review the Natural Gas Electricity Interface Review Decision (the "NGEIR Decision", EB-2006-0322, -0338, -0340, May 22, 2007). In the NGEIR Decision, the Board stated that the purpose of the threshold question is to determine whether the grounds put forward by a moving party raised a question as to the correctness of the order or the decision, and whether there was enough substance to the issues raised such that a review based on those issues could result in the Board varying, cancelling or suspending the decision. The Board indicated that "the review is not an opportunity for a party to reargue the case", and that “it is not enough to argue that conflicting evidence should have been interpreted differently”[1].

Board staff submitted that, in accordance with the NGEIR Decision, the threshold question requires a motion to review to meet the following tests:

- the grounds must raise a question as to the correctness of the order or decision;
- the issues raised that challenge the correctness of the order or decision must be such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended;
- there must be an identifiable error in the decision as a review is not an opportunity for a party to reargue the case;
- in demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature; it is not enough to argue that conflicting evidence should have been interpreted differently;

[1] *Natural Gas Electricity Interface Review Decision* (the "NGEIR Decision"), EB-2006-0322, -0338, -0340, May 22, 2007) at page 18.

> and the alleged error must be material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.[2]

Board staff submitted that NAN has failed to identify any error or change in the facts or circumstances that could give rise to a different interpretation or any material issue not considered by the Board.[3] Board staff submitted, therefore, that the threshold tests have not been met.

NAN submitted that its Motion does not amount to rearguing the case. According to NAN, the Motion does not rely principally on an error in fact, rather on the reasons given by the Board which could not have been anticipated by the parties and therefore could not be addressed adequately in argument. NAN submitted that the alleged error relates to the Board's statement in the Decision that it is bound by Regulation 442/01 (the "Regulation"). NAN submitted that the Board has broad discretion to accept or not accept the amount of rate increase as prescribed in the Regulation. It submitted that the Board erred in concluding that, because of the Regulation, it does not have discretion to consider factors other than the level of increase of other distributors.

In NAN's submission, the Board has to consider additional factors, in particular the ability of Remotes' customers to pay higher electricity rates when setting just and reasonable rates. NAN submitted that the Board erred in concluding that the ability of Remotes' customers to pay for electricity had been taken into account in the Regulation.

Board Findings

The Board finds that NAN's Motion does not pass the threshold test, and shall, therefore, not conduct a review on the merits of the Motion.

The Board's reasons are as follows.

The Board concludes that the statement that it is bound by the Regulation, as set out in the Decision, is not an error in fact or in law. The Board is required to follow the Regulation. However, the Regulation affords discretion in that the language provides

[2] *Motions to Review, Natural gas Electricity Interface Review Decision, Decision with Reasons, May 22, 2007* (EB-2006-0322, EB-2006-0338, EB-2006-0340)
[3] P.6

that the amount of rate "shall be adjusted in line with the average…" [4], and while the Decision does not specifically state whether the Board exercised its discretion in approving the 3.45% rate increase there is no requirement to do so. Furthermore, the Board notes that there was no evidence provided during the original proceeding to substantiate a different outcome such as the 2% proposed by NAN. The fact that the 3.45% increase is equal to the average of the increases approved for the other Ontario distributors does not establish that the Board understood this to be its only option under the Regulation.

Further, the Board is of the view that the "ability to pay" argument raised by NAN was a consideration in the Decision. This issue was raised and canvassed in the original proceeding before the Board. NAN did not present any new facts regarding this issue in its Motion from those raised in the original proceeding. The Motion does not constitute an opportunity to re-argue the same facts.

In conclusion, NAN has not established that the Board erred in its interpretation of the Regulation or of the Act or made any other error that raises a question as to the correctness of the Decision outcome.

THE BOARD ORDERS THAT:

The Motion to Review is hereby dismissed.

[4] Regulation 442.01:

(3.1) For each year, in respect of the rates for a distributor serving consumers described in paragraph 5 of section 2, the Board shall calculate the amount by which the distributor's forecasted revenue requirement for the year, as approved by the Board, exceeds the distributor's forecasted consumer revenues for the year, as approved by the Board. O. Reg. 335/07, s. 1 (2).

(3.2) For the purpose of subsection (3.1), the distributor's forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2).

DATED at Toronto, January 16, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

CITATION: Corporation of the Municipality of Grey Highlands v. Plateau Wind Inc., 2012 ONSC 1001
DIVISIONAL COURT FILE NO.: 463/11
DATE: 20120209

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

LEDERMAN, SWINTON AND HARVISON YOUNG JJ.

BETWEEN:	)	
THE CORPORATION OF THE MUNICIPALITY OF GREY HIGHLANDS	)	*Michael M. Miller*, for the Appellant
Appellant	)	
– and –	)	
PLATEAU WIND INC. and ONTARIO ENERGY BOARD	)	*John Terry* and *Alexander C. W. Smith*, for the Respondent, Plateau Wind Inc.
Respondents	)	*Michael D. Schafler* and *Kathleen Burke*, for the Respondent, Ontario Energy Board
	)	**HEARD at Toronto:** February 9, 2012

SWINTON J. (ORALLY)

[1] The Corporation of the Municipality of Grey Highlands ("the Municipality") appeals the decision of the Ontario Energy Board ("the Board") dated April 21, 2011, in which the Board declined to review a previous decision dated January 12, 2011. In the original decision the Board had held that Plateau Wind Inc. is a "distributor" under s.41 of the *Electricity Act, 1998*,

S.O. 1998, c. 15, Sched. A, and therefore Plateau was entitled to build distribution facilities on the Municipality's road allowances.

[2] An appeal lies to this Court on a question of law or jurisdiction (see s. 33(2) of the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sched. B). Rather than appeal the original decision, the Municipality sought a review of that decision pursuant to Rule 42.01 of the Board's *Rules of Practice and Procedure*.

[3] Rule 44.01 sets out the criteria for a notice of motion to review a decision stating:

> 44.1 Every notice of motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error in fact;
>
> (ii) change in circumstances;
>
> (iii) new facts that have arisen;
>
> (iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

[4] Pursuant to Rule 45.01, the Board held a hearing in writing to determine the threshold question of whether the original decision should be reviewed. It held that a review was not warranted. The Municipality had not shown an error of fact and, in any event, the one alleged error of fact was not material to the decision. In the Board's view, the Municipality essentially restated the legal arguments made in its original submissions. As the Municipality had failed to raise a question as to the correctness of the original decision, the review was refused.

[5] The Municipality submits that the Board erred in law by interpreting its review power too narrowly, as its review power permits it to consider alleged errors of law.

[6] The standard of review of the Board's decision is reasonableness, as the Board was exercising its expertise and discretion, determining questions of fact and applying its own rules.

[7] The Board's decision to reject the request for review was reasonable. There was no error of fact identified in the original decision, and the legal issues raised were simply a re-argument of the legal issues raised in the original hearing.

[8] We do not agree that the word "may" in Rule 44.01 requires the Board to consider errors of law. This is not consistent with the plain meaning of the rule or the nature of a review or reconsideration process. We see no reason to interfere with the Board's exercise of discretion.

[9] The appellant argued that the participation of a Board member in the review process gave rise to a reasonable apprehension of bias when that member had participated in the original decision. This argument fails to take into account the difference between an appeal and a review or reconsideration. The participation of a member of the original panel ensured that the review panel would have at least one member familiar with the facts of the case to provide context and to determine the impact of alleged factual errors or new facts and circumstances. Given the highly technical nature of matters before the Board, it makes sense that one of the original members would be present on the reconsideration. Therefore, we would not give effect to this ground of appeal.

[10] The Board's reasons clearly set out the basis for the decision and were transparent and intelligible. Therefore, the appeal is dismissed.

<u>LEDERMAN J.</u>

[11] I have endorsed the Record to read, "This appeal is dismissed for the oral reasons delivered by Swinton J. The Board does not seek costs. Counsel for the appellant and the respondent, Plateau, have agreed that costs be fixed at $20,000.00 all inclusive, payable by the appellant to Plateau. So ordered.

SWINTON J.

LEDERMAN J.

HARVISON YOUNG J.

Date of Reasons for Judgment: February 9, 2012
Date of Release: February 23, 2012

CITATION: Corporation of the Municipality of Grey Highlands v. Plateau Wind Inc., 2012 ONSC 1001
DIVISIONAL COURT FILE NO.: 463/11
DATE: 20120209

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

LEDERMAN, SWINTON AND HARVISON YOUNG JJ.

BETWEEN:

THE CORPORATION OF THE MUNICIPALITY OF GREY HIGHLANDS

Appellant

– and –

PLATEAU WIND INC. and THE ONTARIO ENERGY BOARD

Respondents

ORAL REASONS FOR JUDGMENT

SWINTON J.

Date of Reasons for Judgment: February 9, 2012

Date of Release: February 23, 2012

EB-2016-0152

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF an Application by Ontario Power Generation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving payment amounts for the generation of electricity for the years 2017 through 2021

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION (Public Version)

May 29, 2017

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11 OTHER MATTERS

11.1 *Effective Date (Issue 12.1)*

11.1.1 ***Determination of Effective Date.*** OPG filed this Application on May 27, 2016, but is seeking a January 1, 2017 effective date. SEC submits that allowing for 218 days to complete this process was unreasonable, and the Board should not allow the January 1, 2017 effective date.

11.1.2 This Application is the biggest and most complex rate application for any utility in Canadian history. Not only does it involve more than $27 billion of proposed revenue requirement, but it also contemplates the review of a large and risky nuclear capital plan. It is a five-year Custom IR application for nuclear, the first time that has ever happened in Canada, and a five year Price Cap IRM application for hydroelectric, also the first time that has ever happened. In addition to the obvious, there are many other twists and turns that the Board must address.

11.1.3 OPG is a large and experienced utility. This is not their first rodeo. It should have been – and undoubtedly was - readily apparent to them that a period of less than nine months would be woefully inadequate to deal with this Application. The time frame for EB-2013-0321 was 447 days from filing to payment amounts order. The time frame for EB-2010-0008 was 321 days from filing to payment amounts order. The time frame for EB-2007-0905 was 367 days from filing to payment amounts order. All of those were less complex applications, with less money involved and fewer major issues to address.

11.1.4 Not only that, but OPG was warned in the last proceeding that it could not simply delay its filing at its own convenience, then expect to recover a deficiency for the intervening period. On the principles at play in determining effective date, the Board had this to say[615]:

> *"The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.*
>
> ***The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding.*** *This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the*

615 *Decision with Reasons* (EB-2013-0321 - OPG 2014-2015), p.134-5.

> *ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and **the Board's practice must be respected.***
>
> *The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect. All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application to the issuance of the final decision, and 280 days until the issuance of the rate order." [emphasis added]*

11.1.5 Further, while there are metrics, the Board has always made clear to regulated utilities that it is their responsibility, not that of the Board, to engage the regulatory process with sufficient time to achieve the results the utility is proposing.

11.1.6 Enbridge and Union Gas get it. While they are aware of the 280 day metric for applications, they will be filing their January 1, 2019 rate applications in November of 2017, giving themselves fourteen months lead time. That is, of course, now included in their filing requirements, but the Board is well aware that they already in any case planned to file that early to ensure a timely result. Those are both expected to be much simpler applications than this one.

11.1.7 OPG, on the other hand, appears not to have listened when the Board told it to get on top of the timing of its regulatory process. It appears to disagree with the Board that "the Board's practice must be respected".

11.1.8 SEC is aware that OEB Staff proposes to give OPG a free pass in this case. SEC disagrees. If the Board can't expect the largest regulated utility in the province to respect its practices, and to be responsible in the timing of its applications, it can hardly expect the smaller utilities to do so.

11.1.9 SEC therefore submits that the effective date for the payments order in this proceeding should be the beginning of the month following the payment amounts order. It is our estimate that will be October 1, 2017, 461 days after the Application was filed. While this is longer than the Board's normal 280 day window, this is not a normal application. Further, it is in the same range as EB-2013-0321, which took 447 days, and generated the Board's comments on effective date and the utility's regulatory responsibility, quoted above.

11.1.10 ***Clawback Issue***. Stung by the result in EB-2013-0321, where despite the Board's determination on effective date, OPG subsequently recovered much of the intervening deficiency through deferral and variance accounts in EB-2014-0370, SEC in cross-examination of OPG witnesses in this proceeding asked whether a later effective date would mean OPG actually loses anything.

11.1.11 OPG's response was in Undertaking J23.1. In that undertaking, OPG claims that it would use the RSVA to claw back the entire amount of the deficiency for the period from January 1, 2017 to the effective date ordered by the Board.

11.1.12 SEC is not surprised, but does submit that the Board should refuse to allow this perversion of the plain meaning of O.Reg.53/05 and the RSVA concept. In no way is O.Reg. 53/05 designed or intended to take away from the Board its statutory right to control its process, including its right to determine the effective date of new payment amounts.

11.1.13 We note that this is not the first time OPG has argued for limitations on the Board's control of this aspect of its mandate. In EB-2013-0321, OPG made the shocking argument that, once the Board makes rates interim, it cannot choose an effective date later than the date of interim rates, because then they would not be just and reasonable. The Board obviously rejected that argument in its decision.

11.1.14 In this case, OPG claims that if the Board determines a revenue requirement for calendar 2017, then under O.Reg.53/05 OPG is entitled to collect that entire revenue requirement, no matter what the Board says about effective date.

11.1.15 SEC submits that the Board has an easy solution to this absurd technical argument. The Board should, in our submission, determine that the revenue requirement for the period from January 1, 2017 to the effective date of new payment amounts is the actual volumes for hydroelectric and nuclear for that period, multiplied by the existing payment amounts approved in EB-2013-0321 and in effect during that period. It should then determine that the revenue requirement for the period from the effective date until December 31, 2017 is the pro rata calculation of the calendar revenue requirement that otherwise would have been determined.

11.1.16 By way of example, if the effective date ends up being October 1, 2017, the actual nuclear production for January 1, 2017 to September 30, 2017 is 28.6 Twh[616], and the annualized 2017 revenue requirement for nuclear, after Board adjustments, would have been $3,000M[617], the Board would determine the 2017 nuclear revenue requirement for ratemaking purposes as follows:

[616] 75% of the current 2017 12 month forecast.
[617] OPG has applied for $3,161M for 2017, and for the purposes of the hypothetical we are assuming some reductions by the Board in its Decision.

(a) For the period January 1, 2017 to September 31, 2017, the volume of 28.6 TWh. times the approved nuclear payment amount, $59.29, for a total of $1,695.7M.

(b) For the period October 1, 2017 to December 31, 2017, the annualized revenue requirement of $3,000M, multiplied by 92 days in October through December, and divided by 365, for a total of $756.2M.

(c) For the calendar year 2017, the revenue requirement, including the figure to be used for RSVA purposes, is the sum of the two, being $2,451.9M.

11.1.17 SEC notes that, whatever the Board does to protect its process and avoid this RSVA clawback trick, it is likely that some of the effective date reduction will still be clawed back by OPG through other deferral and variance accounts. As the Board saw in EB-2014-0370, even with the best of intentions the regulator has only limited ability to hold OPG to account, given the strong protection it has from government-mandated deferral and variance accounts.

11.1.18 SEC therefore submits that the Board should take proactive steps to ensure that its decision on effective date is not subverted by an inappropriate use of the RSVA, but should recognize that even with those steps the cost to OPG of an effective date later than January 1, 2017 is likely to be only a fraction of what it first appears to the Board.

11.2 ***Costs***

11.2.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible

All of which is respectfully submitted.

Original signed by

Jay Shepherd & Mark Rubenstein
Counsel for the School Energy Coalition

ONTARIO ENERGY BOARD

ONTARIO POWER GENERATION INC.
PAYMENT AMOUNTS
2017-2021

EB-2016-0152

FINAL ARGUMENT OF THE CONSUMERS COUNCIL OF CANADA

I. INTRODUCTION:

On May 27, 2016 Ontario Power Generation ("OPG") applied to the Ontario Energy Board ("OEB" or "Board") pursuant to section 78.1 of the Ontario Energy Board Act, 1988, (the "Act") for an order or orders approving payment amounts for its regulated hydroelectric facilities and its nuclear generating facilities for the period January 1, 2017 to December 31, 2021.

This Application is far more complex than any previous OPG Applications that have become before the Board. It is the first five-year application and the first where payment amounts have been derived under Incentive Rate-making Mechanisms ("IRMs"). The outcome of the Board's Decision in this case will impact Ontario electricity ratepayers for years to come, even beyond the test period. The most significant aspects of OPG's Application include:

- The Darlington Refurbishment Project (DRP") and the request by OPG for the OEB to approve over $5 billion in capital additions and over $100 million in Operating, Maintenance and Administration costs associated with the DRP over the 2017-2021 test period;

- Five years of payment amounts related to the nuclear assets based on a new Custom IRM proposal;

- A rate smoothing proposal for those payment amounts to reflect a constant 2.5% rate increase during the 2017-2021 test period;

- Hydroelectric payment amounts of $41.71/MWh effective January 1, 2017, and approval of a deferral and variance account rider of $1.44/MWh applied to the hydroelectric facilities;

- An proposal to set the hydroelectric payment amounts for the period 2018-2021 on the basis of a new IRM proposal;

CITATION: Corporation of the Municipality of Grey Highlands v. Plateau Wind Inc., 2012 ONSC 1001
DIVISIONAL COURT FILE NO.: 463/11
DATE: 20120209

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

LEDERMAN, SWINTON AND HARVISON YOUNG JJ.

BETWEEN:	)	
THE CORPORATION OF THE MUNICIPALITY OF GREY HIGHLANDS Appellant	)	*Michael M. Miller*, for the Appellant
– and –	)	
PLATEAU WIND INC. and ONTARIO ENERGY BOARD Respondents	)	*John Terry* and *Alexander C. W. Smith*, for the Respondent, Plateau Wind Inc. *Michael D. Schafler* and *Kathleen Burke*, for the Respondent, Ontario Energy Board
	)	**HEARD at Toronto:** February 9, 2012

SWINTON J. (ORALLY)

[1] The Corporation of the Municipality of Grey Highlands ("the Municipality") appeals the decision of the Ontario Energy Board ("the Board") dated April 21, 2011, in which the Board declined to review a previous decision dated January 12, 2011. In the original decision the Board had held that Plateau Wind Inc. is a "distributor" under s.41 of the *Electricity Act, 1998*,

S.O. 1998, c. 15, Sched. A, and therefore Plateau was entitled to build distribution facilities on the Municipality's road allowances.

[2] An appeal lies to this Court on a question of law or jurisdiction (see s. 33(2) of the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sched. B). Rather than appeal the original decision, the Municipality sought a review of that decision pursuant to Rule 42.01 of the Board's *Rules of Practice and Procedure*.

[3] Rule 44.01 sets out the criteria for a notice of motion to review a decision stating:

> 44.1 Every notice of motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error in fact;
>
> (ii) change in circumstances;
>
> (iii) new facts that have arisen;
>
> (iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

[4] Pursuant to Rule 45.01, the Board held a hearing in writing to determine the threshold question of whether the original decision should be reviewed. It held that a review was not warranted. The Municipality had not shown an error of fact and, in any event, the one alleged error of fact was not material to the decision. In the Board's view, the Municipality essentially restated the legal arguments made in its original submissions. As the Municipality had failed to raise a question as to the correctness of the original decision, the review was refused.

[5] The Municipality submits that the Board erred in law by interpreting its review power too narrowly, as its review power permits it to consider alleged errors of law.

[6] The standard of review of the Board's decision is reasonableness, as the Board was exercising its expertise and discretion, determining questions of fact and applying its own rules.

[7] The Board's decision to reject the request for review was reasonable. There was no error of fact identified in the original decision, and the legal issues raised were simply a re-argument of the legal issues raised in the original hearing.

[8] We do not agree that the word "may" in Rule 44.01 requires the Board to consider errors of law. This is not consistent with the plain meaning of the rule or the nature of a review or reconsideration process. We see no reason to interfere with the Board's exercise of discretion.

[9] The appellant argued that the participation of a Board member in the review process gave rise to a reasonable apprehension of bias when that member had participated in the original decision. This argument fails to take into account the difference between an appeal and a review or reconsideration. The participation of a member of the original panel ensured that the review panel would have at least one member familiar with the facts of the case to provide context and to determine the impact of alleged factual errors or new facts and circumstances. Given the highly technical nature of matters before the Board, it makes sense that one of the original members would be present on the reconsideration. Therefore, we would not give effect to this ground of appeal.

[10] The Board's reasons clearly set out the basis for the decision and were transparent and intelligible. Therefore, the appeal is dismissed.

LEDERMAN J.

[11] I have endorsed the Record to read, "This appeal is dismissed for the oral reasons delivered by Swinton J. The Board does not seek costs. Counsel for the appellant and the respondent, Plateau, have agreed that costs be fixed at $20,000.00 all inclusive, payable by the appellant to Plateau. So ordered.

SWINTON J.

LEDERMAN J.

HARVISON YOUNG J.

Date of Reasons for Judgment: February 9, 2012
Date of Release: February 23, 2012

CITATION: Corporation of the Municipality of Grey Highlands v. Plateau Wind Inc., 2012 ONSC 1001
DIVISIONAL COURT FILE NO.: 463/11
DATE: 20120209

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

LEDERMAN, SWINTON AND HARVISON YOUNG JJ.

BETWEEN:

THE CORPORATION OF THE MUNICIPALITY OF GREY HIGHLANDS

Appellant

– and –

PLATEAU WIND INC. and THE ONTARIO ENERGY BOARD

Respondents

ORAL REASONS FOR JUDGMENT

SWINTON J.

Date of Reasons for Judgment: February 9, 2012

Date of Release: February 23, 2012

9. RATE IMPLEMENTATION/EFFECTIVE DATES:

OPG is requesting an effective date of January 1, 2017, with respect to the payment amounts for both the nuclear and hydroelectric facilities. This includes a request for payment riders to recover the difference between existing payment amounts and the payment amounts sought in this Application from the effective dates to the implementation date.

From OPG's perspective the requested effective date for new payment amounts should be approved because OPG complied in all material respects with the OEB's filing guidelines and any directions provided in OPG's last payment amounts proceeding. It is OPG's position that it worked diligently with all parties and OEB Staff to advance the application in a reasonable and efficient manner.[98]

The Council submits that for OPG's rates to be effective January 1, 2017, the Application should have been filed earlier. The OEB has made it clear in recent years that applicants need to file well in advance of the date on which they are seeking to have their rates effective. The Board has become less inclined to allow for retroactive recovery, and from the Council's perspective this is important for electricity consumers. As the Council submitted in OPG's last application (EB-2013-0321) it is simply not fair to say to Ontario customers, "By the way, we are asking you now to pay more for the electricity you consumed over the last year." There may be isolated reasons to allow for retroactive adjustments, but in this case the Council urges the Board to reject an effective date, as requested by OPG, of January 1, 2017. The Council supports an effective date, one month following the final payment amounts order.

The Council notes that the effective date was a contentious issue in the last proceeding. OPG filed its Application in that proceeding on September 27, 2013, and was seeking an effective date of January 1, 2014, for the nuclear and previous regulated hydroelectric facilities. In its Decision the Board stated:

> The Board's general practice with respect the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. The practice is predicated on a forecast test year which establishes rates going forward, not retrospectively rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.

[98] AIC, p. 173

> The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been not to allow the utility to retrospectively recover the amounts from the period where the interim order was in effect. All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application and to the issuance of the final decision, and 280 days until the issuance of the rate order.[99]

The OEB also cited a number of Decisions where it denied retroactive adjustments. These in include: EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawksbury); EB-2012-0113 (Centre Wellington); and EB-2013-0130 (Fort Frances). The Council notes a further Decision issued on August 18, 2016, where Grimsby Power was denied its request to have rates approved retrospectively on the basis of when its filed its application.

OPG filed its application on May 27, 2016. As OPG noted in its Argument-in-Chief:

- By any measure this is a significant Application. It includes a review of the Darlington Refurbishment Program, the single largest project ever to come before OEB and requests some $5,177.4 of DRP-related in-service additions. It requests funding to extend Pickering's operation. It introduces new ratemaking methodologies for both the nuclear and hydroelectric payment amounts. It covers five years;

- In the course of this Application, OPG filed thousands of pages of evidence supported by dozens of company witnesses. It responded to more than a thousand interrogatories and undertakings. Numerous benchmarking reports were filed covering nuclear performance, compensation and benefits, corporate costs and hydroelectric costs. In certain key areas, OPG sponsored the testimony of expert witnesses. All this material was provided in aid of explaining what is a complex business;

- OPG is the only generator regulated by the OEB. It is a large generating company producing over half of the energy generated in Ontario. It operated two facilities that differ in size, number of units and vintage of CANDU technology employed. It has extensive regulated hydroelectric facilities that range from the very large and complex generation at Niagara Falls to much smaller facilities on rivers across the Province. The diversity of technology, the numerous facilities of different sizes and vintage, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and regulate;

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[99] Decision with Reasons, EB-2013-0321, pp. 134-135

- Even without DRP, OPG is unique among regulated companies, electric or gas, in terms of scope, scale and complexity. [100]

The Council agrees with all of these assertions. The complexity of this case, the scope of the issues and the size of the "ask" go beyond any application the OEB has had to consider. It is also important to recognize that OPG has a large and experienced regulatory staff that closely follow Board decisions and policies. They are not new to regulation submitting the first payment amounts application in November 2007 for payment amounts effective April 1, 2008. The regulatory staff is undoubtedly aware of the Board's position on setting retrospective rates, as the position was clearly articulated in the previous OPG proceeding decision.

If OPG wanted an effective date of January 1, 2017, it should have submitted the Application much sooner. This is not a typical rate case and the timelines set by the OEB for other applicants, especially the smaller electric utilities is not sufficient for an OPG application, especially this one.

The Council remains concerned about the implications of retrospective rate-making and its impact on customers. Except under very exceptional circumstances the Board should not permit an applicant to recover amounts from customers for a prior period, even if it is rolled into a rate rider and the recovery is spread out over a future period. In this case customers were not given notice that their bills could be impacted in this way. The Council supports the current policy and is of the view this panel should adhere to it in this case. As noted above, the Council supports an effective date that flows one month from the final payment amounts order.

COSTS:

The Council requests that it be awarded its reasonably incurred cost associated with its participation in this proceeding. The Council has worked extensively with other intervenors throughout this proceeding in order to reduce duplication and has managed its participation efficiently and effectively.

All of which is respectfully submitted,

May, 29, 2017

[100] AIC, p. 1

Ontario Power Generation Inc.

2017-2021 Payment Amounts

EB-2016-0152

Association of Major Power Consumers in Ontario

Final Submission

May 29, 2017

IMPLEMENTATION

Issue 12.1: Are the effective dates for new payment amounts and riders appropriate?

291. AMPCO has had the benefit of reviewing a draft of SEC's argument, including its argument in respect of effective date. For the reasons argued by SEC, AMPCO supports an effective date for the final payment amounts determined in this proceeding being the beginning of the month following the date of issuance of the order herein.

292. We will not simply repeat SEC's points in argument in support of this result, other than to note that AMPCO has reviewed them, has considered them, and endorses them.

293. In the section of this argument that addresses Issue 11.3, and the appropriate scope for the mid-term review and the ratemaking approach associated therewith, the opening of OPG's AIC is excerpted. That entire section of OPG's argument underscores the scale, scope and complexity of this application. OPG's own view of the scale, scope and complexity of this application supports the argument well articulated by SEC, and supported by AMPCO, for an effective date following issuance by the Board of the order herein.

EB-2016-0152

ONTARIO ENERGY BOARD

Ontario Power Generation Inc.

Application for payment amounts for the period
from January 1, 2017 to December 31, 2021

SUBMISSIONS OF
CANADIAN MANUFACTURERS & EXPORTERS ("CME")

May 29, 2017

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440. The smoothing proposal results in the deferral of approximately $1B over the 2017-2021 period which amount attracts interest at approved rates.

441. Both OPG and Board staff are recommending that the determination respecting rate smoothing be deferred until the Board makes a determination on payment amounts. CME submits that this is a reasonable approach given that the amount of the revenue requirement should govern the extent to which it is reasonable to incur interest costs to smooth rates.

13.0 IMPLEMENTATION

442. OPG requests that the Board grant an order approving payment amounts effective January 1, 2017 through December 31, 2021.[192]

443. OPG's request for retroactive application would burden ratepayers with significant costs associated with 2017 payment amounts not currently included in rates.

444. CME submits that retroactive amounts should not be recovered from ratepayers and that this is inconsistent with the Board's practice as articulated in OPG's last payment amounts application:

> ***The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.***
>
> ***The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the Ontario Energy Board EB-2013-0321 Ontario Power Generation Inc. Decision with Reasons November 20, 2014 135 ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.***

192 Exhibit A1, Tab 2, Schedule 1, p.1.

> ***The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.***[193]

445. As observed by the Board, the principle that the Board sets rates prospectively and not retroactively is a pillar of the rate setting process. It allows the utility to know, going forward, how much money it has available to spend, and, more importantly from CME's perspective, it allows ratepayers to know "how much it is going to cost to use electricity in order to make consumption decisions."

446. Board staff, in their submission, contend that a retroactive effective date is reasonable in this case because OPG filed shortly after the 2015 audited results were filed because OPG met the deadlines established by the OEB in Procedural Order No. 1 issued on August 12, 2016.

447. CME submits that these reasons are unpersuasive.

448. The selection of a filing date for a new payment amounts order is a matter which was entirely within OPG's control, irrespective of when audited financial results became available.

449. OPG understood that this particular application would be inherently complex, presented a number of issues not previously addressed in the context of an OPG proceeding and would require the presentation of a large volume of information.[194]

450. Knowing this, it filed this Application on May 27, 2016, just less than six months before January 1, 2017, being the date to which it now requests that the payment order be retroactive. In light of how long OPG's previous applications have taken to complete the regulatory process as calculated by SEC, we submit that there is no reasonable basis

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[193] EB-2013-0321, Decision with Reasons, pp.134-135.
[194] OPG AIC at p.1

upon which OPG could have expected a new payment order to issue prior to January 1, 2017.

451. CME submits that had the Board set an order which condensed the necessary timeframe such that a ruling could be ready by January 1, 2017, there would be significant risks to procedural fairness, completeness of the hearing, and the ability to set just and reasonable rates.

452. CME submits OPG's adherence to Procedural Order No. 1 does not justify a departure from the long standing and important principle that rates are to be set on a prospective basis, with all of the attendant cost consequences of ratepayers that this would entail.

13.1 Recovery of these Amounts through Other Means

453. We agree with SEC and Board staff that the recovery of the retroactive rates using tools such as the RSDA is inappropriate and would subvert a principled finding that rates should be determined on a prospective basis.

454. CME therefore submits that the Board should expressly provide in its decision that revenues forgone on account of the effective date should not be recorded in the RSDA.

EB-2016-0152

Ontario Power Generation Inc. (OPG)
2017-2021 Payment Amounts

SUBMISSIONS
OF
LONDON PROPERTY MANAGEMENT ASSOCIATION

May 29, 2017

I. INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board ("OEB") on May 27, 2016 under section 78.1 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes in payment amounts for the out of its nuclear generating facilities and most of its hydroelectric generating facilities. The request sought approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request also sought approval for hydroelectric payment amounts to be effective January 1, 2017 to December 31, 2017 and approval of the formula used to set the hydroelectric payment amount for the period January 1, 2017 to December 31, 2021.

The OEB issued a Notice of Hearing on June 29, 2016. OPG subsequently filed supplemental evidence on July 29, 2016.

The OEB issued Procedural Order No. 1 on August 12, 2016 in which it set dates, for among other things, an untranscribed application presentation, an untranscribed technical conference, interrogatories on the OPG evidence, responses to those interrogatories, a technical conference, technical conference undertaking responses, staff and intervenor evidence, interrogatories on that evidence, responses to those interrogatories, a motions hearing day, a settlement conference and an oral hearing.

While some dates were changed, the application generally followed the schedule as set out in the procedural order. For example, the settlement conference proceeded on the scheduled days, while the beginning of the oral hearing was delayed from February 21, 2017 to February 27, 2017.

LPMA submits that the OEB should direct OPG to provide the unsmoothed WAPA figures as part of the draft payment order and allow all parties, including OPG, to provide submissions on an appropriate soothing proposal that balances the impacts on both ratepayers and the company.

General

<u>11.7 Is OPG's proposed off-ramp appropriate?</u>

The OPG proposal related to an off-ramp indicates that a regulatory review may be initiated if OPG's annual reporting shows performance outside of the +/- 300 basis points ROE dead band, or if performance erodes to unacceptable measures (Exhibit A1, Tab 3, Schedule 2, page 7). LPMA has taken measures to mean levels.

OPG states that the regulated return on equity would be calculated on a combined basis, including both regulated hydroelectric and nuclear generation lines of business (Ex. L, Tab 11.7, Schedule 11, LPMA-012).

OPG further states (Exhibit L, Tab 11.7, Schedule 1, Staff-271) that the calculation of the regulated return on equity would not impacted by the rate smoothing mechanism. The regulated ROE would be reflective of the unsmoothed revenue and the amount included in RSDA each year would continue to be included in income for the purposes of calculating the actual ROE.

LPMA submits that the proposed off-ramp is appropriate and should be approved by the OEB. The off-ramp is consistent with that set out in the RRFE Report and as noted earlier under Issues 11.1 and 11.3, LPMA believes that the incentive mechanism used by OPG should be aligned and as consistent as possible with the RRFE Report. The use of 300 basis point dead band and calculating the ROE based on actual income (i.e. excluding the impact of rate smoothing) and calculating the ROE based on the entire regulated entity are all consistent with the RRFE Report.

12.IMPLEMENTATION

<u>12.1 Are the effective dates for new payment amounts and riders appropriate?</u>

LPMA notes that OPG has requested rates be effective January 1, 2017. LPMA submits that the Board should deny this request and make rates effective the first day of the month following the Board Decision and approval of the rate order. There should be no recovery of any shortfall from the beginning of 2017 to the implementation date.

OPG did not file its evidence until near the end of May, 2016 and should have known that with only seven months to the end of the year, it would be almost impossible to have rates in place for January 1, 2017. In fact, LPMA submits that OPG should have filed several months earlier than it did in order to get new rates implemented for January 1, 2017.

OPG was, or should have been, acutely aware of the OEB's practice of not allowing a utility to retrospectively recover amounts from the point where the interim order was in effect in cases where utilities did not file their applications in time to have rates in place prior to the effective date. This was spelled out in great detail by the OEB in the EB-2013-0321 Decision with Reasons dated November 20, 2014 for OPG. In that decision, the OEB stated in response to the request for a January 1, 2014 effective date proposed by OPG that (pages 134-135):

> *The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.*
>
> *The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.*
>
> *The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.*[124]

The footnote (124) in the above passage referred to the following decisions: EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawkesbury); EB-2012-0113 Centre Wellington; and EB-2013-0130 Fort Frances.

In the even more recent EB-2015-0072 Decision and Order dated August 18, 2016 for Grimsby Power Inc., OEB staff submitted that 266 days is the established metric to issue a decision and rate order after an application is filed and an oral hearing is held. Grimsby filed its application on December 23, 2015. As a result, OEB staff submitted that the appropriate effective date for 2016 rates was September 1, 2016.

Under the Findings heading (page 11) of the August 18, 2016 EB-2015-0072 Decision and Order the Board stated:

> *The OEB approves September 1, 2016 as the effective date of Grimsby Power's 2016 rates. The OEB finds that the delay in filing the application was within Grimsby Power's control and sufficient time must be allowed for the OEB's open and transparent rate setting process. The OEB finds that September 1, 2016 is appropriate given the date of this Decision and the time provided for the rate order process.*

Ratepayers have been very clear on the issue of retroactive rates, whether changes are made retroactively for energy already consumed, or through rate riders that collect foregone revenues based on future consumption. In either case, ratepayers do not want to pay for past consumption based on rates that were not in place at the time consumption took place. The onus is on the utility to ensure a timely filing is made in order to have new rates in place when requested. LPMA submits that OPG failed to meet this onus.

OPG was well aware that this application would be significant, complex and unique. It said so on the very first page of its Argument-In-Chief (emphasis added):

> ***By any measure, this is a significant Application***. ***It includes review of the Darlington Refurbishment Program ("DRP" or the "Program"), the single largest capital project ever to come before the OEB****, and requests approval of some $5,177.4M of DRP-related in-service additions****. It requests funding to extend Pickering's operation***. ***It introduces new ratemaking methodologies for both the nuclear and hydroelectric payment amounts. It covers five years.***

> *In the course of this Application, OPG filed thousands of pages of evidence supported by dozens of company witnesses. It responded to more than a thousand interrogatories and undertakings. Numerous benchmarking reports were filed covering nuclear performance, compensation and benefits, corporate costs and hydroelectric costs. In certain key areas, OPG sponsored the testimony of expert witnesses.* ***All this material was provided in aid of explaining what is a complex business.***
>
> ***OPG is the only generator regulated by the OEB****. It is a large generating company producing over half the energy generated in Ontario. It operates two nuclear facilities that differ in size, number of units and vintage of CANDU technology employed. It has extensive regulated hydroelectric facilities that range from the very large and complex generation at Niagara Falls to much smaller facilities on rivers across the Province.* ***The diversity of technology, the numerous facilities of different sizes and vintages, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and to regulate.***
>
> *In this Application, as in past filings, OPG has tried to present a large volume of information in an organized and understandable way.* ***But these efforts cannot make simple what is inherently complex.*** ***Even without the DRP, OPG is unique among Ontario regulated companies, electric or natural gas, in terms of scope, scale and complexity.***

OPG was fully aware that its application was complex, even without the DRP and that it is unique among the companies regulated by the OEB. Not only is OPG complicated to operate, it is complicated to regulate. This is the first OPG application that is not based on a cost of service application, but rather splits the organization into two parts, with different regulatory instruments proposed to be used to regulate the hydroelectric assets versus the nuclear assets. This is the first OPG application that covers a period of 5 years. Adding to complexity are the various provincial government regulations that the OEB must abide by, but are difficult to mesh with price cap and custom incentive regulation frameworks developed by the OEB and intervenors. In short, this application bears no resemblance whatsoever to a typical application before the OEB under cost of service, custom IR or price cap methodologies.

LPMA notes that the OEB set a deadline for electricity distributors filing a cost of service or custom IR application or April 29, 2017 for rates effective January 1, 2017. OPG failed not only to meet this deadline by a month, but it failed to account for the additional time that could reasonably be expected to be needed to deal with a significant, complex and unique application.

On page 1 of its Argument-In-Chief, OPG requests the following:

> *In recognition of these inherent differences, OPG respectfully requests that the OEB evaluate the evidence and decide the issues in this proceeding based on the size, nature and complexity of OPG's business and develop regulatory approaches that fit OPG.*

In recognition of the inherent differences between the OPG application and other applications that come before the OEB, LPMA respectfully submits that OPG should have been aware that based on the size, nature and complexity of its application, it should have known that filing 7 months before the proposed implementation date was not only unreasonable but also unachievable. Rather than expecting the OEB to "develop regulatory approaches that fit OPG", OPG should have developed a timetable for their regulatory approach that fit the OEB general practice with respect to effective dates.

Recently, in the EB-2016-0105 proceeding for Thunder Bay Hydro, the Presiding Member made this point succinctly (Tr. Vol. 1, page 54):

> *MS. DUFF: I mean, At the same time, you have asked for rates to be effective May 1st. It is April 20th, and, you know, we have a saying here at the OEB: Applicant; own your application; Board, own your process.*

LPMA submits that OPG has failed to own its process by filing an application significantly later than what would reasonably be expected to have rates approved for January 1, 2017.

LPMA further submits that the OEB should not approve a revenue requirement for that portion of 2017 between January 1 and the implementation date. In other words, there should be no retrospective change in the payment amounts and no recovery of any such amounts through charges on future consumption. The interim payment amounts that were declared interim on December 8, 2016 should be declared final for the period from January 1, 2017 through to the end of the month prior to the implementation date for the new payment amounts. The new payments amount should only reflect that portion of 2017 from the implementation date to the end of 2017. This would uphold the EB-2013-0321 Decision noted above that the general practice of the OEB is that final rates become effective at the conclusion of the proceeding, which is predicated on a forecast test year which establishes rates going forward, not retrospectively.

<u>III. COSTS</u>

LPMA requests that it be awarded 100% of its reasonably incurred costs. LPMA worked with other intervenors throughout the process to eliminate duplication while ensuring that the record was complete. LPMA's key areas of concern were fully addressed through the evidence, interrogatory responses and technical conference question responses, along with cross-examination by other parties. This eliminated the need for LPMA to elongate the hearing by doing any separate or repetitive cross-examination. Finally, as noted in the Introduction, there was a significant sharing of draft submissions on a number of issues between several intervenors.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

May 29, 2017

Randy Aiken
Consultant to London Property Management Association

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

DECISION AND ORDER

EB-2014-0369

ONTARIO POWER GENERATION INC.

Motion to review and vary the Decision with Reasons on the 2014-2015 payment amounts (EB-2013-0321)

BEFORE: **Ken Quesnelle**
Presiding Member

Cathy Spoel
Member

January 28, 2016

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 THE PROCESS 3

3 STRUCTURE OF THE DECISION 4

4 MOTIONS TO REVIEW 5

4.1 THE OEB'S *RULES OF PRACTICE AND PROCEDURE* 5

4.2 THE THRESHOLD TEST 5

5 NIAGARA TUNNEL PROJECT 7

5.1 THE PRE-DECEMBER 2008 DISALLOWANCE 7

5.2 THE AMENDED DESIGN BUILD AGREEMENT DISALLOWANCE 12

6 TAX LOSS CARRY-FORWARD 15

7 IMPLEMENTATION AND COST AWARDS 18

7.1 IMPLEMENTATION 18

7.2 COST AWARDS 19

8 ORDER 20

1 INTRODUCTION AND SUMMARY

This is a Decision of the Ontario Energy Board (OEB) in response to a notice of motion filed by Ontario Power Generation Inc. (OPG) to review and vary the OEB Decision with Reasons on 2014-2015 payment amounts.[1]

OPG is the largest electricity generator in Ontario. The OEB sets the rates that OPG charges for the generation from its nuclear facilities (Pickering and Darlington) and most of its hydroelectric facilities (e.g. Sir Adam Beck I and II on the Niagara River). The rates charged by OPG are referred to as payment amounts. These payment amounts are included in the electricity costs which are shown as a line item on the electricity bill from a customer's distributor, and make up about half the total of an average household bill.

The OEB issued the 2014-2015 OPG payment amounts decision on November 20, 2014. OPG filed a notice of motion to review and vary the 2014-2015 payment amounts decision on December 10, 2014. In OPG's view, there are errors related to the OEB's disallowance of $88.0 million for the Niagara Tunnel Project and the OEB's direction to reduce the 2014 income tax provision to account for the carry-forward of a regulatory tax loss in 2013.

The OEB's $88.0 million disallowance was made up of two parts: $28.0 million related to a settlement of a claim by the tunnel contractor, (the Pre-December 2008 Disallowance), and $60.0 million related to incentives paid to the tunnel contractor (the Amended Design Build Agreement Disallowance).

Subject to the OEB review, the remedy OPG proposed in its motion is an increase to payment amounts, and an account to recover the difference from November 1, 2014 to the effective date of the higher payment amounts.

Rule 42.01 of the OEB's *Rules of Practice and Procedure* states that all motions brought under Rule 40.01 shall set out the grounds for the motion that raise a question as to the correctness of the order or decision.

The OEB's *Rules of Practice and Procedure* also states that the OEB may determine a threshold question of whether the matter should be reviewed before conducting any review of the merits of the motion. The OEB must ensure that the motion is not merely a

[1] EB-2013-0321 Decision with Reasons, Payment Amounts for Prescribed Facilities for 2014 and 2015, November 20, 2014

request for a reconsideration of the original application. A full explanation of the application of the threshold test is contained in chapter 4 of this Decision.

The OEB made provision for written and oral submissions on both the threshold and the merits of the motion in the current proceeding.

Most parties and OEB staff argued that the grounds for the motion put forward by OPG are insufficient and therefore the motion should be denied at the threshold stage.

In OPG's view, the threshold test is satisfied as there are material factual errors in the 2014-2015 payment amounts decision regarding the Niagara Tunnel Project and regarding taxes. OPG challenged the correctness of the 2014-2015 payment amounts decision on the basis that the findings are contrary to the evidence that was before the OEB.

For reasons that are contained in the following chapters the OEB has determined that OPG has not passed the threshold test on two of the three parts of its motion. The OEB has determined that errors were not made with respect to the disallowance associated with the Amended Design Build Agreement or with respect to the income tax provision to account for regulatory losses. The motion is denied on those two parts.

The OEB finds that the reasons provided in the original decision regarding certain elements of the disallowance of $28.0 million pertaining to the Pre-December Disallowance are contrary to the evidence. The OEB review panel has determined that the original disallowance of $28.0 million will be varied to a disallowance of $6.4 million.

The motion by OPG is partially granted with a variance of the original decision disallowance for the Niagara Tunnel Project of $88.0 million to a disallowance of $66.4 million.

2 THE PROCESS

OPG filed the notice of motion to review and vary the Decision with Reasons on 2014-2015 payment amounts on December 10, 2014.

The Notice of Hearing and Procedural Order No. 1 was issued on January 13, 2015. The OEB adopted all parties to the 2014-2015 payment amounts proceeding. The following intervenors participated in the motion proceeding:

- Association of Major Power Consumers in Ontario
- Canadian Manufacturers & Exporters
- Energy Probe Research Foundation
- Power Workers' Union
- School Energy Coalition (SEC)
- Society of Energy Professionals
- Vulnerable Energy Consumers Coalition

OEB staff filed its submission on February 20, 2015, and intervenors filed their submissions by March 2, 2015. The submissions addressed the threshold question of whether the matter should be reviewed as well as on the merits of the motion.

The oral hearing of the motion was held on March 24, 2015.

3 STRUCTURE OF THE DECISION

The OEB has organized this Decision into chapters, reflecting the issues that the OEB has considered in making its findings.

Chapter 4 provides an explanation of the OEB's considerations with respect to motions to review, including the application of the threshold test.

Subsequent chapters deal with the three parts of the 2014-2015 payment amounts decision that OPG requested be reviewed and varied. Chapter 5 deals with the Niagara Tunnel Project, both the threshold test and the merits of the motion pertaining to the Pre-December Disallowance and the analysis and findings pertaining to the threshold test for the Amended Design Build Agreement. Chapter 6 contains the OEB's analysis and findings on the threshold test pertaining to the tax loss carry-forward. The Decision concludes with chapter 7 dealing with implementation of the OEB's findings and the procedures for the awarding of costs to eligible parties.

4 MOTIONS TO REVIEW

4.1 The OEB's *Rules of Practice and Procedure*

Rule 42.01(a) of the OEB's *Rules of Practice and Procedure* provides the grounds upon which a motion may be raised with the OEB:

> Every notice of a motion made under Rule 40.01, in addition to the requirements under Rule 8.02, shall:
>
> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error in fact;
> (ii) change in circumstances;
> (iii) new facts that have arisen;
> (iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

Rule 43.01 of the *Rules of Practice and Procedure* states:

> In respect of a motion brought under Rule 40.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

4.2 The Threshold Test

In the Motions to Review the Natural Gas Electricity Interface Review Decision, EB-2006-0322/0338/0340, May 22, 2007, the OEB found:

> Therefore, the grounds must "raise a question as to the correctness of the order or decision". In the panel's view, the purpose of the threshold test is to determine whether the grounds raise such a question. This panel must also decide whether there is enough substance to the issues raised such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended.

> With respect to the question of the correctness of the decision, the Board agrees with the parties who argued that there must be an identifiable error in the decision and that a review is not an opportunity for a party to reargue the case.
>
> In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently.
>
> The applicant must also be able to demonstrate that the alleged error is material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.
>
> In the Board's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review.

The OEB has adopted these findings in its consideration of the threshold question on many occasions over the past several years and does so again in consideration of arguments on the threshold question in this motion to review and vary. The analysis and findings on the threshold question are provided in the following chapters dealing with the three elements of this motion.

5 NIAGARA TUNNEL PROJECT

The Niagara Tunnel Project is a 10.2 km long tunnel with a diameter of 12.7 meters which runs under the City of Niagara Falls. Its purpose is to increase the flow of water to hydroelectric generation facilities owned by OPG at Niagara Falls.

OPG sought to add $1,452.6 million of Niagara Tunnel Project expense to rate base in the 2014-2015 payment amounts proceeding and to earn a return on that investment. The OEB's $88.0 million disallowance was made up of two parts: $28.0 million related to a settlement of a claim by the tunnel contractor, Strabag Inc. (the Pre-December 2008 Disallowance), and $60.0 million related to incentives paid to Strabag to complete the Niagara Tunnel Project after December 2008 (the Amended Design Build Agreement Disallowance).

5.1 The Pre-December 2008 Disallowance

OPG and Strabag disagreed on the resolution of additional costs that were incurred in the early stages of the Niagara Tunnel Project. Strabag claimed that the additional costs were the result of subsurface conditions not previously identified and that the costs should be borne by OPG, the owner. OPG's position was that no differing subsurface condition existed, and that additional costs were related to modifications to tunnel boring and rock support and that the costs should be borne by the contractor.

The dispute, in which Strabag claimed costs of $90 million, was referred to a Dispute Review Board. Strabag offered five reasons that it believed supported its claim for differing subsurface conditions. OPG had performed an audit of Strabag's costs and concluded that certain costs should not be included. It had determined that $77.4 million was the amount of additional costs associated with the claim.

The Dispute Review Board's report was structured according to the five reasons presented by Strabag. The Dispute Review Board agreed that there were differing subsurface conditions, but not for each of the five matters presented. The report does not include any analysis of how much of the total cost could be attributed to any of the five individual issues presented by Strabag. As OPG and Strabag jointly developed the Geotechnical Baseline Report which formed the basis on which claims for differing subsurface conditions were to be assessed, the Dispute Review Board found that Strabag and OPG should share the shortcomings of the resulting documents and that both must accept the responsibility for some portion of the additional cost. OPG and Strabag ultimately negotiated a settlement and OPG paid Strabag $40 million.

In the 2014-2015 payment amounts decision, the OEB found that the payment was not prudent and disallowed $28.0 million in relation to the settlement of the Strabag claim.

Threshold Test

OEB staff and most of the parties argued that the motion should be dismissed at the threshold stage as there was no new evidence in OPG's notice of motion. Parties submitted that OPG made the same arguments in its submissions to the OEB in the 2014-2015 payment amounts proceeding.

OPG agreed that the arguments made in its motion submission were the same as the arguments made in the 2014-2015 payment amounts proceeding. OPG argued that given that the grounds for the motion are based on OPG's contention that the OEB decision contained errors it would be peculiar if the submissions were different. OPG stated that the implication of having a different submission when the grounds for the motion are based on an alleged error is that the applicant had misidentified what the issue was in the original arguments.[2]

The OEB accepts that OPG's arguments on this motion repeat arguments made in the 2014-2015 payment amounts proceeding. OPG used these same arguments in expressing its contention that the analysis and reasoning in the payment amounts decision demonstrates that the original panel misinterpreted OPG's original argument and the evidence before it. The OEB does not consider that to be inappropriate.

OPG grounded its motion to review and vary this part of the decision on the assertion that an error had been made in interpreting evidence and this led to a decision that is inconsistent with the evidence.

The interpretation of the evidence pertaining to this part of the motion is a key factor in the payment amounts decision that if found to be incorrect would change the outcome of the decision. The OEB finds that the grounds for this part of the motion have substance and has therefore considered its merits.

[2] Motion Hearing Transcript pages 153,154

Findings

The OEB finds that OPG has successfully demonstrated that the findings on the $28 million disallowance that were supported by the conclusions of the Dispute Review Board's report are contrary to the evidence that was before the OEB.

OPG's notice of motion states that the OEB did not understand the nature of the Dispute Review Board process and that the OEB's findings are factually incorrect and inconsistent with the evidence. OPG stated that the only question before the Dispute Review Board was whether there were differing subsurface conditions. If there was a positive finding on any of the reasons put forth by Strabag, then a differing subsurface condition existed.

OEB staff argued that the issue before the OEB was not simply whether there were or were not differing subsurface conditions, but rather the issue was the amount to be included in rate base. OEB staff submitted that as the Dispute Review Board made discrete findings on each of the five matters raised by Strabag, there was therefore a range of possible disallowances and as the decision to disallow $28 million was within that range, it was supported by the evidence.

At page 31-32 of the 2014-4015 payment amounts decision, it states:

> The Board is not satisfied that paying Strabag $40M for its claims up to December 2008 was prudent. This Board finds that the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate. However, paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view. There were five issues of dispute that were referred to the Dispute Review Board. The Dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified.
>
> As a result of the contract renegotiation with Strabag, OPG had the right to audit Strabag's claimed losses of $90M. To the extent that the $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. OPG's witnesses testified that OPG's internal auditors conducted the audit and found that a total of $12.6M was not associated with legitimate expenses, resulting in a loss of only $77.4M. The auditors

> did not recognize inter-company transfers within Strabag's organization, thereby reducing the amount from \$90M to \$77.4M. OPG's evidence was that they could reduce the \$40M settlement proportionately based on the audit, but did not do so.
>
> The Board is unable to find that a \$40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the \$77.4M to be the appropriate starting point for the Board's calculation, not the \$90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the \$77.4M audited amount, or \$15.5M. In addition, the Board denies the associated carrying costs of the disallowed \$24.5M,[3] which results in a reduction of another \$3.5M.[4] The Board finds this disallowance of \$28.0M reasonable given the evidence provided.

As noted above, the 2014-2015 payment amounts Decision states:

> In the absence of information regarding the costs attributable to each of the five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board.

This statement explains the original panel's approach to determining a reasonable amount of payment in the absence of certain information. However, the original panel based its finding that the \$40 million payment was excessive on the premise that there was a correlation between the attribution for responsibility contained in the Dispute Review Board's conclusions and a reasonable sharing of responsibility for the costs. The OEB finds that there is no such correlation.

[3] \$40M – (20% x \$77.4M)
[4] \$24.5M x 5.25% x 33/12 months

The finding that paying the $40 million settlement was excessive is based solely on the Dispute Review Board's analysis of the five issues contained in its report. The analysis provides the Dispute Review Board's conclusions with respect to responsibility for the five issues. The payment amount decision does not identify any other determinative factors that influenced the original panel's determination that the settlement payment was excessive.

The findings that the results of OPG's audit and the carrying costs should also be considered relate only to the final calculation of the disallowance.

The OEB accepts OPG's assertion that the only question before the Dispute Review Board was whether there were differing subsurface conditions. The fact that there was no quantification of costs related to each of the five issues analyzed suggests that they were either not individually quantifiable or not relevant. This is demonstrated by the fact that the parties that were engaged in the dispute and the Dispute Review Board did not or could not quantify the costs associated with each of the five issues. OPG provided evidence describing the usual approach taken by the Dispute Review Board in dealing with these matters.[5] OPG's witness stated that it is usual to only deal with the merits of a dispute in a hearing and then only return to the Dispute Review Board seeking a resolution if parties are not able to negotiate an agreement on costs. It is clear from the Dispute Review Board's report that cost was not considered in its analysis. The OEB finds that the Dispute Review Board's conclusions on attribution of responsibility have no bearing on costs and therefore cannot be used in support of the finding that the $40 million settlement was not prudently incurred.

Two other factors were included in the $28 million disallowance. These are the impact of the OPG audit results which the OEB found should have been considered, and the calculation of the carrying costs. Neither of these depends on the interpretation of the Dispute Review Board's conclusions, so the findings on these issues are unchanged.

The disallowance will be varied only by removing the amount pertaining to the Dispute Review Board's conclusions from the original disallowance calculation. The OEB has applied the same contributing share of 44% to OPG that was derived through negotiation to the post audit quantum of $77.4 million. As decided in the original decision, carrying costs on the new disallowance will not be recoverable.

[5] EB-2014-0369 Supplemental Motion Record filed January 26, 2015, page 20 – Oral Hearing Transcript Volume 1 June 12, 2014, page 64

The varied disallowance is $5.6 million[6] with an associated carrying cost of $0.8 million[7], resulting in a total varied disallowance of $6.4 million.

The difference between the original disallowance and the varied disallowance is $21.6 million. The revenue requirement impact of this difference is estimated to be $2.16 million[8] on the total annual revenue requirement for the OPG regulated facilities of $4,200 million.[9]

5.2 The Amended Design Build Agreement Disallowance

In 2009, following receipt of the Dispute Review Board's report, OPG and Strabag negotiated an Amended Design Build Agreement which increased contracted costs from $622.6 million to $985.0 million. While the structure of the initial agreement was fixed price, the structure of the amended agreement was based on target cost with incentives.

In the 2014-2015 payment amounts decision, the OEB found that the incentives were excessive and disallowed $60.0 million. At page 33 of the decision, it states:

> OPG's witnesses further confirmed that Strabag would suffer serious repercussions were it to walk away from the Project, including being sued by OPG for breach of contract, and suffering a serious blemish on its business reputation.
>
> Strabag, therefore, had very strong incentives to reach an agreement with OPG to find a way to complete the Project. Walking away from the Project would have been an extremely expensive and unpalatable option for Strabag, and for its parent company.
>
> Under these circumstances, the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed it took steps that should have mitigated that risk through a letter of credit

[6] $40 million – ($77.4 million x ($40 million/$90 million))
[7] $5.6 million x 5.25% x (33 months/12 months)
[8] EB-2013-0321 Oral Hearing Transcript, June 16, 2014, Vol 3 page 37: "So if you assume that you're bringing into rate base approximately $1.5 billion of capital, the kind of annual carry on that, reflective of depreciation and return on capital, rule of thumb is about 10 percent or, say, $150 million."
[9] EB-2013-0321 Payment Amounts Order, December 18, 2014, OEB approved revenue requirement for 2015

> and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal. The Board will disallow recovery of $60M. The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent.

OPG argued that the OEB's reliance on the Strabag parental guarantee and indemnity was in error. As Strabag was not in default and there was no litigation in process, the indemnity provided OPG with no leverage in negotiating the Amended Design Build Agreement. OPG was advised by professionals with tunneling and litigation expertise and the negotiation was hard-fought.[10] It was necessary to include incentives in the Amended Design Build Agreement, and in the end, Strabag's profit over the 5 year project was very small.

As with the $28 million disallowance, OEB staff and most of the intervenors argued that OPG made the same argument before the panel hearing the 2014-2015 payment amounts proceeding. There were thousands of pages of evidence and two days of cross examination on the Niagara Tunnel Project. Most intervenors argued that OPG was in a position of strength following the Dispute Review Board's report and that no one can determine Strabag's real profit except Strabag.

Threshold Test

OPG contends that the OEB's reliance on the parental guarantee and indemnity was in error. The decision clearly cites the risk of Strabag suffering a serious blemish on its business reputation as an incentive for it to remain on the job.

The 2014-2015 payment amounts decision makes reference to OPG's witnesses' testimony in confirming the existence of reputational risk. OPG does not allege an error in the OEB's reliance on the existence of reputational risk. OPG argues that the OEB placed too much significance on the parental guarantee and indemnity features of the agreement.

[10] Motion Hearing Transcript, pages 156-7

The threshold test findings from the motions to review the Natural Gas Electricity Interface Review Decision covered in chapter 4 of this decision include the following:

> In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently.

The OEB finds that the determination that the $60 million in incentives was not prudently incurred was based on the panel's findings on evidence that is not in dispute; that being the existence of reputational risk. The existence of the parental guarantee and the indemnity features was not the determinative factor in the finding of the existence of reputational risk. The OEB does not accept that there is an identifiable error in the decision that could lead to the conclusion that the findings are contrary to the evidence that was before the original panel.

The OEB does not consider the grounds for this part of OPG's motion to warrant any further consideration.

6 TAX LOSS CARRY-FORWARD

OPG incurred a regulatory tax loss of $211.6 million in 2013 that OPG attributes to a shortfall in nuclear production. In the 2014-2015 payment amounts proceeding, OPG submitted that the associated tax loss carry-forward should not be applied to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts. OPG argued that its shareholder incurred the costs associated with the loss in 2013 and should receive the benefit of the resulting tax loss carry-forward in 2014.

In the 2014-2015 payment amounts decision, the OEB found that the tax loss carry-forward should be applied against the 2014 tax provision. At page 101 of the decision, it states:

> The Board directs OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013. This finding is consistent with Board policy as indicated in the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook") and in subsequent Filing Requirements.[11] The Board understands the policies contained in the Handbook and the Filing Requirements apply to electricity distributors, not directly to OPG as an electricity generator, yet finds that the underlying Board policy should be applicable to OPG in this application.
>
> The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.
>
> OPG referred to two decisions in which the Board did not apply the policy, namely OPG's EB-2007-0905 decision and Great Lakes Power's EB-2007-0744 decision. The Board finds that the circumstances in these two cases were unique and are not comparable to OPG's current circumstances.

At the motion hearing, OPG reviewed the EB-2007-0905 and EB-2007-0744 decisions in detail and explained how these decisions and the benefits follows costs principle is applicable to 2013 regulatory tax loss. OPG argued that the 2014-2015 payment

[11] A requirement to identify any loss carry-forwards and when they will be fully utilized has been included in the Board's Filing Requirements for electricity distributors' cost of service applications since 2012. With the issuance of the 2012 Filing Requirements (for 2013 rates), the Board included any remaining relevant sections of both the 2000 and 2006 Electricity Rate Handbooks.

amounts decision did not correctly consider the two cases and made several errors, including limiting the reference to the Great Lakes Power case to the matter of regulated and non-regulated businesses. There were tax matters related to the regulated business and the OEB considered the benefits follows costs principle as well as the guidance of the Distribution Rate Handbook. OPG submitted that Great Lakes Power case is the leading case with respect to tax loss and that the OEB took a principled approach.

Threshold Test

As with the Niagara Tunnel Project disallowance, OEB staff and most of the intervenors argued that OPG made the same argument before the panel hearing the 2014-2015 payment amounts proceeding. OEB staff argued that there is no error as the basis of the OEB decision in the 2014-2015 payment amounts proceeding was the application of guidance in the Distribution Rate Handbook, not the benefits follows costs principle. OEB staff noted that tax loss carry-forwards have been applied in eleven distribution rate applications from 2005 to 2011. SEC submitted that a cost of service application rebases all costs, including taxes.

OPG argued that the panel's determinations with respect to the comparability of the two cases cited are erroneous. OPG provided what it considered to be the applicable common elements that the OEB should have considered.

The decision states that the two cases were considered to be unique and found not to be comparable to OPG's current circumstances. The decision does not contain a description of the distinguishing characteristics of the two other cases that would make them unique.

The OEB does not consider the lack of analysis of the comparability of the two cases to the current OPG circumstance to be an error. The decision to apply the tax loss carry-forward to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts was not primarily based on a determination that the current circumstances differ from the circumstances in the two cases cited by OPG.
The decision is clear as to why the OEB determined that the tax loss should be treated as directed. As noted above, the decision stated:

> The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with

> Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.

The threshold test findings from the motions to review the Natural Gas Electricity Interface Review Decision covered in chapter 4 of this decision include the following.

> The applicant must also be able to demonstrate that the alleged error is material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.

The OEB finds that even if the finding that the current circumstances differ from those in the cases cited by OPG, and was made in error, it would not affect the outcome of the decision as it would not change the primary basis on which the decision was made. As submitted by OEB staff, the basis of the OEB decision in the 2014-2015 payment amounts proceeding was the application of guidance in the Distribution Rate Handbook, not the benefits follows costs principle.

The OEB does not consider the grounds for this part of OPG's motion to warrant any further consideration.

7 IMPLEMENTATION AND COST AWARDS

7.1 Implementation

Subject to the OEB review of OPG's notice of motion, the remedy OPG proposed in its motion was an increase to payment amounts, and an account to recover the difference from November 1, 2014 to the effective date of the higher payment amounts.

The OEB has determined that errors were not made with respect to the disallowance associated with the Niagara Tunnel Project Amended Design Build Agreement or with respect to the income tax provision to account for regulatory losses. The OEB has determined that the Niagara Tunnel Project Pre-December 2008 Disallowance will be varied. The original rate base addition disallowance of $28.0 million will be varied to a disallowance of $6.4 million.

As noted earlier in this Decision, the estimated revenue requirement impact of the varied disallowance is $2.1 million per year. The approved 2015 total annual revenue requirement for the OPG regulated facilities is $4,200 million. Given the small percentage of payment amount impact the OEB finds that increasing payment amounts at this time to reflect the varied disallowance is not necessary.

The OEB orders the establishment of a variance account called the "Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account". The variance account shall record the difference between the annual revenue requirement impact of the original rate base addition disallowance of $28.0 million and the varied disallowance of $6.4 million. The account shall record the difference from November 1, 2014. OPG shall record interest on the balance using the prescribed interest rates set by the OEB from time to time. OPG shall apply simple interest to the opening monthly balance of the account until the balance is fully recovered. The clearance of the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account will be reviewed in OPG's next payment amounts application.

Given the nature of the costs to be tracked in the new account and their quanta, the OEB will dispense with the requirement to establish a more detailed accounting order at this time. OPG shall include all relevant details as to the manner in which it made all entries into the new variance account at the time of disposition.

7.2 Cost Awards

As noted in the Notice of Hearing and Procedural Order No. 1, any party that was determined to be eligible for an award of costs in the 2014-2015 payment amounts proceeding (EB-2013-0321) shall be eligible for costs in this proceeding.

In determining the amount of the cost award, the OEB will apply the principles set out in section 5 of the OEB's *Practice Direction on Cost Awards* and the maximum hourly rates set out in the OEB's Cost Awards Tariff.

8 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. OPG shall establish the following new variance account as described in this Decision: Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

2. Intervenors shall file with the OEB and serve on OPG, their cost claim within 7 days from the date of issuance of this Decision.

3. OPG shall file with the OEB and serve on intervenors any objections to the claimed costs within 14 days from the date of issuance of this Decision.

4. Intrervenors shall file with the OEB and serve on OPG any responses to any objections for cost claims within 21 days of the date of issuance of this Decision.

5. OPG shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, **EB-2014-0369**, be made through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto January 28, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2004-0167
EB-2005-0188

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates for the 2005 fiscal year commencing October 1, 2004;

AND IN THE MATTER OF a Motion by Natural Resource Gas Limited for a rehearing and variance of the decision of the Board as set out in its Decision with Reasons RP-2004-0167/EB-2004-0253 dated December 20, 2004**.**

BEFORE: Gordon Kaiser
Vice-Chair and Presiding Member

Pamela Nowina
Vice-Chair and Member

Paul B. Sommerville
Member

DECISION WITH REASONS

October 6, 2005

On February 23, 2005 Natural Resource Gas Limited filed a Motion with the Ontario Energy Board to rehear and vary certain findings of the Board's Decision dated December 20, 2004.

In that Decision the Board ruled that the deemed long term debt rate for the 2005 fiscal year was 8% and set NRG's cost of unfunded short term debt at 5.5%, which reflected 150 basis point premium over forecast prime of 4.00%. This translated to a weighted cost of debt of approximately 7.07%[1]. In this Decision the Board also disallowed the Applicant's request for the recovery of legal expenses incurred in its appeal of the Board's April 19, 2004 Decision. The Applicant seeks a variance of these two aspects of that Decision.

NRG requested that this Motion be heard in writing and by a new panel of the Board. The Board issued its Notice of Oral Hearing and Procedural Order No. 1, dated February 17, 2005 indicating that a new panel had been appointed, and set February 23, 2005 as the filing deadline for further evidence and submissions. The Motion was heard on April 11, 2005.

Relief Sought

The Motion sought a variance of the Board finding:

a) that the deemed long-term debt rate was 8.00%;

b) that disallowed the recovery through rates of the legal fees associated with NRG's appeal to the Divisional Court of the Board's April 19, 2004 Decision.

As an alternative to the relief sought in paragraph (a), NRG seeks an Order that it be permitted to recover its actual long-term debt costs; or in the alternative be

[1] Fiscal 2005 weighted average cost of debt, calculated using a Long-Term debt rate of 8% and 5.50% on the Short-Term & Unfunded Debt.

permitted to maintain a deemed debt rate of 9.20% for its deemed debt load based upon a 50% debt, 50% equity capital structure;

As an alternative to the relief sought in paragraph (b), NRG sought an Order that the legal costs be recoverable and a variance account for that purpose or an Order establishing a deferral account to track the legal costs. NRG also requested an Order permitting recovery of such amounts, including interest thereon, over a 12-month period commencing either July 1, 2005 or October 1, 2005.

Cost of Debt

The first issue before the Board in this Motion is whether to vary its finding in the December 20, 2004 Decision regarding the long-term debt rate relied on for rate-making purposes. In this Decision, the Board established NRG's rates using a deemed capital structure. As the Applicant's actual long-term debt ratio is approximately 30%, the Board imputes short term debt in an amount that 'tops' debt up to the deemed 50% level.

The June 27, 2003 Decision

Historically, the Board has used NRG's reported cost of long-term debt and deemed a cost of short-term debt at 150 basis points greater than prime. The Board's Decision of June 27, 2003 dealt with both the 2003 and 2004 test years. For 2003, NRG proposed an 11.38% cost of long-term debt and a 6.17% cost of short-term debt; for 2004 it proposed 11.60% and 7.52% respectively. The Board accepted NRG's cost of debt for the 2003 fiscal year and deemed an overall cost of debt of 9.00% for the 2004 fiscal year. This reflected a Board finding that NRG could reduce its interest expense through the refinancing of its debt and the Board's concern that an affiliate of NRG held a significant portion of its total debt.

In its Decision of June 27, 2003 the Board stated:

> The Board is of the view that NRG should be able to refinance its entire debt in a manner which will reduce its carrying costs even when the pre-payment penalties and transactions costs are added to the debt. …the Board sees no reason to believe that NRG cannot obtain an interest rate of better than 8.75% in the current environment. The Company's financial position has improved greatly in the past few years. The Company is a rate regulated monopoly with a relatively low risk. Interest rates have declined even since NRG's preliminary discussions with two financial institutions. While, as the Applicant points out, this leads to an increase in the pre-payment penalties, it also should mean a reduction in the new rate which NRG can obtain.
>
> The Board accepts the position of the Company that it would not be appropriate to adjust the debt rate for the 2003 test year as it will take some time for NRG to complete a refinancing. The Board is prepared to accept that the 2004 interest rate should be somewhat higher than 8% as this rate will be applied to the current forecast debt, whereas a refinancing will require NRG to incur more debt to fund the pre-payment penalties and the transactions costs….the Board also notes that the calculations during the hearing of carrying costs used a figure for transactions costs of $250,000 which was at the top of the range of such costs of $100,000 to $250,000 cited by NRG. The Board has also used this figure of $250,000 in making its determinations.
>
> In light of the utility's evidence that a potential lender would be looking to re-finance its entire debt, including short-term dent, the Board believes it is appropriate to deem an overall debt rate for the 2004 test year.

The December 20, 2004 Decision

In NRG's subsequent main rates case to fix rates for the 2005 fiscal year, it sought an overall cost of debt of 9.20% on an overall debt of $4,705,623. The Company stated that the debt instruments for the 2005 fiscal year were the same as the debt instruments for the 2004 fiscal year, with one exception: the instruments previously held by NRG's affiliate were sold to Banco Securities Inc. at the face value of the debt, under the original terms and with no change in the interest rate. The Company testified that it would pursue refinancing over the next several months and that it anticipated being able to negotiate an interest rate of around

8%. These discussions were expected to be completed by February or March, 2005.

In its decision of December 20, 2004 the Board stated:

> "The Board does not accept the Utility's request for the use of a deemed debt rate of 9% or 9.2% in calculating its revenue requirement. The Board does not intend to tie the Utility's debt rate to the fluctuations of long term interest rates at this point in time. The Board, in its prior decision, set a deemed debt rate in light of the evidence before it that the Utility would be able to reduce its interest expense if it re-financed its existing debt and the fact that much of the Utility's debt was held by an affiliate.
>
> The Board is concerned about the lack of knowledge exhibited by the President of the Utility as to the identity of a major creditor of the Utility, Banco Securities Inc. The Utility has not brought forward requested evidence to demonstrate that Banco is an unaffiliated, arm's length party. Thus, there remains no evidence from an actual transaction demonstrating the interest rate that NRG could obtain in the open market.
>
> The Board has heard evidence in this proceeding that the Utility could refinance its debt at an interest rate of approximately 8% and that there would likely be associated penalties and transaction costs ("breakage costs"). The Board will adopt a deemed long term debt rate for the 2005 fiscal year of 8%. The Board will consider the prudence of breakage costs if and when they are incurred. At that time, the Board will also address the recovery of any breakage costs through rates.
>
> The Board sets NRG's cost of unfunded short term debt at 5.5%, which reflects 150 basis point premium over forecast prime of 4.00%."

The April 11, 2005 Motion

In the current Motion, NRG requested the Board amend the December 20, 2004 Decision and allow the Company to recover its forecasted debt costs of its actual debt instruments. The Company submitted that the difference between the Applicant's actual cost of debt and the Board approved cost of debt was approximately $98,000.

NRG further stated that it has had discussions with two lenders, both of which were chartered banks. It also stated that it is in the process of preparing a five-year capital expenditure forecast in support of the contemplated refinancing of the Company's existing long-term debt. This total package of existing debt and capital expenditure is valued at approximately $5 million.

NRG stated that in order to get a competitive rate, it must approach the lenders with the complete package (that is short-term debt, long-term debt and costs associated with the capital expenditure program) arguing that if a complete package was not negotiated the premium on a second and third portion of the financing would be very expensive. On further questioning NRG testified that it anticipated that within the next two months, that is May or June 2005, it would have formal discussions with lenders and within four to six months it would be approaching lenders with a final borrowing package.

Board Findings

In the Motion NRG testified that it had not made any progress on refinancing its debt because it was in the process of finalizing its capital expansion plans.

The Board determined that before rendering a decision on the Motion it would be appropriate to obtain an update from NRG as to the status of their capital plans and their financing efforts. Accordingly the Board on August 31, 2005 sent a letter to NRG requesting such an update. NRG responded on September 9, 2005 and indicated that it had still not taken any action with regard to its debt refinancing. The letter did not provide a response on the capital plans.

The Board has on a number of occasions expressed its concern that the loan to NRG is not market based and therefore not all of the interest costs associated with it are properly borne by ratepayers. The fact that the loan is now owned by a different party does not change this concern. NRG chose to transfer this loan at face value with its high interest rate.

This is not a hearing of the application *de novo*. In considering a motion to vary, the Board considers whether new evidence has been presented by the Applicant, or whether the original panel made an error in law or principle so as to justify the reversal of the original Decision.

After reviewing the evidence and the submissions of NRG, the Board has found no compelling evidence that would cause it to vary its December 20, 2004 Decision. It is also apparent from the Company's September 9, 2005 letter in response to the Board's August 31, 2005 letter, that NRG has made no progress whatsoever with regards to new financing.

The Board therefore finds and confirms that the deemed long-term debt rate for the 2005 fiscal year of 8.00% and an unfunded short term debt rate of 150 basis point premium over forecast prime of 4.00%, as set in the Board's December 20, 2004 Decision is just and reasonable for rate setting purposes.

Legal Expenses

The second issue before the Board in this Motion is whether to vary that aspect of the Board's Decision of December 20, 2004 that disallowed the recovery of $175,000 in legal fees.

In its original 2005 rates filing, NRG budgeted $15,000 for legal fees. In its updated filing, in that case this amount was increased to $190,000 to reflect the anticipated costs of an appeal to the Divisional Court of a previous Board decision.

The background to the Divisional Court Appeal is as follows:

In October 2003, NRG discovered that its gas costs for the period October 2002 to December 2003 were under-recovered, by approximately $531,000 due to an accounting error. NRG reported the discrepancy to the Board and in November 2003 filed an Application[2] to recover these costs. In January 2004 the Board issued its decision and authorized NRG to establish a Gas Purchase Rebalancing Account to capture future unrecorded costs, but denied NRG's proposal to recover the $531,000.

Subsequently, NRG sought and was granted a review of that decision. In an April 19, 2004 Decision[3] the Board approved NRG's recovery of these unrecorded gas costs of $531,000 over three years but disallowed the interest on the outstanding balance and the legal and regulatory costs of that review. The Board stated;

> We are surprised and disappointed with the time that it took NRG to realize that its PGCVA mechanism was incorrect, which exposed the utility and its customers to unnecessary risk and created a difficult situation for the customers and the Board. However, we accept that the misrecording was the result of error, not a purposeful action by NRG. [paragraph 33]

The rationale for the Board's initial disallowance of both interest charges and legal and regulatory costs is relevant to the disallowance of legal costs at issue in this proceeding. It is clear that the Board in the earlier decision was motivated by the fact that NRG was responsible for additional costs that should not be borne by the ratepayer. At Paragraphs 38 to 40 of the Decision, the Board stated;

> Had NRG recorded gas cost variances properly in the PGCVA, the present conundrum would have been avoided….we find that NRG's error has resulted in a substantial and avoidable accumulation of potential customers' charges, through no fault of the customers.
>
> We must therefore look for a balance.

[2] RP-2002-0147/EB-2003-0286
[3] RP-2002-0147/EB-2004-0004

The Board further stated;

> …we find that a reasonable balance is recovery of the $531,794 amount over a three year period, in equal portions, without interest… Further, NRG shall not include the regulatory costs it incurred in this proceeding in estimating the regulatory costs for future test years. [paragraph 44, 47]

In summary, the Board refused the NRG request that the costs be collected in one year with interest. Instead, the Board held that it should be collected over three years without interest and that the Company would be disallowed its legal and regulatory costs of the review.

NRG then appealed to the Divisional Court seeking recovery of interest and legal costs associated with the review. The Divisional Court dismissed the appeal in its April 21, 2005 Decision[4].

The Court in upholding the Boards decision accepted the Board's judgement that NRG was partially responsible for the error and its inadvertence had caused costs to consumers. Specifically, the Court stated;

> The matter was compounded by the added issue of how to deal with the accumulation of costs caused by the appellant's inadvertence. The Board determined that customers must pay the prudently incurred unrecorded costs of the appellant, but the impact of the recovery of the accumulated total should be ameliorated by allowing recovery over three years. The accumulated cost of the time over which recovery from customers would be required and the appellant's regulatory costs (over and above the $60,312 allowed it) must be borne by the appellant…The issue before the Board in this case is much more confined: how to deal with the consequences of a failure to identify and report prudently incurred costs, and in determining that question the Board was entitled within its broad mandate to consider both the utility's and customers' interests, as it did. [paragraph 14, 15]

In the 2005 rates case, NRG sought to recover the legal costs of $190,000 related to the Divisional Court appeal.

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[4] [2005] O.J. No. 1520

The Board in its Decision of December 20, 2004 disallowed these legal expenses on three grounds. First, the legal costs were solely for the benefit of the shareholder; Second, the legal costs were out-of-period; Third, the Board found that the costs were excessive. Specifically, the Board stated;

> The Board will not allow the legal expense incurred by NRG in its appeal of Board decision in RP-2002-0147/EB-2004-0004 to be recovered from its ratepayers. The Utility's return on equity compensates the Utility for the risks it incurs - including regulatory risk. This appeal was launched at management's discretion and solely for the benefit of its shareholder. It is inappropriate for ratepayers to support legal actions that, if successful, will benefit the Utility's shareholder exclusively.
>
> By way of comment, $50,000 of legal expenses has already been invoiced in the prior fiscal year. NRG ought to be aware that its proposal to include this amount in the test year for this Application represents a request for relief for costs incurred out-of-period and therefore would not be recoverable through rates. Further, the Board questions the prudence of a decision to spend $175,000 for a potential recovery of up to about half that amount. Finally, the Board questions the size of the claimed legal expenses for an appeal the Applicant expects to last no more than two days. [paragraph 3.0.7, 3.0.8]

NRG in its Factum at paragraphs 101 to 110 responded to these findings.

With respect to the ruling that the legal costs were solely for the benefit of shareholders, NRG argues, that if NRG is successful in its appeal, this could have the effect of reducing its borrowing costs because lenders take some comfort from the fact that regulated utilities such as NRG can recover there costs in the regulatory process.

With respect to the Boards findings that the cost award was out-of-period, NRG responded that the cost of the appeal could not be ascertained with greater precision prior to the filing of the updated evidence. The Company argued that at the time it submitted its evidence the $175,000 amount was the best information it had. NRG further argued that NRG did not control the timing and was required to accommodate the Courts scheduling.

NRG also argued that claiming 2004 costs during fiscal year 2004 would have necessitated a separate application which would have been unnecessarily expensive and would have given rise to the issue of retro-activity. The Company submitted that waiting for the 2005 rate case was the appropriate business decision as it reduced the regulatory burden to NRG, the rate payers and the Board.

In this Motion NRG also argued that as a regulated utility, it should not be constrained from appealing regulatory decisions it considers inappropriate.

With respect to the ruling that the costs were excessive, NRG introduced new evidence and advised the Board that the costs were now reduced from the original estimate and would be no greater than $70,000. Board Counsel advised the panel that this new level of costs was reasonable.

Board Findings

Although the Board finds that there is some merit in NRG's arguments with respect to both the out-of-period issue and the amount of the costs, in reviewing all factors, the Board finds that the Board's previous Decision with respect to legal costs should stand and not be varied.

NRG has argued that it should not be penalized when appealing decisions of this Board by disallowance of costs associated with these appeals. This panel agrees with that submission. However, there is no suggestion that the earlier panel was attempting to penalize NRG in this regard.

As to whether these costs were out-of-period, there is merit to NRG's position that these costs were not crystallized at the time they had to be presented in the 2005 rate case.

The Board also notes that the costs have now been finalized and are considerably less than the earlier estimate of $175,000. The Company now claims that the costs will not exceed $70,000. This is new evidence that was not before the previous panel, but the quantum of costs was only one of the several reasons given by the panel for disallowance.

The Board's ruling that the appeal was solely for the benefit of the shareholders and therefore the costs should be disallowed is a more difficult issue. It can be argued that all costs that a regulated utility seeks to recover from ratepayers are to the benefit of the shareholders. On the other hand, it can be argued that all Decisions will have an impact beyond the shareholder interest.

NRG argues in this case that lenders will be comforted by the fact that the utility is successful in recovering its costs. However, the more fundamental question is why these costs were disallowed in the first instance.

A careful review of the Decisions indicates that the disallowance of the interest costs and the legal and regulatory costs has been the subject of three separate Decisions. The first was the Board's April 19, 2004 Decision[5], the second was the Divisional Court ruling on the appeal from that Decision[6] and the third was the December 20, 2004 Decision[7].

[5] RP-2002-0147/EB-2004-0004
[6] [2005] O.J. No. 1520
[7] RP-2004-0167/EB-2004-0253

It's clear why the Board disallowed both the interest and legal costs. In the April 19, 2004 Decision, the Board stated;

> Had NRG recorded gas cost variances properly in the PGCVA, the present conundrum would have been avoided….we find that NRG's error has resulted in a substantial and avoidable accumulation of potential customers' charges, through no fault of the customers.
>
> We must therefore look for a balance. [paragraph 38-40]

At paragraph 44 and 47 of that Decision, the Board concludes that the "balance" was to allow recovery of the $531,794, but not over one year as requested by the utility. Rather, the Board said the utility could recover those costs over three years but <u>without</u> interest. The Board added that it was also not going to allow the regulatory costs incurred with respect to the review.

NRG then appealed to the Divisional Court. The Court upheld the Board's Decision indicating, "The matter was compounded by the added issue of how to deal with the accumulation of costs caused by the appellant's <u>inadvertence</u>." The Court further stated " The issue before the Board is much more confined: how to deal with the consequences of a failure to identify and report prudently incurred costs, and in determining that question the Board was entitled within its broad mandate to consider both the utility's and customers' interests, as it did."

On review of the complete record, the Board finds that the principle motivation for the panel in disallowing these costs in both Decisions was that the costs were in part as a result of NRG's own error. This "inadvertence" as the Divisional Court describes it, imposed costs on customers which were the consequences of a failure to identify and report prudently incurred costs. The Divisional Court found at paragraph 15 of its Decision, "The Board's disposition, in seeking and determining a reasonable balance, was not punitive in nature."

This panel agrees with the Divisional Court's assessment. The issue of the costs of the appeal is the same issue that was before the Divisional Court. There, the costs were the costs of the review as opposed to the costs of the appeal. The principle is the same. This Board has consistently ruled that utilities should not be entitled to recover costs where those costs are a result of its own error and that error has imposed unnecessary costs on the ratepayers.

It is true that lenders and others look to the ability of a regulated utility to recover costs from its regulator. But they also look for consistency of Decisions on part of the regulator. The issue before this panel has been before the Board twice and the before the Divisional Court once. We see no reason to alter the findings.

Costs

The costs of, and incidental to, this proceeding shall immediately be paid by the Applicant upon receipt of the Board's invoice.

DATED at Toronto, October 6, 2005

ONTARIO ENERGY BOARD

Original signed by

Gordon Kaiser
Vice-Chair and Presiding Member

Original signed by

Pamela Nowina
Vice-Chair and Member

Original signed by

Paul B. Sommerville
Member

EB-2009-0063

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15;

AND IN THE MATTER OF an Application by Brantford Power Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2008.

AND IN THE MATTER OF a Motion being brought by Brant County Power Inc. to review and vary the implementation of the Board’s Interim Order Dated April 21, 2008 in this proceeding; and the Board’s Decision dated July 18th, 2008;

BEFORE: Gordon Kaiser
Vice-Chair and Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

[1] This is an appeal by Brant County Power Inc. (“Brant County”) of the Board’s Decision of July 18, 2008[1] regarding the distribution rates to be charged by Brantford Power Inc. (“Brantford”). For the reasons set out below, the Board is granting a variance of this Decision.

[2] The heart of this motion concerns a billing dispute between Brantford and Brant County concerning the rates that Brantford charges Brant County for electricity. There are two rates at issue, the rate for distribution services and the rate for retail transmission services (“RTS”). Aside from the actual rate, there is a question as to when Brantford is entitled to start charging for these services. The School Energy Coalition intervened in this Motion but did not present argument. Board Counsel participated and presented detailed argument.

Background

[3] Brantford Power Inc. is a licensed distributor of electricity providing service to 35,000 consumers within the City of Brantford. Brantford supplies electricity to Brant County, an embedded distributor.

[4] Brant County is a licensed distributor, providing distribution service to approximately 9,500 customers, in the Municipality of Brant County. The Brant County service area completely surrounds the service area of Brantford. Part of the Brant County distribution system is embedded within the Brantford distribution system. Brantford delivers power to Brant County through three transformer stations; Colborne East, Colborne West and Powerline Road.

[5] The Decision that Brant County is appealing is the Board’s Decision of July 18, 2008 which, for the first time, set the rates that Brantford should charge Brant County. Those rates, the Board determined, should be set at the rate that Brantford was currently charging the GS > 50 kW class of customers.

[6] The rates that the Board set in the Decision of July 18, 2008 were effective September 1, 2008. Notwithstanding that, Brantford apparently issued its first bill to Brant County on June 15, 2008. That bill was paid by Brant County on July 7, 2008 but Brant County refused to pay any subsequent bills. On February 25, 2009, Brant County

[1] *Re: Brantford Power Inc.,* EB-2007-0698, (July 18, 2008).

filed this Motion asking the Board to alter the distribution rate that the Board had established for Brant County.

[7] Brantford is also is seeking payment of $2.1 million for unbilled RTS charges. These relate to the acquisition by Brantford of certain assets from Hydro One on October 15, 2005 at two transaction sites, Colborne East and Colborne West. Apparently, Brantford did not start billing Brant County for RTS at that time. This mistake was discovered in these proceedings. This Motion was then amended seeking recovery of these costs.

[8] There are also unbilled RTS charges relating to the Powerline Road transformer station which is jointly owned by Brant County and Brantford. Those charges date back to July, 2008.

[9] There are eight issues in this motion:

i. Should the Board hear the Motion and review the July 18, 2008 Decision
ii. Was the notice provided by Brantford sufficient?
iii. What is the Standard of Review?
iv. Is the distribution rate charged by Brantford to Brant County just and reasonable? If not, what rate should be charged by Brantford?
v. At what date should Brantford be permitted to commence charging Brant County for distribution services?
vi. At what date should Brantford be permitted to charge Brant County for RTS Network and Connection Charges for Colborne East and Colborne West?
vii. What interest should be paid on the monies owed? and
viii. What time period should be allowed for payment?

Should the Board Review the July 18, 2008 Decision?

[10] Rule 42.01 permits any person to bring a motion to the Ontario Energy Board requesting a review and variance of a Board's decision. Rule 44 provides:

> 44.01 Every notice of motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> > (a) set out the grounds for the motion that raise a question regarding the correctness of the order or decision, which grounds may include:

(i) Error in fact;

(ii) Change in circumstances;

(iii) New facts have arisen;

(iv) Facts that were not previously placed into evidence in the proceeding and could not have been discovered by the reasonable diligence at the time.

[11] Brant County relies on subsections (a)(i), (iii) and (iv), and states:

i. The Decision was based upon Brantford evidence that underforecasts the demand for the General Service Greater than 50 kW ("GS > 50kW") rate classification.

ii. Brantford did not inform the Board of its discussions with Brant County regarding a separate rate classification for Brant County.

iii. Brantford has not been charging Brant County Retail Transmission Services at Colborne East and Colborne West and therefore the cumulative impact on Brant County of both distribution and RTS charges was not put before the Board at the time of the Decision.

iv. The distribution revenue claimed by Brantford far exceeds the proposed allocated costs to Brant County. Brantford included Brant County in a rate classification that has a revenue to cost ratio of at least 1.39:1. With the 2008 approved rates, Brant County would be subsidizing Brantford ratepayers by more than $120,000 each and every year.

v. The distribution charge by Brantford represents approximately 8% of Brant County's revenue requirement.

[12] Brant County also argues that Board staff raised the issue of a separate rate classification during the proceeding and the Board accepted, based upon the evidence before it at that time, that using the GS > 50kW classification was acceptable. Brant County submits that had all the facts been available during the original hearing, a different decision would have resulted.

[13] Before the Board will hear a Motion to vary a previous Decision it must be satisfied that the review raises a question as to the correctness of the Decision. The test was clearly stated by the Board in the *Connection Procedures* Decision[2];

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[2] *Re Hydro One Networks Connection Procedures*, EB-2007-0797 (November 26, 2007) at paragraph 20.

The moving party must also satisfy the Board of the following:

To the extent that an error in the *Connection Procedures* Decision is alleged:

- that the error is identifiable, material and relevant to the outcome of the *Connection Procedures* Decision and that, if the error is corrected, the reviewing panel could change the outcome of the Connection Procedures Decision (in other words, there is enough substance to the issues raised that a review based on those issues could result in the reviewing panel deciding that the *Connection Procedures* Decision should be varied, cancelled or suspended); and

- that the findings of the *Connection Procedures* panel are contrary to the evidence that was before that panel, the panel failed to address a material issue, the panel made inconsistent findings, or another error of a similar nature was made by the panel.

To the extent that the incompleteness of evidence is raised as a ground for review:

- that the facts now sought to be brought to the attention of the Board could not have been discovered by reasonable diligence at the time; and

- that those facts are material and relevant to the outcome of the *Connection Procedures* Decision and that, if considered by the reviewing panel, could change the outcome of the *Connection Procedures* Decision (in other words, the facts are such that a review based on a consideration of those facts could result in the reviewing panel deciding that the *Connection Procedures* Decision should be varied, cancelled or suspended).

Board Findings – Grounds for Review

[14] Applying the *Connections Procedures* test we find that Brant County has met the threshold for review. There is no question that there is new evidence. The issue of the RTS charges was not even before the panel in the 2008 hearing. Not only was Brant County not aware of it but even Brantford was apparently not aware of until it was discovered in the course of these proceedings. This is an important issue with significant consequences. The Board believes it should be determined as soon as possible.

[15] Having decided to consider the billing dispute regarding RTS it is also important to consider billing dispute regarding the distribution rate. While the question of whether the GS > 50 kW rate was the proper rate for Brant County was before the original panel,

there was very limited discussion of the issue and very little evidence. That was driven, in large part, by the fact that Brant County did not participate in the hearing.

[16] It is also significant that the original panel's Decision was driven in part by an understanding that the Board would be studying the question of embedded distributor charges in an upcoming proceeding[3]. It now turns out that this proceeding no longer exists and has been substituted by another, more distant, proceeding[4].

[17] This is an important issue. It is in the interest of all parties to have the distribution rate, like the RTS charges, resolved. We find that the Applicant has met the threshold test and are prepared to review the Decision with respect to the billing disputes in question. In addition, we face two issues that were not before the original panel which is the proper start date for billing each of the services.

Was Proper Notice Given?

[18] Brant County also argues that the Board should review the July 18 Decision because Brant County did not receive effective notice of Brantford's Application for 2008 rates. Brant County goes so far as to say that because effective notice was not given, the Board lacked jurisdiction and the Decision of July 18 should be set aside.

[19] Brant County claims that the Notice was deficient in terms of both delivery and content. With respect to delivery, Brant County says that they have no record of receiving the Notice. Brantford, however, claims they delivered the Notice to Brant County. Regardless of whether the Notice was physically received by Brant County, there is evidence that Brantford published the Notice, as approved by the Board, in the local newspaper.

[20] As to content, Brant County says the Notice did not indicate that Brantford had decided not to create a special embedded distributor charge for Brant County (as Brant County believed they would) but instead proposed to bill Brant County as a GS > 50kW customer. Nor, they argue, was there any indication what impact the rate would have on Brant County. Brant County argues that the impact will be approximately $425,000 a

[3] *Review of Electricity Distribution Rate Design*, EB-2007-0031

[4] *Review of Electricity Distribution Cost Allocation Policy*, EB-2010-0219

year which they claim is a material amount that should have been disclosed in the Notice.

Board Findings – Notice

[21] In reviewing the legal standards with respect to Notice it is useful to consider the remarks of the panel in the recent *Hydro One Networks* case[5]. In that case the intervenors claimed insufficient notice because the Notice made no reference to the Board's Cost of Capital Report which had the effect of increasing the Return on Equity for the Applicant. The reason was that the Report was issued by the Board after the date of the Notice but nonetheless had an impact on the decision.

[22] The Board's remarks in the *Hydro One Networks* case go to the question of the how detailed the Notice can be from a practical point of view.

> Drafting a notice for a complex hearing is an important responsibility of the Board. The Board discharges its responsibility by converting a highly technical application of several thousand pages into a two- to three-page summary.
>
> It must be able to be published in a newspaper, and to be read quickly and easily. It must accurately summarize the general potential impacts of the application. It must use language that can be understood by a person who has no background whatever in the complex field of utility rate setting.
>
> It must find a balance between including too much information, which could be confusing in addition to being impractical, and including too little information such that the reader is unable to understand how the application may impact him or her.
>
> Due to the length and the complexity of the hearing process, a number of changes may occur to the application after the notice is issued. There may also be other factors external to the application itself that have an impact on rates.
>
> The Board notes that the notice also provides information on how the application itself can be accessed through both the Board's and Hydro One's websites. In this way, an interested person is invited to supplement the information imparted by the notice by reading as much of the detail of the application as he or she may wish.

[5] *Re Hydro One Networks Inc*, EB-2009-0096 (January 19, 2010).

> The Board is satisfied that the notice in this case strikes an appropriate balance and provided readers with the necessary information for them to determine if they wanted to participate further.

[23] As indicated in the *Hydro One Networks* Decision adequate Notice is always a balancing act and often turns on the sophistication of the party questioning the Notice. The *Hydro One Networks* Decision referenced the *Nolan* case[6], where the Ontario Court of Appeal stated;

> When determining whether adequate notice has been given, two questions must be asked: (1) was the content of the notice accurate and sufficient? And (2) were all affected parties given notice?

[24] In the *Central Ontario Coalition*[7] case, the Ontario Divisional Court stated;

> In any event, it is well established that where the form or content of notice is not laid down it must be reasonable in the sense that it conveys the real intentions of the giver and enables the person to whom it is directed to know what he must meet.

[25] It is also accepted as the Ontario Court of Appeal said in *Ontario Racing*[8] that the adequacy of Notice will often turn on the circumstances of the case;

> I now turn to the other issue as to whether or not the Respondent was denied natural justice by the action of the Board. The cases establish beyond peradventure that whether a notice given in any particular case is sufficient depend entirely upon the circumstances of the case.

[26] And as the Court said in *Wilson*[9], it is also important to consider who was the party reviewing the Notice;

> I, therefore, now consider the contents of the notice. In my view the principle is that the notice must be in such terms as are fairly and reasonably necessary to enable members of the public in the area of the land affected to appreciate that they are interested and to make representations or objections

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[6] *Nolan v. Ontario (Superintendent of Financial Services)*, [2007] OJ. No. 2176, 86 O.R. (3d) 1 (C.A.) (QL).

[7] *Central Ontario Coalition Concerning Hydro Transmission Systems and Ontario Hydro* (1984) 46 OR (2d) 715, 10 DLR (4th) 341 (Div. Crt.)

[8] *R. v. Ontario Racing Commission*, (1971), 1 O.R. 400, 15 D.L.R. (3d) 430.

[9] *Wilson v. Secretary of State for the Environment* [1973] 1 WLR 1083

> if they think fit. In deciding whether the notice would give the necessary information, one must, in my view, assume an imaginary member of the public familiar with Aldridge. One must not assume a trained lawyer nor someone experienced in local government, whether a councilor or an officer. On the other hand, one must not assume someone unusually stupid or unusually careless.

[27] Brant County in alleging inadequate Notice relies on the *Conception Bay*[10] case. There, the Court found that the Nova Scotia Public Utilities Board failed to give adequate notice to a number of municipalities of a new charge to the municipalities that was not disclosed in the Notice. We do not believe that *Conception Bay* applies here. In *Conception Bay,* the municipalities were not familiar with the Board's process. Here, the customer is a utility not an ordinary consumer.

[28] It is significant that prior to filing this Notice of Application, the two parties, Brant County and Brantford, through senior officers, had been negotiating a special rate for Brant County. And the discussion was whether it would be the GS > 50 kW rate or some special rate. Brant County states that they believed they would get a special rate and were "shocked" to find that Brantford unilaterally decided to change its approach and took no steps to inform Brant County. The first indication of the new approach, they claim, was an email after the first invoice was issued.

[29] That, however, is not the issue. This Notice was published on January 18, 2008 in the Brantford Expositor which had the highest circulation rate in the Brantford service area. The Notice of Application, which was issued by the Board on January 9, 2008, allowed any interested party to request intervenor status no later than 10 days after the publication date.

[30] It is highly improbable that someone in authority at Brant County was not aware of the Notice. It is also highly improbable that they would not have a passing interest in knowing what Brantford had decided regarding the rate under negotiation. The Board believes that Brant County, in these circumstances, had an obligation to take reasonable steps to determine what rate would apply to them and whether they should participate in the hearing.

[31] Instead, they took no steps and now complain that the utility did not inform them. There is no question that Brantford could have been more responsive. But in our view

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[10] *Conception Bay v. Newfoundland Public Utilities Board*, (1991) Admin L.R. (2d) 287.

the Notice was sufficient. It may not have detailed the specific rate but as the Board found in *Hydro One Networks* it is impossible to detail every specific rate change.

[32] In the end this was a sophisticated customer. Not only was it the largest customer, it was also a utility that had recently been negotiating the rate at issue. It is difficult to believe that they would not have reviewed the evidence. The Notices often state, as this one did, that the evidence can be easily found on the utility's website or the Board's website. That is the logical step that those receiving the Notice should take to determine if their interests will be impacted. It is impossible to detail every change in rates in a Notice published in a newspaper.

[33] These Notices have to be prepared so that they can be read by the common person. Brant County was certainly not the common man. Rather they were a large and sophisticated customer that apparently they did not review any of the evidence. While there was only one line in the evidence identifying the rate it did indentify the rate. That rate turned out to be the GS > 50kW rate.

The Standard of Review

[34] Counsel for Brant County also made submissions regarding the standard of review to be used by the Board in reviewing this Decision. Counsel argues that if the reviewing tribunal does not reach the same Decision, the reviewing tribunal must consider the Motion as if it were hearing the matter for the first time. Specifically Counsel argued;

> A tribunal must determine the appropriate standard – that of reasonableness or correctness – upon which to consider the prior decision. BCP submits that the Board, in conducting a motion to review and vary a decision, must consider whether the original decision on a correctness standard and not defer to the prior panel. Would the current panel have reached the same decision? If not, then the reviewing tribunal panel must replace the prior decision.
>
> The Board's Rules provide that the threshold for such a review is grounds "that raise a question regarding the correctness of the order or decision". Therefore, the appropriate standard of review to be applied in the consideration of such a motion is correctness. This is the most stringent standard of review required by law. The reviewer must insert themselves in the original tribunal's place and determine whether it would have reached the identical result as the original tribunal. It is insufficient for the reviewer to state

> that the original decision was reasonable or that it was not unreasonable – the decision **must** be correct[11].

Board Findings – Standard of Review

[35] With respect we disagree. A reviewing panel should not set aside a finding of fact by the original panel unless there is no evidence to support the decision and is clearly wrong. A decision would be clearly wrong if it was arbitrary or was made for an improper purpose or was based on irrelevant facts or failed to take the statutory requirements into account. That is not the situation here.

[36] The standard of review with respect to Decisions of the Ontario Energy Board was most recently canvassed by the Ontario Court of Appeal in the *Toronto Hydro Dividend*[12] case. There, the Court of Appeal upheld the Board's Decision that required any future dividends to be approved by the majority of the independent directors. The Court noted that "in judicial review reasonableness is concerned mostly with the existence of justification, transparency, and intelligibility within the decision-making process. But it also concerned with whether the Decision falls within a range of possible acceptable outcomes which are defensible in respect of facts and law".

[37] In finding that the Decision was justified, the Court referred to the often cited passage from *Law Society of New Brunswick vs. Ryan*[13] where Iacobucci, J. articulated the relationship between the reasons of the tribunal and the reasonableness of its Decision.

> A decision will be unreasonable only if there is no line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived. If any of the reasons that are sufficient to support the conclusion are tenable in the sense that they can stand up to a somewhat probing examination, then the decision will not be unreasonable and a reviewing court must not interfere. *This means that a decision may satisfy the reasonableness standard if it is supported by a tenable explanation even if this explanation is not one that the reviewing court finds compelling.*

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[11] Brant County Power Inc. Argument-In-Chief, page 6, para. 10 - 11

[12] *Toronto Hydro-Electric System Ltd v. Ontario Energy Board* [2010] OJ No. 1594

[13] [2003] 1 SCR 247 at para 55.

[38] We believe that the standards that a court would use in reviewing a Board Decision are no different than those this panel should use in reviewing a prior Board Decision.

What is the Correct Distribution Rate?

[39] The Board in its Decision of July 18, 2008 regarding the Brant County rate stated at page 16;

> **Rate Classes**
>
> The Company is a host to one embedded distributor, Brant County Power, and also serves one large customer with demand greater than 5000 kW.
>
> Board staff noted that the Company did not propose separate rate classifications for these loads; rather, they are being served within the GS>50 kW rate class.
>
> With respect to the large customer, the Company noted that the customer is new in this size range and the Company did not want to jeopardize the timing of its application for 2008 rates by designing and implementing a new rate class. The Company proposed that it would undertake a cost allocation study to support the establishment of a large user rate class for its next rate rebasing.
>
> With respect to the embedded distributor, Brantford clarified in response to an interrogatory that it intends to begin billing the embedded distributor in the 2008 rate year, and will do so by using the GS>50 kW rate classification. Board staff submitted that host distributors should be proposing a rate for embedded distributors, but noted that the practice of using the General Service rate is not unusual.
>
> **Board Findings**
>
> The Board accepts as reasonable the Company's proposal to defer the rate classification matter for the time of its next rebasing application. The Board notes that the issue of rates for embedded distributors is in the scope of a study currently underway at the Board (EB-2007-0031), the Rate Design study. The Board expects Brantford to keep itself informed as to potential developments through that process.

[40] Brant County argues that the GS > 50kW rate which Brantford used to charge Brant County is not just and reasonable because it over-recovers from Brant County. They say that the charges are not based on a proper cost allocation, that the services

being charged to Brant County are different than other customers in the GS > 50kW rate classification, that the rate does not include a proper loss factor for Brant County and the rate is based on an under forecast of demand.

[41] Brantford's response is that the Board should reject Brant County's Motion and confirm that Brant County must pay Brantford for all distribution services from May 1, 2008 at the GS > 50kW rate.

[42] Board staff presented a detailed submission regarding the proper rate that Brant County should be paying to Brantford. They argue that Brant County's consumption was greater than GS > 50kW category and that the services being provided to Brant County are different than those provided to the other customers in the GS > 50kW classification.

[43] Board staff examined the volume characteristics of the customers in the GS > 50 kW class and found that Brant County's energy and demand volumes were much greater than the average for customers in this class. For example at one delivery point (Colborne East) monthly demand for Brant County was 8500 kW. The response to Board Staff Interrogatory No. 9 indicated that the average demand for customers in the GS > 50 kW class, without Brant County, is 271 kW per month. This compares to an average monthly demand for Brant County of 4700 kW. In the case of energy, the average annual consumption for the members of the class, without Brant County, is 1.3 million kWh compared to 25.7 million kWh for Brant County.

[44] The cost differences of serving Brant County and the GS > 50 kW rate class are set out at Page 6 of the Board Staff submission. The relative costs which are reproduced in the table below are based on information provided by Brantford in response to Board Staff Interrogatory No. 9. It indicates that the average cost per kWh of serving Brant County is 40% less than for the GS > 50 kW class. This suggests that the rate should be 40% less for Brant County than for the rate to serve the GS > 50 kW class.

	GS > 50 kW	**Brant County**
Revenue Requirement ($)	3,295,266	303,456
kWh	513,051,214	77,273,702
¢/kWh	0.6423	0.3927

[45] Board staff also argues that the costs associated with Brant County are different than other customers in that class. They argue that Brant County should not be responsible for the cost of transformers, distribution lines, poles and related equipment which do not apply to Brant County.

[46] There is also a difference in the distribution loss factor. The factor applied to Brant County customers was 4.2% which represents the total distribution system. In response to Board Staff Interrogatory No. 11, Brant County estimated the loss on its system at approximately 1% for the main feed and approximately 2% for the alternative feed.

[47] In the end, Board staff argues that the Board should direct that a separate rate be set for Brant County. They argue that rate should reflect the following principles;

(a) The revenue-to-cost ratio for any specific rate for Brant County should fall with in the range for the Large User class, that is 85% - 115%,

(b) The GS 50 – 4,999 kW class' revenue-to-cost ratio remain at the approved EB-2007-0698 ratio of 140%, and

(c) Any additional revenue is to be recovered from those classes that have revenue-to-cost ratios below 100%.

Board Findings – The Distribution Rate

[48] We agree with Board staff that a separate rate should be set for Brant County. We also agree that rate should be set based on the principles set out above by Board staff. We are also of the view that further delay is no longer warranted. This issue first arose in Brantford's Application for 2008 rates. It remains unresolved and no payments are being made by Brant County.

[49] The Board directs Brantford to design a rate in compliance with principles set out by Board staff and to file that rate within 10 days of receipt of this Decision. Brant County will have an opportunity to comment on the proposed rate within 5 days of receipt. The Board expects to be in a position to issue a written decision following these submissions.

[50] If the new rate is less than the existing rate there may be an under-recovery by Brantford. That is, the utility would not be able to achieve its revenue requirement.

Accordingly, the difference between the existing approved GS > 50 kW rate and the new Brant County rate times the Brant County volumes for the relevant period should be tracked in a variance account for recovery at Brantford's next rebasing. The Board notes that Brant County has no objection.

The Retail Transmission Rate

[51] Brant County has paid RTS charges for Power Line Road at the GS > 50 kW rate for the period commencing December 2005 until August 2008 and these amounts are not in dispute. The RTS charges for Colborne Street East and Colborne Street West have not been paid but Brant County does not dispute the quantity of electricity or the rate. The parties agree that the $2.1 million is owing.

[52] What Brant County disputes is the period for which it is responsible for the costs. Brant County, in this Motion, asked the Board for an Order specifying the date at which Brantford is entitled to charge Brant County for retail transmission, network and connection charges for Colborne Street East and Colborne Street West. Brantford seeks an Order that Brant County must pay Brantford, in full, for all retail transmission service since Brantford acquired Colborne Street East and Colborne Street West from Hydro One in October, 2005.

[53] Board staff agrees that there is no dispute between the parties as to the rate and the volumes and agrees that this is an obligation of Brant County. However, Board staff takes the position that the RTS arrears should be limited to two years based on the *Limitations Act*[14].

[54] Board staff submits that Brantford's claim against Brant County is in the nature of a debt and that there is a claim of money owed to Brantford which is governed by the *Limitations Act*. They argue that the limitation period is two years from the date that the claim arises or the date the claiming party discovered the claim or should have discovered the claim. Board staff states that Brantford's claim arose on the day it acquired the Colborne assets (October 2005) and Brantford therefore has two years from that date to commence an action for payment.

[14] SO 2002 Ch.35

[55] Board staff argues that a claimant is not entitled to a longer limitation period because it did not discover its right to make a claim until some later date unless the delayed discovery was reasonable. Section 5 of the Act provides that the discovery of the claim occurs on the day on which a reasonable person in the circumstances ought to have known of the claim.

[56] Board staff argues that Brantford is a sophisticated commercial entity and should have exercised greater diligence in exercising its right to charge the RTS upon acquiring the two Colborne assets. The utility failed to invoice Brant County within the two year limitation period, that is by October 2007.

[57] Board staff also argue that Brantford's claim for the RTS is not completely prescribed by the *Limitations Act* since the claim has been ongoing. Accordingly, Board staff submits any amounts owing by Brant County for the two years prior to the date that Brantford made its claim (December 11, 2009) are outside the limitation period and Brantford should only be entitled to recover amounts from and after December 10, 2007.

Board Findings – Retail Transmission Rates

[58] Brantford acquired transmission assets at Colborne Street East and Colborne Street West from Hydro One on October 2005. Brantford began billing Brant County for RTS service for Powerline Road in 2005. For some reason, Brantford failed to bill Brant County for RTS services at Colborne Street East and Colborne Street West until much later.

[59] There is no question that Brantford provided Brant County RTS services at Colborne Street East and Colborne Street West facilities. The question is, when should the payments start? Brant County states that the payments should start September 1, 2008, when the Brant County rate first became effective. Brantford responds that the payments should start when the services first started (October 2005). Board staff submits that the payments should be governed by the *Limitations Act, 2002* and payments therefore should start December 10, 2007.

[60] It is significant that there will be no harm to Brant County customers if Brant County pays the full amount to Brantford. Brant County has continued to collect for RTS service in its rates and has approximately $4.2 million in reserve accounts. Brantford

submits, and Brant County agrees, that approximately $2.1 million is owed to Brantford for RTS service. Brantford argues that there is no good reason why Brant County should not pay the entire amount owing. Brant County does not risk under recovery from its customers because the entire amount can be paid from these reserve accounts.

[61] The Board is not persuaded that the *Limitations Act, 2002* constrains the Board's jurisdiction to order full recovery. This is not a claim being pursued in a court. It is not clear that the *Limitations Act* applies.

[62] In any event, the Board has the exclusive jurisdiction to set just and reasonable rates and that includes not only the rate, but the time period in which the rate should be paid. Section 19(6) of the *Ontario Energy Board Act, 1998* gives the Board exclusive jurisdiction in all areas where the Act confers jurisdiction. Where there is a conflict between the OEB Act and any other Act the OEB Act prevails[15]. Special legislation like the Ontario Energy Board Act takes precedence over general legislation like the *Limitations Act*[16]*.* The Board has exercised jurisdiction in this area in enacting Section 7.7 of the *Retail Settlement Code* with respect to residential and non-residential customers.

[63] We conclude that the full amount is owing and should be paid by Brant County. However, Brantford will not be entitled to any interest payable on the outstanding amounts for Colborne East and Colborne West. There is no good reason why Brantford failed to bill for RTS service at the two assets. It was an error on the utility's part. Under those circumstances interest is disallowed.

[64] Where there is a billing error, the Board will allow a utility to correct that error and bill (or credit) customers going forward. There can, however, be a penalty in terms of loss of interest if there is an element of negligence on the part of the utility. This was the situation in the *NRG Gas Cost* case[17]. There, NRG, due to an accounting error failed to collect over $500,000 in gas costs that incurred over a period of 15 months between October, 2002 and December, 2003. The Board, in setting 2004 rates, allowed NRG to recover these costs through rates going forward but refused the utility's request for

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[15] *Kingston vs. Ontario Energy Board* [2001] OJ No. 3485

[16] *Union Gas v. Dawn* (1977) 15 OR (2d) 722, 76 DLR (3d) 613

[17] *Re Natural Resource Gas Ltd*, Board Review Decision, April 19, 2004. *Natural Resource Gas Ltd. v. Ontario Energy Board* [2005] OJ No. 1520 (Div Ct.)

interest and the recovery of the regulatory costs involved in bringing forth the Application.

[65] The remaining issue is the time period over which the unpaid RTS is to be paid. There appears to be no dispute that Brant County has collected these amounts from its customers and is holding funds in a reserve account. In the circumstances, RTS amounts should be repaid within 30 days of the Board's Order in this proceeding.

Retroactivity – Distribution Rates

[66] If a new rate is set for Brant County, is it effective at the date of this Decision or September 1, 2008? Or May 1, 2008? Brant County argues that it should become effective, September 1. 2008. Brantford and Board staff argue that it should become effective on the date of this Decision. The reason for that position, they claim, is the rule against retroactivity prevents back dating to September 1, 2008.

[67] No one disputes that retroactive rate making is not proper. This was most recently recognized by the Supreme Court of Canada in the *ATCO* Decision[18] and a number of decisions before[19].

[68] Board staff relies upon the Supreme Court of Canada decision in *Bell Canada vs. CRTC*[20] where the court distinguished between Interim Rate and Final Rate noting that if the rates are interim the Board could backdate the effective date to the date of the interim order which is not possible in the case of a Final Order. We do not agree that this principle applies to the present case. This is not a case where the Board is varying the rate for the GS > 50 kW class. This is the case of a billing dispute. In particular, a dispute related to a rate classification. To say that a utility could hide behind the retroactivity principle and never address billing disputes would be contrary to the Board's policy objectives.

[18] *ATCO Gas & Pipelines Ltd. v. Alberta Energy & Utilities Board* [2006] 1 SCR 140, 263 D.L.R. (4th) 193

[19] *Northwestern Utilities Ltd. v. City of Edmonton*, [1979], 1 S.C.R. 684; *Re Coseka Resources Ltd. And Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical Canada Inc. and Union Gas Ltd.* (1982), 141 D.L.R. (3d) 641, aff'd (1983), 42 O.R. (2d) 731.

[20] *Bell Canada v. Canada Radio-Television and Telecommunications Commission,* (1989) S.C.J. No. 68 at 708.

[69] The overriding responsibility of the Board is to set just and reasonable rates. That principle applies to the actual level of the rates as well as the time period during which the rates are in effect. It is also important to understand the fundamental principle behind the retroactivity principle in public utility law. This is not a mechanical rule of statutory interpretation. The rule is based on two fundamental principles.

[70] The first principle is that a utility must be able to rely on Decisions to have revenue certainty in order to be able to plan its investments. If the revenue requirement is subject to change this is impossible. In other words, a utility must be able to rely on a Final Order and the revenues that flow from the Final Order unless there is clear notice that this is not the case. That's why this Board will often convert a Final Order to an Interim Order and then proceed with the next rate case. The magic of that conversion is that the utility has <u>notice</u> that it can no longer rely upon that revenue stream. It may go up or it may go down, depending on the result of the next rates case. And that rate decision can then be back dated to the date of the Interim Order.

[71] The utility also has notice where there is a billing dispute with a customer. In this case there was a period of time when there was no rate. Then the Board applied a rate to this particular customer that was admittedly incorporated in a Final Order. The matter did not end there. The customer refused to pay and launched this appeal. There has been an ongoing dispute and the utility was well aware that this matter would likely be subject to adjustment in a subsequent proceeding.

[72] The other principle behind the retroactivity rule is that future customers should not pay for electricity consumed by past customers. This is also known as the intergenerational equity problem. Broadly speaking, that means that today's customers should not be responsible for the expenses associated with the services provided to yesterday's customers.

[73] The principles behind the retroactivity rule were set out by the Newfoundland Court of Appeal in *Re: Board of Commissioner of Public Utilities*[21] at Page 25.

> Doctrinally, in the context of utility rate regulation, the retroactivity principle is described by Penning in this way:

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[21] *Re Section 101 of the Public Utilities Act* (1998) CanLII 18064 (NL C.A.)

> …the rule is concerned more with issues of fairness, both to customers and to the utility shareholders. The customer-related fairness issue is often referred to as the "inter-generational equity" problem, which, broadly stated, means that today's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers. The fairness concern in terms of utility shareholders arises because to attract and maintain reasonably-priced equity investment in a utility, shareholders require some certainty that matters already dealt with by the regulator have some degree of finality associated with them.

[74] The *Newfoundland* case questioned the importance of intergenerational equity at Page 28.

> While it is true that any rebate would not, because of the fluid nature of the customer base, result in a return to exactly the same body of consumers who had paid the original rates, this is not an insuperable objection to using this type of mechanism. Penning observes:
>
> As a practical matter, however, at least some of this concern appears misplaced. By far the majority of today's rate payers for the majority of regulated public service utilities were also yesterday's rate payers – especially since the time frames at issue are typically not more than a year or two. So the unfairness argument about cost allocation loses some of its force.

The Supreme Court of Canada in the *Bell Rebate* case[22] made the same point;

> ….it is true that the one time credit ordered by the appellant will not necessarily benefit the customers who are actually billed excessive rates. However, once it is found that the appellant does have the power to make remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The appellant admits that the use of a one-time credit is not the perfect way of reimbursing excess revenues. However, in the view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside and of quantifying the amount of excessive payments made by each, and having regard to the appellant's broad jurisdiction in weighing the many factors involved in apportioning respondent's revenue requirement among its several classes of customers to determine just and reasonable rates, the appellant's decision was imminently reasonable…

---

[22] *Bell Canada v. Canadian Radio-Television & Telecommunication Commission* [1989] 1 SCR 1722 at 1762-3.

[75] The rule against retroactivity was first established by the Supreme Court of Canada in 1961[23]. That Court established an important qualification 20 years later in Nova V. Amoco[24]. There, the court was dealing with a regulatory scheme that provided that the utility could set a rate that would be in effect until such time that any interested party or the Public Utilities Board complained that the rate was not just and reasonable. At that point the Public Utilities Board would hold a hearing and make a decision.

[76] The question in *Nova* was, having made a decision to change the rate, was the new rate effective the date of the decision or at the date of the complaint. Mr. Justice Estey speaking for the Court held that it was permissible to issue a retroactive order and that the new rate could become effective at the date of the complaint because at that point the utility had notice.

[77] The British Columbia Court of Appeal in *EuroCan Pulp and Paper vs. British Columbia Energy Commission*[25] came to the same conclusion stating at Page 731;

> Under either section it is contemplated that the Commission may consider rates established and collected in the past, or the rates to be collected or enforced by it in the future. In the former case there would be a retroactive aspect to any consequent order made by the Commission. Under s. 38 it seems clear that the Commission would have jurisdiction to entertain a complaint that existing rates in effect and collected are unjust or insufficient. In that event it would clearly have the jurisdiction to correct the injustice or the insufficiency. There is nothing to lead one to the conclusion that the Legislature intended that the Commission could only act in this respect prospectively.
>
> Reading the Act as a whole, it is my opinion that the Commission has been empowered to make rates effective to the date of the application, even though there is no specific language in the Act to that effect.

[78] In summary, this is a billing dispute that relates to one particular customer not all customers in the rate class. That customer never accepted the rate, never paid the rate and gave clear notice to the utility.

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[23] *Edmonton v. Northwestern Utilities Ltd.* [1961] SCR 392.

[24] *Nova v. Amoco Canada Petroleum Co.,* (1981) 2 SCR 437.

[25] (1978) 87 DLR (3d) 727.

[79] This is no different than correcting a utility error as this Board did in the *NRG Gas Cost* case[26]. Natural Resource Gas, like Brant County, was an embedded distributor. NRG discovered in October 2003 that its gas costs for 15 months were under-collected by over $500,000 due to a flaw in its accounting methodology. The Board allowed the utility to recover these costs in a subsequent rate case. The Board recognized that there was a retroactivity issue but at the same time was satisfied there was an under-recovery of costs due to a faulty accounting method. The Board, however, stated;

> In light of the above, while we accept that NRG's customers have underpaid by $531,794 and the 2003 PGCVA balances have not been finalized by the Board, we find that NRG's error has resulted in a substantial and avoidable accumulation of potential customers' charges, through no fault of the customer.
>
> We must therefore look for a balance.
>
> It would not be reasonable in our view to deny NRG recovery of reasonably incurred gas costs of a magnitude of $541,794 because of an accounting error. These are legitimate costs incurred prudently on behalf of the customers, and are of material consequence to the utility.
> Considering the need for NRG to recover its prudently incurred unrecorded gas costs and mitigating the impact on customers, as well as not creating undue inter-generational inequity, we find that the reasonable balance is recovery of the $531,794 amount over a three year period, in equal portions, without interest.
>
> Further, NRG shall not include the regulatory costs it incurred in this proceeding in estimating the regulatory costs for future test years.

[80] In summary, the Board in *NRG* allowed past costs to be recovered in future rates. However, the Board imposed a penalty and disallowed the interest claimed by NRG as well as the regulatory costs incurred to recover the missing gas costs and the legal costs associated with proceeding. The Board could have disallowed all recovery on a broad interpretation of the retroactivity rule. However, there as here, the Board must consider what constitutes just and reasonable rates. If by error there is an under-collection or over-collection it should be remedied going forward. The NRG decision was upheld by the Divisional Court[27] and the Court of Appeal[28].

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[26] *Re Natural Resource Gas Ltd*, Board Review Decision, April 19, 2004.
[27] *Natural Resource Gas Ltd. v. Ontario Energy Board* [2005] OJ No. 1520 (Div. Crt.)

[28] *Natural Resource Gas Ltd. v. Ontario Energy Board* [2006] OJ No. 2961 (CA)

[81] It is also helpful to refer to Section 7.7 of the Retail Settlement Code. The Code provides that where there is a billing error from any cause that results in a consumer being overbilled, the distributor should credit the consumer the amount erroneously billed for a period of up to 6 years. In the case where the billing error causes the consumer to be under-billed, the distributor can charge the consumer the amount not previously billed. The time limit, however, varies depending on whether the customer is a residential or a non-residential customer. In the case of an individual residential customer, who is not responsible for the error, the maximum period for which the consumer may be charged is two years. However, in the case of a non-residential consumer, the consumer can be charged for the entire period.

[82] It is unlikely that Section 7.7 of the Retail Settlement Code applies to the case at hand. That is because the definition of a "consumer" in the Code is a person who uses electricity "for his own consumption". While Brant County may not be a consumer within that definition, the section does indicate the Board's policy with respect to billing errors – the rule against retroactivity does not apply.

Board Findings – Retroactivity

[83] For the reasons indicated above, the Board does not believe that the rule against retroactivity prevents the Board from correcting certain billing errors. It would appear that the rate should be significantly less than the rate used which means we have a case of overbilling for distribution services. And in the case of RTS, there has been a period when there was no billing and therefore under-collection.

[84] This leaves open the question regarding the date which billing should begin. The Board in the previous Decision set the Brant County rate (and the rates for other customers) effective September 1, 2008. The rates could have been made effective on April 21, which is the date of the Interim Order. The Board chose not to go back to April 21st because they felt that Brantford had been late in filing and penalized the utility by making the rates effective September 1. That Decision, however, had an unintended consequence. Brant County can argue that any distribution charges levied by Brantford beginning May 1, 2008 to September 1, 2008 had no force or effect. That is based on the argument that the Interim Order did not have a Brant County rate component because all it did was convert the 2007 rates from a Final Order to an Interim Order. The 2007 Rates Decision did not have a Brantford County rate.

[85] This clearly was not a matter addressed by the Panel in the July 18, 2008 Decision. Brant County does have an argument but it is a technical argument. The fact of the matter is that the utility provided service for the period of May 1, 2008 to September 1, 2008, and billed Brant County. In fact, Brant County paid one invoice. Having received service from the utility we believe that Brant County should pay for the service. But it should do so at the correct rate. Accordingly, Brantford is entitled to be paid distribution charges beginning as of May 1, 2008[29]. The rate to be used is the new rate to be set pursuant to this proceeding.

[86] The other question left open is whether Brant County should have time to pay. We believe that it is appropriate to allow Brant County 24 months to pay the distribution charges. Unlike the situation with RTS rates, there is no failure to bill by Brantford and accordingly interest shall be allowed on any outstanding balances.

THE BOARD THEREFORE ORDERS THAT:

1. Brantford shall file a proposed new distribution rate for Brant County within 10 days of this Decision. Brant County and Board staff will have 5 days, after receiving the proposed new rate, to file written comments on the proposed new rate.

2. Brant County shall pay the outstanding RTS charges within 30 days of the date of the Board's Order in this proceeding. The charges outstanding for Powerline Road date from July, 2008 while the charges outstanding for Colborne Street East and Colborne Street West date from October, 2005. No interest charges will be included in the Colborne Street East and Colborne Street West amounts. Interest will be allowed on the Powerline Road amounts.

3. The new distribution rate for Brant County shall be effective May 1, 2008. Brantford is entitled to interest on all outstanding amounts at the interest rate the Board currently allows for deferral accounts. The amount outstanding will be paid in 24 equal instalments commencing 30 days after the date of the Rate Order.

4. Brantford will track the amount of any revenue deficiency that may result from the differences in the GS > 50 kW rate and the new rate in a tracking account which will be considered for disposition by the Panel in Brantford's next rate case.

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[29] Brantford does not seek payment for service prior to May 1, 2008. Brantford Power Inc. Final Argument paragraph 80.

DATED at Toronto, August 10, 2010

ONTARIO ENERGY BOARD

Original Signed By

Gordon Kaiser
Vice-Chair

Original Signed By

Ken Quesnelle
Board Member

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

Ontario

DECISION AND ORDER

EB-2016-0255

MILTON HYDRO DISTRIBUTION INC.

Motion to review and vary the Decision and Order dated July 28, 2016 on Milton Hydro Distribution Inc.'s electricity distribution rates and charges beginning May 1, 2016 (EB-2015-0089)

BEFORE: **Christine Long**
Vice Chair and Presiding Member

Cathy Spoel
Member

Peter C. P. Thompson, Q.C.
Member

February 22, 2018

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 THE PROCESS 2

3 FACTS 4

4 REASONS FOR DECISION OF VICE-CHAIR LONG AND MEMBER SPOEL 9

4.1 INTRODUCTION AND SUMMARY 9

4.2 NATURE OF THE OEB'S REVIEW 9

4.3 FAIR MARKET VALUE AND THE GAIN AMOUNT 10

4.4 PORTION OF THE CAPITAL GAIN ALLOCATED TO RATEPAYERS 13

4.5 MECHANISM FOR CREDITING THE GAIN AMOUNT TO RATEPAYERS ... 14

4.6 IMPLEMENTATION 14

4.7 COST AWARDS 15

5 ORDER 16

6 DISSENTING REASONS OF MEMBER THOMPSON 17

6.1 INTRODUCTION AND SUMMARY 17

6.2 THE REASONABLENESS STANDARD OF REVIEW AND ITS APPLICATION 21

6.3 RECORD UNDER REVIEW 29

6.4 FAIR MARKET VALUE AND THE GAIN AMOUNT 34

6.5. PORTION OF THE GAIN ALLOCATED TO RATEPAYERS 44

6.6 MECHANISM FOR PAYING THE GAIN AMOUNT TO RATEPAYERS 50

6.7 IMPLEMENTATION 52

1 INTRODUCTION AND SUMMARY

This is a motion brought by Milton Hydro Distribution Inc. (Milton Hydro) to review and vary certain aspects of the decision of the Ontario Energy Board (OEB) dated July 28, 2016 (the Decision) concerning Milton Hydro's electricity distribution rates for 2016.[1]

Milton Hydro asserts that the OEB panel that heard the case (the Hearing Panel) erred in fact in making its findings related to:

1. The fair market value of the property located at Fifth Line and Main Street in Milton (the Property), which was sold by Milton Hydro to an affiliate in December 2015;

2. The allocation to ratepayers of the capital gain on the portion of the Property not included in rate base; and

3. The mechanism by which the gain allocable to ratepayers is to be paid to them.

The Decision found the market value of the Property on the date of its sale to the affiliate to be $2.73 million using a per acre value of $425,000 for the 6.43 acre parcel. For the purpose of rate-making, the Decision allocates to ratepayers the entire capital gain of almost $506,000. This amount includes the gain realized on portions of the Property included and excluded from Milton Hydro's rate base.

The Decision directs the use of a permanent rate base reduction mechanism, rather than a time limited revenue offset mechanism, to credit ratepayers with the amount of the gain for the purpose of setting rates.

The members of this Review Panel disagree on the disposition of the motion.

The majority grants variance relief in relation to all three of the errors of fact alleged by Milton Hydro, while the dissenting decision would limit the grant of variance relief to the mechanism for crediting, for rate-making purposes, the portion of the capital gain on the land allocable to ratepayers.

The majority's reasons are found in chapter 4. The minority's reasons are found in chapter 5. This introductory chapter, as well as chapters 2 (Process) and 3 (Facts) were jointly authored by the majority and minority.

[1] EB-2015-0089.

2 THE PROCESS

Milton Hydro's August 28, 2015 cost of service application for OEB approval of 2016 rates was partially settled under the terms of a Settlement Proposal dated February 9, 2016 and an addendum dated April 7, 2016.[2]

An oral hearing of the issues remaining in dispute was held on April 4 and 5, 2016. Milton Hydro made oral submissions in chief on April 5, 2016 and written reply submissions on April 28, 2016 to the written arguments made by intervenors and OEB staff.

The Decision approving the settled issues and determining the disputed issues was released on July 28, 2016.

The Motion to Review and Vary (the Motion) was filed with the OEB on August 17, 2016. The Motion relied upon an affidavit sworn on that date making certain changes to the August 5, 2015 appraisal report that was before the Hearing Panel.

In its September 1, 2016 Procedural Order No. 1, the Reviewing Panel determined that the threshold under Rule 43 of the OEB's *Rules of Practice and Procedure* (Rules) had been met and that it would proceed to review, on the merits, each of the issues raised by Milton Hydro in the Motion.

Procedural Order No. 1 established a schedule for the presentation of further written submissions from Milton Hydro and from the other parties who participated in the proceedings giving rise to the Decision.

On September 15, 2016, Milton Hydro filed submissions in support of the Motion. Written submissions followed on September 20, 2016 from the School Energy Coalition (SEC) and, on September 22, 2016, from Energy Probe Research Foundation (Energy Probe) and OEB staff. Milton Hydro delivered its reply submissions on October 5, 2016.

After considering these submissions, the Reviewing Panel determined that it wished to obtain additional information from Milton Hydro and its appraiser of facts on the record of this case related to the Property valuation and capital gain allocation findings in the Decision.
The OEB asked its staff to arrange with Milton Hydro a suitable date for a brief oral hearing to deal with the issues raised. In a December 22, 2016 letter to the Chair of the

[2] EB-2015-0089 Settlement Proposal, February 9, 2016, Addendum April 7, 2017.

OEB, the president of Milton Hydro objected to this proposal and requested that the OEB consider written responses to any questions that needed to be answered to enable the OEB to render an informed decision on the Motion.

Procedural Order No. 2 was issued on January 17, 2017, attaching 16 questions for Milton Hydro and the appraiser. Written responses to these questions (PO2 Responses) were filed by Milton Hydro on January 29, 2017.

3 FACTS

Chronologically, the facts in the record before the Hearing Panel,[3] in the Affidavit, and in the PO2 Responses that are relevant to the Property valuation, capital gain allocation and payment mechanism issues include the following:

a) In 2009 Milton Hydro purchased the 6.43 acre Property for $2,218,530. The vacant land was acquired for future use as the utility's office and service center. A Royal LePage real estate agent assisted Milton Hydro in this transaction.[4]

b) Immediately adjacent to the Property was a privately owned 1.3 acre parcel that Milton Hydro wished to acquire to increase the size of its development land to about 7.7 acres.

c) In 2010 Milton Hydro had the adjacent 1.3 acre parcel appraised by Royal LePage. The appraised value range was between $600,000 and $700,000 or between about $461,000 and $538,000 per acre.[5]

d) In December 2010, Milton Hydro offered to buy the 1.3 acre parcel for $699,000 or about $538,000 per acre. The property owner would not sell for less than $750,000 or about $577,000 per acre.[6]

e) In Milton Hydro's EB-2010-0137 Application for 2011 cost of service rates, 50% of the $2,218,530 cost of the Property was included in rate base because that portion of the Property was being used for the outside storage of utility materials and equipment. The remaining 50% of the Property, being held for future utility use as the location for the new office and service centre, was not included in rate base.[7]

f) In November 2012, at a time when locations for the future office and service centre other than the Fifth and Main location were being examined,[8] Milton Hydro ascribed a $2.7 million value to the Property and a per acre value of $450,000.[9] The record showed that by the end of March 2012 Milton Hydro had

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[3] All of the references in the footnotes that follow are to the EB-2015-0089 record unless otherwise noted.
[4] Interrogatory Responses, December 18, 2015 at pages 787-790; PO2 Responses, February 3, 2017 at page 3.
[5] PO2 Responses, February 3, 2017 at page 6.
[6] Transcript Vol. 1 at page 152 and Exhibit K1.3 Option 11.
[7] Transcript Vol. 2 at page 108 and Exhibit 1, August 28, 2015, page 32.
[8] See Interrogatory Responses, December 18, 2015 at pages 739-743.
[9] Interrogatory Responses, December 18, 2015 at page 756 of 901. The document containing the $2.7 million and $450,000 per acre amounts (a presentation by the President/CEO to the Relocation.

investigated the suitability and pricing of 12 properties and had identified three sites to be pursued. This evidence notes prices in Milton had been skewing upwards since August 2011.[10]

g) In or about May of 2014, Milton Hydro decided to replace the Property as the location for its new office and service centre with lands and premises at 200 Chisholm Drive in Milton. The serviced land at Chisholm Drive was valued at $4.040 million or about $575,000 per acre. The purchase was completed in September in 2014. The building was renovated and the utility moved in to the premises in late 2015.[11]

h) Having acquired the 200 Chisholm Drive premises to replace the land at Fifth and Main, Milton Hydro decided to sell that land to its affiliate Milton Energy and Generation Solutions Inc. (MEGS).To that end it retained Colliers International Inc. (Colliers) to appraise the Property.[12]

i) Colliers prepared an appraisal report dated August 5, 2015. In the cover letter to the report, and in the signed certification included as Appendix E to the report, the market value “as at August 5, 2015”, was estimated at $2.4 million. This estimate was based on Colliers analysis and was subject to the “Contingent and Limiting Conditions” listed in Appendix A. This Appendix states that: “This report has been prepared… for the purpose of providing an estimate of value of the development site located at 5th Line and Main Street… for Internal Purposes”. This condition also notes that the OEB “... may rely on the appraisal for regulatory purposes.”[13]

j) The Executive Summary, in the analysis section of the report, showed the “rate per acre” as $425,000 (which multiplied by 6.43 acres would produce $2.73 million). At page 33 in the analysis section, under a heading entitled “Final Estimate of Value”, the opinion that the Property “should achieve a rate per acre in the narrowed range of $339,217 to $442,213 per acre” is expressed. The report then refers to the value range for the five key comparable sales from $339,217 to $478,723 followed by the opinion that “a rate in the range of

Committee of the board of directors on November 14, 2012) was referenced in the Decision text at pages 46 and 55 in statements that reflect the allocation of the gain amount related thereto to defray total project costs.

[10] Interrogatory Responses, December 18, 2016 Relocation Committee Minutes, April 2, 2012, pages 739-743.

[11] Interrogatory Responses, December 18, 2015, page 845 of 901.

[12] Exhibit 1, August 28, 2015, page 32.

[13] Exhibit 1, August 28, 2015, Attachment 1-3, page 149 of 920.

$400,000 and $450,000 would be reasonable". Immediately below that finding is a table showing a range per acre of $350,000 to $400,000.[14]

k) Before completing its August 2015 report, Colliers did not investigate and Milton Hydro did not inform Colliers of the market activity related to the 1.3 acre parcel adjacent to the property including the 2010 appraisal done by Royal LePage of that parcel; Milton Hydro's offer to purchase that parcel for $699,000 (about $538,000 per acre); or of Milton Hydro's 2012 internal estimate ascribing to the Property a value estimate of $2.7 million based on a per acre value of $450,000.[15]

l) The initial draft of the appraisal report estimated a $2.7 million value for the Property using a per acre value of $425,000 being the mid-point of a $400,000 to $450,000 per acre subset of the comparable sales value range.[16]

m) A peer review process at Colliers involving another appraiser resulted in a reduction in the initial value estimate value from $2.7 million to $2.4 million in the report sent to Milton Hydro. This report used the same information set out in the initial draft. The report establishes the reasonable range of value outcomes by stating "The Subject should achieve a rate per acre in the narrowed range of $339,217 to $442,213."[17]

n) In their reviews of the report, which was eventually finalized and filed with the OEB, neither Milton Hydro nor Colliers staff noticed that the value range of $400,000 to $450,000 that the report described as reasonable and the mid-point rate per acre value of $425,000 had not been changed as a result of the peer review process.[18]

o) Evidence in the EB-2015-0089 Application dated August 28, 2015 stated that "The land Milton Hydro owns at Main and Fifth has been appraised at $2,400,000 and will be put up for sale". The evidence refers to the August 5, 2015 appraisal done by Colliers.[19]

[14] Exhibit 1, August 28, 2015, Attachment 1-3, page 149 and table at page 179 of 920.
[15] PO2 Responses, pages 6-7 and Attachment B.
[16] Exhibit 1, August 28, 2015, Attachment 1-3, page 149 of 920.
[17] PO2 Responses, Attachment B, page 28 (page 117 of 140).
[18] PO2 Responses, page 28 of 20.
[19] Exhibit 1, August 28, 2015, page 32.

p) In interrogatory responses filed in December 2015, Milton Hydro reported that the land had been sold in December of 2015 for its appraised value.[20]

q) Minutes of Milton Hydro meetings held in 2015 stated that the property would be sold to MEGS “until a decision regarding final disposition or use has been made”.[21]

r) The Settlement Proposal that the OEB was asked to approve included a term stating, “Other Revenue: The parties accept the evidence of Milton Hydro that its Other Revenue in the amount of $2,018,810 is appropriate and correctly determined in accordance with OEB policies and Practices”. Within this amount was Milton Hydro’s calculation of the capital gain amount of $87,975 per annum related to the 50% portion of the Property that was in rate base.[22]

s) At the oral hearing on April 4, 2016, Milton Hydro relied on the property owner’s rejection of an arm’s-length offer that it made in 2011 of $750,000 to support its use of a cost of $800,000 to acquire the 1.3 acre parcel adjacent to Milton Hydro’s Property at Fifth and Main (about $615,000 per acre). Milton Hydro treated its own arm’s length market activity in prior years related to the adjacent parcel as a reliable indicator of current value.[23] This cost estimate was being used to support the presentation of the total costs of the 200 Chisholm Drive project as being less than the total costs of acquiring the 1.3 acre parcel for use in combination with the Property to develop an appropriately sized office and service centre.[24]

t) No questions were asked during the oral hearing about the $2.4 million valuation of the Property or the allocation of the capital gain realized on the portion of the Property not in rate base. There were no submissions in chief from Milton Hydro or from intervenors on these points.

u) Milton Hydro’s April 28, 2016 written reply argument contained a request that the OEB reduce the Settlement Proposal allocation to ratepayers of the $87,595 per annum capital gain amount related to the portion of the Property in rate base in the event that the amount was not brought into account when

[20] Interrogatory Responses, December 18, 2015, 4.0 Staff 63, page 217 of 901.
[21] Interrogatory Responses, December 18, 2015, SEC 14, Report to the Board of Directors, August 26, 2015, page 851 of 901.
[22] Settlement proposal, February 9, 2016, page 18.
[23] When testifying about the $800,000 cost to acquire estimate at Tr. Vol.1 at page 152, the CEO of Milton Hydro stated “The owner had in 2011 turned down 750, so we felt that’s quite a realistic estimate of what it might cost us to purchase that corner property.”
[24] Exhibit K1.3, page 5 and Tr. Vol. 1, page 152.

considering possible rate base disallowances.[25] The evidence in the record relating to the calculation of that $87,595 capital gain amount included the evidence pertaining to the affiliate transaction sale price for the Property of $2.4 million.[26] The Hearing Panel considered this evidence to inform its response to the new point raised by Milton Hydro in its reply submissions.

[25] Reply Argument, April 28, 2016, page 34.
[26] Interrogatory Responses, December 18, 2015, 4.0-Staff 63, page 217 of 901.

4 REASONS FOR DECISION OF VICE-CHAIR LONG AND MEMBER SPOEL

4.1 INTRODUCTION AND SUMMARY

We have read the reasons of our colleague. We agree with his analysis and conclusion in respect of Issue 3: the Hearing Panel erred in applying the capital gain on the Property as a permanent reduction to rate base, because that approach would result in ratepayers being overcompensated for their contribution to the cost of the Property.

We are, however, unable to agree with our colleague on Issues 1 and 2. On Issue 1, we find that the Hearing Panel erred in deeming the market value of the Property to be $2.73 million, rather than the actual sale price of $2.4 million. Although the Hearing Panel was correct to point out discrepancies in the appraisal report that supported the $2.4 million valuation, we find that those discrepancies have now been adequately explained by Milton Hydro and the appraiser.

On Issue 2, we find that the Hearing Panel erred in returning the entire amount of the capital gain on the Property to ratepayers. In our view, only half of the capital gain should have been returned to ratepayers, because ratepayers had only paid for half of the cost of the Property in the first place.

4.2 NATURE OF THE OEB'S REVIEW

Milton Hydro's motion is brought under Rule 40.01 of the OEB's *Rules of Practice and Procedure*, which provides that, "Subject to **Rule 40.02**, any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision." Rule 42.01 states that every motion brought under Rule 40.02 must:

> Set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error in fact;
> (ii) change in circumstances;
> (iii) new facts that have arisen; [or]
> (iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

Under Rule 43.01, the OEB may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits. In this case, the OEB determined that the threshold had been met, and therefore established a process for reviewing the motion on the merits:

> Milton Hydro's notice of motion raises questions concerning the correctness of the Decision insofar as it relates to the disposition of the property at Fifth Line and Main Street; it would appear that Milton Hydro does not seek merely to reargue its case.[27]

The OEB has said that in a motion to review, the original hearing panel is entitled to deference. In its decision on a motion to review brought by Brant County Power Inc. in connection with the distribution rates for Brantford Power Inc., the OEB found, "A reviewing panel should not set aside a finding of fact by the original panel unless there is no evidence to support the decision and [it] is clearly wrong."[28] The OEB referred to the decision of the Ontario Court of Appeal in *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, 2010 ONCA 284, where the Court confirmed that it was appropriate to review the impugned OEB decision (to require the utility's dividends to be approved by a majority of the independent directors) on the standard of reasonableness. The OEB added that, "We believe that the standards that a court would use in reviewing a Board Decision are no different than those this panel should use in reviewing a prior Board Decision."[29]

4.3 FAIR MARKET VALUE AND THE GAIN AMOUNT

The facts concerning this issue are set out above. In brief, Milton Hydro bought the Property at Fifth and Main in 2009 for $2,218,530 and sold it to an affiliate in 2015 for $2.4 million. The 2015 price was based on an appraisal report prepared for Milton Hydro by Colliers.

The Hearing Panel noted discrepancies in the appraisal report:

> This appraisal states, in the "Final Estimate of Value" section, that "Given the Subject's location, development potential, land use controls in place and other influencing factors of employment land sites, a rate [per acre] in the range of $400,000 and $450,000 would be reasonable for the Subject Parcel". The

[27] Notice of Hearing and Procedural Order No. 1.
[28] EB-2009-0063, Decision and Order, August 10, 2010, para. 35.
[29] EB-2009-0063, Decision and Order, August 10, 2010, para. 38.

> "Executive Summary" section of the appraisal ascribes a "Rate per Acre" of $425,000 to the land having an area of 6.43 acres.
>
> The appraisal inexplicably presents a chart for values per acre ranging between $350,000 and $400,000 rather than the $400,000 to $450,000 already found to be reasonable. The value of $2.4 million that Milton Hydro has used to derive the capital gain realized on the sale of the land falls well below the $2.73 million value that results from multiplying the appraiser's $425,000 "Rate per Acre" by the area of the parcel consisting of 6.43 acres. At a sale value of $2.73 M, the capital gain is $505,950 and not the amount of $175,950 used by Milton Hydro for rate-making purposes. Milton Hydro proposes to deduct 50% of its calculation of the gain of $175,950 or an amount of $87,975 from the 2016 base revenue requirement.[30]

The Hearing Panel deemed the sale price to be $2.73 million, based on the $425,000 rate per acre found in the appraisal, rather than the $2.4 million appraised value:

> With respect to the first question, the OEB finds that for rate-making purposes, the appraisal evidence supports a sale value of $2.73 million for the 6.43 parcel rather than the $2.4 million amount presented by Milton Hydro. This sale value is derived by multiplying the $425,000 per acre mid-point of the value range, as determined by the appraiser, by the land area of 6.43 acres. The OEB finds that the capital gain realized on the sale is $505,950 and not the $175,950 calculated by Milton Hydro.[31]

In its motion materials, Milton Hydro asserted that the discrepancy in the appraisal report was due to "typographical errors". It filed a "corrected appraisal" showing a rate per acre of $375,000, and confirming the original total Property value of $2.4 million.

In Procedural Order No. 2, the OEB requested further information about the discrepancy in the appraisal report as filed in the original proceeding. In response, Milton Hydro explained that certain portions of the appraisal report had not been adjusted to reflect the appraiser's final decision. In its response to questions asked in Procedural Order No. 2, Milton Hydro confirmed that no communications/discussions took place between Milton Hydro and Colliers as to the values to be included in the appraisal report.[32]

[30] Decision and Order, page 46 (footnotes omitted).
[31] Decision and Order, page 54.
[32] PO2 Responses, page 15.

We accept Milton Hydro's explanation, which is supported by Colliers. There was a mistake in the rate per acre shown on page 33 of the appraisal report. The mistake has now been corrected. It is important to note that the actual signed certification included in the report attested to a value of $2.4 million.

Although the rate per acre, before the correction was made, was shown on page 33 of the report as $400,000 to $450,000, the very same page also had a table with a rate per acre of $350,000 to $400,000, which is what Colliers says was the correct amount. Although the mix-up was regrettable, and has caused considerable confusion, we are satisfied that it has now been resolved.

In his reasons below, our colleague suggests that Milton Hydro should have advised Colliers about its efforts to purchase a 1.3 acre property next to the Fifth and Main Property in 2010. Milton Hydro had obtained an appraisal for that neighbouring property showing a rate per acre of $461,000 to $538,000 per acre, and Milton Hydro's offer of about $538,000 per acre was rejected by the owner for being too low. In our view, it was not improper for Milton Hydro to keep that information to itself. Providing such details might have been seen as interfering with the independence of the appraiser.

In any case, local property markets can change considerably in five years, and it is not apparent that having 2010 data would have been relevant for Colliers's 2015 appraisal.

The Decision also refers to an internal presentation by the President/CEO of Milton Hydro to the Relocation Committee of the Board of Directors in which a value of $2.7 million was ascribed to the Property based on a value of $450,000 per acre.[33] While the Hearing Panel considered the internal presentation in coming to its decision, we find that the evidence of the appraiser (Colliers) as corrected, to be of more weight than a reference in an internal presentation.

In conclusion, we find that, in light of the new information provided in this motion by Milton Hydro, the Decision of the Hearing Panel was not within the range of reasonable outcomes. The Hearing Panel deemed the property to have a value of $2.7 million. This conclusion was reached as a result of ambiguity in the appraisal report. Now that the new information has resolved that ambiguity, deeming the Property to be a different value than the appraised value is not reasonable. The appraised value should be varied to reflect a purchase price of $2.4 million, and a corresponding capital gain of $175,950, as presented in Milton Hydro's Motion to Review and Vary application.

[33] EB-2015-0089 Decision, pages 38 and 55, referring to a November 14, 2002 presentation.

4.4 PORTION OF THE CAPITAL GAIN ALLOCATED TO RATEPAYERS

The Decision allocated 100% of the capital gain to ratepayers while expressly acknowledging that only 50% of the asset which created the capital gain was in rate base. Our colleague's view is that the allocation of the gain is a discretionary exercise which is within the purview of the Hearing Panel and as such falls within the reasonableness standard of review.

The Decision finds that the entire Property was initially purchased for future use as a utility asset. By 2011, 50% of the Property was in rate base as it was being used for storage. The Decision finds that the other 50% was for future utility use. On that basis, the Hearing Panel determined that the gain on the second 50% should be credited to ratepayers. With one property replacing another, the Hearing Panel determined that it was appropriate for 100% of the capital gain to be attributed to ratepayers.

The Decision clearly sets out the Hearing Panel's rationale for including 100% of the capital gain. These reasons are highlighted in the dissenting reasons below. The Decision also clearly demonstrates that the Hearing Panel was aware that only 50% of the Property was included in rate base.

Our colleague's reasons rely on the premise that a panel is permitted to exercise discretion and that it is not the Reviewing Panel's role to substitute its discretion for the Hearing Panel's exercise of that discretion.

We are of the view that the costs vs. benefits concept is a key regulatory principle that should not be easily strayed from. It is unclear to the Majority in this review decision how the fact that the original Property (of which only 50% was allocated to rate base) was replaced by a future utility property would precipitate a move to include 100% of the capital gain to the benefit of ratepayers.

Our colleague is of the view that the discretion exercised by the Hearing Panel was within the range of reasonable outcomes and therefore cannot be changed by the Review Panel.

At outlined at the beginning of this decision, the Review Panel agrees that the standard of review is reasonableness.

We find that the allocation of 100% of the gain is not a reasonable outcome in this case. There was nothing in the record to support a departure from one of the OEB's key regulatory principles. In our view, consistency of approach is important for the OEB, the utilities and the ratepayers. In this case, neither the applicant nor any of the other parties had an opportunity to make submissions on the appropriateness of this treatment of the capital gain. In our view, it is unreasonable to depart from the OEB's usual approach without affording the affected party an opportunity to address the issue. As such, the motion to review on this point succeeds.

4.5 MECHANISM FOR CREDITING THE GAIN AMOUNT TO RATEPAYERS

We are in full agreement with our colleague's reasons for varying the Hearing Panel's decision to allocate the capital gain to ratepayers by way of a permanent reduction to rate base. However, our approach to implementing the variance differs from our colleague's proposed approach.

4.6 IMPLEMENTATION

The Review Panel, in agreeing with Milton Hydro that the sale price of the Property was $2.4 million rather than $2.7 million, reduces the capital gain from $506,000 to $175,950, and credits half of that gain to ratepayers ($87,975). The Review Panel also finds that this amount should have been returned to ratepayers as an annual revenue offset of $17,595 for five years, starting May 1, 2016, the effective date of the Decision.

In the Decision, the Hearing Panel reduced Milton Hydro's rate base by $506,000 to address the capital gain issue, rather than the requested revenue offset. This reflected 100% of the deemed capital gain on the Property.

That aspect of the Decision is varied. The Review Panel finds that the sale price of the Property was $2.4 million, which means the capital gain was $175,950 rather than $506,000. Only half of that amount ($87,975) should have been credited to ratepayers, which Milton Hydro proposed to be disposed of by way of an annual revenue offset of $17,595 over five years, effective May 1, 2016.

This means that Milton Hydro's rates (as determined in the Decision) have been lower than they should have been over the 2016 and 2017 rate periods. Accordingly, a revised rate order for 2016 and 2017 is required. Milton Hydro shall prepare a draft rate order for approval by the Review Panel, reflecting this Decision and Order, in the manner set out below:

1) For the 2016 Cost of Service year, Milton Hydro is directed to calculate its revised revenue requirement by increasing its rate base by $506,000 and then offsetting this revenue requirement amount by $17,595. The difference between the 2016 approved revenue requirement and the revised revenue requirement will determine the lost revenue total for 2016.

2) For 2017, a year where Milton Hydro's rates were adjusted using the IRM formula, Milton Hydro is directed to create a revised 2016 rate schedule, and use this schedule to produce a revised 2017 rate schedule by applying the 2017 IRM formula and any other aspects of its 2017 IRM Decision. (The revised 2017 rate schedule will be used to determine the 2018 IRM rate schedule.)

3) Milton Hydro is then directed to calculate 2017 lost revenue by applying the revised 2017 rate schedule to 2017 actual and forecast loads to April 30, 2018, compare these revenues to the actual/forecast revenues using the actual approved 2017 rate schedule. This lost revenue shall also be offset by the $17,595 annual capital gain credit.

4) Milton Hydro shall then add the 2016 and 2017 lost revenue totals and subtract the remaining capital gain amount, $52,785, to arrive at the net lost revenue to be collected from ratepayers through a rate rider in the 2018 rate year (if a material amount).

4.7 COST AWARDS

Provision for cost awards will be made when the OEB issues a decision with the final rate order.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Decision and Order dated July 28, 2016 (EB-2015-0089) is varied so that:

    a) The capital gain on the Property is determined to be $175,950
    b) 50% of the capital gain shall be allocated to ratepayers
    c) The allocation to ratepayers shall be effected through an annual offset of $17,595 over five years, effective May 1, 2016.

2. Milton Hydro shall file a draft rate order reflecting this Decision and Order, providing detailed calculations of all steps to arrive at the lost revenue amount, no later than **March 9, 2018**.

3. OEB staff and intervenors may make submissions on the draft rate order no later than **March 16, 2018**.

4. Milton Hydro may reply to any submissions of OEB staff and intervenors no later than **March 20, 2018**.

DATED at Toronto February 22, 2018

ONTARIO ENERGY BOARD

Original Signed By

Christine Long
Vice Chair and Presiding Member

Original Signed By

Cathy Spoel
Member

6 DISSENTING REASONS OF MEMBER THOMPSON

6.1 INTRODUCTION AND SUMMARY

All members of this Review Panel agree that the reasonableness standard of review is to be applied when assessing Milton Hydro's challenges to the findings of fact and exercises of discretion made by the Hearing Panel. These findings relate to the fair market value, gain allocation and gain repayment issues. We also agree that the principle that findings of fact and exercises of discretion made by a hearing panel are to be accorded a high degree of deference is embedded within an application of the reasonableness standard.

The reasonableness standard of review implies that two or more alternatives are available to a decision-maker to appropriately determine a matter in dispute. Each of the alternatives falls within a range of reasonable outcomes supported by the record before the decision-maker. In contrast, the correctness standard of review implies that there is a single defensible answer.[34]

A proper application of the reasonableness standard of review calls for the reviewing panel to scrutinize the entire record under review to consider the range of reasonable outcomes that it supports. If the outcome of the initial decision falls within that range, then, on review, that outcome cannot be varied and replaced with another outcome within the range.

Under the auspices of the reasonableness standard of review, an OEB review panel cannot substitute its preferred decision outcome for an initial decision that falls within the range of reasonable outcomes supported by the record being reviewed. When determining this range of reasonable outcomes in a particular case, the reviewing panel is obliged to consider the record under review in its entirety. Pieces of information in the record are not to be considered in isolation.

In conducting a reasonableness analysis, it is not within a review panel's authority to substitute its decision for a decision that it may disagree with. Rather, it is obliged to

[34] See *Wilson v. Atomic Energy of Canada Ltd.*, [2016] 1 S.C.R. 770 at para. 23 for the limited class of cases to which the correctness standard applies. That standard of review is limited to (i) constitutional questions regarding the division of powers; (ii) true questions of jurisdiction; (iii) questions of general law that are both of central importance to the legal system as a whole and outside the adjudicator's specialized area of expertise; and (iv) questions regarding the jurisdictional lines between two or more competing specialized tribunals.

make an assessment of whether the conclusion reached by the hearing panel falls within the range of reasonable outcomes supported by the entire record under review.
I disagree with the majority decision on the market value and gain allocation issues because it does not adhere to the requirements of the reasonableness standard of review. The entire record under review in this case reveals that the determinations made by the Hearing Panel on the market value and gain allocation issues were decision outcomes that fell within the range of reasonableness. These determinations are not subject to variance under an application of the reasonableness standard of review.

The majority decision is one that the reasonableness review standard does not allow. It constitutes an impermissible substitution of the majority's preferred outcomes for the decisions made by the Hearing Panel that fall within the range of reasonable outcomes supported by the entire record under review.

My disagreement with the majority decision stems from its failure to properly apply the essential requirements of the reasonableness standard of review to the entire record under review in this case.

An essential feature of a reasonableness review is an objective assessment by the reviewing panel to determine the range of reasonable outcomes that the record under review supports related to each of the challenged findings. The "range of reasonable outcomes" feature of the reasonableness review standard determines whether a challenged finding is or is not subject to variance by a review panel.

If a finding made by a hearing panel falls within the range of reasonable outcomes supported by the record under review, then that finding is "reasonable" and not subject to variance. Findings that fall within the range of reasonable outcomes supported by the record under review cannot be found by a reviewing panel to be "unreasonable".
An objective consideration of the breadth of the range of reasonable outcomes that the record under review supports in relation to each of the challenged findings is a prerequisite to a determination of whether each finding is either reasonable and not variable or unreasonable and variable.

The majority decision fails to apply this essential prerequisite of a reasonableness assessment. It finds that the market value finding of $2.73 million was "unreasonable" even though the record under review clearly supports a range of per acre market value alternatives at a level that includes a $425.000 per acre and $2.73 million value for the Property having an area of 6.43 acres.

The $2.4 million amount, which the majority decision prefers, also falls within the range of value outcomes supported by the record under review. However, under the reasonableness standard of review, a review panel cannot substitute its preferred outcome within the range of reasonableness for the outcome within that range that the Hearing Panel has found to be appropriate.

This principle was recently expressed by the Ontario Court of Appeal in its January 25, 2018 decision in *Finkelstein v. Ontario Securities Commission*, 2018 ONCA 61. At paragraph 101 of that decision the Court stated:

> The function of a reviewing court, such as the Divisional Court, is to determine whether the tribunal's decision contains an analysis that moves from the evidence before it to the conclusion that it reached, not whether the decision is the one the reviewing court would have reached: *Ottawa Police Services*, at para. 66. With due respect to the Divisional Court, it failed to do so in the case of the Panel's decision about Cheng. Instead, it impermissibly re-weighed the evidence and substituted inferences it would make for those reasonably available to the Panel. That was an error. The findings of fact made and inferences drawn by the Panel in respect of Cheng were reasonably supported by the record.

The majority decision disregards this principle when it substitutes its $2.4 million market value for the $2.73 million value found by the Hearing Panel. To achieve its preferred result, the majority engages in the impermissible re-weighing of evidence. The majority decision also inappropriately focusses on isolated pieces of evidence in the record being reviewed rather than on the contents of the entire record as a whole.

Similarly, on the gain allocation issue the majority decision finds that the option favoured by the Hearing Panel was "unreasonable" even though that option was among those that fell within the range of gain allocation alternatives that the record under review supported. Under a proper application of the reasonableness standard, the finding made by the Hearing Panel is not subject to variance. Under the principles applicable to a reasonableness assessment, the Hearing Panel's finding is "reasonable" and cannot be found by the Review Panel to be "unreasonable".

Once again, the majority decision impermissibly ascribes greater weight to the benefits follow costs allocation alternative that it favours, as a substitute for the different allocation option falling within the range of allocation options supported by the record that the Hearing Panel found to be appropriate.

The findings that the majority decision makes in relation to the market value and gain allocation issues are a result of a misapplication of the principles embedded in the reasonableness standard of review.

The concern expressed in the majority decision about the process followed by the Hearing Panel in relation to the gain allocation issue is irrelevant to a determination of whether the Hearing Panel's allocation approach fell within the range of reasonable allocation outcomes that the record supported. Process concerns call for a process remedy. They do not tilt the scales one way or the other when considering whether a particular finding does or does not fall within the range of reasonable allocation outcomes supported by the record being reviewed.

The section that follows elaborates upon the principles related to the reasonableness standard of review and its application. Included in this "principles" section is a sub-section that describes the careful approach that the OEB takes to ensure that utility transactions with affiliates do not prejudice ratepayers. This item is relevant to the factual context that gave rise to the market value issue and its gain allocation and credit mechanism derivatives.

That section is followed by a consideration of matters raised by parties in their submissions related to the contents of the record to be considered by the Review Panel. This section considers the admissibility of the Affidavit on which Milton Hydro relies. This section also includes a consideration of the applicability of provisions of the OEB's Accounting Procedures Handbook (APH) to a determination of the gain allocation issue. The analysis in this section leads me to conclude that the record under review consists of the record before the Hearing Panel, Milton Hydro's affidavit, the relevant provisions of the APH and the PO2 Responses.

This dissenting opinion then applies the principles to the facts in the record under review related to each of the challenges made by Milton Hydro. This opinion provides a detailed description of those facts and concludes that:

a) The finding of a $2.73 market value for the land, as of the end of 2015, falls within the range of reasonable value outcomes supported by the record. That finding is not subject to variance on review.

b) The discretionary allocation to ratepayers of the entire gain on property acquired for a specific utility project, but not yet in rate base, was a tenable exercise of discretion in a case where the gain is realized on an item of utility property held for future use that is being sold because of the utility's acquisition of a replacement property for the same purpose. The benefits follow costs principle applicable to non-utility business activities has no priority status in relation to gains realized on the sale of utility assets being held for future utility-specific project use.

c) The Hearing Panel's direction that rate base be permanently reduced by the amount of the capital gain was unreasonable and incorrect. The gain repayment mechanism should credit ratepayers with the allocable amount of the gain, but no more.

The relief that I would grant Milton Hydro is summarized in the Implementation section of this dissent.

6.2 THE REASONABLENESS STANDARD OF REVIEW AND ITS APPLICATION

6.2.1 The OEB's Standard of Review

The principles that are to be applied in an OEB review proceeding have been articulated in many cases. These principles include a requirement that an applicant for review and variance of a decision by a hearing panel "… must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently."[35]

This principle, expressed in the May 22, 2007 Natural Gas Electricity Interface Decision (NGEIR Review Decision), has been repeatedly adopted in subsequent OEB decisions.[36] In the Ontario Power Generation Inc. (OPG) Review Decision, EB-2009-0038, dated May 11, 2009, the OEB stated, at page 15:

> If a reviewing panel is satisfied that an identifiable error that is material and relevant to the outcome of the reviewed decision has been made, the Board may vary, suspend or cancel the order or decision, or if they find it to be appropriate, remit the matter back to the original panel. As noted above, the

[35] NGEIR Review Decision, EB-2006-0322/EB-2006-0338/EB-2006-0340, page 18.
[36] NGEIR Review Decision, EB-2006-0322/EB-2006-0338/EB-2006-0340, page 18; Connection Procedures Review Decision, EB-2007-0797, pages 7-9; OPG Review Decision, EB-2009-0038; OPG Review Decision, EB-2011-0090, pages 5-7; London Hydro Review Decision, EB-2012-0220, pages 6-8; Hydro One Remote Communities Review Decision, EB-2013-0331, pages 2-3; and OPG Review Decision, EB-2014-0369, pages 5-6.

> Board has determined that identifiable errors that are material and relevant to the outcome of the reviewed decision have been made.

Specific errors in the decision under review are to be identified and shown to be incorrect in a material way before the OEB's power to vary that decision is engaged. Findings of fact and exercises of discretion that lie within the range of reasonable outcomes supported by the record under review cannot be shown to be incorrect in a material way.

There must be a clear, identifiable and material error or new facts that take the case outside the range of reasonable outcomes that the record under review supports. Changes to evidence in the record before a hearing panel that do not alter the range of reasonable outcomes supported by the entire record being reviewed cannot justify a variance to an original decision.

In the Connection Procedures Decision released a few months after the May 27, 2007 NGEIR Review Decision, the OEB addressed the scope of its power to review in response to submissions made by OEB staff that the OEB has a wide latitude in relation to reviews. The OEB stated:

> This panel acknowledges that the scope of the Board's power to review is broad, but remains of the view that a motion for review must raise a question as to the correctness of the decision in issue. The Board has previously indicated, in the NGEIR Motions Decision and in the Notice and PO, that the grounds for review set out in Rule 44.01 are not exhaustive. It may be that the emergence of previously unknown or unforeseen implications of a decision could be considered a ground for review. However, in the circumstances of this case this panel does not need to decide that issue….[37]

This dissent adheres to the NGEIR Review Decision and supports the conclusion that exceptional and unforeseen circumstances would need to occur before any departure from that approach might be justified.

Other cases have elaborated on the standard of review applicable to OEB review proceedings. For example, in a 2010 decision related to a motion for review and variance brought by Brant County Power Inc., the OEB adopted the principle that:

> A reviewing panel should not set aside a finding of fact by the original panel unless there is no evidence to support the decision and is clearly wrong. A

[37] Connection Procedures Review Decision, supra, page 9.

> decision would be clearly wrong if it was arbitrary or was made for an improper purpose or was based on irrelevant facts or failed to take the statutory requirements into account.[38]

The deference that an OEB review panel is to extend to findings of fact that fall within the range of factual outcomes supported by the record being reviewed was recognized in a 2011 Motion for Review brought by OPG as follows:

> …the Board agrees with the submissions made by the parties who argued that a reviewing panel should only interfere with an original finding of fact in the clearest of cases. The law generally afforded original findings of fact considerable deference.[39]

The "submissions" with which the OEB agreed in that case included the submissions made by OEB staff that were quoted earlier in the decision as follows:

> As stated in the Board staff submission, "Only if the review panel determines that the finding reached by the Decision panel was not within the range of reasonable alternatives should its decision be overturned." In Board staff's view, it is not the task of the reviewing panel to substitute its own judgement for that of the original panel unless it is convinced that the original panel made a clear and material error, and that the original panel clearly misapprehended the evidence.[40]

The August 10, 2010 Brant County Power review decision cited earlier adopted the principle that, in conducting its reviews of prior OEB decisions the OEB should use the same "reasonableness" standard that a court uses in reviewing such decisions. After articulating the reasonableness standard of review expressed by the Ontario Court of Appeal in the Toronto Hydro Dividend case[41] and a passage from the Supreme Court of Canada's decision in *Law Society of New Brunswick v. Ryan,*[42] the OEB stated: "We believe that the standards that a court would use in reviewing a Board Decision are no different than those this panel should use in reviewing a prior Board Decision."[43]

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[38] Brant County Power Review Decision, EB-2009-0063, page 11, paragraph 35.
[39] OPG Review Decision, EB-2011-0090, page 11.
[40] See footnote 39, page 8.
[41] *Toronto Hydro-Electric System Limited v. Ontario Energy Board*, 2010 ONCA 284.
[42] *Law Society of New Brunswick v. Ryan,* [2003] 1 S.C.R. 247.
[43] Brant County Power Review decision, EB-2009-0063, page 12, paragraph 38.

Descriptions of how reasonableness is determined in a particular case are provided in each of the Toronto Hydro Dividend and *Law Society of New Brunswick v. Ryan* cases and referred to in the Brant County Power case as follows:

> The standard of review with respect to Decisions of the Ontario Energy Board was most recently canvassed by the Ontario Court of Appeal in the *Toronto Hydro Dividend* case. There, the Court of Appeal upheld the Board's Decision that required any future dividends to be approved by the majority of the independent directors. The Court noted that "in judicial review reasonableness is concerned mostly with the existence of justification, transparency, and intelligibility within the decision-making process. <u>But it is also concerned with whether the Decision falls within a range of acceptable outcomes which are defensible in respect of facts and law.</u>
>
> In finding that the Decision was justified the Court referred to the often cited passage from *Law Society of New Brunswick vs. Ryan* where Iacobucci J. articulated the relationship between the reasons of the tribunal and the reasonableness of the Decision:
>
>> A decision will be unreasonable only if there is no line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived. If any of the reasons that are sufficient to support the conclusion are tenable in the sense that they can stand up to a somewhat probing examination, then the decision will not be unreasonable and a reviewing court must not interfere. *This means that a decision may satisfy the reasonableness standard if it is supported by a tenable explanation even if this explanation is not one that the reviewing court finds compelling.*[44]

Two features of a reasonableness assessment contained in these descriptions should be noted. The first is the adoption of the "range of reasonable outcomes" approach expressed in the Toronto Hydro Dividend case. The second, expressed in the *Law Society of New Brunswick v. Ryan* case, is the adoption of the concept that a review panel should refrain from substituting its own decision for a decision of a hearing panel that is supported by a tenable explanation, even though that explanation is not one that the reviewing panel finds compelling.

[44] See footnote 43, page 11, paragraphs 36 and 37 (underlining added by OEB; italics appeared in Brant County Power decision).

The Courts have regularly applied a reasonableness approach when determining motions for judicial review of an exercise of adjudicative decision-making by an administrative tribunal. Reasonableness assessments apply to all questions of fact or exercises of discretion raised in a request for adjudicative review.

In the *Newfoundland and Labrador Nurses* case,[45] the Supreme Court of Canada unanimously confirmed that the standard of review of adjudicative decision-making by an administrative tribunal is reasonableness. In commenting on conducting a reasonableness assessment of the reasoning and outcomes components of decision-making the Court emphasized that "…. the reasons must be read together with the outcome and serve the purpose of showing whether the result falls within a range of possible outcomes."[46]

That decision emphasizes that a review panel should show deference and respect for the decision making process of administrative bodies with regard to the facts and that care should be taken to refrain from substituting their own decision of the appropriate outcome when the decision being reviewed falls within the range of outcomes supported by the record being reviewed. The decision states:

> In assessing whether the decision is reasonable in light of the outcome and the reasons, courts must show "respect for the decision-making process of adjudicative bodies with regard to both the facts and the law" (*Dunsmuir*, at para. 48). This means that courts should not substitute their own reasons, but they may, if they find it necessary, look to the record for the purpose of assessing the reasonableness of the outcome.[47]

The decision adds: "Reviewing judges should pay 'respectful attention' to the decision-maker's reasons, and be cautious about substituting their own view of the proper outcome by designating certain omissions in the reasons to be fateful."[48] The Court quoted with approval the following with respect to the sufficiency of reasons:

> When reviewing a decision of an administrative body on the reasonableness standard, the guiding principle is deference. Reasons are not to be reviewed in a vacuum – the result is to be looked at in the context of the evidence, the

[45]*Newfoundland and Labrador Nurses Union v. Newfoundland and Labrador (Treasury Board)*, [2011] 3 S.C.R. 708.
[46] See footnote 45, paragraph 14
[47] See footnote 45, paragraph 15
[48] See footnote 45, paragraph 17

> parties' submissions and the process. Reasons do not have to be perfect. They do not have to be comprehensive.[49]

The *Newfoundland and Labrador Nurses* case also emphasizes that reasons need not refer to every piece of evidence in the record that is capable of supporting a factual finding. The decision under review is not deficient because it does not specifically refer to each and every item in the record related to the market value and gain allocation issues. The absence of such references does not impugn either the reasons or the result under a reasonableness analysis.[50] Put another way, a reasonableness assessment of findings of fact and exercises of discretion is based on the entire record. It is not limited in scope to only the items of evidence specifically referenced in the reasons for decision.[51]

The case concludes with a statement that the decision under review should not be varied because the hearing panel "… was alive to the question at issue and came to a result well within the range of reasonable outcomes."[52]

Under the reasonableness standard of review that these precedents establish, the factual and discretionary aspects of a decision under review are correct if they fall within the range of reasonable outcomes that the record under review supports. There is no identifiable and materially incorrect error when a particular finding of fact or exercise of discretion under review falls within the range of reasonable outcomes supported by the record under review. A finding of fact or exercise of discretion under review contains an identifiable and materially incorrect error when it is shown to lie outside this "range of reasonable outcomes".

A determination of the range of outcomes that the record under review supports is essential under the reasonableness standard of review articulated in OEB precedent decisions. This essential component of the standard cannot be disregarded. The range of outcomes that the record supports must be determined in this review proceeding to comply with the OEB's review standard.

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[49] See footnote 45, paragraph 18
[50] See footnote 45, paragraph 16.
[51] This point was recently highlighted in the Ontario Court of Appeal decision in *Finkelstein v. Ontario Securities Commission* cited in the Introduction and Summary part of this dissent. At para. 84(iii) of that decision the Court endorsed findings made by the Divisional Court in that case that included the proposition that "The evidence must be examined and weighed in its entirety. The evidence should not be viewed in isolation."
[52] See footnote 45, paragraph 26.

6.2.2 Regulatory Treatment of Affiliate Transactions

Within the legal framework that applies to a determination of the Property value issue in this case are the regulatory principles that apply, for ratemaking purposes, to determine the appropriateness of amounts paid by an affiliate to acquire assets owned by the utility.

The need for regulators to protect ratepayers from transactions that benefit a utility affiliate at the expense of utility ratepayers is well established. The Ontario Court of Appeal noted this in paragraph 60 of its decision in the Toronto Dividend case by referring to paragraph 5.1.7 of the OEB decision under appeal and stating: "The decision notes that there is extensive jurisprudence in gas cases with respect to transactions between a regulated utility and an affiliate."[53]

A regulator needs to take care to ensure that the unregulated affiliate is not deriving an inappropriate benefit at the expense of utility ratepayers.

At a high level, the record under review in this proceeding that relates to the appropriateness of the value paid by the affiliate in its acquisition of the Property has three separate components:

a) The August 5, 2015 appraisal report;

b) The sworn testimony of Milton Hydro's CEO at the oral hearing before the Hearing Panel that the realistic 2015 cost of acquiring the 1.3 privately owned parcel at the corner of Fifth Line and Main was about $800,000 or about $615,000 per acre; being an amount substantially in excess of the $375,000 per acre price that that Milton Hydro's affiliate paid to acquire the utility's 6.43 acre parcel at the same location; and

c) The $450,000 per acre and $2.7 million Property value amounts which Milton Hydro's CEO presented to Milton Hydro directors in late 2012, some three years before the 2015 sale to the affiliate, which also materially exceeded the $375,000 per acre and $2.4 million Property value amounts that the affiliate paid to the utility.

The Hearing Panel adopted a $400,000 to $450,000 value range and its mid-point of $425,000 to find, for ratemaking purposes, that the value per acre and the Property values should be $425,000 per acre and $2.73 million for the 6.43 acres of land. The

[53] *Toronto Hydro-Electric System Limited v. Ontario Energy Board*, 2010 ONCA 284, paragraph 60.

Hearing Panel rejected the $350,000 to $400,000 value range, and the use of its mid-point of $375,000 per acre to derive the $2.4 million Property value presented in the August 5, 2015 appraisal report. There was nothing ambiguous about the values that the Hearing Panel used to determine a market value for the Property, for ratemaking purposes, of $2.73 million as stated in the majority decision.

I disagree with the majority decision when it states that the Hearing Panel's market value finding was "based on an ambiguity". The Decision unambiguously reveals the value per acre range of $400,000 to $450,000 and mid-point per acre value of $425,000 that the Hearing Panel considered to be appropriate.

The Hearing Panel was alive to sources of land value information other than the appraisal report referenced in the Decision. One of these other sources of information was the 2012 report to directors in which Milton Hydro officials ascribed a $450,000 per acre value to the Property and a total value of $2.7 million. Another consisted of the oral testimony and supporting exhibit provided by a Milton Hydro executive at the OEB hearing to the effect that the 1.3 acre parcel abutting the Property had a market value of $800,000 or about $615,000 per acre.

The foregoing facts are part of the entire record that is to be considered when reviewing Milton Hydro's assertion that the Hearing Panel's findings of fact related to the affiliate transaction are unreasonable and incorrect.

The majority decision uses the phrase "actual sale price" when referring to the $2.4 million affiliate transaction amount. An "actual sale price" has relevance to ratemaking when a transaction between a utility and another is an arm's length open market transaction. The phrase should not be used to refer to an affiliate transaction amount because an affiliate transaction amount derives from an estimate or appraisal of value and not from an open market transaction.

The "price" in an affiliate transaction involving an OEB regulated utility is the amount that the OEB accepts as reasonable. The Hearing Panel made a finding of fact that, for ratemaking purposes, the market value of the property at the time of its transfer to the affiliate was $425,000 per acre and $2.73 million for the 6.43 acre parcel. An adjudicative finding of fact based on supporting evidence does not amount to "deeming" a price as the majority decision suggests. The action of "deeming" an outcome implies that there are no facts to support that result. That is not the situation in this case.

This $425,000 per acre and resulting $2.73 million value are the findings of fact that are to be reviewed and the question is whether these amounts fall within the range of reasonable value outcomes that the entire record under review supports.

The foregoing comprise the well-established principles that should be applied by the Review Panel in this case to determine whether the Hearing Panel's decisions related to the market value of the Property, the portion of the gain to be allocated to ratepayers and the mechanism for crediting the gain amount to ratepayers are incorrect as Milton Hydro asserts.

The sections that follow include a determination of items related to the components of the record being reviewed followed by an analysis of the range of reasonable outcomes that the record under review supports in relation to each of the matters in issue.

6.3 RECORD UNDER REVIEW

Subject to the determination of an issue related to admissibility, the record being reviewed in this case consists of the record before the Hearing Panel, Milton Hydro's August 17, 2016 Affidavit (Affidavit), the accounting policies in the APH, and the PO2 Responses.

6.3.1 Admissibility of the Affidavit

Milton Hydro seeks to change portions of the appraisal evidence referenced in the Decision on the grounds that these portions of the evidence constitute an "error of fact" under Rule 40.01(a) of the OEB Rules. The Affidavit is relied upon to effectively seek a re-opening of the EB-2015-0089 proceeding to reduce the $400,000 to $450,000 value range and the $425,000 amounts contained in the Colliers August 5, 2015 appraisal that was before the Hearing Panel.

These changes are proposed on grounds that Milton Hydro had no opportunity to explain the inconsistencies in the report before the Decision issued and that the numbers in the report that it proposes to change are typographical errors.

In its September 20, 2016 submissions SEC's position is that the OEB should not accept this evidence without affording the parties an opportunity to test it. SEC's submissions detail five topic areas on which it has questions about the appraisal.[54] In

[54] SEC's concerns included: the very low increase in value of the property compared to its purchase price in 2009 and inflation increase over the period 2009-2015; the reason for the lowest comparable of about

their September 22, 2016 submissions, neither Energy Probe nor OEB staff had any objections to the changes being made as proposed by Milton Hydro.

After reviewing these submissions, the OEB sought to have its staff schedule with Milton Hydro a date for a brief oral hearing to deal with questions of this nature. Milton Hydro objected to this process and requested that questions be submitted in writing. Written questions were submitted by the OEB with Procedural Order No. 2 and responses were provided shortly thereafter.

The PO2 Responses reflect the extent to which SEC's concerns have been addressed. The PO2 Responses reveal that the amounts in the Report before the Hearing Panel accurately reflected the opinion of the appraiser who prepared the initial draft of the report. That appraiser used the comparable sale and other information in the report to establish a value range of about $339,000 to about $482,000, a subset value range of $400,000 to $450,000 and a Property value of $2.7 million. This range was a correct expression of the initial appraiser's estimate.

A peer review process at Colliers involving another appraiser led to a lower Property value estimate of $2.4 million. It is unclear from the PO2 Responses whether the second appraiser actually reduced the $400,000 to $450,000 value range contained in the initial draft. Attachment B of the PO2 Responses, being a letter from Colliers, states as follows:

> Within our file there are three Drafts. The third Draft is the only report that was sent to the client. Within Draft 1, we concluded at a market estimate of $2,700,000 (rate per acre ranging from $400,000 to $450,000). This value was never communicated to the client. Following a peer review process (review by a second AACI designated appraiser), we deemed the rate should be at the lower end of the range given that the Subject falls within phase 3 of the Derry Green Corporate Business Park a policy plan that covers approximately 2000 acres of Employment lands.

This statement makes no mention of any value range other than the $400,000 to $450,000 range.

In the course of revising the initial opinion draft to reflect the outcome of the peer review process, Colliers did not revise and Milton Hydro staff did not question the value range subsets and price per acre amounts in the successive drafts of the report.

$339,000 not being eliminated as an outlier; the average of the comparable sales of $433,651; and the contents of successive drafts of the appraisal reports – see SEC Sept. 20, 2016 Submissions.

The e-mail exchanges between the appraiser and Milton Hydro, over the 17 days between July 20 and August 6, 2015, show that Milton Hydro received the draft of the report on July 20, 2015, sent it back with comments on August 4, received a further draft on August 5 that was reviewed and sent back to the appraiser on August 6. The final report containing both the value range supported by the comparable sale and the $400,000 to $450,000 range was sent to Milton Hydro on August 6, 2015.[55]

The PO2 Responses establish that Colliers did not investigate whether there had been any market activity related to the property adjacent to Milton Hydro's property and that Milton Hydro did not disclose to Colliers any of the facts related to its evaluation and offer to purchase the 1.3 acre parcel at Fifth Line and Main Street owned by its immediate neighbour; or the fact that it had ascribed a value of $2.7 million to the Property some three years before its sale to its affiliate.

The PO2 Responses reveal that the changes that the Affidavit makes to the appraisal report that was before the Hearing panel are probably more appropriately characterized as editorial changes that were missed following the peer review process rather than as typographical errors.

Regardless of whether these items are characterized as editorial revisions or typographical errors, they were made by Milton Hydro and Colliers and not by the Hearing Panel. That said, Milton Hydro correctly states that it had no opportunity before the Decision issued to explain the inconsistencies in the appraisal report that was before the Hearing Panel. The Decision reveals that the Hearing Panel, while alive to these inconsistencies, did not reconvene the hearing to receive further submissions on the relief that Milton Hydro requested, for the first time, in its written Reply argument.

That late request for relief triggered the Hearing Panel's consideration of the Property value and gain allocation and recovery issues.

Situations often arise in proceedings before the OEB where submissions made in argument prompt the OEB's examination of evidence in the record upon which no questions have been posed during the course of the oral hearing. A hearing panel has process options that it can consider in such circumstances. These include prolonging the hearing process related to the issue by either calling for submissions on the issue or deferring a determination of the issue to a future proceeding. Another option is to refrain from reconvening or deferring the matter and, instead, dealing with the issue on the basis of the existing record. This was the course taken by the Hearing Panel in this case.

[55] PO2 Responses, Attachment F.

However, because Milton Hydro had no opportunity to address the inconsistencies in the appraisal report before the Decision issued, the affidavit containing the explanation for these deficiencies and PO2 responses pertaining to that explanation should form part of the record being reviewed in this proceeding.

While the Affidavit is admissible and forms part of the record under review, the question for the Review Panel is not whether they do or do not accept the Affidavit's explanation of the circumstances giving rise to the deficiencies in the appraisal. Regardless of this explanation, under the reasonableness standard of review the question is and remains whether the $2.73 million value finding made by the Hearing Panel falls within the range of value outcomes supported by the entire record being reviewed. The question for the Review Panel is, "What range of value outcomes did all of the evidence before the decision-makers reasonably support?"

Milton Hydro's explanation for the portions of the appraisal report that the Hearing Panel found to be "inexplicable" does nothing to reduce the upper limit of the range of per acre values that is supported by a consideration of all of the evidence in the record under review related to that value issue. The changed and unchanged parts of the report remain as one of the items of evidence in the entire record to be considered when determining the range of reasonable value outcomes that the record under review supports.

The explanation provided in the Affidavit does not elevate the $375,000 per acre amount that appeared in the initial report and in the changed and unchanged parts of the revised report to some superior status in the record under review. Reducing the sub-set value range and its mid-point in the August 5, 2015 appraisal report does nothing to alter the evidence in the report of the range of values regarded as achievable. Nor do the changes to the report have any impact of the two other independent sources of value evidence being Milton Hydro's own arm's length marketing activities related to many other properties in the area, its own $2.7 million value estimate in 2012 and the value evidence related to the 1.3 acre parcel immediately adjacent to the Property.

The original and revised appraisal reports each support, as achievable, a rate per acre of up to about $442,000. The Hearing Panel's finding of a value of $425,000 per acre lies below the upper limit of the range that the appraisal regards as achievable. The second appraiser's preference for a subset range of $350,000 to $400,000 and a mid-point value of $375,000 per acre does not take the $425,000 acre amount out of the range of values that the appraisal finds to be achievable.

Moving the appraisal’s value range subset and mid-point amount down by $50,000 per acre are not “new” facts or information that lies outside of the range of value outcomes that the record supports. Rather they are revisions to existing facts to support a particular value finding within the value range supported by the record under review being a particular value that the Hearing Panel rejected. Under the OEB’s reasonableness standard of review, a post-decision explanation or elaboration in support of one value over another cannot justify a variance when each of the values falls within the range of reasonableness established by the whole of the evidence before the decision-makers.

As more fully discussed below, there is per acre value evidence in the record, independent of the August 5, 2015 appraisal report; that supports values per acre well in excess of $425,000.

The reasonableness standard of review requires an applicant seeking variance of a finding of fact made by a hearing panel to establish that there is no evidence in the record under review that is capable of supporting that finding. Milton Hydro has not and cannot discharge that onus.

6.3.2 OEB Accounting Policies

The APH contains provisions dealing with the recording of the original cost of land used for utility purposes and land held for future utility use. It also includes provisions that specify the accounts that are to be used for dealing with gains or losses arising from the disposition of utility assets and assets held for future utility use.[56]

Milton Hydro relies of the provisions of these accounting rules to support its position that the Hearing Panel erred in directing a permanent rate base reduction in the amount of the capital gain allocable to ratepayers. However, Milton Hydro disregards the provisions of these rules related to land being held for future utility use but not yet in rate base.

Under the APH, gains and losses on land held for future utility use are treated the same as gains or losses on land already being used for utility purposes. These provisions of

[56] APH section 1905 deals with utility land in service. APH 2040 deals with assets held for future utility use but not yet in service. Account 2040 covers land held for future utility use but not yet in service. Gains on Disposition of Utility Property in service are covered by section 4355 of the APH on which Milton Hydro relies to support the revenue requirement offset for ratepayers stemming from the disposition of the portion of the land in service and in rate base. Gains from Future Use Utility Property under section 2040B are to be recorded in APH account 4345. The APH Rules treat utility property in service and property held for future utility use but not yet in service in the same manner.

the APH, as well as those upon which Milton Hydro relies, have relevance to both the gain allocation and credit mechanism issues.

I accept that the accounting rules in the APH are a component of the OEB's policy framework that should be considered when determining the range of outcomes that the record being reviewed supports in relation to each of these issues. As OEB staff point out in their submissions, these rules do not bind the OEB. They do however identify allocation and credit mechanism options that fall within the range of reasonable outcomes for each of these issues.

6.3.3 Conclusions on the Record under Review

For these reasons I would find that the record to be reviewed to determine the range of outcomes that it supports in relation to each of the matters in issue consists of the record before the Hearing Panel, the Affidavit, the OEB's accounting policies in the APH and the PO2 Responses.

6.4 FAIR MARKET VALUE AND THE GAIN AMOUNT

To properly apply the OEB's reasonableness standard of review to the Hearing Panel's market value finding of $2.73 million, the reviewing panel should first examine the Hearing Panel's decision on the value issue. Second, the entire record under review is to be screened to ascertain the range of value outcomes that it supports. Third, the criteria under the reasonableness standard of review that an applicant must satisfy to set aside a finding of fact are to be considered. The reviewing panel concludes by determining whether the criteria for varying the Hearing Panel's finding of fact have been satisfied.

6.4.1 Hearing Panel's Decision on the Value Issue

As a preliminary matter, the Decision found that Milton Hydro's request, presented for the first time in its reply argument, for a reduction in the annual capital gain revenue requirement offset amount of $87,950 in the Settlement Proposal, was a request that fell within the ambit of the unresolved 200 Chisholm Drive issue.[57]

[57] Decision, page 10.

The Decision notes that the sale of the property for $2.4 million was not an open market transaction but an affiliate transaction between Milton and MEGS.[58] The Hearing Panel was alive to the fact that the property had not been put up for sale on the open market. Upon becoming alive to the fact that sale of the Property was to an affiliate, the Hearing Panel had an obligation to take care to ensure that ratepayers were not being prejudiced by that affiliate transaction.

The Decision notes that the body of the analysis section of the August 5, 2015 appraisal report does not support the concluding opinion as to value.[59] The Decision considers but rejects as “inexplicable” the $375,000 per acre value that is the basis for the estimated $2.4 million market value of the land contained in the appraisal report.[60] The Decision finds that, for ratemaking purposes, the appraisal evidence supports a value range of $400,000 to $450,000 and a sale value of $2.73 million based on a per acre value of $425,000 for the 6.43 acre parcel. The Decision unambiguously states the per acre value range and its mid-point value upon which the $2.73 million market value finding is based.

The Decision refers to the November 2012 presentation made by the President/CEO of Milton Hydro to the Relocation Committee of the Board of Directors. That presentation ascribed a $2.7 million sale value to the Property based on a per acre value of $450,000.[61] The Hearing panel was “alive” to that information related to the market value issue.

A review of that entire presentation, in the context of the testimony and exhibits presented at the oral hearing about many properties that Milton Hydro had investigated over the years as alternative sites to Fifth and Main for the location of its utility office/service centre project, demonstrates Milton Hydro’s familiarity with land and property values in the area.[62] The oral testimony and exhibits filed at the hearing referred to ten property options that Milton Hydro had investigated since 2010 as alternatives to Fifth Line and Main for the location of its utility office/service centre project.[63]

[58] Decision, page 46.
[59] Decision, page 46.
[60] Decision, page 46.
[61] See Chapter 3 Facts, footnote 9.
[62] See Interrogatory Responses, December 18, 2015, Relocation Committee Minutes April 12, 2014, pages 739-743, listing the 12 properties investigated by Milton Hydro personnel, per acre prices, and the three properties identified for further pursuit, and the November 14 Meeting Minutes and 15 page presentation, pages 744-761.
[63] Exhibit K1.3, pages 17-18, and Tr. Vol 1, pages 150-152.

At the oral hearing Milton Hydro's testimony also referenced the arm's length market activity in which it had engaged in prior years in an attempt to acquire the privately owned 1.3 acre parcel at Fifth Line and Main to give it sufficient development land at that location to satisfy its utility office/service centre needs. That prior market activity was relied upon by Milton Hydro to support a realistic value estimate for the 1.3 acre parcel of $800,000 or about $615,000 per acre. The Hearing Panel was "alive" to this information relating to the market value issue. During their oral testimony about the cost of property at this location the Milton Hydro witnesses never referred to the appraisal certified value estimate of immediately adjacent land at $375,000 per acre.

The Hearing Panel's value finding of $425,000 per acre ($2.73 million for the 6.43 acres) was supported by the appraisal and other evidence specifically referenced in the Decision. There was no need for the Hearing Panel to list in the Decision all of the information in the record that supported a conclusion that a per acre value of $425,000 fell within the range of reasonable per acre value outcomes.[64]

6.4.2 Does the Reasonable Range of Value Outcomes Include $425,000/Acre?

Any estimate of the fair market value of a particular item of property, regardless of whether it is expressed in a written appraisal or in some form of presentation, stems from an analysis of arm's length open market activity. The best evidence of market value is actual arm's length market activity related the particular property being assessed and other properties similarly situated.

An appraisal is nothing more than an estimate of the value of a particular property derived from market activity selected by the appraiser to form the factual basis for the estimate. Appraisers use examples of actual market activity to develop ranges of value that they regard as achievable and then select a point within that achievable range as their value estimate. The certificate in an appraisal merely formalizes the estimate that is based on the market activity described and analyzed in the body of the appraisal report. Such a certificate is not the equivalent of a price in an arm's length open market transaction.

Any appraiser retained by a property owner to support the pricing for a property to be sold in the open market would investigate market activity related to properties that adjoin the property to be sold. Any property seller seeking an appraisal for the purpose of pricing the property for sale in the open market would inform the appraiser of the market activity in which it had engaged in relation to adjoining property. This is particularly so when the seller was planning to rely on that activity to support a

[64] See footnotes 50 and 51.

presentation to the OEB of a current cost to acquire adjoining property of about $615,000 per acre.

One can reasonably ask how Milton Hydro can credibly assert that a per acre value of $375,000 for development land at Fifth Line and Main Street is reasonable when its CEO told the OEB that it would realistically cost $615,000 per acre to purchase a 1.3 acre parcel at that very location.

When an OEB hearing panel is called upon to consider the fair market value of a utility property that has been sold to an affiliate, it is not obliged to accept, as reasonable, the particular value estimate presented by the utility's appraiser. A hearing panel can consider the actual market activity on which the utility's appraiser has relied to formulate its estimate along with other market activity information and value estimates based thereon that the utility's appraiser did not consider. It is open to a hearing panel to find a value different from the appraiser's estimate as the value that should be accepted as reasonable for ratemaking purposes.

The three components of market activity evidence reflected in the record under review relevant to a consideration of the breadth of the range of per acre property values that the record supports are referenced above in Section 5.2.3 and include:

a) The arm's length market activity described in the August 5, 2015 Colliers appraisal that was before the Hearing Panel, which remained unchanged in the revised version of that report presented with the Affidavit. Each version of the August 5, 2015 appraisal supports as achievable per acre values of up to $442,000;

b) The arm's length market activity in which Milton Hydro participated related to the 1.3 acre parcel at Fifth Line and Main. This activity supports a per acre value much higher than $425,000; and

c) The market activity in which Milton Hydro engaged over the years 2010 to 2014 in relation to the many other properties that it investigated as alternatives to completing the development of its office/service centre project on property located at Fifth Line and Main Street. This activity supported the $450,000 per acre value ascribed to the property in the CEO's November 2012 presentation to directors.

Milton Hydro's witnesses referred to and relied upon the second and third sources of these market activities in their oral testimony before the Hearing Panel. This testimony alerted the Hearing Panel to these sources of information. Milton Hydro made no reference to the Colliers appraisal report during the course of the proceeding. Where errors of fact are alleged, an OEB review panel is obliged to consider all information in the record before the decision makers in determining the range of factual outcomes supported by that record.

A careful analysis of all three sources of the market activity information that was before the Hearing Panel is presented in the “Facts” section of this consolidated decision. This evidence is summarized below.

6.4.3 Colliers’ Appraisal Report

The August 5, 2015 appraisal report in the record before the Hearing Panel states that it was being prepared for the purpose of providing an estimate of value to Milton Hydro for “internal purposes” and notes that the OEB may rely on the report for regulatory purposes. As previously noted, this report relies on five comparable property sales; one at $339,217 and the other four falling within a range of $442,000 to $478,000. The report states that: “The Subject Parcel should achieve a rate per acre in the narrowed range of $339,217 to $442,213.” This statement supports a finding that a reasonable range of rate per acre outcomes for the Property includes a per acre value of $425,000.

This analysis section of report establishes a value range of $400,000 to $450,000 for the Property with a mid-point rate per acre of $425,000.

The revised August 5, 2015 Report filed with the Affidavit relies on the same market transactions and the same achievable sales range with an upper limit of $442,213. This report makes changes to the initial report by reducing the limits of the value range in the analysis section of the report by $50,000 to conform to the $$350,000 to $400,000 value table in the initial report and the $375,000 per acre value used to estimate the value of the property at $2.4 million.

The Affidavit and PO2 Responses state that the appraiser who prepared an initial draft of the report concluded at a market value estimate of $2.7 million using a value range of about $339,000 to $478,000 per acre established by a set of comparable sales, a subset thereof with a rate per acre of $400,000 to $450,000 and a mid-point per acre value of $425,000. Following a peer review by another appraiser it was deemed that the rate should be at the lower end of the range. On its face this response indicates that the range of $400,000 to $450,000 was not an error. It was the opinion of the appraiser who drafted the initial report that led him to value the Property at $2.7 million.

The PO2 Responses at Attachment F reveal that during the three separate e-mail exchanges between the appraiser and Milton Hydro over the period July 20, 2015 to August 6, 2015 relating to the reviews of the draft report, no one questioned the $400,000 to $450,000 value range.

The August 5, 2015 appraisal report makes no reference to the arm's length market activity in which Milton Hydro engaged in relation to the 1.3 acre parcel at Fifth Line and Main nor to the many other properties that Milton Hydro investigated over the years 2010 to 2014. The PO2 Responses reveal that the appraiser did not ask and Milton Hydro did not disclose the activities in which it had engaged that supported a $615,000 per acre value estimate for development property at Fifth Line and Main that Milton Hydro subsequently presented to the OEB as a "realistic" estimate of current market value.

6.4.4 Milton Hydro's Market Activities Related to the 1.3 Acre Parcel

The record before the Hearing Panel and the PO2 Responses reveal that Royal LePage provided Milton Hydro with a 2010 appraisal of the 1.3 acre parcel of its immediate neighbour at between $461,000 and $538,000 per acre. Milton Hydro made an arm's length offer in 2010 to its immediate neighbour of about $700,000 or a per acre rate of about $538,000. The neighbour wanted $750,000 or about $577,000 per acre. As already noted at the April 4, 2016 oral hearing, Milton Hydro estimated that it would cost $800,000 or about $615,000 per acre to purchase this land and relied on its own arm's length market activity with the property owner to support that cost as a realistic estimate of the 2015 value of that parcel.

6.4.5 Other Market Activities and the 2012 Value Estimate of $2.7 Million

The record under review reveals that by March 2012 and before the CEO made the November 2012 presentation to Milton Hydro directors, Milton Hydro had already investigated the availability and pricing of 12 property alternatives to a Fifth Line and Main Street location for its office/service centre project and had then identified three property options to be pursued.[65]

This activity was in addition to its own arm's length efforts to purchase the adjacent 1.3 acre parcel. These activities and the 15 page November 2012 presentation reveal that Milton Hydro was very involved in and familiar with the prevailing prices for property in the area. Milton Hydro was not a neophyte in matters relating to property values when

[65] See footnote 62.

the CEO made the November 2012 presentation. In that presentation Milton Hydro ascribed a $450,000 per acre and $2.7 million value to the Property.

6.4.6 Impermissible Re-weighing of Evidence

When applying the reasonableness standard of review a reviewing panel is not to examine the evidence in isolation. The evidence is to be examined in its entirety. A reviewing panel cannot re-weigh the evidence to support findings that are substitutes for findings made by a hearing panel that are supported by the record. The majority decision does not comply with these principles. The majority decision impermissibly ascribes little, if any, weight to the following evidence related to the market value issue:

a) Milton Hydro's arm's length market activities related to the adjoining 1.3 acre parcel;

b) Its other market activities and its 2012 value estimate for the Property of $2.7 million;

c) The value of about $442,000 per acre considered by the Colliers appraisal to be achievable; and

d) The diluted quality of the Colliers appraisal report that does not consider all of the market activities in which Milton Hydro itself engaged.

The majority decision discredits the evidence of Milton Hydro's arm's length market activities related to the 1.3 acre parcel on the grounds that "property markets can change considerably in five years". I disagree with this feature of the majority decision.

The majority's observation is in conflict with the record under review and Milton Hydro's testimony at the oral hearing stating, unequivocally, that the market activity in which it engaged some years ago was a realistic indicator of current value. The record under review reveals that, since 2012, property values in the area were increasing and not decreasing as the observation in the majority decision suggests. The Review Panel must respect the record under review.

The majority decision discredits Milton Hydro's $2.7 million value estimate in 2012 for the Property on the grounds that this value estimate made by the CEO was contained in an "internal" document. I disagree with this feature of the majority decision. It is not the form of the presentation but the substance of the information that underpins a value estimate that matters.

At the time that the CEO made his presentation to the directors, Milton Hydro officials had, for years, been personally involved in and were very experienced in property values related to sites at which its new office/service centre might be located. These activities included the investigation and offer on the 1.3 acre parcel and the investigation some 12 other properties as alternatives for the location of its office/service centre project.

Milton Hydro's market based activities that supported the CEO's November 2012 presentation were essentially the same market based activities on which the CEO relied when making his presentation made to the OEB at the oral hearing in this case. Each of the presentations was supported by the significant market activity in which Milton Hydro officials had personally engaged. These presentations and supporting documents and the appraisal prepared for Milton Hydro's "internal purposes" are equivalents.[66] These presentations and the market activities supporting them cannot be discredited on review because they were "internal" and not presented in an appraisal format.

The majority decision disregards the failure of Milton Hydro to disclose and the failure of the Colliers appraisers to ask about the market activities in which Milton Hydro had engaged that supported Milton Hydro's $615,000 per acre value estimate at the hearing for the 1.3 acre parcel at Fifth Line and Main Street. The majority's rationale for this approach is that this non-disclosure and failure to investigate was not "improper" and that the appraisers' knowledge of this information might have compromised their "independence".

An investigation of these activities by the appraiser and/or disclosure of them to the appraiser by Milton Hydro does not compromise the independence of the appraiser as the majority decision finds. The lack of investigation and disclosure do not relate to appraiser "independence". Rather these items relate to the quality of the appraisal report which depends upon the arm's length market activities that are reflected in that report. A failure to include in an appraisal information related to the property adjacent to the property being appraised dilutes the quality of the appraisal.

Similarly I disagree with the majority's disregard of all of the market activity information that is separate and apart from the market activity reflected in the revised appraisal on the grounds that the appraiser's estimate is deserving of greater weight. As already noted the Ontario Court of Appeal has recently confirmed that a review panel is not to re-weigh various items of evidence in the record under review. Rather it considers the probative capability of the entire record to identify the range of outcomes that the record supports.

[66] See Chapter 3, FACTS, subparagraph (i).

There is no factual basis in the record for treating the appraiser's market activity based value estimates any differently than the value estimates derived from the market activities in which Milton Hydro officials participated that the appraiser did not consider. The majority's attribution of greater weight to the appraisal is both inappropriate in a review proceeding and untenable having regard to the extensive participation of Milton Hydro officials in market-related activities over a period of some four years.

6.4.7 Summary

In summary the record under review overwhelmingly supports a range of values that includes a value of $425,000 per acre and a $2.73 million value for the Property's 6.43 acres for ratemaking purposes. That the range of values includes $425,000 per acre value is supported by:

a) the $339,212 to $442,217 per acre range that initial and revised Colliers appraisal reports establishes as achievable for the Property;

b) the value range of the $400,000 to $450,000 per acre range established by the Colliers appraiser who prepared the initial draft of the report;

c) the $400,000 to $450,000 per acre range in the report before the Hearing Panel;

d) the values for four of the five comparable properties in the Colliers reports equal to or greater than $442,000;

e) the per acre values for the 1.3 acre parcel immediately adjacent to the property reflected in Milton Hydro's presentation to the Hearing Panel ($615,000), its arm's length open market offer to purchase the property ($538,000) and the appraisal of the property that it obtained from Royal LePage ($461,000 to $538,000); and

f) the $450,000 per acre and $2.7 million values that Milton Hydro ascribed to the Property in 2012.

6.4.8 Criteria to be Satisfied to Set Aside a Finding of Fact

The applicant for review must show that the challenged finding of fact is contrary to the record under review. A reviewing panel should not set aside a finding of fact by the original panel unless there is no evidence to support the decision and the decision is clearly wrong. A reviewing panel should only interfere with a finding of fact in the clearest of cases. The law accords considerable deference to findings of fact.

In my view, having regard for the record being reviewed, Milton Hydro has not and cannot satisfy these criteria.
There is no identifiable and materially incorrect error in a finding of fact that falls within the range of reasonable factual outcomes that the record under review supports. Under the OEB's reasonableness standard of review a finding of fact not reviewable if it falls within the range of reasonable factual outcomes that the record under review supports.

A review panel is to refrain from substituting its own decision of the appropriate outcome when the decision being reviewed falls within the range of outcomes supported by the record being reviewed.

6.4.9 Conclusion

The record under review overwhelmingly supports, as reasonable, a range of decision alternatives to the market value issue in excess of $375,000. The August 5, 2015 appraisal report, on which the majority relies, regarded a per acre value of $442,213 per acre as achievable. In 2012 Milton Hydro considered a per acre value of $450,000 to be appropriate. At the 2015 hearing, Milton Hydro was asking the OEB to treat the Property as having a per acre value of about $615,000.

In my view, Milton Hydro cannot credibly contend that the Hearing Panel's $2.73 million Property value finding falls outside the reasonable range of value outcomes when that value is:

a) essentially the same as the $2.7 million value that Milton Hydro ascribed to the Property some three years prior to its sale; and

b) much lower than the $615,000 per acre value for development property at Fifth Line and Main Street presented by Milton Hydro's CEO to the Hearing Panel during the course of his oral testimony on April 4, 2016.

Based on the foregoing review of all of the facts in the record under review pertaining to the Property value issue, I would find that the Hearing Panel's Property value finding of $2.73 million falls within the range of reasonable per acre value outcomes established by that record. The $2.73 million value finding has not been clearly shown to be incorrect in a material way.

Moreover, in the context of Milton Hydro's extensive property investigations that informed its own 2012 value estimate for the Property of $2.7 million, I find the substitution of a $2.4 million year-end value for 2015 for the $2.73 million amount found by the Hearing Panel to be appropriate to be incompatible with the OEB's obligation to ensure that ratepayers are not prejudiced by transactions between a utility and its affiliates. The substituted value of $2.4 million materially reduces the capital gain amount to be considered in setting rates by $330,000, from about $506,000 to about $176,000.

I would deny the request for a variance of the $2.73 million market value finding.

6.5. PORTION OF THE GAIN ALLOCATED TO RATEPAYERS

As with the previous issue, to apply the established standard of review the Review Panel examines the Hearing Panel's decision to determine the rationale for allocating the entire gain on land not in rate base to ratepayers. This is followed by a screening of the record under review to determine the range of gain allocation outcomes that it supports. The criteria that must be satisfied to justify a variance are then applied to determine whether the variance relief requested should be granted or denied.

6.5.1 Hearing Panel's Decision on the Gain Allocation Issue

The question for the Hearing Panel in relation to the gain allocation issue was to determine the allocation as between the utility shareholder and its ratepayers of the amount of the capital gain on the Property attributable to the 50% portion of the land not yet in rate base. Milton Hydro had allocated to ratepayers the gain attributable to the land in rate base. The issue for determination by the Hearing Panel related to the appropriate regulatory treatment of the gain on the remainder not in rate base.

No changes to the record before the Hearing Panel are relied upon to support the requested variance of the hearing Panel's allocation of the entire gain to ratepayers for ratemaking purposes. Rather Milton Hydro's request for variance is effectively based on the proposition that the gain on the portion of the land not in rate base cannot, in any circumstances, be allocated to ratepayers. On this issue the question for the Review Panel is whether the gain allocation alternatives available to the Hearing Panel included the option of an allocation of some or all of the gain to ratepayers.

I agree with that portion of the majority decision on this issue that acknowledges that the Hearing Panel did not disregard the fact that 50% of the land had not yet been included in rate base. The Hearing Panel was clearly alive to that fact.

The Decision reveals that the factors that prompted the Hearing Panel to allocate to ratepayers all of the gain attributable to the portion of the land not in rate base included:

a) The fact that the Property had been acquired by Milton Hydro pursuant to a utility project plan to develop its own office/service centre; and

b) The fact that the land at the 200 Chisholm Drive premises was purchased as a substitute and replacement for the Property as a new location for the utility office/service centre project.

At page 39, the Decision refers to the Settlement Agreement in Milton Hydro's 2011 cost of service proceeding where the parties agreed that the Property would be the site for the future office/service centre. The Decision at page 54 finds that the property was purchased for this specific utility purpose.

At page 54, the Decision notes that the Chisholm Drive premises was a substitute and replacement for the Property.

At page 55, the Decision finds that the appropriate regulatory treatment of a gain realized when one parcel of property, acquired for a future utility use, is replaced with another to serve that same utility use is to allocate that gain to ratepayers. The Hearing Panel's gain allocation rationale referred to the CEO's November 2012 presentation to directors that showed the entire $2.7 million value of the property been applied as a credit to the then total estimated office/service centre project costs budget to defray the costs estimated to be incurred for completing the utility project at a different location.

In that 2012 presentation, the amount of the then estimated sale value of the Property of $2.7 million that was applied to defray the total project costs included, rather than excluded, the portion of the total capital gain amount of about $500,000 attributable the land not included in rate base.[67] The gain of the portion of the land not in rate base was allocated to ratepayers to defray the costs of substituting the land at 200 Chisholm Drive for the Property as a new location for the utility office/service centre project.

The evidence indicated that the land related costs for the 200 Chisholm Drive premises were $4.040 million compared to the costs of the Property of about $2.2 million and the additional $0.8 million that Milton Hydro said that it would likely have to pay for the 1.3 acre parcel that was needed to provide sufficient lands at the Fifth Line and Main Street location to satisfy its utility needs.

[67] The original cost of the land was about $2.2 million. A $2.7 million value produces a gain of about $500,000.

6.5.2 Range of Outcomes Supported by the Record under Review

The Record under review in relation to the gain allocation issue includes the OEB's accounting policies expressed in its APH. What is informative about these provisions in relation to this issue is that gains and losses on land and other assets acquired for future utility use are treated the same; they are allocated to ratepayers.[68]

While I accept the submissions of OEB staff that the accounting rules are not necessarily binding in a particular case, these APH provisions, at the very least, identify gain allocation options that fall within the range of outcomes that the record under review supports.

For ratemaking purposes, it is important to distinguish between assets acquired for a non-utility purpose and assets acquired and held for future use in connection with a specific utility project not yet in service because it has yet to be completed.

Assets acquired and held for the purpose of a specific utility project, but not yet in service because the project has not been completed, are utility assets "in the making" and not assets acquired to support non-utility business activities. Under the provisions of the APH, gains and losses on utility assets "in the making" are treated in the same manner as gains and losses on utility assets.

The majority decision fails to distinguish between assets acquired by a utility company to serve a particular utility project purpose and assets acquired to support a non-utility business activity. All of the land at the Fifth Line and Main Street location was acquired by Milton Hydro for a specific utility project purpose. The fact that Milton Hydro put a fence around the portion of the property that it used for outside storage purposes does not alter the fact that the entire property was acquired for a specific utility project purpose.[69] When one utility asset in the making is disposed of at a gain or a loss because of the acquisition of a substitute asset, the gain or loss allocation options available to the OEB include the allocation of all, some, or none of the gain or loss to ratepayers.

Put another way, the OEB's broad discretion over gains and losses realized on assets in service and in rate base extends to assets acquired and held for the purpose of their use in a specific utility project, but not yet in service because the project has not yet been completed.

[68] See footnote 56.
[69] See PO2 Responses, page 20.

While I readily accept that the benefits follow costs allocation principle traditionally applies to capital gains and losses realized on assets acquired to support non-utility business activities, I disagree with the majority that the benefits follows costs principle has any priority status when considering gains and losses on the disposition of utility-specific project assets acquired and held for future use but not yet in service because the utility project has not yet been completed.

The range of allocation options supported by the record under review includes an allocation of all of the gain to ratepayers to defray the increased costs associated with the utility's acquisition of replacement land at a cost greater that the property initially acquired as the location for the utility office/service centre project.

6.5.3 Criteria to be Satisfied to Set Aside an Exercise of Discretion

The question for the Review Panel is whether the discretion to make an allocation of the entire gain to ratepayers exists, and if so, whether the Hearing Panel's asset replacement and project costs defrayal rationale for allocating the entire amount to ratepayers was tenable.

The majority decision accepts that the Hearing Panel had the discretion to make an allocation of the entire gain to ratepayers, but that it should not have departed from the benefits follow costs allocation principle because the asset was not yet in service and in rate base. The majority decision effectively treats the portion of the Property not yet in rate base as an asset acquired to support a non-utility business activity rather than a utility specific project asset not yet in service because the project has not yet been completed.

An example of an OEB exercise of ratemaking power over utility-specific project assets, not yet in service and rate base because the project has not yet been completed, is the Decision with Reasons in EB-2006-0501 dealing with a transmission rates application by Hydro One Networks Inc. That decision found that circumstances related to an inability to complete the construction of the Niagara Reinforcement Project were sufficiently special to warrant an imposition on ratepayers of some of the carrying charges on the millions of dollars that had been spent on the project even though the project was incomplete and not in service.

The OEB's findings in that case, that the discretion exists to impose costs on ratepayers when they are not receiving any benefits from assets acquired for a utility specific project purpose, supports the conclusion that the discretion exists to do the opposite, namely to transmit benefits to ratepayers even though they have incurred no costs in connection with utility-specific project costs that are not in rate base because the project has not yet been completed.

I disagree with the majority's conclusion that the Hearing Panel erred in failing to apply the benefits follow costs allocation approach. This conclusion fails to recognize the distinction between assets acquired to support non-utility business activities, to which the benefits follow costs principle traditionally applies, and assets acquired and held for a specific utility project but not yet in service because the project had not been completed.

The breadth of the OEB's discretion over gains or losses on utility project assets held for future use but not yet in service is the same as the breadth of the OEB's discretion over gains of losses on utility assets in service and in rate base. While the benefits follow costs principle lies within the range of outcomes that the record under review supports, this allocation principle has no presumptive priority status as the majority suggests.

Applying the gain realized on a disposition of a utility asset to defray the increases in costs associated with its replacement has been previously accepted by the OEB and affirmed by the Courts as a legitimate exercise of gain allocation discretion.[70] Extending that rationale to utility assets in the making makes good sense and is compatible with OEB accounting procedures that treat gains and losses on utility assets and utility assets in the making in the same manner. The Hearing Panel's rationale for allocating 100% of the gain to ratepayers is tenable even if the majority does not find that rationale to be compelling.

As an alternative to its conclusion that the Hearing Panel erred in departing from the benefits follow costs principle, the majority finds that the Hearing Panel's gain allocation was unreasonable because it was made without calling for submissions on the issue from Milton Hydro. This is a process concern that has no relevance to the question of whether the entire record under review supports the gain allocation alternative that the Hearing Panel found to be appropriate.

In their submissions, SEC and OEB staff supported the Hearing Panel's decision on the gain allocation issue. LPMA supported Milton Hydro's position on the issue. The process concern that the majority decision expresses does not tilt the scales related to the gain allocation alternatives that the record supports one way or another. Put another

[70] EB-2007-0680, Toronto Hydro-Electric System, at page 27 and *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, (2009), 252 OAC 188, paragraphs 23, 29 and 32.

way, Milton Hydro's position on the gain allocation does not prevail by default because the majority decision has raised a process concern.

As already noted, the process options available to the Hearing Panel, when the request made by Milton Hydro in its reply argument led to the Hearing Panel's consideration of the market value and gain allocation issues, included reconvening the hearing to receive submissions on the issue, or deferring the matter for consideration in a future proceeding or deciding the issue on the basis of the existing record. The Hearing Panel decided to proceed on the basis of the existing record.

I question whether the majority decision can reasonably assert that the Hearing Panel should have called for further submissions from the utility on an issue raised by the utility, for the first time, in its reply submissions. Regardless of that issue and even if there was procedural error in not calling for further submissions on an issue that arose because of relief requested in reply argument, that procedural error has been remedied by calling for submissions on the gain allocation issue in this review proceeding and by inviting Milton Hydro to express its views on the applicability of the relevant APH provisions in the PO2 Responses.

Milton Hydro's reply submissions addressed the gain allocation issue. Milton Hydro has not sought an opportunity to make further submissions on the point. It resisted the efforts of the OEB to schedule a brief oral hearing related to the market value and gain allocation issues. That resistance led to the issuance of Procedural Order No. 2 and the PO2 Responses in which Milton Hydro provided information relating to the applicability of the APH to the gain allocation issue. What more can Milton Hydro say about this issue?

The majority decision does not provide a process remedy for its process concern. A process concern calls for a process remedy. If the majority is not satisfied with the opportunities that Milton Hydro has had to be heard on the gain allocation issue, then the process remedy is to either call for further submissions in this review proceeding; or send the matter back to the members of the Hearing Panel that continue to be OEB members; or direct that the matter be brought forward by Milton Hydro for determination in its next rate case. The majority decision does not adopt any of these process remedies.

The procedural issue that the majority raises has no relevance to a determination of the range of options that the record under review supports. All members of the Review Panel are obliged to objectively apply the criteria reflected in the standard of review and determine whether the allocation made by the Hearing Panel falls within the range of reasonable outcomes supported by the entire record being reviewed.

Milton Hydro has now had its say on the gain allocation issue. In my view, its position that benefits follow costs invariably applies to all assets not yet in rate base lacks merit when the OEB is dealing with gains or losses on utility-specific project assets acquired for future use but not yet in rate base because the project has not yet been completed.

6.5.4 Conclusion

The range of reasonable allocation options available to the hearing panel included the option of following the provisions of the APH to allocate to ratepayers the entire gain on the utility-specific project assets being held for future use, but not yet in service because the project had not been completed.

The Hearing Panel's explanation for selecting that allocation alternative, being that the entire gain on the Property should be applied to defray the costs of its replacement, was tenable.

The majority decision disregards the obligation under the reasonableness standard of review to respect the range of outcomes that the record under review supports. In disregarding the range of discretionary outcomes that the record supports, the majority decision impermissibly substitutes its preferred exercise of discretion for that exercise of discretion made by the Hearing Panel that falls within the range of outcomes supported by the record being reviewed.

6.6 MECHANISM FOR PAYING THE GAIN AMOUNT TO RATEPAYERS

6.6.1 Hearing Panel's Decision

The Hearing Panel's Decision directed that a permanent rate base reduction be implemented to credit ratepayers with the gain on the land not in rate base.
The primary matter of concern is whether the Hearing Panel erred in failing to limit the duration of the gain credit mechanism to the time required to pay no more than the total amount of the gain to ratepayers.

All members of the Review Panel agree with Milton Hydro that the Decision erred in making the duration of the reduction permanent rather than time limited. Ratepayers are entitled to receive the amount of the gain allocable to them, but no more. The Decision shall be varied to achieve that outcome.

6.6.2 Range of Allocation Outcomes Supported by the Record under Review

There were two options available to the Hearing Panel to credit the amount of the gain to ratepayers.

One option was to use a term limited rate base reduction of about $506,000 to effectively credit the gain amount to ratepayers at the rate of $39,400 per year.[71] The duration of this credit mechanism would depend on the dollar amount of the gain allocation to ratepayers.

The other option was to use a revenue offset mechanism of the type specified in the provisions of the APH on which Milton Hydro relies. Under this approach, with an amortization period terminating at the end of Milton Hydro’s 2020 rate year, the annual revenue offset amount in the case of a capital gain amount allocable to ratepayers of $506,000 will be considerably larger than the annual reduction amount of $39,400 that results from a rate base reduction of about $506,000. However, the utility’s obligation to ratepayers will be discharged much earlier than it would be under the rate base reduction approach.

6.6.3 Criteria to be Applied

The reasonableness standard of review calls for the gain credit mechanism to fall within the range of allocation outcomes that the record under review supports. The permanent rate base reduction directed by the Decision falls outside that range and is unreasonable and an error.

6.6.4 Conclusion

The gain credit mechanism for ratemaking purposes must be corrected. I agree with Energy Probe that a shorter payment period better aligns the credit to ratepayers of the gain amount with the 2015 date of its realization.

For these reasons the gain-related rate base reduction embedded in Milton Hydro’s rate base should be eliminated effective May 1, 2018, being the beginning of Milton Hydro’s 2018 rate year. At that time the portion of the gain remaining to be paid to ratepayers

[71] Affidavit, paragraph 10.

should be credited by way of a revenue requirement offset, with any amortization thereof to be completed no later than the end of Milton Hydro's 2020 rate year.

6.7 IMPLEMENTATION

For these reasons I would deny the requested variance of the $2.73 million value amount and the resulting capital gain amount of $506,000 of which Milton Hydro will have paid about $78,800 by May 1, 2018. I would also deny the request to eliminate the allocation to ratepayers of the portion of the gain amount attributable to land not in rate base.

For the two years ending April 30, 2018 Milton Hydro will have credited ratepayers with a sum of about $78,800 under the rate base reduction credit mechanism. This leaves about $427,200 to be paid by way of a three-year amortized revenue offset, or about $142,400 per year for each of the years 2018, 2019, and 2020 in the scenario where the entire gain is allocated to ratepayers.

I would direct Milton Hydro to reduce its rate base by $506,000 effective May 1, 2018 and to include in its revenue requirement for each of the years 2018, 2019 and 2020 an annual revenue requirement offset amount of $142,400.

Original Signed By

Peter C. P. Thompson, Q.C.
Member

RP-2005-0020
EB-2005-0361
EB-2006-0197
EB-2007-0016

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Sched. B.);

AND IN THE MATTER OF an application by Erie Thames Powerlines Corporation for an Order or Orders approving and fixing just and reasonable distribution rates and other charges effective May 1, 2006;

AND IN THE MATTER OF a Notice of Motion by Erie Thames Powerlines Corporation seeking an Order Varying the Decision and Order of the Board in RP-2005-0020 / EB-2005-0361 / EB-2006-0197.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cathy Spoel
Member

DECISION ON MOTION

June 8, 2007

Background

On January 19, 2007, Erie Thames Powerlines Corporation ("ETPC") filed a Notice of Motion ("Motion") with the Ontario Energy Board ("Board") in relation to the Board's Decision and Order dated January 2, 2007 (the "final decision") in the application by ETPC for 2006 electricity distribution rates, under file number RP-2005-0020 / EB-2005-0361 / EB-2006-0197. On February 2, 2007 ETPC filed an amended Motion with the Board.

In the final decision dealing with 2006 rates, the Board set rates effective January 1, 2007, rather than May 1, 2006. In so finding, the Board determined that the delay in implementation was due to the lack of appropriate evidence originally filed by ETPC, which was within the control of management.

The Motion sought an order of the Board which would permit the recovery of foregone revenue of approximately $1,382,644. The Motion also sought correction of an error, amounting to $50,000, between the final decision and the final rate order, relating to allowance for bad debt expense.

On March 28, 2007, the Board issued Procedural Order No. 1 and agreed to hear the amended motion by way of an oral hearing. The School Energy Coalition (SEC) was the only intervenor who participated in this Motion proceeding. A technical conference was held on April 20, 2007 followed by an oral hearing on April 27, 2007.

The Hearing of the Motion

Neither Board Staff nor SEC took issue with the $50,000 relief sought by ETPC relating to bad debt expense.

ETPC argued that the Board's final decision should have accounted for the impact created by the use of an interim order for the period between May 1, 2006 and January 1, 2007. ETPC argued that the rates established by an interim rate order are transitory and cannot be considered final. However, in not making any adjustments to account for the impact of interim rates, ETPC contends that the

Board effectively transformed an interim order into a final order without its knowledge.

ETPC also claimed that in denying the utility the ability to recover its annual revenue requirement, the final decision raised the issue of retroactivity for the first time. ETPC contends that, as a result of the timeframe, it was unable to address this issue. ETPC also noted that the final decision did not permit retroactive rates on the basis that ETPC was solely responsible for the delay. ETPC disputed this as the Board's November 2, 2005 acknowledgment letter indicated that its application was complete, and thus ETPC had no reason to believe that its application would not be processed in time to receive rates effective May 1, 2006. ETPC also argued that the purpose of a rate proceeding is to set just and reasonable rates, not to punish applicants for any perceived shortcomings in their filings.

Board Staff argued that the decision of whether or not to grant retroactive rates for a period of interim rates is entirely at the Board's discretion and not a requirement. Board staff further argued that there was no evidence to indicate that the original panel did not give due consideration to the impact that the interim rate order would have on the utility.

Board Staff took the position that the act of setting interim rates is notice to parties that the issue of rate retroactivity would be addressed in the final rate order. As a result, the Board is not required to give any further notice that retroactivity is an issue where an interim rate order is in effect. Board Staff further argued that no new evidence was brought forth to suggest that the rates set by the Board were either unjust or unreasonable.

Board Staff argued that the Board's order should not be viewed as punishment. The Board's general practice is to not apply rates retroactively where there is a rate increase so as to not harm ratepayers and that the Board has only been inclined to grant retroactive rate orders for rate decreases. Board Staff also noted that ETPC had plenty of notice that audited financial statements for the wires company were required. Therefore, it should not have been a surprise to ETPC that the decision was delayed when the utility did not file these statements as requested.

Board Staff submitted that if the Board were to grant relief to ETPC, a rate rider be implemented for a period of two years, in order to mitigate the rate impact to ETPC's customers.

SEC argued that the Board should deny the relief sought by ETPC, since the final decision set rates that are just and reasonable. However, SEC stated that if the Board decided to re-open ETPC's application based on the issue of retroactivity, then the Board should also reconsider the entire application. It was SEC's submission that, since one of ETPC's grounds for review was that the final rates were not just and reasonable, SEC should be permitted to explore and comment on all of the factors that make up a just and reasonable rate and not be limited to the narrower scope of the review as set out by ETPC. In particular, SEC argued that the issue of affiliate transactions should be reexamined.

Findings

One of the grounds for ETPC's motion is that the January 2, 2007 final rates are in error, in that the rates approved by the Board did not provide for the appropriate level of bad debt expense. On the basis of the evidence adduced, the Board accepts that the rate schedules did not properly reflect the decision in that regard and therefore an error in fact was committed. ETPC's rate schedules should be adjusted to recover an additional annualized amount of $50,000.

Another ground for ETPC's motion is that since ETPC cannot implement the final rates effective on the date they were declared interim, the rates cannot be just and reasonable and therefore, in effect, the Board erred in law.

Counsel to SEC claims that in determining whether the final rates are just and reasonable the Board must in this case broaden its consideration to encompass a review of affiliate transactions, recent financial performance, and rate comparisons with other utilities. The Board does not accept this position. This motion is on the issue of an appropriate effective date. ETPC is not contesting any other matters that underpin the revenue requirement found by the Board. It was open to SEC to file a motion if it wanted to contest the revenue requirement and rates approved by the Board at the time that the Board issued its decision. It did not.

With respect to ETPC's arguments, rates are set so that they generate sufficient revenues on an annualized basis. Once rates are set, they are presumed to be just and reasonable until they are superseded by a further order of the Board. The test period could be a future year, a current year, or a historical year. In this case the test year chosen by ETPC was 2004, as allowed in the Handbook. Rates underpin a utility's revenue requirement. ETPC does not contest the revenue requirement found by the Board in its January 2, 2007 decision, except for the $50,000. The Board agrees with Board staff's submission that the Board is not required to apply final rates retroactively for the period of interim rates. The Board is required to consider what the effective date for the final rates should be; that is to say it must look at each case on its own merits before reaching this decision. The original panel in this case did turn its mind to this issue, and determined that the effective date should be January 1, 2007.

The remaining grounds for ETPC's motion are that there has been a change in circumstances as the final decision transformed an interim order into a final order without ETPC's knowledge, and that there has been also a change in circumstances as ETPC did not receive notice that retroactivity would be an issue. The issue in effect is whether retroactivity should have been an issue and, if so, whether the Board was required to inform ETPC of that.

Having declared the rates interim as of May 1, 2006, the Board's jurisdiction to make the final rate order effective as of that date is not questioned by Board staff or any party. However, as Counsel to Board Staff argued, ETPC is confusing the Board's <u>ability</u> to retroactively change rates with the <u>requirement</u> to do so.

Once the rates were made interim, the requirement is that in the determination of final rates the Board must consider on what date the rates should take effect. The Board has the legal authority to set the effective date at any time from the date rates were set interim forward. The effective date that the Board selects will be determined after a consideration of all the relevant circumstances. The original panel discharged the requirement that it consider the appropriate effective date and used its discretionary powers to rule, with reasons, that the final rates should not be applied retroactively.

Counsel to EPTC relied in part on the Supreme Court's decision in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*,

[1989] S.C.J. No. 68. In that case, the Court held that the tribunal had the power to carry final rates back to the time at which interim rates had been set. The case does not, however, state that the tribunal is *required* to adjust the interim rates retroactively. It is also important to note the full context behind the Bell decision. In the Bell case, the final rates were in fact lower than the interim rates. The purpose of adjusting the rates retroactively, therefore, was to protect the ratepayers who have little or no control over the timing of either the interim of final order. This is not to say that the Board could never adjust rates retroactively where the final order was higher than the interim order.

The determination of an effective date is inextricably linked with a rates proceeding. The Board has no requirement to give notice of its intention to consider retroactivity as it has no requirement to give notice of the fact that it will set rates based on what it finds to be just and reasonable. In any event, the fact that the Board had set interim rates constitutes in effect notice that the effective date would be an issue.

Considerable time was devoted in the hearing on the causes of the delay in processing and hearing the application for 2006 rates.

Every electricity distributor applying for 2006 rates and wishing to use 2004 as a test year was obligated to make an application pursuant to the provisions of the Board's Handbook.

The Handbook specifies that an applicant must submit audited financial statements. In its original application filing of September 6, 2005, ETPC did not include any financial statements. In the Board's acknowledgement letter of September 13, 2005, the Board identified audited financial statements as one of twenty seven items that constituted deficiencies in ETPC's filing. On October 12, 2005, ETPC refiled its application but did not include audited financial statements; it only included Notice to Reader statements. On October 21, the Board issued an acknowledgment letter identifying two additional deficiencies, but it did not repeat the deficiency of the non-filing of audited financial statements. On November 2, 2005, the Board indicated that the application was complete for processing. In its interrogatories dated January 11, 2006, among other requests, Board Staff asked for the production of audited financial statements or to explain why they were not available. ETPC's response to Board

Staff's request was that it does not have stand-alone audited financial statements and included the parent's consolidated financial statements. The Board issued its decision on the application on April 12, 2006, in which it noted the absence of audited financial statements, directed ETPC to prepare audited financial statements within 90 days and re-file an application within 120 days.

ETPC filed utility audited financial statements on July 6, 2006 and filed its new application on August 14, 2006. By letter dated August 25, 2006 the Board identified a number of deficiencies in the August 14 application. ETPC refiled its application on September 16, 2006. By letter dated October 10, 2006 the Board accepted the new application for processing and informed ETPC to expect a decision on or about March 2, 2007. The record, including interrogatories and submissions, was concluded on December 8, 2006. The Board issued its decision on January 2, 2007.

The decision stated (page 6):

> The rates set out in the attached Tariff of Rates and Charges will be effective as of January 1, 2007. The Board notes that the delay in implementation is due to the lack of appropriate evidence <u>originally filed</u> by the Applicant. This delay was within the control of management and therefore there is no justification for the Board to not follow its general policy of not granting retroactive rate increases…[emphasis added]

ETPC had three notices; the first in provision 2.1.3 of the Handbook dated May 11, 2005, the second in the Board's September 13, 2005 letter, and the third through Board Staff's interrogatory on January 11, 2006. It is widely accepted practice, and it is repeated in the Handbook that that the onus is on an applicant to demonstrate that the rates it is seeking are just and reasonable, supported by the appropriate evidence. The fact that the audited financial statements were not materially different from the Notice to Reader information, as argued by ETPC, is not determinative of ETPC's motion. The original panel was in no position to know that at the time it had to make a decision.

Counsel for ETPC noted that electricity distributors may not yet be fully familiar with the Board's process. This is not an excuse, but it is a consideration. It is not fair to unnecessarily burden ratepayers with retroactive charges, regardless of the method of recovery, for a utility's unfamiliarity of rate setting, the very essence of being a regulated monopoly.

Responsibility also lies with the Board itself. It is unfortunate that the Board's November 2, 2005 letter did not repeat the earlier request for stand-alone audited financial statements. The original panel was not made aware of this fact, and this constitutes a new consideration for this panel. Also, the Board itself did not act as quickly as it could have in rendering the new application complete and ready for deliberation.

Given all the circumstances and in balancing the interests of the shareholders and ratepayers, the Board considers it appropriate to vary its January 2, 2007 decision. The Board considers a reasonable effective date to be September 1, 2006. The Board also considers it reasonable for EPTC to recover the foregone revenue over two years, through a rate rider. The rider shall be calculated based on consumption determinants.

ETPC shall file with the Board and serve on intervenors of record proposed rates incorporating the Board's findings, with appropriate documentation, within 7 days from the date of this decision.

Intervenors and Board Staff shall make any submissions within 7 days from the above date.

DATED at Toronto, June 8, 2007.

Original signed by

Gordon Kaiser
Presiding Member & Vice Chair

Original signed by

Paul Vlahos
Member

Original signed by

Cathy Spoel
Member

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

DECISION AND ORDER

EB-2016-0085

INNPOWER CORPORATION

Application for electricity distribution rates and other charges beginning July 1, 2017

BEFORE: Allison Duff
Presiding Member

Lynne Anderson
Member

Michael Janigan
Member

March 8, 2018

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 THE PROCESS 3

3 DECISION ON ISSUES 5

3.1 CAPITAL ADDITIONS 5

3.2 DISTRIBUTION SYSTEM PLAN 6

3.3 RATE BASE – CORPORATE HEADQUARTERS AND OPERATIONS CENTRE 7

3.4 WORKING CAPITAL 12

3.5 COST OF CAPITAL 12

3.6 LOAD FORECAST 13

3.7 REVENUES AND COSTS RELATING TO AFFILIATE - INNSERVICES 14

3.8 OPERATIONS, MAINTENANCE & ADMINISTRATION EXPENSES 18

3.9 PAYMENTS IN LIEU OF TAXES 25

3.10 COST ALLOCATION AND RATE DESIGN 25

3.11 RETAIL TRANSMISSION SERVICE RATES & LOW VOLTAGE RATES 28

3.12 DEFERRAL AND VARIANCE ACCOUNTS 29

3.13 RATE RIDERS 32

3.14 OTHER OPERATING REVENUE 34

3.15 INNPOWER'S COLLECTION PROCESS 38

3.16 EFFECTIVE DATE 40

4 IMPLEMENTATION 42

5 ORDER 43

SCHEDULE A 45

1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) to finalize rates for InnPower Corporation (InnPower) for 2017.

InnPower filed an amended cost of service application with the OEB on May 11, 2017 under section 78 of the *Ontario Energy Board Act, 1998* (Act), for approval to change the rates it charges customers for electricity distribution effective July 1, 2017.

InnPower provides electricity distribution services to approximately 16,000 customers in the Town of Innisfil and the lands located in South Barrie. InnPower was formerly Innisfil Hydro Distribution Systems Limited (IHDSL) incorporated in 2000 with a Board of Directors responsible to the sole shareholder, the Town of Innisfil. IHDSL changed its name to InnPower Corporation in January 2015. InnServices Utilities Inc. (InnServices) was incorporated as a municipal services corporation in 2015 with responsibility for the water and wastewater services formerly provided by the Town of Innisfil. InnPower currently provides the water and waste water billing and financial services for InnServices. InnPower and InnServices also share a CEO.

InnPower proposed to increase its rates based on a projected 2017 test year revenue requirement of $10.955 million. For a typical residential customer with monthly consumption of 750 kWh, the total bill impact would be an increase of about 6.4%.[1]

The OEB hosted two community meetings regarding InnPower's 2017 application in Innisfil on March 9, 2017. Approximately 300 customers attended the meetings, and 41 customers filed written comments. Subsequent to the community meetings, InnPower updated its application by reducing its proposed rate increase and deferring its proposed effective date to July 1, 2017.

The OEB's findings in this Decision are summarized as follows:

- Approved 2017 capital additions of $4.4 million as proposed
- Addition to rate base of $11.141 million for the new Corporate Headquarters and Operations Centre, less accumulated depreciation

[1] As a result of this Decision, the total bill impact will be lower. The updated total bill impact will not be available until InnPower completes its draft rate order

- Approved OM&A budget of $5.317 million, a reduction of $0.673 million to the proposed budget
- Recognition of affiliate revenue of $757,539 and affiliate expenses of $704,939 associated with InnServices

InnPower filed a settlement proposal reflecting a complete settlement for the charge to be applied to other parties attaching to InnPower's poles. The OEB accepts the pole attachment settlement proposal (Schedule A).

2 THE PROCESS

The OEB's policy for rate setting is set out in a report of the OEB entitled *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*[2]. Subsequently, the OEB issued the *Handbook for Utility Rate Applications* (Handbook) which expanded the Renewed Regulatory Framework (RRF) and provides for three alternative rate-setting methods that are available to electricity distributors: Price Cap Incentive Rate-setting (Price Cap IR), Custom Incentive Rate-setting (Custom IR) and Annual Incentive Rate-setting Index.

InnPower filed a Custom IR application on June 6, 2016 to change rates effective January 1, 2017. The OEB found this application to be incomplete. InnPower decided to change its application to a Price Cap IR application, which was filed on November 28, 2016. With the Price Cap IR option, rates for 2017 are set based on a forecast of costs and sales volumes. These 2017 rates are then adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of InnPower's efficiency. This application is for the setting of 2017 rates based on a detailed review of InnPower's forecasts.

The OEB issued a Notice of Application on February 22, 2017 inviting parties to apply for intervenor status. Parties that were granted intervenor status in this proceeding are Rogers Communications Canada Inc. (Rogers), School Energy Coalition (SEC), and Vulnerable Energy Consumers Coalition (VECC).

The OEB hosted two community meetings regarding InnPower's 2017 rate application in Innisfil on March 9, 2017. At the meetings and in written comments, customers expressed concerns about high electricity rates, including some comments regarding InnPower's corporate governance and lack of regard for cost control. Subsequent to the community meetings, InnPower filed an amended application with the OEB on May 11, 2017, reducing its requested rate increase and delaying the effective date for the rates to July 1, 2017.

The OEB issued Procedural Order No. 1 on May 16, 2017, which provided for the filing of interrogatories and responses. Procedural Order No. 2 was issued on May 26, 2017

[2] Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012

to provide further notice of this application for specific customer groups and allow for additional related interrogatories and responses.

Procedural Order No. 3 was issued on September 1, 2017 in which the OEB established a process for developing a draft issues list and set dates for a technical conference and an oral hearing. In addition, the OEB expressed its intent to establish separate procedural steps regarding InnPower's proposed pole attachment and microFIT charges.

An oral hearing was held on October 3rd and 4th, 2017 regarding all issues raised in the application, except for the pole attachment and microFIT charges. Written submissions were filed by SEC, VECC, OEB staff and InnPower.

Pole Attachment and microFIT Charges

In Procedural Order No. 3, the OEB directed InnPower to give further notice of its application to customers or customer groups that would be affected by the proposed pole attachment and microFIT charges. To avoid further delay to the hearing schedule while further notice was served, the OEB established separate procedural steps for the pole attachment and microFIT charges in its Decision and Procedural Order No. 7 issued November 10, 2017.

In its Decision and Procedural Order No. 7 issued on November 10, 2017 the OEB indicated it would not consider a change to the microFIT charge of $5.40. However, the OEB would consider a change to the current pole attachment charge of $22.35. The OEB established a process related to the pole attachment charge for the filing of interrogatories and responses, and a settlement conference.

A settlement conference was convened on January 8, 2018 and January 9, 2018 related to the charge for pole attachments. A settlement proposal was filed by InnPower on February 2, 2018 reflecting a complete settlement (Schedule A). Parties to the settlement proposal are InnPower, SEC, VECC and Rogers. A submission from OEB staff on the settlement proposal was filed on February 9, 2018. The parties to the settlement proposal filed a joint reply submission on February 23, 2018.

3 DECISION ON ISSUES

3.1 Capital Additions

InnPower's actual and forecast capital additions are shown in Table 1.

Table 1 – Net Capital Additions[3]

Actual $'000					Forecast $'000				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
3,818	4,751	5,031	15,263	4,548	4,405	5,176	6,435	5,795	5,768

Table 1 includes the increase in capital contributions for 2017 through 2021, which were updated at the Technical Conference. As a result, the net capital additions (net of capital contributions) for 2017 through 2021 have decreased from the pre-filed evidence. The impact on the 2017 rate base is to lower net capital additions for 2017 by $2.284 million[4]. Five projects in the Distribution System Plan (DSP) that were previously categorized as System Service in 2017 were re-categorized as System Access projects, as they related directly to new subdivision developments. InnPower submitted that capital contributions totaling $2.284 million should have been assessed against these projects. As a result, InnPower's revised net capital addition proposal for 2017 is $4.4 million.

SEC did not object to InnPower's proposed capital additions. However, SEC noted that that the capital spending per customer, excluding the new Corporate Headquarters and Operations Centre, increased by 111% over the last nine years such that InnPower's net capital additions per customer were 56% higher than the industry average in 2016.

VECC sought to have the 2017 capital additions updated to actuals. OEB staff submitted that $4.4 million of capital additions should be approved using an "envelope" approach, and that a more up-to-date forecast of capital additions was not required. OEB staff indicated that the 2017 rate base should be updated for items such as the revised lower cost of power and a higher amount of amortized capital contributions.

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[3] 2017_Filing_Requirements_Chapter2_Appendices TC_20170920. Appendix 2-AB

[4] InnPower_transcript_vol1_TC_20170912, page 87

In reply submission, InnPower stated that if the OEB prefers to use a more up-to-date forecast of capital additions, there should be a comprehensive review of the entire capital program to accurately reflect both increases and decreases. InnPower also indicated that it plans to commence developing a new business plan after this application is completed.

Findings

The OEB approves InnPower's forecast net capital additions of $4.4 million for 2017. While the OEB notes that these capital additions are directionally congruent with the DSP, InnPower will need to review its capital additions and revise the Distribution System Plan to align with expectations arising from the implementation of a new business plan.

3.2 Distribution System Plan

InnPower provided a Distribution System Plan (DSP) as part of its application, including appendices related to its Asset Condition Assessment which was completed by METSCO Energy Solutions (METSCO).

OEB staff submitted that InnPower had not utilized sufficient pacing and prioritization in planning its capital investments and this should be corrected going forward. During the Technical Conference, InnPower confirmed that its pacing and prioritization efforts have been focused on 2017 and not the years beyond 2017. However, InnPower indicated in its reply submission that OEB staff cited little evidence to support this statement of pacing and prioritization.

OEB staff submitted that InnPower should investigate initiatives that could reduce costs, such as non-destructive testing of cables. In its reply submission, InnPower indicated that it is willing to assess the use of non-destructive cable testing as part of its project prioritization process.

Regarding InnPower's Asset Condition Assessment, VECC argued that InnPower's assessment has a problem common among utilities in that the data from which assessments are made is simply plant age, adding little new information to the existing known depreciation life of assets. VECC submitted that METSCO has not completed an assessment of the availability, reliability or relevance of the data provided to it by InnPower. VECC advised that the OEB needs to approach the recommended outcomes in InnPower's DSP with caution and an asset data analysis must be completed by InnPower at the time of its next DSP or Asset Condition Assessment.

In reply, InnPower disagreed that the Asset Condition Assessment was flawed, or in any way misleading.

Findings

The DSP provides useful information to evaluate the performance of the distributor in meeting its performance objectives, and should be updated with the new business plan. This is particularly the case where the evidence of InnPower is that it significantly reduced important System Renewal expenses over the last term. These reductions were ostensibly to accommodate System Access demands and to mitigate potential impacts of distribution rates on customers.

The OEB accepts that METSCO's evidence satisfied concerns about pacing and the asset condition assessment. The OEB expects that InnPower's new business plan and DSP will adhere to the principle of "growth will pay for growth" expressed by its witnesses in this proceeding.

3.3 Rate Base – Corporate Headquarters and Operations Centre

InnPower proposed a 2017 rate base of $53.1 million and depreciation expense of $2.7 million[5].

InnPower submitted that a key component of its revenue deficiency relates to the new Corporate Headquarters and Operations Centre (Building) to be added to rate base in 2017. InnPower provided evidence that the actual total cost of the Building project was $13,491,210. This includes costs of $13,246,704 that were submitted by InnPower in its 2015 Incentive Rate-setting Mechanism (IRM) application[6] which included an Incremental Capital Module (ICM application), as well as an additional $244,506 in Building-related costs for furniture and improvements submitted in this application. InnPower maintains that the need for, and prudence of the Building was approved by the OEB in the ICM application.

[5] October 10, 2017 InnPower_Cross Reference Document_20171011

[6] EB-2014-0086

The OEB’s approval of the Building in the ICM application followed the presentation of a settlement proposal that provided that the amount of $10,896,704 was prudent for inclusion in the ICM (ICM settlement). The revised amount reflected a reduction of $2,350,000 from InnPower’s (then IHDSL) ICM application. The OEB-approved ICM settlement also provided that rental income for space in the Building in excess of InnPower’s requirements would be included to reduce revenue requirement at the time of the next rebasing application on a prospective basis.

InnPower submits that the reduction of $2.35 million in the ICM settlement was made to account for the exclusion of the available rental space in the Building from ICM recovery. InnPower maintains that the OEB’s acceptance of the $10,896,704 in the ICM settlement did not include the rental space. InnPower asserts that its actual costs of $13,491,210 to date for the Building, including the rental space, are prudent.

In this application, InnPower proposes to reduce the Building capital addition allowed into rate base by $2.35 million which they argue is the portion of the Building related to the rental space. The reduced amount would mean that the cost related to the available rental space would not be included in rate base. InnPower proposes to retain all rental revenue and be responsible for rental expenses for this portion of the Building. InnPower also indicated that the actual leasing of the extra space was significantly delayed. A lease was only signed in September 2017, with forecasted leasing revenue dropping to $33,000.

OEB staff submitted that the $2.35 million reduction made as a result of the ICM application should be a permanent adjustment to the capital amount allowed in rate base for the Building, and any rental revenue from surplus space should be used to reduce InnPower’s revenue requirement in accordance with the ICM settlement. In addition, OEB staff rejected the inclusion of further capital additions of $244,506 in rate base which are in excess of the amount in the ICM settlement.

OEB staff’s submission also observed that InnPower had not clearly shown where in its evidence the old building costs had been removed from rate base, which should have been dealt with in accordance with the ICM settlement. OEB staff requested that InnPower confirm in its reply submission that the specific amounts related to the old building were removed from rate base and indicate where in the evidence this reduction is reflected. InnPower did not respond to OEB staff’s requests in its reply submission.

SEC submitted that the OEB should accept the ICM-reduced cost of the Building in rate base as well as InnPower’s proposal to retain revenues for the rental of excess space.

VECC indicated that it technically agreed with OEB staff, but accepted InnPower's approach to the rental space.

Findings

The OEB finds that its decision related to the ICM application (ICM decision) approved the ICM settlement which established the prudence of a specific capital amount of $10,896,704 for the Building. The OEB determines that the $10,896,704 was inclusive of building space available for rent that was and remains in excess of the operational requirements of InnPower.

The ICM settlement approved by the OEB in the ICM decision acknowledged the parties' acceptance of InnPower's need for a new Building. The relevant sections of the ICM settlement fixing the capital cost amount of the Building as prudent for inclusion in the ICM is set out as follows:

> 1c) Prudence
>
> For the purposes of settlement, the Parties agree to an incremental capital reduction of $2,350,000 from the submitted capital amount of $13,246,704. The Parties agree that the revised capital amount of $10,896,704 is prudent considering:
>
> - The current square footage and operational requirements of IHDSL;
> - A reasonable allowance for future staffing growth expected over the next 20 years due to IHDSL's growth predictions; and
> - Reasonable comparisons with industry Distributors who have recently constructed new administration and /or operations facilities (Enersource, Powerstream and Waterloo North Hydro) considering current market construction rates.
>
> As discussed below, administrative and/or operational space that is in excess of IHDSL current requirements will be available for lease. Related leasing income will be included at the time of IHDSL's next rebasing application on a prospective basis. This arrangement provides a means of protecting IHDSL's customers from costs associated with the difference between the utilities needs over time and the total area available at the new Administration and Operations Centre….
>
> 3. What is the appropriate treatment of leasing revenues for the new Corporate Headquarters and Operations Centre?

> In response to OEB Staff IR – 12, IHDSL requested a Deferral and Variance Account ("DVA") to record any leasing revenues it will receive for the new Corporate Headquarters and Operations Centre. The Parties agree that IHDSL will be able to rent/lease any excess square footage at the new Corporate Headquarters and Operations Centre. As of the date of filing, IHDSL is negotiating with two parties for leasing square feet at market rates. It is anticipated that the sites will be leased by July 2015.
>
> IHDSL has indicated that it expects additional OM&A costs for the Corporate Headquarters and Operations Centre, above those incurred at the 2073 Commerce Park Drive facilities (IRR EP 4a – 4b).
>
> For the purposes of the settlement, the Parties agree that since an ICM is intended to recover the revenue requirement associated with capital additions only, there will be no DVA to record leasing revenues during IHDSL's IRM term. IHDSL does agree to include revenue off-sets from leasing revenues in its next Cost of Service or Custom IR application.[7]

The above provisions set out that the reduced ICM amount of $10,896,704 is prudent, reasonable and sufficient considering the square footage and operational requirements of InnPower at the time of the ICM settlement and for 20 years thereafter. This reduced amount also allowed for reasonable space for future staffing growth, and puts the Building costs in line with other distributors' facilities. To alleviate the burden on customers for the cost of the portion of the Building that would not be used by InnPower but could accommodate future growth, it was agreed that rental revenue for that portion of the Building would be included in the next rates application as an offset to revenue requirement.

In this proceeding, InnPower now argues that the $2.35 million reduction to the ICM amount was simply the result of excluding the Building space surplus to its needs that would be available for rent. The OEB cannot accept InnPower's contention as it is not supported by the plain meaning of the relevant sections of the ICM settlement referenced earlier in this Decision. The OEB's finding is also supported by the following analysis:

[7] EB-2014-0086, Decision and Rate Order, Appendix A (Settlement Proposal), December 4, 2014, pages 9 and 12

- Paragraph 1c of the ICM settlement does not indicate that the $2.35 million reduction in Building costs is a result of excluding that amount as the capital cost attributable to the portion of the Building that is available as rental space.
- Sections 1c and 3 of the ICM settlement contemplate revenue from renting out space that is surplus to InnPower's operations as an offset benefitting customers. There is no mention of a condition precedent to recognizing such revenue offsets.
- There is no calculation or rationale in the ICM settlement equating the ICM reduction with rental space costs as justification for the exclusion of the quantum ($2.35 million) from the ICM, nor is there any analysis of the effects on rate base of the potential future use of all or some of the rental space.
- InnPower's position in this application implicitly argues that the prudence of the full Building cost of $13.5 million was accepted by all parties in the ICM application. Such an argument conflicts with the comparison of other distributors' costs referenced in the ICM settlement as a reason for the $2.35 million reduction.
- As the Building was almost completed, total costs, including those for excess space, were largely known at the time the parties were negotiating the settlement proposal, and subsequent approval of the settlement proposal by the OEB.

For the foregoing reasons, the OEB finds that the ICM decision approved the amount of $10,896,704 as prudent for the Building capital additions. This included the cost of any Building space that was not needed for InnPower's current use and was available for lease. Accordingly, rent collected for any space not utilized by the utility, now estimated by InnPower to be $33,000 for 2017, will be a revenue offset until InnPower submits its next rebasing application, at which time it is expected that the revenue offset would be a full year of rental revenue

The OEB adopts the ICM decision as to the need for the Building and the prudent amount to be included in rate base, which was settled at $10,896,704. The OEB also accepts the capital addition of $244,506, less accumulated depreciation, claimed for Building costs incurred over and above the ICM amount found to be prudent. The $244,506 is for furniture and fixtures, costs that were not included in the forecast capital for the ICM. The OEB finds that this amount should be included in rate base along with the $10,896,704, less accumulated depreciation.

The OEB directs InnPower to file a revised 2017 rate base and depreciation expense in its draft rate order to reflect the findings in this Decision, including removal of the specific amounts related to the old building (2073 Commerce Park Drive) from rate base, in accordance with the ICM settlement.

3.4 Working Capital

InnPower proposed to use the OEB’s 7.5% working capital default rate to calculate its working capital allowance.

Findings

The OEB approves InnPower’s proposed use of 7.5% for the calculation of the working capital allowance. The 7.5% is applied to the total of the cost of power plus the OM&A expenses. The OEB accepts InnPower’s cost of power calculation methodology[8] but directs InnPower to update its cost of power for the approved load forecast discussed later in this Decision, and for the Rural or Remote Electricity Rate Protection (RRRP) charge of $0.0003[9]. InnPower is required to file an updated working capital allowance to reflect the cost of power and OM&A expenses approved this Decision.

3.5 Cost of Capital

InnPower proposed a 2017 weighted average cost of capital of 5.58%. No parties objected.

Findings

The OEB approves a 2017 cost of capital of 5.58% as set out in Table 2.

Table 2 – Weighted Average Cost of Capital 2017

	Capitalization Ratio	Cost Rate
Long-term Debt	56.0%	3.57%
Short-term Debt	4.0%	1.76%
Total Debt	60.0%	3.45%
Total Equity	40.0%	8.78%
Total	**100.0%**	**5.58%**

[8] Undertaking J1.7
[9] EB-2017-0234, Decision and Order on RRRP charge and DRP, June 22, 2017

3.6 LOAD FORECAST

InnPower proposed a load forecast of 239.6 GWh but revised it to 239.7 GWh after the Technical Conference, based on actual load and customer counts from January to August 2017. InnPower's load forecast relied on a total loss factor of 1.0731 based on ten years of data from 2007-2016[10]. InnPower submitted that the proposed load, customer forecast, loss factors, Conservation and Demand Management (CDM) adjustments and resulting billing determinants were appropriate.

VECC had no issues with InnPower's final load forecast or its associated methodology, based on actuals to August 2017 and extrapolated monthly values for the balance of the year.

OEB staff submitted that InnPower's loss factor had improved over time and the total loss factor to be used in calculating the forecast of billed energy should be based on the recent five-year average of 1.0604.

OEB staff also noted that InnPower had used the same five-year total loss factor when calculating bill impacts for secondary metered customers at less than 5,000 kW and on its proposed Tariff of Rates and Charges (Tariff). In reply submission, InnPower agreed that OEB staff's proposed change was reasonable.

Findings

The OEB finds it appropriate for InnPower to revise the load forecast for billed energy by using the recent five-year average of 1.0604 for the total loss factor. The OEB finds that losses based on the ten-year average overstates the recent trend in losses and understates the load forecast. In its reply submission, InnPower indicated that this change was reasonable.

The OEB directs InnPower to revise its 2017 load forecast, updating the billed energy forecast by applying a loss factor of 1.0604 to the purchased energy, consistent with undertaking J1.9, for inclusion in the draft rate order.

[10] "Table 3-8 Conversion of Total System Purchases to Total Billed" included in the update to Exhibit 3 reflected in the August 4, 2017 interrogatory responses, file "InnPower Response IRR_EB-2016-0085_20170804 Renamed"

The OEB also approves the five-year average losses to be used for the loss factor for billing purposes. InnPower already included this five-year average on the proposed Tariff, and in calculating bill impacts for secondary metered customers. The loss factors for billing are approved as follows:

Secondary metered customers at less than 5000 kW	1.0604
Primary metered customers at less than 5000 kW	1.0498

The loss factor for primary metered customers is amended from the 1.0480 proposed by InnPower in its proposed Tariff and bill impacts model filed on September 20, 2017. The approved 1.0498 loss factor is calculated as 1% lower than the loss factor for secondary metered customers, consistent with how it was calculated for the previous Tariff.

3.7 Revenues and Costs relating to Affiliate - InnServices

InnServices is the water and waste water utility for the Town of Innisfil and an affiliate of InnPower. InnPower provides services to InnServices for:

- providing the back office for financial services (Financial Services)
- issuing bills, customer care, and collections (Billing Services)

InnPower updated its forecast for revenues from InnServices for Financial Services to $346,309[11], and revenue for Billing Services to $245,000 in an undertaking following the oral hearing[12].

SEC submitted that the annual bill for Financial Services of $346,309 would be substantially higher if costs were allocated fully rather than on an incremental basis. SEC noted that InnPower bills InnServices based on docketed hours spent on the affiliate's work with a standard payroll burden, but no overhead charge for other costs such as work space, computers or administrative support. SEC submitted that the revenue offset for Financial Services should be increased to $550,000.

[11] The $346,309 is the sum of the following:
- $232,198 revenue of Financial Services
- $112,981 additional expected revenue (J1.6)
- $1,130 administrative fee of 1% (other income)

[12] Undertaking J1.6

SEC submitted that the forecasted revenue for Billing Services of $245,000 is too low, creating an unfair subsidy provided by InnPower's electricity distribution customers. SEC calculated that InnPower's billing costs were $1,071,681, yet only $644,733 of this amount was divided between InnServices and InnPower. In addition, SEC argued that there should be overhead costs associated with the labour costs, yet none were allocated to InnServices. SEC submitted that the revenue offset for Billing Services should be increased by at least $100,000.

OEB staff submitted that the 2017 revenue requirement should be updated to include the increased amounts of other revenue proposed by InnPower.

In its reply submission, InnPower reinforced its commitment to ensure all affiliate services were priced appropriately and in accordance with the OEB's *Affiliate Relationships Code*. InnPower acknowledged SEC's submission regarding overhead costs and performed an analysis of all general and administrative expenses forecast in 2017. InnPower identified overhead costs attributable to Financial Services of $40,990 and Billing Services of $125,240, for an additional $166,230 in other revenue from InnServices. InnPower clarified that these overhead amounts were in addition to the additional forecast revenues of $112,981 that were included in the revised $346,309 Financial Services revenue in accordance with Undertaking J1.6. This amendment would result in a total of $757,539 in affiliate revenue[13], including $245,000 of Billing Services revenue that had already been incorporated into InnPower's forecast of other revenue submitted on September 20, 2017[14].

In addition to these revenues, InnPower charges $5,000 rent to InnServices for a couple of employees who occupy space in the office building. InnPower confirmed that the rent is $5,000 for 2017[15], and is based on rates that InnPower bills non-affiliate parties. The revenue for this was included as other operating revenue.

InnPower explained that it used different accounting treatment for Billing Services and Financial Services. Revenue related to Billing Services was included with other revenue. Expenses related to Financial Services were removed from OM&A, rather than included in other revenue (except for a 1% administration fee).

[13] $757,539 = $346,309 for Financial Services + $245,000 for Billing Services + $166,230 (125,240 + 40,990) for additional overhead costs related to Billing Services and Financial Services, respectively)
[14] 2017_Filing_Requirements_Chapter2_Appendices TC_20170920, Appendix 2-H, cell H100
[15] Hearing transcript volume 1, page 123. Based on 7 months, $9,000 per year.

Findings

The OEB finds that InnPower's accounting practices related to affiliate services are inconsistent with the OEB's *Accounting Procedures Handbook*[16] (APH). For example, InnPower accounted for Billing Services and Financial Services OM&A expenses differently. The APH's Uniform System of Accounts requires the use of:

- Account 4375 Revenues from Non Rate-Regulated Utility Operations
- Account 4380 Expenses from Non Rate-Regulated Utility Operations

The OEB is also not clear if InnPower has followed the APH's Article 340, Allocation of Costs and Transfer Pricing.

The net amount from these two accounts is a revenue offset to the revenue requirement. Had InnPower adhered to the APH, non-rate regulated revenues and expenses would be segregated in the above-noted accounts to keep the accounting for the regulated utility clear.

Based on the evidence and InnPower's reply submission, InnPower's proposed 2017 affiliate revenue for Financial Services and Billing Services is $757,539. The OEB approves this amount for inclusion in Account 4375, Revenues from Non Rate-Regulated Utility Operations, as part of other revenue in 2017 as discussed in the OM&A section of this Decision.

The evidence indicates that InnPower forecast $1,087,311 for Account 4375, which includes $245,000 related to Billing Services revenue and $0 related to Financial Services revenue[17]. The OEB directs InnPower in its draft rate order to provide a summary of the updated 2017 amount for Account 4375, reflecting this Decision.

During the oral hearing, InnPower acknowledged that its affiliate transactions were based on incremental costs rather than fully-allocated costs. In its reply submission, InnPower provided an estimate of $166,230 in overhead costs associated with affiliate services. Unfortunately, this information was provided at the close of the record in InnPower's reply submission, without an opportunity for the information to be tested

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[16] Ontario Energy Board Accounting Procedures Handbook, December 2011, Article 220 Uniform System of Accounts

[17] Appendix 2-H, Other Operating Revenue, September 20, 2017

applying fully-allocated costing principles as articulated in the *Affiliate Relationships Code*.

InnPower indicated that it negotiates its service agreements with InnServices. As InnPower and InnServices have the same CEO, the OEB finds any negotiated agreements are inappropriate for the purpose of determining affiliate revenue or expenses. For example, the OEB questions the sufficiency of the 1% administration fee for Financial Services. It also does not appear that InnPower takes into account the use of its assets and a return on its invested capital. For example, while InnPower's breakdown for the cost of issuing bills includes $75,000 for annual maintenance of the Customer Information System (CIS)[18], this cost does not appear to include sharing the cost of owning the CIS (i.e. depreciation and return on the asset), the system used for producing the bills.

The OEB will undertake an audit of InnPower's affiliate transactions to ensure its allocation of costs and approach to costing and applicable revenue complies with the *Affiliate Relationships Code*. The audit will take into consideration guidance on the approach to fully allocated costing previously issued by the OEB[19], in addition to the APH's Article 340, Allocation of Costs and Transfer Pricing. This audit is expected to be completed so that the audit findings are implemented by InnPower prior to the end of 2018. The OEB is not commenting on InnPower's compliance with the *Affiliate Relationships Code* at this time. This proceeding is addressing the rate-making implications.

The OEB directs InnPower to create two new Group 2 variance accounts. The first variance account will record the difference between the approved forecast of affiliate service revenues of $757,539 and actual revenues determined as a result of the audit. The approved affiliate forecast is being used to calculate rates for 2017, yet the variance account will be based on the appropriate actual amount, following the OEB audit results.

[18] Undertaking JT2.3

[19] For example, Guideline G-2009-0300 on Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities which includes Appendix A - Fully Allocated Costing Methodology for Non-Rate Regulated Activities

The second variance account will record the difference between the approved forecast of affiliate service expenses approved in this Decision, as discussed in the OM&A section of this Decision, and the fully-allocated costs as determined by the OEB audit.

These two new variance accounts will start effective January 1, 2018, the effective date of this Decision, and continue until the OEB closes the accounts. The OEB will consider annual dispositions of these two new Group 2 variance accounts as part of InnPower's future Price Cap IR applications.

3.8 Operations, Maintenance & Administration Expenses

InnPower proposed a 2017 operations, maintenance and administration (OM&A) budget of $5.990 million. The proposed budget was 22.5% higher than InnPower's OEB-approved budget in 2013. InnPower's OM&A budgets from 2013 to 2017 are set out in Table 3.

Table 3 – OM&A Budgets 2013-2017 ($'000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Proposed	Increase over 2013 Approved
OM&A	$4,890	$4,995	$5,225	$5,558	$5,689	$5,990	22.5%

InnPower indicated that its historical OM&A increases were in line with customer growth plus inflation, and driven by factors outside of management's control. InnPower submitted that cost controls had been implemented by its new management team and further reductions to OM&A could not be made at this time.

SEC, VECC and OEB staff did not support the OM&A budget proposed by InnPower.

SEC proposed a budget reduction of $0.650 million. SEC submitted that a top-down adjustment was required. SEC compared InnPower to other distributors, focusing on customers per FTE and OM&A per customer using the OEB's 2016 yearbook data. SEC concluded that InnPower had 422 customers per FTE compared to the industry average of 553 and calculated InnPower's 2017 OM&A cost per customer to be $351, which is 28% higher than the average.

SEC submitted that given the size of the affiliate, InnServices, a total cost of $550,000 for a CEO and back office services is a “bargain”. SEC stated that the revenue offsets for Financial Services should be increased (or administrative costs should be decreased, depending on how InnPower proposes to account for it), by $550,000, rather than the $346,309 proposed by InnPower.

VECC proposed an OM&A budget reduction between $0.500 and $0.800 million. VECC submitted that there were no outstanding circumstances to warrant an increase above inflation. However, if an OM&A adjustment was made to reflect customer growth, a reduction of $0.700 million would still be required.

OEB staff proposed an OM&A budget reduction of $0.420 to $0.500 million. OEB staff estimated a reduction of $0.420 million based on an extrapolation of January to July 2017 actuals. OEB staff submitted that a further reduction in OM&A was warranted as InnPower’s revenue deficiency did not appear to be “in touch” with its customers’ concerns regarding high distribution rates.

VECC and OEB staff noted that InnPower’s customers are already paying among the highest distribution charges in the province. High customer rates are demonstrated by InnPower’s inclusion in the Fair Hydro Plan’s Distribution Rate Protection (DRP) program, which is applicable to only eight distributors in the province with the highest rates[20].

In reply submission, InnPower claimed that the parties’ submissions largely ignored cost drivers such as inflation, customer growth and spatial density. InnPower submitted the OEB should also consider exceptional annual OM&A costs, such as the Building cost of $138,713, the increase in cable-locates of $130,984, pension and benefit costs due to IFRS of $60,500 and the OEB assessment cost increase of $19,453.[21]

InnPower also indicated that OM&A costs attributable to InnServices had grown by more than inflation and customer growth, as InnPower was doing more work for its affiliate. InnPower indicated the OEB should consider these costs if the proposed OM&A budget is adjusted. As outlined in the evidence and in InnPower’s reply

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[20] https://www.ontario.ca/page/ontarios-fair-hydro-plan - Lakeland Power Distribution Ltd. (Parry Sound), Atikokan Hydro Inc., InnPower Corporation, Chapleau Public Utilities Corporation, Sioux Lookout Hydro Inc., Northern Ontario Wires Inc., Algoma Power Inc., and Hydro One Networks Inc.
[21] InnPower_ReplySUB_20171113, page 13

submission, the proposed 2017 OM&A budget includes expenses related to affiliate services.

InnPower indicated in undertaking J1.6, that revenues from providing Financial Services to its affiliate InnServices will be $112,981 higher than the original forecast of $232,198. However, InnPower stated that to remain consistent with the original application, this increase needs to be accomplished by a reduction in OM&A of $112,981 as this change was not reflected in the forecast 2017 budget of $5.990 million.

In addition, InnPower reiterated its need to fill three vacant positions as the work still needs to be done, and to address a variety of operational issues that have arisen due to the current understaffing situation. InnPower pointed to increased overtime, increased stress leaves, increased turnover, and the higher costs of subcontractor work, all of which lowers worker productivity and efficiency.

Findings

The OEB approves an OM&A budget of $5.317 million for 2017, which represents a reduction of $0.673 million from the $5.990 million proposed by InnPower. The OEB finds that InnPower's proposed OM&A budget is too high compared to other electricity distributors. One reason for this conclusion is that InnPower incorrectly includes affiliate service expenses in its OM&A budget.

InnPower started the oral hearing with a summary of the staffing challenges it faces and also stated in the argument-in-chief that, "Existing staff are severely strained at current workloads".[22] According to InnPower's witness, Ms. Cowles, from 2016 to 2017, union absenteeism increased by 109%, overtime increased by 59%, staff turnover was 19%, and there were seven stress leave occurrences.[23] Also InnPower noted that 50% of the CEO's time was reallocated to InnServices[24] and three positions remained unfilled.[25]

Given these staffing challenges, InnPower would not appear to have excess operational capacity to leverage.

[22] InnPower_ARGChief_20171006, page 4
[23] InnPower_hearing transcript_Volume 1 Public Redacted_20171003, page 13 & 14
[24] InnPower_hearing transcript_Volume 1 Public Redacted_20171003, page 68 & 69
[25] InnPower_ReplySUB_20171113, page 14

Nevertheless, InnPower and its shareholder decided to proceed with increasing the services provided to affiliates. InnPower is now a provider of Billing Services and Financial Services for InnServices, and is a lessor of rented space for a daycare. InnPower's statement that its staff are severely strained is difficult to reconcile with its willingness to take on more work for its affiliates and others.

The OEB's mandate is to set just and reasonable rates, taking into account the statutory objectives of protecting consumer interests and balancing the needs of the distributor, its customers and its shareholder(s). It is not incumbent (or appropriate) for this regulator, through increased electricity distribution rates, to address the cost pressures and staffing challenges faced by InnPower if they are due in part to the provision of services to its affiliate, InnServices.

The OEB finds it necessary to calculate a revised OM&A budget for the electricity distribution business only before it can assess the reasonableness of InnPower's proposal. InnPower's proposed OM&A budget is a mix of affiliate and distribution expenses, thereby inhibiting the analysis of the stand-alone regulated utility's OM&A costs and trends. All affiliate expenses related to InnServices should be properly allocated and reclassified in Account 4380 (see Revenues and Costs relating to Affiliate – InnServices section of this Decision).

Before taking into consideration any further reductions, the OEB calculates a revised 2017 OM&A budget of $5,517,259 in Table 4, related to electricity distribution only, after eliminating expenses related to affiliate services, based on the evidence and InnPower's reply submission.

Table 4: 2017 OM&A budget related to electricity distribution

Source	**Type of service provided**	**Cost of each service**	**OM&A budget 2017**
OM&A budget proposed by InnPower			$5,990,000
Cost included in $5.990 million	Billing Services	($193,530)	
Overhead costs included in $5.990 million	Billing Services	($125,240)	
Cost of $232,198 already excluded from $5.990 million[26]	Financial Services	No change	
Reduction from OM&A for additional costs[27]	Financial Services	($112,981)	
Overhead costs included in $5.990 million	Financial Services	($40,990)	
Total budget expenses related to affiliate services eliminated from OM&A	Billing Service & Financial Services	($472,741)	($472,741)
OM&A budget revised related to electricity distribution only			**$5,517,259**

Based on the calculations in Table 4, the OEB approves the reallocation of $472,741 of affiliate service expenses from OM&A to Account 4380, as calculated by the OEB

[26] Undertaking J1.6 and InnPower's Reply Submission, paragraph 41
[27] Undertaking J1.6

above. The OEB also approves the inclusion of $232,198 of Financial Services expenses in Account 4380. This amount had already been removed from OM&A by InnPower. A total of $704,939 will be included in Account 4380 Expenses from Non Rate-Regulated Utility Operations for Billing and Financial Services.

The evidence indicates that InnPower's forecast for Account 4380 is $983,861, which includes $145,500 for "Miscellaneous Non-Utility Water"[28]. The OEB cannot reconcile this amount with the $193,530 of costs for Billing Services in undertaking J1.6. The OEB directs InnPower in its draft rate order to provide a summary of Account 4380, including the reclassifications required to reflect this Decision.

Based on the $5,517,259 revised OM&A budget related to electricity distribution only, the OEB expects InnPower to find an additional $200,000 in OM&A savings through efficiencies in its electricity distribution business. InnPower is poised to do so. It has a new CEO, a new management team, a growing customer base and a pending Business Plan. This is an opportunity for InnPower to assess and align its operating structure and processes to meet the needs of its future customers. The OEB approves an OM&A budget of $5.317 million for 2017.

As a secondary check to assess the reasonableness of this OM&A budget of $5.317 million, the OEB did an envelope analysis of the expected total increase from 2013 to 2017 using the following steps.

<u>Step 1</u>

The 2013 approved OM&A budget of $4.890 million was adjusted to exclude Billing Service expenses of $190,269[29] which were included in the approved budget.

<u>Step 2</u>

From 2013 to 2017, an adjustment of 10.2% was applied as follows:

- OEB's Price Cap IR inflation of 7.3%
- Pacific Economics Group Research, LLC (PEG) estimated increase due to customer growth of 4.1%
- InnPower's stretch factor of -1.2%

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[28] Appendix 2-H Other Operating Revenue, September 20, 2017

[29] InnPower Reply Submission, p. 11

<u>Step 3</u>

The OM&A increase of $138,713 related to the new Building, an amount referenced in the approved ICM settlement proposal was added.

The OEB did not find the other expenses identified by InnPower in its reply submission to be exceptional for inclusion in the analysis. The calculated 2017 OM&A budget is provided in Table 5.

Table 5: OM&A calculated increase from 2013 to 2017

Steps	Source	OM&A adjustments	OM&A
Step 1	2013 OEB-approved budget	$4,890,000	
	Remove 2013 expenses related to affiliate for comparison purposes	(190,269)	**$4,699,731**
Step 2	10.2% increase for inflation, customer growth minus stretch from 2013 to 2017	$479,373	$5,179,104
Step 3	Add annual expense increase related to the Building	$138,713	**$5,317,817**
Result	Expected OM&A increase in 2017 from 2013 OEB-approved (with affiliate expenses removed)	$618,086	13%

In calculating a reasonable expected OM&A in 2017, the OEB did not use InnPower's customer growth rate of 9.4%. The OEB does not agree that OM&A costs should be driven in lockstep with customer growth rates. To do so would be inconsistent with the OEB's expectation that distributors find efficiencies and strive for continual improvement. Accordingly, the OEB used the PEG adjustment of 0.44%[30] for every 1% of customer growth in this calculation. The resulting 2017 calculated OM&A budget of $5,317,817 mirrors the approved budget of $5.317 million.

Accordingly, for the reasons set out above, the OEB approves an OM&A budget of $5.317 million for 2017 for rate-setting purposes.

3.9 Payments In Lieu of Taxes

InnPower initially requested 2017 Payments In Lieu of Taxes (PILs) of $146,808 in its May 2017 amended filing, then updated its request to $165,450 in the September 20, 2017 filing. This revision was made by updating the return on equity that is incorporated into taxable income and increasing capital cost allowance (CCA). No parties objected to the 2017 test year PILs of $165,450.

Findings

The OEB directs InnPower to update its 2017 test year PILs provision to reflect the OEB's findings in this Decision.

3.10 Cost Allocation and Rate Design

InnPower submitted that its proposed cost allocation methodology, allocations and revenue-to-cost ratios are appropriate. InnPower also submitted that its proposals for rate design are appropriate.

With respect to the transition to fixed rates for Residential customers, InnPower proposed to extend its transition period from four to five years. All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB's residential rate design policy stipulates that distributors will transition residential

[30] Report of Pacific Economics Group Research, LLC, Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, May 2013, Table 19, Customers Industry Average 2002-2011 of 0.44

customers to a fully fixed monthly distribution service charge over a four-year period, beginning in 2016[31].

The OEB expects an applicant to apply two tests to evaluate whether mitigation of bill impacts for customers is required during the transition period. Mitigation usually takes the form of lengthening the transition period. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10th percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

InnPower calculated a fixed charge increase of $4.71 over a four-year period which exceeded the $4 increase test established by the OEB. Over a five-year period the proposed increase would be $3.53.

With respect to the GS > 50kW class, InnPower proposed to maintain the same fixed-variable split that informed the rate design in the previous cost-of-service settlement agreement[32], updated to reflect 2016 approved rates, resulting in a fixed charge increase to $229.34. InnPower submitted that this approach has been previously approved by the OEB.[33]

VECC, SEC and OEB staff disagreed with the increase in the fixed charge for the GS > 50kW class.

VECC submitted that InnPower's proposed split did not reflect the current fixed-variable split or the split in the settlement agreement. VECC submitted that the fixed charge for the GS > 50kW class should be maintained at $151.60 as it already lies beyond the upper boundary of OEB policy.

OEB staff also submitted that the existing fixed charge for the GS > 50kW class should be maintained at $151.60. OEB staff indicated that the existing fixed charge was

[31] OEB Policy – A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410, April 2, 2015

[32] EB-2012-0139

[33] In page 32 of the reply submission, InnPower referred to the following cases: Horizon Utilities Corporations' 2015 rate decision (EB-2014-0002), as well as in EB-2012-0113, EB-2011-0293, EB-2011-0319, EB-2010-0131, EB-2010-0132 and EB-2010-0135.

already above the ceiling and should not be increased. SEC stated that the fixed charge for GS>50 should be set at the 2016 level, and not increased.

In its reply submission, InnPower argued that the parties' submissions regarding the GS>50kW fixed rate were based on a misreading of Section 2.8.1 of the Chapter 2 filing requirements and are not consistent with the OEB's practice as it relates to rate design, as set out in other OEB decisions.[34]

InnPower indicated that if the OEB reduces the fixed rate for the GS>50kW class to $151.60, this would reduce the fixed component of the fixed/variable split from 22.95% to 15.5%. InnPower stated that this change would be in the wrong direction, as the vast majority of distributor cost drivers are fixed, and such a move contradicts the OEB's general policy with regards to the fixed cost drivers.

Findings

The OEB approves InnPower's proposed cost allocation methodology. The OEB approves InnPower's rate design proposals with one exception.

With respect to the proposed five-year transition to fixed rates for the residential class, the OEB finds it unnecessary to extend InnPower's transition period beyond four years. Given the reductions in revenue requirement approved in this Decision, the OEB expects the resulting increase to the fixed charge to be close to $4. The OEB prefers to adhere to the four-year transition period, as it was previously approved and aligns with the transition period for most electricity distributors in Ontario. InnPower is directed to update its rate calculation in the draft rate order to reflect three remaining years of transition.

With respect to the proposed GS >50kW fixed rate, the OEB approves InnPower's proposal to maintain the current fixed-variable split that results from 2016 approved rates. Maintaining the fixed-variable split results in an increase to the fixed charge which is consistent with the approach approved in past OEB decisions including the Horizon Utilities Corporation 2015 rate decision[35].

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[34] On page 32 of its reply submission, InnPower referred to the following decisions: Horizon Utilities Corporations' 2015 rate decision (EB-2014-0002), as well as in EB-2012-0113, EB-2011-0293, EB-2011-0319, EB-2010-0131, EB-2010-0132 and EB-2010-0135.

[35] EB-2014-0002

3.11 Retail Transmission Service Rates & Low Voltage Rates

InnPower is fully embedded within Hydro One Networks Inc.'s (Hydro One's) distribution system. Hydro One is therefore the host distributor to InnPower. As a result, InnPower pays to Hydro One host-Retail Transmission Service Rates (RTSRs) charges for transmission services and low voltage service charges for distribution services. InnPower passes the cost of these services to its customers through its own RTSR and Low Voltage (LV) charges.

Neither VECC nor SEC made submissions with respect to the proposed RTSRs or LV rates. OEB staff did not make a submission on the LV rates. For the RTSRs, OEB staff submitted that the RTSRs, as updated, are acceptable, but should be updated if any new Uniform Transmission Rates (UTRs) are approved by the OEB. In its reply submission, InnPower agreed it was appropriate to update the RTSRs if new UTRs are approved.

Following the Technical Conference, InnPower filed an updated model that calculates proposed RTSRs based on the most recent host-RTSRs that have been approved for Hydro One, as shown in Table 6.

Table 6: Hydro One Networks Inc. Sub-Transmission Host-RTSRs[36]

Current Applicable Sub-Transmission Host-RTSRs (2017)	per kWh
Network Service Rate	$3.1942
Connection Service Rates	
Line Connection Service Rate	$0.7710
Transformation Connection Service Rate	$1.7493

OEB staff submitted that the updated RTSR model was acceptable.

Findings

InnPower's proposed RTSRs filed following the Technical Conference are approved. These RTSRs were adjusted to reflect the current host-RTSRs charged by Hydro One.

[36] Decision and Order, EB-2016-0081, December 21, 2016

While new UTRs have been approved by the OEB, InnPower is fully embedded within Hydro One's distribution system and new host-RTSRs have not yet been approved for 2018.

Cost differences resulting from the approval of new host-RTSRs from Hydro One will be captured in Accounts 1584 and 1586 for future disposition.

The LV charges proposed by InnPower are approved. InnPower used an average of costs over four years (2012 to 2015) and adjusted for projected load growth. Cost differences resulting from the approval of new LV charges from Hydro One will be recorded in Account 1550 for future disposition.

The OEB notes that InnPower accumulated a debit balance in Account 1550 in both 2015 and 2016. This means that InnPower has been collecting less from customers for LV charges than it has paid to Hydro One. If this trend continues, InnPower should propose an update to its LV rates as part of a future IRM application, rather than waiting to adjust the rates in its next cost of service rate application.

3.12 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 over-collected money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the under-collected 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.

InnPower is seeking disposition of its deferral and variance accounts (DVAs) as at December 31, 2015, with interest projected to December 31, 2016. During the oral hearing, OEB staff questioned InnPower's approach to allocating costs between regulated price plan (RPP) and non-RPP customers and the resulting balances in Account 1588 RSVA Power and Account 1589 RSVA Global Adjustment.

In its response to undertaking J1.8, InnPower withdrew its request to dispose of Accounts 1588 and 1589. InnPower proposed to perform a reconciliation and true up of the allocation of the Global Adjustment charges and to adjust Accounts 1588 and 1589. InnPower stated that it would request disposition of Accounts 1588 and 1589 at its next IRM rate application. InnPower also withdrew is request for disposition of $26,651 in

Account 1568 Lost Revenue Adjustment Mechanism Variance Account, as well as the removal of certain Z-factor amounts recorded in Account 1572 Extraordinary Event Costs of approximately $296k. With its Argument-in-Chief, InnPower filed an updated continuity schedule for its DVAs. This included Group 1 and Group 2 balances, excluding Accounts 1568, 1572, 1588 and 1589. VECC and OEB staff both found InnPower's proposal acceptable.

OEB staff submitted that InnPower should provide a report of its analysis and adjustments made to Accounts 1588 and 1589. OEB staff was of the view that a Special Purpose Audit of InnPower's Account 1588 and Account 1589 should be conducted. VECC qualified its acceptance by saying that InnPower should address and resolve the discrepancies and clarifications raised by OEB staff.

Findings

The OEB approves the disposition of the Group 1 balances as of December 31, 2015 with interest projected to December 31, 2017, with the exception of Accounts 1568, 1572, 1588 and 1589. The approved balances with interest projected to December 31, 2016 are provided in Table 7, and are based on the continuity schedule filed by InnPower as part of its Argument-in-Chief. As part of the draft rate order process, InnPower is expected to update balances for interest projected up to the effective date of the disposition rate riders, December 31, 2017.

Table 7 – Approved DVA balances with interest to December 31, 2016[37]

Group 1	**Account No.**	**December 31, 2015 balances with interest projected to December 31, 2016**
LV Variance Account	1550	307,729
Smart Metering Entity Charge Variance Account	1551	(5,532)
RSVA - Wholesale Market Service Charge	1580	(535,257)
RSVA - Retail Transmission Network Charge	1584	94,572
RSVA - Retail Transmission Connection Charge	1586	188,124
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(352)
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	6,711
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	104
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(13,803)
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	203,730
Total of Group 1 Accounts Approved for Disposition		**246,026**

Group 2	**Account No.**	**December 31, 2015 balances with interest projected to December 31, 2016**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	11,929
Other Regulatory Assets - Sub-Account - Other	1508	2,565
Retail Cost Variance Account – Retail	1518	61,171
Retail Cost Variance Account – STR	1548	26,247
Total of Group 2 Accounts Approved for Disposition		**101,912**

While it is generally preferable to dispose of all Group 1 balances together, it is most important that balances are accurate. Therefore the OEB accepts InnPower's proposal to withdraw its request to dispose of the balances in Accounts 1588 and 1589 pending its review of these accounts. It is also important that balances are disposed on a timely basis. The OEB will therefore permit the other Group 1 balances to be disposed now since they are 2015 balances and it is now 2018.

The OEB policy is to only dispose of Group 2 accounts in a cost of service application. It is therefore appropriate to dispose of these balances in this proceeding.

[37] Final balances will include interest to December 31, 2017

InnPower confirmed in it response to interrogatory 9.0-Staff-59 that it is foregoing its recovery of the Account 1568 balance accumulated to December 31, 2015 and the Z-factor amount recorded in Account 1572, not just deferring recovery. InnPower is expected to record balances in Account 1568 from January 1, 2016 onwards for future consideration.

The OEB approves two new variance accounts to start effective January 1, 2018, as discussed in the Revenues and Costs Relating to Affiliate – InnServices section in this Decision, as follows.

- Account 1508 –Other Regulatory Assets, Sub-account Difference in Revenues from Affiliate Services
- Account 1508 – Other Regulatory Assets, Sub-account Difference in Expenses from Affiliate Services

The OEB directs InnPower to include draft accounting orders for these two new accounts in its draft rate order.

3.13 Rate Riders

InnPower had three rate riders approved in its ICM Application[38] with expiry dates of December 31, 2016:

- Rate Rider for Recovery of Incremental Capital - fixed charge
- Rate Rider for Recovery of Incremental Capital - volumetric charge
- Rate Rider for Disposition of Capital Gains

InnPower also had two rate riders approved in its 2016 Price Cap IR application[39] with expiry dates of December 31, 2016:

- Rate Rider for Disposition of Deferral/Variance Accounts (2016)
- Rate Rider for Disposition of Global Adjustment Account (2016)

InnPower indicated that it has continued to collect the ICM rate rider through 2017 consistent with the terms of the rate order declaring its rates interim effective January 1,

[38] EB-2014-0086
[39] EB-2015-0081

2017. InnPower proposed that a final reconciliation of these rate riders be included with its next Price Cap IR application.

OEB staff submitted that the rate rider reconciliation should be completed as part of this proceeding.

OEB staff noted that as the new rates will reflect the new Building in rate base for the first time, InnPower should show detailed calculations in its draft rate order. OEB staff submitted that if any amounts have been over recovered, InnPower should propose a rate rider to refund amounts to customers. OEB staff indicated that if InnPower prefers the balances to be audited as part of its annual financial statement audit, any refunds may be deferred to a future Price Cap IR proceeding.

Findings

The OEB finds that InnPower incorrectly continued to charge these rate riders after the approved expiry dates. The rate order declaring rates interim should not override a pre-approved rate rider expiry date. In addition, rates were declared interim the day after the expiry dates for the rate riders.

In a letter dated January 9, 2018 (letter), the OEB indicated that it expected InnPower to end three of the rate riders which continued in 2017, effective December 31, 2017. InnPower confirmed it ended the rate riders effective December 31, 2017. In particular:

- Rate Rider for Disposition of Capital Gains
- Rate Rider for Disposition of Deferral/Variance Accounts (2016)
- Rate Rider for Disposition of Global Adjustment Account (2016)

In the letter, the OEB explained that as these rate riders were established to dispose of specific approved account balances, and money was either over collected or over refunded to customers. To address this issue, the OEB directs InnPower to transfer any over refunded balances with respect to capital gains to a sub account in Account 1595 for future disposition. To the extent there has been an over or under collection of the 2016 DVA and 2016 Global Adjustment balances, the residual balances in Account 1595 can be addressed in a subsequent application.

The remaining two rate riders that continued past December 31, 2016 related to incremental capital approved in the ICM proceeding. These rate riders provided rate relief to InnPower until its rates were rebased. In this application, InnPower proposes to add the related assets to rate base and earn a return through base rates in the revenue requirement calculation.

The OEB directs InnPower to use the net book value of the associated net ICM assets on the effective date of this Decision as the addition to rate base.

On the effective date, the incremental capital rate riders should have been displaced by the return provided through the new base rates. To the extent that the rate riders continued to be charged after the effective date, this amount should be considered in the forgone revenue calculation.

The OEB does not find it necessary to true-up the ICM rate riders. A true up would reconcile any difference between the actual and expected revenue collected through the incremental capital rate riders. A true-up was not proposed by InnPower and there is no evidence to indicate the difference would be material.

3.14 Other Operating Revenue

Specific Service Charges

InnPower proposed to increase four of its specific charges included in other operating revenue. InnPower described these charges in its Argument-in-Chief as follows:

(a) An increase in the “Disconnect/reconnect charge – at meter- during regular hours” charge from $40 to $65 to better reflect current contractor average costs for disconnects/reconnects.

(b) An increase in the “Temporary Service – Install & Removal – Underground – No Transformer” charge from $300 to $468, to better reflect actual costs associated with both the install and removal portions of the activity.

(c) An increase in the “Temporary Service – Install & Remove – Overhead – No Transformer” charge from $500 to $632, to better reflect the actual costs associated with both the installation and removal activities.

(d) An increase in the “Temporary Service – Install & Remove – Overhead – With Transformer” charge from $1000 to $2525, to better reflect the actual costs associated with both installation and removal activities.

OEB staff had no issues with the proposed changes to the specific service charges.

Findings

The OEB approves the increase in the Disconnect/Reconnect charge from $40 to $65. Consistent with the Distribution System Code (DSC), this charge should only apply upon the reconnection of a service that has been disconnected. In approving the increase, the OEB notes that most distributors have a Disconnect/Reconnect charge of $65, as this was the generic charge set by the OEB within the *2006 Electricity Distribution Rate Handbook* (2006 Handbook). InnPower will therefore have a charge consistent with most other distributors.

The OEB approves the increase to the three charges for Temporary Services. The OEB has previously approved Temporary Service charges for Hydro Ottawa[40] and Toronto Hydro[41] that exceed the new charges proposed by InnPower.

<u>MicroFIT Charge</u>

In its application, InnPower proposed to change its microFIT charge from $5.40 to $10 but later withdrew this request. In its Decision and Procedural Order No. 7 issued on November 10, 2017, the OEB agreed to retain the charge at $5.40, which is the provincial-wide charge calculated by the OEB.

Findings

The microFIT charge is approved on a final basis to remain at $5.40 per month.

<u>Pole Attachment Charge</u>

InnPower also sought to withdraw its request to increase its pole attachment charge from the current charge of $22.35 per pole per year. The OEB denied this request in its Decision and Procedural Order No. 7, and established separate procedural steps regarding the pole attachment charge.

The OEB has initiated a generic policy review of pole attachment charges that is considering the methodology to be used for determining pole attachment charges. The OEB’s current methodology was established in a 2005 decision in the RP-2003-0249

[40] EB-2016-0084

[41] EB-2014-0116

proceeding (2005 Decision). At the time of Procedural Order No. 7, the OEB had not established any new policy direction and the OEB stated that it would be guided by the 2005 Decision until any new methodology is determined. InnPower was ordered to file new evidence based on the current methodology.

On December 18, 2017, the OEB issued a draft Report of the Board Framework for Determining Wireline Pole Attachment Charges[42]. This described a new methodology for determining pole attachment charges (Draft New Methodology). The OEB has not issued a final report at this time.

InnPower reached an agreement with the intervenors on the pole attachment charge and filed a settlement proposal with the OEB for its consideration (pole attachment settlement proposal). The parties agreed to a pole attachment charge of $38.82, not including a charge for vegetation management. Parties also agreed that the forecasted revenue from the charge would be $269,217.

The parties to the pole attachment settlement proposal agreed to use the current methodology from the 2005 Decision[43] in the calculation of the new rate. There is an existing joint-use agreement between Rogers and InnPower that allows InnPower to charge an amount for vegetation management. InnPower and Rogers have agreed “to meet and discuss an appropriate approach to facilitate InnPower to begin charging for the provision of vegetation management services pursuant to the terms of the existing joint-use agreement going forward”. The pole attachment settlement proposal makes provision for a deferral account to record “revenues received by InnPower prior to its next cost of service application for the provision of vegetation management services”.

OEB staff raised a number of concerns about the accuracy of costs and data used in the calculation of the rate in the pole attachment settlement proposal. OEB staff recommended that the OEB not accept the pole attachment settlement proposal.

The parties filed a joint reply and argued that the costs for a smaller distributors like InnPower might reasonably be expected to differ from the costs of larger distributors that were used in the calculation of the rate using the Draft New Methodology.

[42] EB-2015-0305

[43] As modified in the EB-2015-0004 proceeding for Hydro Ottawa and the EB-2015-0141 proceeding for Hydro One

Findings

The OEB accepts the pole attachment settlement proposal (Schedule A). It does so with the expectation that InnPower and Rogers will reach an agreement on a charge for vegetation management under the terms of the joint-use agreement. InnPower is expected to adhere to any requirements that the OEB may establish for the tracking of costs related to pole attachments, including the setup of new sub-accounts.

The OEB has not yet finalized a new policy with respect to pole attachments, and evidence was filed in this proceeding using the methodology from the 2005 Decision, as ordered by the OEB. Given this unique circumstance of timing, the OEB accepts the methodology adopted by the parties to calculate a new charge. The OEB's acceptance of this pole attachment settlement proposal should not be understood as approving this methodology for use by InnPower in its next rebasing application.

In accepting this pole attachment settlement proposal, the OEB notes that the forecast revenue resulting from the new charge is $269,217, which is a 67% increase from the actual revenue of $161,207 received from pole attachments in 2015. Furthermore, the difference between the $269,217 in forecast revenue resulting from the pole attachment settlement proposal and the revenue that would result from using the charge from the Draft New Methodology (with the component for vegetation management removed for comparison purposes) would not exceed InnPower's materiality threshold, calculated to be $61,927 in the application.

It is unclear the extent to which any data issues exist. The OEB expects that there will be requirements resulting from the OEB's policy review for InnPower to track costs going forward. This will ensure that any data issues are resolved for the next time that InnPower rebases.

InnPower shall file a draft accounting order as part of the rate order process for the deferral account for revenue from vegetation management services, consistent with the terms within the pole attachment settlement proposal.

Other Income

As outlined in the evidence and in InnPower's reply submission, the proposed 2017 other operating revenue budget includes revenues related to affiliate services. Findings with respect to the costs and revenue for affiliate services are elsewhere in this Decision.

Findings

The OEB approves the remaining items of revenue forecast by InnPower and itemized in Appendix 2-H.

The OEB directs InnPower to include $33,000 in Rent from Electric Property in other operating revenue for the rent related to the leased portion of the Building in 2017, as discussed in the Rate Base - Corporate Headquarters and Operations Centre section earlier in this Decision. The expected rent for the remaining four months of 2017 is $33,000.

InnPower should also update Appendix 2-H to reflect the OEB findings in the Revenues and Costs relating to Affiliate – InnServices section of this Decision.

3.15 InnPower's Collection Process

At the community meetings held by the OEB on March 9, 2017, and through letters of comment from customers, concerns were raised about InnPower's collections process, particularly disconnection procedures. In the OEB staff Summary of Community Meeting report issued on May 2, 2017, OEB staff reported that: "Several participants described their experiences with InnPower's disconnection procedures, which they found to be unduly aggressive. Several comments also indicated dissatisfaction with customer service."

VECC reiterated these concerns and stated that it was concerned with InnPower's practices around disconnection notices, electricity shut-downs, late payments, and the associated fees. VECC described InnPower's late payment and collection policy as "harsh and restrictive" and submitted that the OEB should require InnPower to allow customers to carry a minimum of one month's balance (with late payment interest applying).

Findings

The OEB directs InnPower to undertake a review of its collections process including the timing and nature of notices, taking into consideration the feedback from its customers. The OEB also requires InnPower to document this process in its Conditions of Service.

The OEB is concerned that InnPower has not provided descriptions of its miscellaneous charges either in its evidence or in its Conditions of Service. InnPower may be relying on the 2006 Handbook for its description of charges, because at the oral hearing

InnPower referred to its use of a “standard charge” from the “rate application process handbook”. The 2006 Handbook was established for the setting of 2006 rates and should not be relied upon as OEB policy. However, given that InnPower has provided no other description for its specific service charges, InnPower’s Tariff of Rates and Charges will need to be based on the descriptions from the 2006 Handbook until it next rebases, or until the OEB issues new guidance with respect specific service charges.

Both InnPower’s customers and VECC raised concerns about InnPower’s collections process. InnPower responded that its practices are in strict compliance with the OEB’s DSC.

The OEB will not comment on InnPower’s compliance with the DSC, other than to note that InnPower’s Conditions of Service does not include the business process it uses to disconnect and reconnect consumers, as is required by the DSC.

On its current Tariff of Rates and Charges, InnPower has a $15 charge for “Collection of account charge - no disconnection”. However, during the oral hearing, InnPower explained that the $15 charge was for the delivery of a disconnection notice. The OEB questions if there is an inconsistency between the tariff sheet description and the application of the fee.

The goal of the customer visit should be to collect payment on an account, or to arrange payments, so that a disconnection is not required. InnPower must reflect on its objective and terminology as it conducts its collection process review.

The OEB is conducting its own review of distributors’ customer service policies[44]. The first phase of that review is examining:

- Disconnection for non-payment
- Billing and payments
- Arrears management programs
- Security deposits including criteria for waiver and refund
- Service charges relating to nonpayment of accounts

InnPower will need to take into consideration any new OEB customer service policies as it reviews its collections process.

[44] EB-2017-0183

3.16 Effective Date

InnPower proposed an effective date of July 1, 2017 for its new rates. InnPower submitted that given the Government of Ontario's announcement of a 25% Fair Hydro Plan reduction of electricity bills was made one week before InnPower's Community Day, there was confusion among customers about the relationship between InnPower's rate application and the government announcement.[45] InnPower submitted that many customers were upset at the Community Day, which was beyond management's control. In response to the feedback from customers, InnPower amended its application in May 2017 on issues applicable to the rate application which were within InnPower's control.[46]

Both VECC and OEB staff noted OEB decisions approving an effective date of the first of the month following issuance of the decision. Both parties declined to urge that the OEB follow this precedent in the event of a significant reduction to InnPower's OM&A, proposing an effective date of October 1, 2017 instead.

SEC argued that the effective date should be the first of the month following the rate order. SEC submitted that the customers of InnPower are already faced with a substantial rate increase and an additional rider to recover the retroactive component of that rate increase would be a further burden to customers already paying high rates.

Findings

The OEB approves an effective date of January 1, 2018 for InnPower's new rates. The OEB finds many of the delays in this proceeding were within the control of InnPower's management. The OEB finds that the timing of the Fair Hydro Plan's announcement was coincidental, yet InnPower's customers had many other issues with existing distribution rates and services, as expressed to the OEB at the Community Day and through letters of comment.

The OEB finds January 1, 2018 to be appropriate as its approvals are based on a full year of expenses, revenues and rate base. The OEB also finds merit in establishing new rates at the start of InnPower's fiscal year given that the net book value of the Building is added to rate base. The capital gains rate rider and DVA rate riders also

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[45] InnPower_ReplySUB_20171113, page 36-37
[46] InnPower_EB-2016-0085_Amended Application_20170508, page 3

ended on December 31, 2017. The OEB notes that January 1, 2018 is two months after InnPower's reply submission was filed on November 13, 2017. InnPower's reply submission included new information and rate making proposals that the OEB considered in its Decision.

The forgone revenue resulting from an implementation date for the approved new rates subsequent to the effective date of January 1, 2018, will be addressed through the draft rate order process as explained in the Implementation section of this Decision.

4 IMPLEMENTATION

The OEB directs InnPower to incorporate the cost consequences of the findings in this Decision in its revenue requirement calculations for 2017 in its draft rate order.

The OEB expects InnPower to file detailed supporting material showing the impact of this Decision on the overall revenue requirement, the allocation of revenue requirement to its rate classes, the derivation of base rates, the determination of the final rates and rate riders, including bill impacts.

InnPower's draft rate order should include a revised Tariff of Rates and charges reflecting this Decision, and including updates to the RRRP charge, loss factors, DVA rate riders, etc.). In addition, the Smart Metering Entity Charge was set at $0.57 by the OEB, effective January 1, 2018 to December 31, 2022[47]. The Tariff of Rates and Charges should be adjusted to incorporate this rate.

InnPower's draft rate order should also include draft accounting orders for the three new variance accounts approved in this Decision.

The implementation date for new rates will be subsequent to January 1, 2018. For the recovery of forgone revenue, the OEB will approve forgone revenue rate riders to be collected from customers from the implementation date to December 31, 2018. InnPower is required to submit a proposal for the calculation of the forgone revenue rate riders as part of the draft rate order process.

As InnPower is included in the Fair Hydro Plan's DRP program, the rates charged to InnPower's customers will be lower than the rates approved in the final rate order in this proceeding.

SEC and VECC are eligible for cost awards in this proceeding. The OEB will make provision for these intervenors to file their cost claims in its final rate order.

[47] Decision and Order, EB-2017-0290, March 1, 2018

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. InnPower Corporation shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision, within **14 days** of the date of this Decision and Order. InnPower Corporation shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to InnPower Corporation within **7 days** of the date of filing of the draft rate order. The OEB intends to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.

3. InnPower Corporation shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order within **7 days** of the date of receipt of the comments.

All filings to the OEB must quote the file number, EB-2016-0085, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Fiona O'Connell at fiona.oconnell@oeb.ca and OEB Counsel, Ljuba Djurdjevic at ljuba.djurdjevic@oeb.ca.

ADDRESS

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DATED at Toronto March 8, 2018

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

SETTLEMENT PROPOSAL

(WIRELINE POLE ATTACHMENT RATE)

DECISION AND ORDER

INNPOWER CORPORATION

EB-2016-0085

MARCH 8, 2018

Ontario

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

REVISED DECISION AND ORDER

EB-2015-0072

GRIMSBY POWER INC.

Application for electricity distribution rates beginning May 1, 2016

BEFORE: **Allison Duff**
Presiding Member

Susan Frank
Member

September 22, 2016

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 THE PROCESS 2

3 DECISION ON THE ISSUES 3

3.1 Settlement Proposal 3

3.2 Operations, Maintenance and Administrative Expenses 3

3.3 Payments in Lieu of Taxes 7

3.4 Effective date for 2016 rates 10

4 IMPLEMENTATION 12

5 ORDER 13

SCHEDULE A 14

1 INTRODUCTION AND SUMMARY

This is a Decision of the Ontario Energy Board (OEB) on an application filed by Grimsby Power Inc. (Grimsby Power) to change its electricity distribution rates effective May 1, 2016 (the Application). Under the OEB Act, distributors must apply to the OEB to change the rates they charge customers.

Grimsby Power provides electricity distribution services to about 14,000 customers in the Town of Grimsby. The rates approved in this Decision are set based on the OEB's determination of the revenue required to cover the cost of operating and maintaining Grimsby Power's distribution system at a level of service that meets the needs of its customers.

Grimsby Power and the intervenors filed a settlement proposal with the OEB on June 24, 2016 (Settlement Proposal). The Settlement Proposal reduced the 2016 proposed revenue required by about $200,000.

The OEB indicated that it was not prepared to accept the settlement regarding deferral and variance accounts (DVA). A revised settlement proposal was filed on July 28, 2016 to address the OEB's concerns (Revised Settlement Proposal). Both settlement proposals indicated that the parties did not agree on three issues:

(i) Operations, Maintenance and Administration (OM&A) expenses
(ii) Payments in Lieu of Taxes (PILs)
(iii) Effective date of 2016 rates

The OEB issued a Decision on August 18, 2016 to approve the Revised Settlement Proposal, OM&A expenses of $3,134,546, a 2016 PILs provision based on the use of $391,821 in tax loss carry forward from 2015, and a September 1, 2016 effective date for 2016 rates.

The OEB is issuing this Revised Decision to enable rate mitigation for the Unmetered Scattered Load (USL) class. Section 3.1 of the Decision dated August 18, 2016 is changed to reject section 5.1 of the Revised Settlement Proposal regarding rate mitigation.

2 THE PROCESS

Grimsby Power filed a cost of service application with the OEB on December 23, 2015, seeking approval for changes to the rates that it charges for electricity distribution, to be effective May 1, 2016.

Energy Probe Research Foundation (Energy Probe), Niagara Peninsula Energy Inc. (NPEI), School Energy Coalition (SEC), and the Vulnerable Energy Consumers Coalition (VECC) were approved as intervenors in the proceeding (the intervenors). COGECO Cable Canada LP was also approved as an intervenor, yet did not actively participate in the proceeding. OEB staff participated in the proceeding.

The OEB provided parties the opportunity to ask Grimsby Power questions about its evidence through interrogatories and a technical conference. A settlement conference was held on May 24, 25 and 26, 2016.

Grimsby Power and the intervenors filed a Settlement Proposal on June 24, 2016 reflecting a partial settlement on the majority of issues in the proceeding, leaving three issues unsettled. Additional evidence and undertaking responses were filed by Grimsby Power regarding the unsettled issues, after the Settlement Proposal was filed.

The OEB held an oral hearing on July 13-14, 2016 to receive a presentation from Grimsby Power on the Settlement Proposal and hear the three unsettled issues. Following the OEB's questions regarding the Settlement Proposal, the parties filed a Revised Settlement Proposal on July 28, 2016 to address the OEB's concerns (Schedule A).

Grimsby Power presented an oral Argument-in-Chief on July 14, 2016. OEB staff and intervenors filed written submissions on July 29, 2016 and Grimsby Power filed a written reply submission on August 9, 2016.

The OEB issued a Decision on August 18, 2016 and established a draft rate order process. The draft rate order indicated that rate mitigation was required for the USL class. This Revised Decision will enable rate mitigation in the final rate order.

3 DECISION ON THE ISSUES

3.1 Settlement Proposal

Grimsby Power and the intervenors filed a Revised Settlement Proposal to address the OEB's concerns raised during the oral hearing regarding the initial settlement of DVA accounts. In particular, Grimsby Power and the intervenors in the revised proposal agreed to discontinue the existing deferral and variance accounts for renewable generation and IFRS transition, and add a deferral account for the costs associated with an asset condition assessment to be filed in Grimsby Power's next cost of service proceeding. The reduction to 2016 capital expenditure of $200,000, the revised cost allocation and rate design for the new Embedded Distributor customer class, and treatment of other issues did not change from the original Settlement Proposal.

The Settlement Proposal indicated that Grimsby Power and the intervenors did not agree on three issues. The three unsettled issues were the 2016 OM&A budget, the PILs provision and the effective date for rates. The OEB decided the three unsettled issues and approved the Revised Settlement Proposal in its Decision dated August 18, 2016.

In the draft rate order process, it was determined that rate mitigation was required for the USL class. The total bill impact on the USL class exceeded 10%. The approved Revised Settlement Proposal had indicated that no mitigation was required for any class. To enable the necessary rate mitigation, this Revised Decision rejects section 5.1 of the Settlement Proposal. The OEB relies on Grimsby Power's confirmation that parties to the Revised Settlement Proposal agree to the rate mitigation, and agree that the balance of the Revised Settlement Proposal remains a valid settlement[1].

The OEB finds that the terms of the Revised Settlement Proposal and this Revised Decision produce outcomes that are compatible with the applicable performance objectives of the Renewed Regulatory Framework (RRFE). The OEB approves the terms of the Revised Settlement Proposal, with the exception of section 5.1 for use in the determination of Grimsby Power's 2016 final rate order.

3.2 Operations, Maintenance and Administrative Expenses

Grimsby Power requested recovery of $3,925,363 in OM&A expenses in 2016, a 63%

[1] Grimsby Power's revised draft rate order, September 15, 2016, pp. 4-6.

proposed increase over the $2.4M approved by the OEB in Grimsby Power's 2012 cost of service rate application (EB-2011-0273).

Grimsby Power revised its 2016 OM&A forecast to $3,733,648 after the oral hearing was complete, in response to an undertaking request from the OEB. This revised OM&A proposal represents a 55% increase over the budget approved for 2012.

Intervenors and OEB staff submitted that the OM&A cost increases proposed by Grimsby Power were unreasonable. Parties noted that Grimsby Power had not consulted with its customers regarding the application as required under the RRFE. In particular, Grimsby Power had not sought customer feedback regarding the increases in FTE expenses that were proposed to address changes in its customer base and needs.

Further, the intervenors and OEB staff disagreed with Grimsby Power's proposal to include normalized costs in the 2016 forecast. It was submitted that in a cost of service application, the test year forecast should only be based on 2016 expenses.

Intervenors and OEB staff submitted the OEB should reduce the OM&A expenses proposed by Grimsby Power. In particular, submissions were to reduce specific expenses such as compensation increases for existing staff, new FTE positions, the advance hiring for retirements and tree-trimming. Energy Probe submitted the OEB should consider an envelope approach to setting OM&A in 2016 based on rates of inflation, base productivity, stretch factors and customer growth since 2012.

As a result of these submissions, the revised OM&A recommended for 2016 ranged from $2,760,201 to $3,233,648.

Findings

The OEB will use the revised 2016 OM&A forecast of $3,733,648 as the starting point for the analysis of OM&A spending, which is an increase of 55% over 2012 OEB approved OM&A. Over this same period inflation was 9% and customer growth was 7%. Since 2012, Grimsby improved its operating performance and exceeded OEB's industry and distributor targets, except for conservation and demand management savings of annual peak demand. Grimsby Power's operations, maintenance and administration practices are now close to the established basic practices of other utilities.

From the perspective of enhancing performance the OEB finds that the evidence was insufficient to justify a 55% increase in OM&A expenses. Grimsby Power indicated that the main drivers of OM&A costs are human resource requirements; base compensation changes; and the amalgamation of Grimsby Power and Niagara West Transformation Corporation (Niagara West). Grimsby Power indicated that "resources have been added to fulfill the needs of the business environment and the direct needs and wants of

Grimsby Power customers as informed by the two customer surveys[12]".
Grimsby Power plans to increase customer communication but the OEB is not clear as to the costs associated with this change or how Grimsby Power will determine if the changes in customer communication have met customer's needs.

As several intervenors submitted, Grimsby Power did not seek its customers' response to the proposed rate increase or operating performance targets. The OEB finds this lack of customer engagement is inconsistent with RRFE filing requirements. Despite Grimsby's lack of confidence in customer engagement activities, it is a requirement to engage customers and ensure the customers' perspective is incorporated in a cost of service application. While Grimsby Power submitted that its survey responses indicated that its customers wanted increased communication particularly regarding outages, the associated cost was not discussed with customers.

Grimsby Power has taken an unusual approach to forecasting its 2016 OM&A spending. Mr. Curtiss testified that the utility had used a normalized approach to forecasting staffing costs for 2016 that exceeded planned spending in 2016. The OEB finds that the normalization of costs over the next 5 years would be typical of a custom application; however, a cost of service application for the test year should include only the planned expenses in that year. Accordingly, the filing expectations for a custom application are more extensive and there is no indication that Grimsby Power was making a custom filing. The OEB is approving only the forecast expenditures in 2016.

In the revised OM&A forecast filed on July 21, the normalized level of incremental staff costs was $817,325 with the 2016 forecast spend for these staff being $298,223. The OEB will not allow the difference of $519,102 which the utility will not spend in 2016.

The $298,223 increase for staffing costs was a combination of vacancies in current positions, succession planning and new hires for expanded work activities. The OEB accepts the $196,508 that Grimsby Power has forecast to spend in 2016 to fill the vacancies.

With respect to the proposed succession planning and new hires, the OEB is not convinced that Grimsby Power's proposal is the best option. Succession planning is important, particularly in a small utility, but this issue should be managed over time. Given that current salaries are representative of utilities of a similar size, the trade-off of acquiring skilled resources from the marketplace rather than training internally by Grimsby Power has not been demonstrated. Several intervenors and OEB staff

[2] Grimsby Power, Reply Submission, August 9, 2016, page 9

questioned why a lineman that is not expected to retire until 2023 should be included in the planned hires in 2016. New hires for expanded work are inconsistent with Grimsby Power's history of effectively using external contracts to deliver core services. The OEB finds that moving from the outsourcing of work programs to hiring permanent staff reduces flexibility and the opportunity for increased productivity through sharing resources across utilities.

The OEB encourages Grimsby Power to take a more careful look at its staffing plans. Grimsby Power forecast the 2016 spending for new hires and succession planning to be about $100,000. The OEB will approve half of this amount.

Several intervenors also questioned the increase in compensation for current staff. Mr. Curtiss has assured the OEB that the staff compensation for 2016 is consistent with the 50th percentile for comparable size companies in the MEARIE study. On this basis the OEB approves the proposed increases for current staff compensation.

In addition, intervenors and OEB staff raised concerns regarding the Application's lack of new productivity initiatives or operating savings associated with new technology or capital investments. During the oral hearing, Mr. Curtiss indicated that the historical productivity achievements could likely be replicated in the future and agreed that a 1% incremental productivity saving was reasonable. Accordingly the OEB will reduce the OM&A budget by $30,000 to reflect the anticipated incremental productivity improvement.

The calculation of the approved 2016 OM&A budget is summarized in the table below.

July 21, 2016 Proposal	$3,733,648
Remove normalization for staffing	($519,102)
Remove half of staff increase	($50,000)
Anticipated productivity saving	($30,000)
OEB Approved 2016 OM&A	$3,134,546

The OEB arrived at this approved level of OM&A by identifying specific concerns with Grimsby Power's 2016 proposal. The OEB also assessed the approved OM&A budget by analyzing historical unit costs, benchmarking and the envelope approach proposed by intervenors.

Using a historical approach to increase OM&A to reflect customer growth, as recommended by OEB staff, Energy Probe and VECC, would result in a 2016 OM&A of $2.76 M. Benchmarking the average OM&A cost per customer for comparable utilities according to OEB Staff, would suggest an OM&A level of $2.945M. Finally the envelope approach used by Energy Probe and supported by VECC yielded a reduction to OM&A of $500,000 to $600,000. These alternative approaches to analyzing the appropriate OM&A budget for 2016 are commensurate with the level of reductions approved by the OEB.

During the oral hearing, Mr. Curtiss expressed Grimsby Power's intention to search for productivity improvements and bring them "front and center" over the next 5 years. The OEB supports this commitment and will continue to monitor the OM&A per customer and related productivity measures.

In addition to the emphasis on productivity, the RRFE stresses the importance of outcome based regulation. The OEB expects there to be a correlation between more money being spent and improved outcomes. Grimsby Power described the need to increase customer communications particularly as it relates to outages. Given the increase in OM&A approved, the OEB expects that Grimsby Power will improve customers' satisfaction in the area of customer communications. Grimsby Power is encouraged to monitor its operating performance and improvement in customer satisfaction and to report the results in its next rate application.

3.3 Payments in Lieu of Taxes

Grimsby Power's Application included recovery of $69,211 in PILs based on a 2016 taxable income forecast of $191,963. This taxable income forecast included a reduction of $166,893 due to the use of a tax loss carry forward from previous years.

The OEB's 2006 Electricity Distribution Rate Handbook (Rate Handbook) indicates that a tax loss carry forward available at the end of the prior year must be disclosed and applied in full to reduce taxable income in the test year[3].

The Application indicated Grimsby Power had $834,468 in tax losses available from prior years. It used one-fifth of the available tax losses in 2016, or $166,893, as 2016 would establish base rates for the next five years. The $834,468 included a forecast taxable income loss in 2015 of $122,313.

Grimsby Power amended its PILs proposal on June 29, 2016 in three respects:

1. The tax loss carry forward available in 2016 was reduced from $834,468 to $391,821 given Grimsby Power's actual 2015 tax filing

[3] 2006 Electricity Distributor Rate Handbook, May 11, 2005, page 61

2. Grimsby Power's actual 2015 tax filing included taxable income of $589,098 based on a number of accounting entries made after Grimsby Power amalgamated with Niagara West, instead of the forecast loss for tax purposes of $122,313

3. All tax loss carry forwards acquired as part of the amalgamation with Niagara West were excluded from the PILs calculation in 2016. The proposed PILs provision for 2016 was reduced from $69,211 to $65,351 after Grimsby Power changed the capital cost allowance for certain Niagara West assets from Class 47 to Class 1, which increased the allowance and decreased taxable income

Grimsby Power based its June 29, 2016 update on a report from KPMG[4], which concluded that the actual tax loss carry forward related to Niagara West at the end of 2015 should be available to Grimsby Power's shareholders, not to its customers.

Findings

The OEB agrees with Grimsby Power's characterization of the two broad matters to be decided:

1. the appropriateness of using actual PILs calculations for the 2015 bridge year, including the calculation and application of tax loss carry forwards, to reflect the actual 2015 tax return

2. whether tax loss carry forwards related to the former Niagara West should be applied to the shareholders or customers in this case

The OEB finds it appropriate to use the actual tax loss carried forward available on December 31, 2015 of $391,821 for consideration in setting rates in 2016.

The intervenors and OEB staff disagreed with Grimsby Power's updated PILs proposals. Parties submitted that Grimsby Power must follow OEB policy and apply the tax loss carry forward to set rates in 2016. Consistent with the policy, parties submitted that Grimsby Power should use the OEB model provided in the filing requirements to calculate the 2015 regulatory PILs amount. If the OEB's PILs model was used without any alterations, the 2016 available tax loss carry forward would be higher than $391,821, thereby increasing the benefit available to customers in 2016.

However, the 2006 Rate Handbook and the 2016 filing requirements assume bridge

[4] "Review of Rate Setting Implications of Tax Loss Carry Forwards" filed June 29, 2016

year numbers are forecast. When actual data is available, the OEB finds that actuals must be used. This finding is consistent with the treatment of PILs in 2014, the “historical year” in the 2016 filing requirements, in which actual tax accounting is used.

The unusual circumstance in this proceeding is that 2015 actuals are available; 2015 is an historical year. The OEB agrees with Grimsby Power that it is appropriate and consistent to use 2015 actual revenue, expenses and taxes.

The second matter to be decided is whether Grimsby Power’s shareholders or customers should benefit from of the tax losses from Niagara West.

The use of Niagara West’s tax loss carry forward in 2016 was argued extensively by KPMG on behalf of Grimsby Power. KPMG indicated that Niagara West’s shareholders had borne the cost of income tax losses from 2005 to 2015 and should receive the benefit. KPMG identified the sources of the losses and recommended that the OEB apply the “benefits follow costs” principle.

Intervenors and OEB staff disagreed with KPMG. The parties indicated that Grimsby Power had previously indicated that the Niagara West tax losses would benefit customers and submitted that it was still appropriate that these losses should benefit customers.

Since 2006, the OEB has typically followed the Rate Handbook and applied tax loss carry forward amounts to the benefit of customers. The two decisions in which the OEB did not apply the policy were the Ontario Power Generation (OPG) EB-2007-0905 decision and Great Lakes Power Limited (Great Lakes Power) EB-2007-0744 decision.

The OEB finds that the circumstances in the OPG and Great Lakes Power cases were unique and are not comparable to Grimsby Power’s circumstances. The OEB’s findings in the OPG decision addressed the fact that OPG was not regulated by the OEB prior to 2008, when the losses occurred. The OEB’s findings in the Great Lakes Power decision turned on the fact that the company conducted both regulated and non-regulated businesses and the disallowed expenses were associated with the non-regulated businesses. In contrast, Niagara West was regulated by the OEB from 2005-2015 when the tax loss carry forward of $391,821 was generated and the OEB did not disallow expenses associated with non-regulatory business activities of Niagara West.

The OEB finds no justifiable reason to deviate from its policy and create a third exception in this proceeding.

The consistent application of ratemaking leads to predictability and certainty in rates. The tax loss carry forward policy was known to NPEI when it agreed to sell its share of

Niagara West to Grimsby Power, when it planned to amalgamate with Niagara West and to the OEB when it approved the amalgamation[5]. To deviate from the OEB policy in this proceeding, after the fact, would be inconsistent and undesirable from a ratemaking perspective.

KPMG raised the benefits follows cost principle to support its opinion that shareholders should benefit from tax loss carry forwards. The OEB notes that the benefits follow costs principle was referenced in the Report of the Board[6] that accompanied the Rate Handbook. In the Report of the Board, the principle was considered only for tax savings arising from non-recoverable or disallowed expenses, including purchased goodwill and charitable donations. The OEB found that tax savings arising from these specified situations would not be allocated to customers, applying the benefit follow cost principle. The OEB finds many factors were involved when Niagara West's rates were established in 2011 and losses were generated between 2011 to 2015. In addition, the context of "disallowed expenses" in the Report of the Board did not include interest costs for a regulated business.

In a cost of service proceeding, the OEB establishes customer rates to recover a utility's forecast cost of operations and to provide shareholders a fair rate of return on equity. If the OEB were to approve Grimsby Power's proposed 2016 PILs provision, customers would pay for taxes that Grimsby Power is not forecast to pay in 2016, thereby exceeding Grimsby Power's cost of service. The OEB finds Grimsby Power's proposal inappropriate from a cost recovery perspective.

In summary, Grimsby Power's shareholders will retain the benefit of the 2015 actual tax filing in which taxable income was increased, significant tax loss carry forwards were utilized and the balance available for 2016 was reduced. However, the tax loss carry forward remaining from Niagara West will go to the benefit of customers. The OEB finds it appropriate to use the actual tax losses available of $391,821 for consideration in setting rates in 2016.

3.4 Effective date for 2016 rates

Grimsby Power proposed an effective date for 2016 rates of May 1, 2016 in its Application. In reply submission, Grimsby Power revised its proposal to July 14, 2016, the date on which Grimsby Power's current rates were declared by the OEB as interim.

Intervenors submitted that the effective date should be the beginning of the first or

[5] EB-2014-0344 Decision and Order, March 26, 2015
[6] RP-2004-0188 Report of the Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, pp. 50-53

second month following the OEB's decision, as is consistent with OEB practice. Intervenors indicated that Grimsby Power filed its application late and that sufficient time is required for the hearing process.

OEB staff submitted that 266 days is the established metric to issue a decision and rate order after an application is filed and an oral hearing is held. As Grimsby Power filed its application on December 23, 2015, OEB staff submitted the appropriate effective date for 2016 rates is September 1, 2016.

Findings

The OEB approves September 1, 2016 as the effective date of Grimsby Power's 2016 rates. The OEB finds that the delay in filing the application was within Grimsby Power's control and sufficient time must be allowed for the OEB's open and transparent rate setting process. The OEB finds that September 1, 2016 is appropriate given the date of this Decision and the time provided for the rate order process.

4 IMPLEMENTATION

Grimsby Power and the intervenors included a draft rate order as an appendix to the Revised Settlement Proposal. With respect to the three unsettled issues, Grimsby Power's proposals were embedded in the calculations for drafting the rate schedules. After implementing the findings of this Revised Decision, Grimsby Power will provide the OEB with a draft calculation of its rates and charges.

The OEB has reviewed the draft accounting order in Appendix F to the Revised Settlement Proposal. The OEB encourages Grimsby Power to work with OEB staff to revise the draft accounting order to include the effective dates for the account and other wording as necessary, and to file it with the draft rate order. The OEB will review these filings and determine Grimsby Power's final rates for 2016.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Grimsby Power shall file with the OEB, and forward to all intervenors, a draft rate order that implements the findings in this Revised Decision set out above, including revised models in Microsoft Excel format as appropriate and a proposed Tariff of Rates and Charges reflecting the OEB's findings no later than August 30, 2016.

2. OEB staff and intervenors shall file any comments on the draft rate order with the OEB and with Grimsby Power no later than September 7, 2016.

3. Grimsby Power shall file with the OEB, and forward to intervenors, responses to any comments on its draft rate order no later September 14, 2016.

All filings to the OEB must quote the file number, **EB-2015-0072**, be made through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available, parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies.

DATED at Toronto September 22, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND ORDER

GRIMSBY POWER INC.

EB-2015-0072

September 22, 2016

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

EB-2014-0073

IN THE MATTER OF AN APPLICATION BY

FESTIVAL HYDRO INC.

FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES FOR 2015

DECISION
April 30, 2015

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Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2014-0073

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Festival Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

BEFORE: Christine Long
Presiding Member

Ellen Fry
Member

DECISION AND ORDER

April 30, 2015

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Table of Contents

INTRODUCTION AND SUMMARY 1
1.0 Rate Base 3
a. Capital Expenditures 3
b. Working Capital Allowance 4
c. The Inclusion of Costs for a Bypass Agreement as an Intangible Asset 5
2.0 Operations, Maintenance and Administration 7
3.0 Incremental Capital Module 11
4.0 Fixed/Variable Split For The GS>50kW Customer Class 16
IMPLEMENTATION AND ORDER 18
APPENDIX A: Festival Hydro Inc. Settlement Proposal

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INTRODUCTION AND SUMMARY

Festival Hydro Inc. (Festival) filed an application with the Ontario Energy Board (the OEB) on May 30, 2014 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Festival charges for electricity distribution, to be effective January 1, 2015.

Festival comprises seven geographically separate service territories (the City of Stratford, and the Towns of St. Marys, Seaforth, Dashwood, Hensall, Zurich, and Brussels). Festival serves about 20,500 residential and commercial customers and has historically had growth of 1% a year. The same rate of growth is expected to continue.

In order to determine the amount Festival can charge its customers for electricity service, the OEB determines how much revenue is reasonable for the company to recover from its customers. This amount is known as the revenue requirement. The OEB considers among other factors, the company's expected operating and maintenance costs and the investments the company expects to make which are necessary to provide reliable, and cost-effective service. An electricity distributor such as Festival uses its revenue requirement, coupled with forecasts of the number of customers it will have, those customers' associated energy needs and other relevant factors to arrive at a set of proposed electricity rates. It is up to the OEB to approve the specific rates a utility can charge its customers.

Festival has asked the OEB to approve distribution rates and charges to recover a base revenue requirement of $10.6 million for 2015, which excludes any other revenues Festival might receive. The requested revenue requirement represents a 2.85% increase over the revenue requirement approved in Festival's last rebasing application, which was approved in 2010. The overall decline Festival has proposed in its rates for the 2015 rate year is due to the expiry of certain temporary charges related to the roll-out of smart meters, as well as refunds of certain amounts that have been kept in deferral and variance accounts. However, as part of Festival's application, after 2015 ratepayers would experience an increase in rates charged to them.

<u>Procedure</u>

In reaching its findings, the OEB was aided by the participation of four intervenors; Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers Coalition (VECC), the School Energy Coalition (SEC) and the Association of Major Power Consumers in Ontario (AMPCO).

A settlement conference took place on September 29 and 30, 2014. Festival, SEC, VECC, AMPCO and Energy Probe and OEB staff participated in the settlement conference. The Parties reached a partial settlement and filed a settlement proposal with the OEB. The OEB approved and adopted the settlement proposal at the oral hearing, which commenced on November 13, 2014. In the settlement proposal, parties agreed to decrease Festival's proposed 2015 revenue requirement from $11.1 million to $10.6 million, a 5.3% reduction. A copy of the settlement proposal is attached as Appendix A.

The OEB heard the unsettled issues at the oral hearing.

This decision addresses in detail the unsettled issues. After implementing the findings of this decision, Festival will provide the OEB with a final calculation of its rates and charges. At that point, the OEB will determine final rates and the impact these rates will have on Festival's customers.

The Unsettled Issues

The unsettled issues are grouped into the following broad areas:

1) Rate Base
    a) The appropriate amount of capital expenditure
    b) The appropriate amount of working capital allowance to be included in rate base.
    c) The inclusion of costs for a bypass agreement as an intangible asset
2) Operations, maintenance and administration (OM&A)
3) Incremental capital module (ICM) true-up
    a) Adjustments to reflect actual capital costs relative to those forecast
    b) Adjustment to depreciation expenses to address the difference from forecasts in Festival's rebasing application and the in-service date of the new asset.
    c) Recovery of additional funding for opterations, maintenance and administration (OM&A) costs incurred in 2013 and 2014.
4) Fixed/variable charges ratio for the general service customer class using less than 50kW

1.0 Rate Base

a. Capital Expenditures

Festival has requested approval for a capital budget of $2,621,500 for 2015, with planned capital expenditures essentially constant from 2015 to 2019. Energy Probe, VECC and AMPCO submitted that the requested capital budget should be reduced. SEC and OEB staff made no submission on the planned capital budget.

Several parties submitted that the amount budgeted for wooden pole replacement, which is 25% of the proposed capital budget, is excessive. SEC and AMPCO submitted that Festival's program to replace poles over 40 years old is not justified, because it is significantly shorter than the Hydro One Networks Inc. (Hydro One) timeframe for pole replacement of 62 years. Festival submitted that its pole replacement program is required for safety and reliability and that the considerations for its urban service and the rural service of Hydro One are different. Based on the evidence provided at the oral hearing and on Festival's submission, the OEB is satisfied that Festival's proposed capital program to replace its wooden poles is reasonable.

Several parties argued that the cost of $70,000 to purchase an electric vehicle and charging station should be disallowed. This expenditure involved an incremental cost of $35,000 over the cost to purchase a conventional vehicle. This incremental amount is below Festival's materiality threshold and therefore is not a matter in issue before the Board in this proceeding.

AMPCO and VECC submitted that Festival's capital budget should be reduced because Festival has underspent historically and because its actual capital spending at the end of September 2014 was significantly lower than its 2014 capital budget. Festival submitted that its proposed capital budget is lower than in previous years; that its percentage underspending decreased from 2010 to 2013; and that its capital budget for 2015 as a percentage of depreciation is low in comparison to the 2013 capital budgets for most other utilities. Concerning 2014, a Festival witness testified that a large portion of its capital spending occurs late in the calendar year.

The OEB agrees with Festival that its overall capital budget compares favorably with that of other utilities, and that Festival is not likely to underspend significantly over the next five years. The OEB also notes that Festival's proposed capital budget would essentially be flat over the next five years. Accordingly, the OEB considers that Festival's proposed capital budget is appropriate.

b. Working Capital Allowance

Festival has proposed using the OEB's default 13% working capital allowance.

The intervenors have submitted that the working capital allowance should be lower, because the default working capital allowance is based on a faulty methodology and because the fact that Festival bills monthly needs to be taken into account. Intervenors took the position that since Festival has not performed its own lead-lag study, lead-lag studies of other utilities should be used as guidance.

OEB staff has submitted that there is no evidence to lead the OEB to reduce the working capital allowance. In its view, methodological issues and monthly billing are factors to be included in the OEB policy review of the working capital allowance.

Festival has submitted that monthly billing is only one factor that impacts its working capital allowance requirement and that lead-lag studies of other utilities would not necessarily address circumstances comparable to those of Festival.

The OEB recently presented a full discussion of the principles currently applicable to the determination of working capital allowance, in the Hydro One Brampton case.[1] As indicated in that case, the policy indicated in the OEB Filing Guidelines is that an applicant may either propose a 13% working capital allowance or propose a different working capital allowance based on a lead-lag study. The only exception occurs when an applicant has previously been directed to file a lead-lag study, which is not the case for Festival. The OEB's existing policy will remain in effect until its policy review concerning the working capital allowance is complete.

The OEB is not of the view that it should depart from its normal policy in this case. The OEB agrees that the fact that Festival bills monthly is relevant, but it is only one of the factors that needs to be considered. As indicated in the Hydro One Brampton case, the OEB has previously explained that it is reluctant to apply a working capital allowance to one utility because it has been considered appropriate for another. The evidence in this case is not sufficient to establish that any other utilities with lead-lag studies have

[1] EB-2014-0083

operational characteristics sufficiently similar to Festival to indicate that Festival should have the same, or a similar, working capital allowance. The Board is not persuaded by the evidence heard in this proceeding that an alternative working capital allowance percentage is appropriate.

Accordingly, the OEB approves a 13% working capital allowance as proposed by Festival.

c. The Inclusion of Costs for a Bypass Agreement as an Intangible Asset

In its 2013 Incentive Regulation Mechanism (IRM) application[2], Festival obtained OEB approval for cost recovery for a new transformer station, through an incremental capital module (ICM).

Festival built the new transformer station to serve a forecast load that was expected to exceed the service capacity of the existing Hydro One transformer station in the near term. However, by the time the new transformer station went into service in December 2013, the closure of the facilities of two industrial customers decreased the forecast load significantly. Festival Hydro was able to transfer 20MW of existing transmission load from the Hydro One transformer station to Festival's new transformer station. This enabled Festival to avoid transmission charges to its customers of $475,000 per year.

In order to transfer this transmission load, the Transmission System Code[3] required Festival to sign a bypass agreement with Hydro One. The bypass agreement requires Festival to make a one-time payment, expected to be $1.2 million, to Hydro One. As of the date of the hearing the amount of the payment had been neither calculated nor invoiced by Hydro One.

According to Festival, it was not aware at the time the OEB approved the ICM for the transformer station that the situation might call for a bypass agreement and therefore it did not make the OEB aware of this possibility.

OEB staff and all intervenors except SEC submitted that payment under the bypass agreement was reasonable, given the avoided transmission charges of approximately

[2] EB-2013-0214
[3] Section 6.7.7

$475,000 per year. SEC submitted that it was not prudent, because the payment amount under the bypass agreement would not decrease if Festival used more Hydro One transmission capacity in the future. Festival gave evidence that it does not intend to use more Hydro One transmission capacity. The OEB agrees that payment under the bypass agreement is reasonable.

Festival proposes to classify the payment as an intangible asset, which would be included in its rate base and amortized over the 45 year expected life of the new transmission station. Festival would earn a return based on the inclusion of the intangible asset in rate base. Festival submitted that treatment as an intangible asset was supported by an unqualified audit report. Festival also gave evidence that its accounting treatment was consistent with a similar situation for another utility and, based on what Hydro One told Festival, was consistent with the accounting treatment followed by Hydro One in respect of the same asset.

The intervenors and OEB staff submitted that Festival has not justified capitalizing the payment as an intangible asset and therefore it should be considered an expense. The intervenors submitted that Festival's auditors did not give an opinion supporting treatment as an intangible asset; that there was no link between the cost of the bypass agreement and the capital cost of the transformer station; and that the alleged accounting treatment by other utilities that was referred to by Festival should not be relied on.

The payment under the bypass agreement was not an integral part of the cost of building the transformer station. Building the transformer station did not require a bypass agreement, and indeed if the need for the bypass agreement had been known at the time of the ICM application, it might have led to a reassessment of the need for the transformer station.

The Transmission System Code, which establishes the requirement for bypass agreements, refers to payments under bypass agreements as "compensation"[4]. The Code does not define "compensation" as either an expense or a capital payment. The parties did not identify any other potential sources of accounting guidance in OEB decisions or policies.

Festival's auditor testified that it was not his function to give an opinion on single, stand-alone transactions. Accordingly, he did not give an opinion on the appropriate

[4] Section 6.7.7

accounting treatment for the bypass agreement. Concerning Festival's submission that auditors in the past approved treatment by another utility as an intangible asset, there was no direct evidence on the content of the auditor's opinion or to what extent the circumstances were similar to those of Festival. There is also no direct confirmation of the accounting treatment by Hydro One, which in any event would be based on Hydro One's own accounting policies and not determinative of Festival's appropriate accounting treatment.

Accordingly, the OEB agrees with the intervenors and OEB staff that payment under the bypass agreement should be treated as an expense rather than an intangible asset.

Several intervenors and Board staff submitted that the payment under the bypass agreement should be recorded in a deferral account for recovery from Festival's customers. SEC submitted that this should not occur. In SEC's view, to allow recording of the payment for recovery at this point would constitute retroactive ratemaking because in its view the expense was incurred when the bypass agreement was signed, not when the payment becomes due.

The OEB finds, given the specific fact situation in this case, that the payment under the bypass agreement is to be removed from the intangible assets and expensed in 2015. The amount is to be recovered through a rate rider outside of the revenue requirement over three years, so that the annual amount of disposition is similar to the annual amount of savings in transmission charges. Accordingly, Festival will need to declassify this asset for regulatory accounting purposes following this decision. This declassification will trigger an expense in 2015. As the expense is incurred upon declassification of the asset for regulatory accounting purposes, no retroactivity issue arises.

2.0 Operations, Maintenance and Administration

Operations, Maintenance and Adiministration (OM&A) costs capture day to day maintenance of Festival's system and include employee compensation, corporate costs, customer service and other operations costs.

OM&A expenses for 2015 total $5,188,507 million and constitute a significant component (approx.49%) of the forecast revenue requirement. The requested OM&A budget represents an increase of approximately 29% over Festival's last OEB-approved OM&A budget and a 5.8% increase over 2013 actuals.

Festival broke down its OM&A budget into uncontrollable and controllable expenses.

It stated that 57% of its OM&A expenses are uncontrollable expenses. These expenses include

- an increase in pension contributions
- incremental operating costs for the new transformer station, put in service in 2013
- additional charges related to smart meters
- mandatory changes to accounting practices that require Festival to charge certain expenses directly rather than including these costs as part of the capital cost of the assets.

The remaining 43% of OM&A expenses are controllable. These expenses are mainly driven by increases in compensation. Festival noted that while it has maintained its headcount at the same level since 2010, compensation increases are due to wage progression and an inflationary increase.

Arriving at an appropriate OM&A budget is critical in ensuring that Festival has sufficient funds to operate a safe and reliable system while at the same time considering the rate impact on customers. A distributor's rates are designed to recover OM&A expenses in the same year that they are made. In order to ensure that the rates it sets are reasonable, the OEB employs a number of tools, including identifying the information that distributors have to include in their applications, methods of testing the evidence through questions from intervenors and OEB staff, and quantitative comparison to similar distributors. In its evaluation of OM&A budgets, the OEB has often used what has come to be known as an 'envelope' approach to determine the appropriateness of an applicant's proposal. Rather than examine all components of OM&A costs line by line, an envelope approach assesses the reasonableness of the overall request, by reference to factors that include any increase from past periods, inflation and expectations regarding productivity and efficiency improvement. The overall amount must be supported by sufficient rationale for planned spending and proposed activities and support the outcomes-based approach under the OEB's Renewed Regulatory Framework.

All intervenors opposed Festival's OM&A proposal. They considered it to be unreasonably high and proposed reductions to the OM&A budget ranging from $104,000 to $279,000. Intervenors suggested a number of specific reductions. Most intervenors also argued that Festival's request does not reflect the outcomes-based approach under the OEB's Renewed Regulatory Framework in the areas of operational effectiveness and financial performance.

Intervenors noted that under the OEB's new total cost benchmarking approach, Festival's operational efficiency ranking has declined significantly. Festival was in the most efficient group (group 1) for the years 2010 to 2013. In 2014, Festival's ranking changed and it is now positioned in the second least efficient group (group 4). Therefore intervenors concluded that Festival's OM&A budget reflects a lack of productivity and associated savings.

OEB staff took no issue with Festival's OM&A request and submitted that its cost per customer is among the lowest in the province, at $250.

During the proceeding, Energy Probe provided a calculation of what it viewed as appropriate OM&A. It used an envelope approach that allowed for an inflation adjustment as applied under the OEB's incentive regulation process, changes due to billable work and new accounting rules under the international financial reporting standards (IFRS). Festival submitted that this envelope approach to assessing OM&A does not properly recognize the reasons for the changes to its OM&A budget, considering both controllable and uncontrollable expenses. Using Energy Probe's methodology of normalizing spending patterns over the 2010 to 2015 period, Festival made additional adjustments to account for incremental OM&A cost related to the new transformer station, smart meters and increased pension premiums. As a result, Festival calculated an annual average increase below 3%.

The OEB finds that Festival's OM&A budget is reasonable and has been supported by the evidence provided in this case. Accordingly, the OEB approves Festival's OM&A request for 2015 of $5,188,507[5]. In making this finding, the OEB has considered Festival's past performance as well as a comparison with other distributors. The OEB has also considered the specific reductions requested by the intervenors and notes that with the exception of compensation these proposed reductions were not material.

The OEB does not agree with the intervenors that Festival's proposed OM&A budget reflects shortcomings in achieving the outcomes-based approach required by the OEB's Renewed Regulatory Framework.

[5] $32,225 (PILs and LEAP funding) of this amount was agreed on by the parties in the Partial Settlement Agreement.

The OEB is satisfied that the reason for the decline in Festival’s efficiency ranking in 2014 is a result of the modified approach in calculating efficiency ratings adopted in that year. Prior to 2014, the OEB measured a distributor’s efficiency based on two benchmarking evaluations of that distributor’s OM&A costs. Festival ranked between 10 and 13 out of 77 distributors in these assessments. In 2014 the OEB changed to a total cost benchmarking evaluation. This methodology added a capital cost component to the calculation. The OEB accepts Festival’s submission that the change in its efficiency ranking reflects the inclusion of this capital component in the benchmarking evaluation.

Festival noted that it has spent considerable capital to upgrade its electricity system since 2002, in particular in respect of the amalgamated distribution utilities that were added to its service area. Festival also submitted that the reduced capital budget put forward in Festival’s Distribution System Plan will move Festival from the fourth cohort to the third cohort over a two and a half year period.

Based on its previous efficiency rating, taking into consideration OEB staff submissions concerning cost per customer, the OEB is satisfied that Festival has been among the province’s more efficient performers.

In determining a reasonable overall OM&A level for Festival, the OEB has also considered the positions of the intervenors on incremental regulatory cost and compensation.

Incremental regulatory costs

While OM&A charges below a utility’s materiality threshold are generally not subject to consideration in a cost of service proceeding, the OEB finds it necessary to comment on the amount of incremental regulatory costs included in Festival’s proposed OM&A. Festival included an amount of $103,000 in regulatory costs to be amortized over 5 years in its application. This amount includes a one-time cost of $42,300 associated with this proceeding. Since parties reached a partial settlement in this proceeding, the parties requested and were granted approval to have the unsettled issues heard as part of an oral hearing. Consequently, Festival Hydro updated its OM&A budget to include regulatory costs of $17,000 per year to account for the costs of an oral hearing.

VECC argued that such an inclusion was an attempt to introduce new evidence and associated additional costs. VECC argued that the additional cost is untested and should be denied as a matter of fairness.

The OEB notes that this update in the proposed OM&A budget was made prior to the oral hearing and that each party had the opportunity to cross-examine Festival on it. It should be clear to all parties that regulatory costs will very likely increase if a matter proceeds to an oral hearing. The OEB finds it appropriate for Festival to recover these costs and will allow incremental regulatory costs of $17,000 annually for 5 years.

Compensation

Festival's total compensation for 2015 is projected at $4.5 million which, compared to OEB 2010 approved compensation of $3.6M represents an increase of 26%. Of this amount, the total compensation allocated to OM&A is $3.9 million, while $0.6 million is capitalized. Intervenors noted that the compensation allocated to OM&A increased from 77.5% in 2010 to 86.8% in 2015. Over the same period, the levels of capitalized OM&A correspondingly decreased significantly. Energy Probe and other intervenors submitted that compensation allocated to OM&A represents an annual compounded increase of 4.75% per year. Energy Probe further stated that this calculation ignores the fact that Festival's number of full-time employees fell from 47 to 45 over that period. The intervenors submitted that the proposed increase exceeds the OEB's adjustment under the incentive regulation mechanism and suggested that a reduction in the increase of the OM&A portion to an average of 4.0% per year would result in a reduction of $137,000 in total OM&A.

The Board accepts Festival's evidence in respect of its compensation costs. Festival noted that its recently completed labour negotiations resulted in a 2.02% average wage increase. Festival gave evidence that its compensation levels are competitive in comparison to its neighboring utilities. Festival has maintained a relatively constant headcount since 2010, despite an increase in the activities it is undertaking. Based on the evidence provided in the proceeding, the Board has determined that the compensation costs as proposed by Festival are reasonable.

3.0 Incremental Capital Module

Adjustments – Forecast to Actual

In the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors,* July 14, 2008, the OEB established a mechanism for distributors under incentive regulation to address incremental capital needs, as they arise, through an incremental capital module (ICM). While the module itself may provide for a broad scope for incremental capital needs, specific ICM requests are tested against the criteria of materiality, need and prudence at the time of an individual application. In accordance with the policy, the OEB conducts a final prudence review as part of the distributor's next rebasing. At that time, the OEB makes a determination as to the amount to be incorporated in rate base and the treatment of differences between forecast and the actual spending during the incentive regulation (IR) term.

As indicated earlier, the OEB's decision on Festival's application for 2013 rates granted incremental capital funding to support the construction and installation of a new transformer station. The new facility went into service in December 2013. In this application, Festival requests recovery of an additional $634,496 as a result of reconciling its forecasted costs, which were approved as part of Festival's ICM application, with the actual costs it incurred. This true-up includes the following:

- Adjustment to reflect the actual capital cost of the transformer station relative to its initial forecast
- Adjustments stemming from the deferral of Festival's rebasing application:
    - Underrecovery of depreciation expenses
    - Correction for actual in-service date of the asset
    - Correction in the applied capital cost allowance for 2014
- Recovery of additional funding for OM&A costs incurred during the 2013 and 2014 rate years

The amounts are described in Table1 below.

Table1: ICM True-up Calculation (as of December 31, 2014)

Category	Amount ($)
1. Initial ICM Revenue Requirement Initially approved revenue requirement based on expected capital costs.	1,120,687
2. Revised ICM revenue requirement, reflecting adjustments for: a) actual capital costs vs. forecast costs b) full depreciation over a 13 month period (as a result of deferral of rebasing) c) adjustment to the capital cost allowance	1,481,229
3. ICM Revenues Collections via the ICM Rate Rider from May 1, 2013 to December 31, 2014, based on the initially approved revenue requirement	1,091,548
4. Variance (3 minus 2)	389,681
5. Additional costs sought for recovery Incremental OM&A in 2013 and 2014	244,815
6. Total Remaining Recovery Applied For (4 plus 5)	634,496

Adjustment to Capital Costs

As part of Festival Hydro's 2013 rate application, the OEB approved an incremental capital module to recover the capital cost of the new transmission station at a total cost of $15,863,113. In its application for 2015 rates, Festival reported actual capital expenditures of $15,311,782 – a reduction of $551,330. As a result of the actual capital costs being lower than forecast, the corresponding revenue requirement is now lower by an amount of $1,120,687. Intervenors and OEB staff supported Festival's request as appropriate.

The OEB finds the capital costs of $15,311,782 to be appropriate.

Depreciation over a 13 month period

Festival applied for the ICM as part of its application for rates for 2013, which was expected to be Festival's final year of its IRM period. Festival applied the half-year rule to the eligible capital costs for the purpose of calculating the incremental revenue requirement. Under the half-year rule, only half the value of an asset, including depreciation, is recovered in rates in the year it is put into service, reflecting the fact that new assets are not always placed in service at the beginning of the year.

Festival's use of the half-year rule for its new facility was consistent with the OEB's policy regarding the ICM, which indicates that a distributor should apply the half year rule if rebasing is expected in the year following an ICM application. The remaining capital investment would be recognized in the distributor's rate base in the subsequent cost of service application.

Following its 2013 incentive rate application, Festival Hydro requested and was granted the deferral of its rebasing application to January 1, 2015, an eight month delay.

In this application, Festival sought to recover the depreciation that would have been included in its rates had the eventual deferral of rebasing been known at the time of its initial ICM application. Festival now seeks to update its ICM calculation to reflect an actual in service date of December 2013 and the expected effective date of new rates on January 1, 2015. This approach reflects 1 month of depreciation in the 2013 rate year, and a full year's depreciation in 2014, 13 months in total.

The OEB notes that as indicated above, the half-year rule was correctly applied in Festival's original ICM application given the information available at the time, and that the current revenue deficiency is the result of the deferral of Festival's request to defer its rebasing application from May 2014 to January 2015. However, in this instance the OEB accepts Festival's proposal of 13 months of depreciation, because it reflects the actual in service date of the transformer station. The OEB considers that this methodology is suitable for this specific case, but it should not be considered a precedent.

Adjustment to the capital cost allowance

Festival also updated its evidence to make a corresponding adjustment to the amount of applicable capital cost allowance, which reflects the tax depreciation for the purpose of calculating taxable income. This adjustment impacted the calculation of payments in lieu of taxes and resulted in a lower ICM revenue requirement.

The OEB accepts Festival's update and finds the adjustment to the capital cost allowance appropriate. In sum, the OEB accepts a total true-up of the revenue requirement related to capital expenditures in the amount of $389,681 for the period of December 1, 2013 to December 31, 2014. The OEB expects Festival to update its true-up calculation to reflect the actual amount collected through the ICM rate rider to date and adjust its incremental rate rider calculation accordingly.

Recovery of additional funding for OM&A costs incurred in 2013 and 2014 related to the new transformer station

In addition to a true-up of capital related costs, Festival requested the recovery of $244,815 in incremental OM&A for operational costs related to the new transformer station incurred during in 2013 and 2014. These costs are composed as follows:

Table 2: Incremental Capital Module - OM&A costs (2013 and 2014)

O & M Expenses	2013	2014
Training Costs	39,826	$ 3,000
TS Monitoring Costs	3,750	15,000
TS Communication Costs	16,614	24,500
Property taxes	9,926	21,500
Insurance & property protection	7,395	18,000
SCADA maintenance		5,000
Internal labour & trucking costs	18,003	13,000
Station maintenance	9,301	40,000
Total	$ 104,815	$ 140,000

These OM&A costs were incurred after the in-service date of the transformer station and incorporate $40,000 in training costs that were approved in the ICM application as capitalized costs. Following Festival's transition to International Financial Reporting Standards (IFRS), OM&A costs that were formerly capitalized can no longer be capitalized; hence Festival has included these costs in its OM&A request.

Festival based the inclusion of the non-training costs on the same principles as it applied to the smart meter recovery process. Festival further submitted that in its accounting treatment of these costs it sought advice from OEB staff, who in an email confirmed that Festival's approach was appropriate.

OEB staff and intervenors submitted that incremental OM&A costs in general are outside the scope of an ICM. Intervenor and OEB staff also noted that Festival did not request deferral account treatment before these costs were incurred. Therefore, the OEB did not have an opportunity at the appropriate time to consider cost recovery of incremental OM&A costs associated with the new transformer station. Accordingly , the OEB finds that these costs are out of period and cannot be recovered from rate payers.

The OEB allows the $40,000 in training costs which were previously approved as part of the overall capital cost of the transformer station. The OEB agrees with Energy Probe's submission that it would not be appropriate to penalize Festival for not allowing the recovery of formerly capitalized training costs as a result of the change to accounting standards under which this expenditure is no longer recognized as capital.

In regard to all the other above OM&A expenses, the OEB notes that the ICM was designed to address concerns regarding the treatment of incremental capital needs.The OEB notes, that unlike the smart meter process, the ICM process approved by the OEB does not contemplate approval of incremental OM&A expenses associated with the new asset. If Festival had considered that these incremental expenses should be approved nonetheless, it could have sought an exception to the general policy in the ICM process as part of its 2013 rates application in the timeframe when the costs were incurred. To approve these 2013 and 2014 expenses at this point would amount to retroactive ratemaking.

Finally, while the OEB recognizes that Festival obtained OEB staff guidance regarding the accounting treatment of such expenses, the OEB notes that Festival's request for advice lacked specific details and context and accordingly yielded advice that was only of a very general nature.The OEB also notes that regardless of any advice that OEB staff might provide, only an OEB order can approve the accounting treatment of the expenses.

4.0 Fixed/Variable Split For The GS>50kW Customer Class

In the settlement proposal the parties reached a partial settlement with respect to rate design. However, the parties were unable to agree on the appropriate division between fixed and variable charges, also known as the fixed/variable split, for the GS>50 kW customer class. Festival proposed rates based on the existing fixed/variable split. This would have resulted in a fixed charge that would move further away from the ceiling amount established by the OEB. The ceiling is based on the calculated cost for a basic system to provide electricity to an individual customer in any given class, irrespective of the amount of electricity consumed. In response to interrogatories, Festival took the position that the maximum fixed charge should be the greater of a) the existing rate or b) the ceiling amount. As a result, Festival Hydro proposed maintainng the status quo, which means retaining the current fixed charge for the GS>50 kW customer class at $227.57, to maintain rate stability and predictability.

During the oral hearing Festival noted that the OEB's policy initiative on rate design for electricity distributors signaled the OEB's intention to pursue a fixed rate design solution for certain classes to achieve class revenue that would be independent of the forecasted electricity demand of that class. Festival submitted that the OEB's direction, at a high level, has been that fixed charges would tend to stay the same or increase.

SEC disagreed with Festival's proosal and proposed a fixed rate of $64.55 for that rate class, consistent with the OEB's ceiling amount. While SEC accepted that a lower fixed rate might cause large variation in year-over-year rates, SEC submitted that a lower fixed rate would balance the impact with fairness to all GS>50 customers, including those on the lower end of the GS>50 demand spectrum, who SEC argues continue to pay higher rates than they should. SEC also argued that the OEB has not adopted a policy in which the cost of the distribution system attributed to the residential class would be recovered through only a fixed monthly rate, irrespective of the electricity consumed by residential customers to date. SEC also submitted that the fixed charges for the GS>50 rate class should not be impacted by a consideration of other rate classes.

OEB staff supported Festival's proposal as consistent with the OEB's 2015 Filing Requirements and aligned with the direction of the OEBinitiative regarding rate design based on fixed charges only.

All other intervenors submitted that the fixed charge should remain at $227.57 for the duration of the incentive rate period as a lowering the charge to the ceiling would unnecessarily impact rate stability and predictability for some customers in the GS>50 kW customer class.

The OEB approves Festival's proposal of $227.57/month for the GS>50 kW customer class. Section 2.11.1 of the 2014 Filing Requirements for Electricity Distributors states that "if a distributor's current fixed charge is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling". The OEB finds that Festival's proposal to maintain the status quo is consistent with the OEB's guidance, promotes rate stability and is consistent with the OEB's practices. The OEB is not persuaded that a change from the OEB's Filing Requirements is warranted in this case.

The OEB notes that its most recent policy document on fixed rates indicated that distributors should implement fixed rates only for residential customers at this time[6]; rates for general service customers are to be the subject of a subsequent review.

IMPLEMENTATION AND ORDER

Festival requested that its rates become effective January 1, 2015. The OEB's general practice with respect to the effective date of rates is that the final rate becomes effective at the conclusion of the proceeding. Consequently, the OEB finds that the rates resulting from the OEB's determination in this proceeding will be effective May 1, 2015. The OEB notes that while Festival's original application in this proceeding was filed on April 28, 2014, this application was incomplete. The OEB notes that a revised, complete application was not filed until May 30, 2014.

The OEB directs Festival to provide a revised ICM true-up calculation to account for ICM funding collected from January 1, 2015 to April 30, 2015. Given the OEB's determination in respect of the rates implementation date, the OEB will allow the ICM true-up calculation to incorporate the full depreciation expenses incurred during since January 1, 2015, raising the number of months of depreciation from 13 to 17. The OEB expects that this revision will be included in the calculation. The OEB also directs that the rate riders for the disposition of Group 1 and Group 2 account balances, Account 1575 and 1576, and stranded meter rate riders reflect a June 1, 2015 implementation date. Festival shall also include a calculation to recover any foregone revenue to reflect an effective date of May 1, 2015. Festival shall submit as part of its draft rate order detailed calculations in Microsoft Excel format.

The results of the settlement proposal together with the OEB's findings outlined in this decision are to be reflected in Festival's draft rate order. The OEB expects Festival to file detailed supporting material, including all relevant calculations showing the impact of the implementation of the settlement agreement and this decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes, and the determination of the final rates, including bill impacts.

[6] Board Policy: *A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015, EB-2012-0410, p 2

The draft rate order supporting documentation shall include, but not be limited to, filing a completed version of the revenue requirement work form spreadsheet which can be found on the OEB's website. Festival shall also show detailed calculations of any revisions to the rate riders or rate adders reflecting the settlement agreement and the findings in this decision.

THE BOARD ORDERS THAT:

1. Festival Hydro shall file with the OEB, and shall also forward to Energy Probe, SEC, VECC and AMPCO a draft rate order attaching a proposed Tariff of Rates and Charges reflecting the OEB's findings in this Decision and Order, within **7 days** of the date of this Decision and Order. The draft rate order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. Energy Probe, SEC, VECC and AMPCO and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Festival Hydro, within **6 days** of the date of filing of the draft Rate Order.

3. Festival Hydro shall file with the OEB and forward to Energy Probe, SEC, VECC and AMPCO responses to any comments on its draft Rate Order within **3 days** of the date of receipt of the submission.

Cost Awards

1. Energy Probe, SEC, VECC and AMPCO shall file with the OEB and forward to Festival Hydro Inc. their respective cost claims within **7 days** from the date of issuance of this Decision and Order.

2. Festival Hydro Inc. shall file with the OEB and forward to Energy Probe, SEC, VECC and AMPCO any objections to the claimed costs within **17 days** from the date of issuance of this Decision and Order.

3. Energy Probe, SEC, VECC and AMPCO shall file with the OEB and forward to Festival Hydro Inc. any responses to any objections for cost claims within **24 days** of the date of issuance of this Decision and Order.

4. Festival Hydro Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, **EB-2014-0073**, be made through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

DATED at Toronto, April 30, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND ORDER
EB-2014-0073

Festival Hydro Inc.
Settlement Proposal

DATED: April 30, 2015

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2013-0130

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Fort Frances Power Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Cathy Spoel
Presiding Member

Marika Hare
Member

DECISION AND ORDER
August 14, 2014

Fort Frances Power Corporation ("FFPC") filed a complete cost of service application with the Ontario Energy Board (the "Board") on February 14, 2014 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that FFPC charges for electricity distribution, to be effective May 1, 2014. The Board issued a Notice of Application and Hearing dated February 25, 2014.

On March 20, 2014, the Board issued Procedural Order No. 1 and Order for Interim Rates granting requests for intervenor status and cost award eligibility to the Vulnerable Energy Consumers Coalition ("VECC") and making FFPC's current approved rates interim effective May 1, 2014 pending the outcome of this proceeding. .

The Board held a written hearing preceded by interrogatories and a non-transcribed teleconference among the parties to allow for the clarification of interrogatory responses.

The following issues are addressed below in considering FFPC's application:

- Effective Date for Rates;
- Foundational Issues
- Performance
- Operating Revenue (Customer Forecast, Load Forecast and Other Distribution Revenue);
- Operating, Maintenance & Administration Expenses;
- Depreciation;
- Rate Base and Capital Expenditures;
- Cost of Capital and Financial Performance;
- Cost Allocation and Rate Design (Cost Allocation, Monthly Service Charges and Specific Service Charges);
- Deferral and Variance Accounts; and
- Implementation.

Unless specifically addressed in this Decision and Order, the Board finds that the evidence filed by FFPC on the issues in this proceeding is sufficient to support the application.

EFFECTIVE DATE FOR RATES

FFPC applied for rates effective May 1, 2014. In Procedural Order No. 1, the Board declared FFPC's current rates interim effective May 1, 2014.

Board staff submitted that an effective date of July 1, 2014 would be appropriate as a complete version of FFPC's application was not filed with the Board until February 14, 2014 which was a delay of four and a half months from the filing date of October 1, 2013. However, Board staff also noted that subsequent to the filing of the application, FFPC filed all materials by the dates set out in the Board's Procedural Orders.

VECC agreed with Board staff that based on the late filing date the requested effective date of May 1, 2014 should not be granted. VECC submitted that rates should be declared on a forward basis subsequent to the issuance of the Board's final rate order.

FFPC agreed with Board staff's submission that an effective date for rates of July 1, 2014 would be appropriate.

The Board finds that a September 1, 2014 effective and implementation date is appropriate given the delay in filing the application, the standard time required for the Board to process a cost of service application (185 days) and the timing of the Board's Decision and Order. Under these circumstances, the Board finds that the first day of the month after the issuance of the Board's final rate order, September 1, 2014, is an appropriate effective date and is consistent with a number of previous decisions.

FOUNDATIONAL ISSUES

FFPC stated that it had organized its Distribution System Plan ("DSP") according to the expected format contained within the March 28, 2013 "Chapter 5 Consolidated Distribution System Plan Filing Requirements Guide".

FFPC stated that it is dedicated to providing services in a manner that responds to customer preferences and that during the summer of 2013, it had conducted an extensive customer satisfaction survey that was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs.

FFPC further stated that the feedback gathered has helped it to shape its capital expenditures, and has allowed it to devote operational resources over the planning period to aligning service offerings with the needs of its customer base.

Board staff submitted that the planning undertaken by FFPC and outlined in the Application, as clarified by interrogatory and teleconference responses, supported the appropriate management of the applicant's assets, subject to the disallowances recommended by Board staff.

Board staff further submitted that the customer engagement activities undertaken by FFPC are commensurate with the approvals requested in the Application considering that 2014 is a transitional year. Board staff also argued that FFPC should obtain more specific customer feedback on its next DSP.

VECC submitted that while it was generally supportive of the customer engagement of FFPC, it considered that there were two deficiencies: The first was that as with most other utility surveys, no effort was made to engage customers as to the cost effectiveness of the utility. The second is that FFPC did not attempt to understand its customers' preferences or interests with respect to its capital budget.

The Board finds that FFPC has appropriately addressed the foundational issues raised by the application and its customers have been adequately engaged, given that 2014 is a transitional year. The Board agrees with Board staff and VECC that FFPC's next cost of service application should be based on customer engagement activities that will provide customers with more specific information as to the costs of its proposals.

PERFORMANCE

FFPC expressed its concern that its current performance scores derived from historic RRR reported OM&A cost data are flawed, as they include costs associated with the upkeep of the 1905 Historical Power Agreement (the "Agreement"), as well as costs associated with the upkeep and operation of a High Voltage Transformer Station, which prior to 2012 was improperly classified as a Distribution Station.

FFPC concluded that a fair assessment of its performance would be based upon its costs without the Agreement and the Transformation Station Costs or, alternatively, at the Total Bill level.

FFPC submitted that it was seeking in this proceeding an order directing Board staff and FFPC to work with the Pacific Economic Group ("PEG") to ensure that the calculations that support the scorecard and efficiency ratings for FFPC are adjusted to exclude capital and OM&A costs associated with the transformer station and the administration of the Agreement.

Board staff argued that most of the concerns expressed by FFPC either relate to costs that would have been incurred in the absence of FFPC's particular circumstances, or are already taken into account by the analysis used in determining the benchmarking categories. Accordingly, Board staff submitted that it was not necessary for the Board to provide the direction requested by FFPC upon this matter.

Board staff noted that FFPC's efficiency benchmarking performance is below average, but accepted that the beneficial effects of the Agreement offset this to some extent and considered that overall FFPC's performance supports the application.

VECC submitted that FFPC's service quality indicators are demonstrative of a well maintained utility. Where FFPC's benchmarking performance is concerned, VECC argued that as noted by Board staff, the costs related to FFPC's transformation station are a relatively small part of the overall costs of the utility and notwithstanding this fact, the FFPC benchmark performance is below average for its cohort. VECC concluded that this argued for a close examination of the proposed OM&A costs.

The Board understands that there may be some confusion as to the extent that the data sets used to determine FFPC's efficiency are appropriate. The Board directs FFPC and Board staff to work together to ensure that appropriate inputs are used for future benchmarking, if they have not already done so.

OPERATING REVENUE

Customer Forecast

FFPC forecast 4,754 customers and connections (including street lighting connections) for 2014. The forecast was derived from a review of historical customer/connection data which was used to determine growth with a geometric mean approach used to determine the 2013 and 2014 forecasts.

Board staff accepted FFPC's customer forecast. VECC submitted that the forecast customer counts by class for 2014 were reasonable, except that for the Streetlighting class, VECC submitted that the actual 2013 connection count of 1,030 should be used for 2014 in place of the forecast count of 1,006.

FFPC submitted that it is not appropriate to single out one customer class for adjustment in this way and that while using the 2013 number for Streetlighting connections happens to result in an expected decrease in rates, using the 2013 numbers for other classes will result in an expected increase in rates.

The Board approves FFPC's proposed customer forecast for 2014. The Board does not accept the adjustment proposed by VECC as it is selective and also unlikely to be material.

Load Forecast

FFPC developed its load forecast by using a multifactor regression model to determine the relationship between historic load with weather data and calendar related events.

FFPC made further adjustments to the 2014 forecast to account for the impact of Conservation and Demand Management ("CDM") activity totaling 1,148,562 kWh to the 2014 test year forecast which has been broken down by rate class. This is determined as one half of the savings from 2012 programs, a full year of savings from 2013 programs and a half year of savings from 2014 programs.

FFPC's proposed load forecast for 2014 is as follows:

Table 1: Load Forecast

Rate Class	kWh
Residential	37,751,518
GS < 50 kW	13,617,679
GS 50 to 4,999 kW	26,376,324
Street Lighting	366,947
Unmetered Scattered Load	48,552
TOTAL	**78,161,019**

VECC submitted that overall FFPC's purchased power forecast model was reasonable, but that the forecast variables for 2014 will need to be adjusted to reflect any changes approved by the Board in its 2014 forecast customer count. VECC also agreed with FFPC's CDM adjustment. Board staff also accepted FFPC's load forecast as reasonable.

The Board finds that FFPC's load forecast is appropriate. The Board notes that no party opposed the load forecast.

Other Distribution Revenue

FFPC forecast total other distribution revenue of $108,033 for 2014. FFPC also proposed the removal of unused specific service charges and a revision of some existing charges to recover current business costs.

VECC noted that FFPC's actual Other Revenues for 2013 were materially higher than FFPC's forecasts for both 2013 and 2014. VECC argued that while FFPC claimed that some of the difference could be attributed to one-time events such as Non-Utility Rental, there was Non-Utility Rental Income in each of the previous four years averaging $24,184 per year, whereas the forecast for 2014 is nil. VECC made a similar argument regarding Retail Service Revenues and submitted that it would accordingly be reasonable to increase the forecast for 2014 Other Revenues by at least $10,000 resulting in an Other Revenue Forecast for 2014 of $118,033.

Board staff noted that the proposed changes in FFPC's Other Revenues were well below its materiality threshold and accepted FFPC's evidence on this matter. Board staff also accepted the request by FFPC to remove the eight specific service charges and to increase six others, although Board staff did note that the eight charges which FFPC is requesting be removed are ones that normally appear on distributor tariffs.

FFPC submitted that its forecast Other Revenue is slightly reduced for 2014 relative to 2013 actuals to reflect realistic income levels as a result of minimal anticipated street lighting related maintenance work and customer capital projects.

The Board accepts FFPC's justification for the 2014 forecast level of Other Revenue and finds that no adjustment is necessary. The Board also accepts FFPC's proposed revisions to its specific service charges. The Board agrees that the reduction proposed by VECC to Other Revenue is well below FFPC's materiality threshold, as is the impact of the changes to FFPC's specific service charges.

OPERATIONS, MAINTENANCE & ADMINISTRATION ("OM&A")

FFPC's proposed 2014 OM&A of $1,657,650 represents a 3.3% increase over the actual 2012 OM&A and a 66% increase over the 2006 Board approved OM&A level.

Table 2: OM&A Expenses $

	2006 Board Approved	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
Operations	142,165	195,697	213,851	209,500	371,000
Maintenance	106,651	169,076	377,219	213,000	304,000
Billing & Collection	144,547	213,984	255,946	235,500	268,000
Community Relations	4,712	6.024	5,978	4,750	37,150
Administrative & General	603,271	717,211	751,977	763,500	677,500
Total	1,001,346	1,301,992	1,604,971	1,426,250	1,657,650
% Change		30.02	23.27	-11.14	16.22

VECC submitted that based on benchmarking FFPC is a high cost utility with OM&A costs per customer much higher than most Ontario electricity distributors. VECC argued that if FFPC's 2006 Board Approved OM&A were adjusted only for customer growth, inflation and incremental responsibilities it would be expected to increase by between $140,892 and $273,129, rather than the $656,304 increase proposed by FFPC. VECC submitted that while it had taken an envelope approach to its analysis, it submitted that there are areas in which OM&A savings might be achieved. VECC made a number of specific suggestions for reductions.

Board staff submitted that FFPC's proposed 2014 OM&A level should be accepted subject to a disallowance of $25,681 for proposed expenses related to the Long Term Load Transfer ("LTLT") capital project which Board staff submitted should not be approved by the Board. Board staff stated that while it did consider FFPC to be a high-cost utility FFPC's rate minimization strategy, characterized by a zero return on equity, has resulted in long term savings for ratepayers and, therefore Board staff is not recommending further OM&A reductions.

FFPC agreed with Board staff's proposal that the only adjustment to its 2014 OM&A should be the disallowance of the $25,681 proposed LTLT expenses.

FFPC submitted that VECC's model for determining expected OM&A costs is entirely unworkable, as VECC's proposed 2014 OM&A allowance would have been barely adequate for FFPC in 2008. FFPC noted that even with the staffing increase allowance of $150,000 supported by VECC, the level of increase in FFPC's 2014 OM&A cost would be lower than its actual OM&A costs from 2012 forward, and would be significantly less than requirements demonstrated by the industry as a whole. FFPC argued that VECC's approach also did not take into consideration FFPC's adjustment of its business needs to align with the requirements of the RRFE and was a backward-looking analysis, while FFPC's is forward looking.

The Board finds that the level of OM&A proposed by FFPC in its application is appropriate subject to any adjustments that may arise from the Board's findings in the Rate Base and Capital Expenditures section of this Decision and Order. The Board will not disallow the $25,681 of proposed expenses related to the LTLT capital project proposed by Board staff as the Board is approving the LTLT project as discussed in the Rate Base and Capital Expenditures section of this Decision and Order.

The Board agrees with FFPC that the adjustments to its OM&A proposed by VECC are unrealistic and therefore inappropriate for FFPC to undertake. The Board also agrees with Board staff that FFPC's rate minimization strategy has resulted in long term savings for ratepayers which allows for somewhat higher OM&A than might otherwise be the case.

DEPRECIATION

FFPC proposed a depreciation/amortization expense of $197,074 in 2014. FFPC stated that it had filed under Canadian Generally Accepted Accounting Principles ("CGAAP") for 2014, but had adjusted depreciation in 2012 to a Modified International Financial Reporting Standards ("MIFRS") calculation.

FFPC further stated that through its contracted services to the Town of Fort Frances, it did not use the Board depreciation policy of the "half-year" rule. FFPC stated that it realized its approach of using a full year of depreciation deviated from standard practice and would implement the half year rule methodology in 2014.

VECC and Board staff accepted FFPC's proposed depreciation expense.

The Board accepts FFPC's depreciation evidence and its proposed 2014 depreciation/amortization expense on the basis that FFPC will implement the half year rule methodology in 2014.

RATE BASE AND CAPITAL EXPENDITURES

FFPC proposed a rate base of $4,793,453, which would represent a 9% increase from the 2012 actual amount and a 7.5% increase from the 2006 Board approved amount. FFPC stated that the proposed increase in 2014 was primarily due to planned feeder expansions to eliminate LTLTs, new line transformers and transportation equipment.

FFPC projected capital expenditures to be in the $660 to $700 thousand range in the 2015 to 2018 period in its DSP, as is shown below:[1]

Table 3: Distribution System Plan Forecast

	Forecast Period (planned) ($000)				
	2014	**2015**	**2016**	**2017**	**2018**
Category					
System Access	422	40	20	45	12
System Renewal	254	419	504	531	361
System Service	49	142	60	58	15
General Plant	97	76	76	33	311
Total Expenditure	820	676	660	667	698

[1] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 20, 2013, Exh 2/Tab3/Sch 1, p.4*

Board staff's submission noted that FFPC's capital spending averaged about $269,000 in the 2006 to 2012 period, but is forecast to average about $704,000 in the 2014 to 2018 period which is close to a three-fold increase in the forecast period compared to in recent years.

Board staff submitted that FFPC's proposed 2014 LTLT project should not be approved at the present time, but that a phased development plan for the servicing of this territory would be appropriate.

Board staff also submitted that the $95,648 requested by FFPC in the category of overhead and pad-mounted transformers should be reduced to $50,000 as FFPC should only replace transformers that have customer impacts categorized by FFPC as "Very High" or "High" in addition to those reported as "Failed" or "Not suitable for reuse", rather than also replacing those in the "Medium" and "Low" categories as proposed by FFPC. This meant that for the 2014 Test year, funding should only be provided for 7 out of the 15 transformers proposed to be replaced.

Board staff suggested that where FFPC's DSP was concerned, while it was relatively comprehensive, the next DSP would benefit from more emphasis on specific customer feedback regarding the DSP. The DSP would also benefit from an attempt to monetize the savings to be achieved in FFPC's OM&A over the five year planning period as it moves from a maintenance mode to a proactive capital rebuild mode.

VECC expressed general agreement with Board staff with respect to the capital renewal program. VECC submitted that the relatively young vintage of the utility's plant and the lack of detailed information on existing plant argue for a more conservative approach. VECC noted that Board staff had suggested reducing the Overhead & Pad-Mounted Transformer Replacement Program by about 50% for 2014. VECC agreed and submitted that it would be reasonable for FFPC to reduce its anticipated spending on the program by 50% for the entire 5 year period.

VECC also argued that FFPC's LTLT proposal should not be approved as it was neither reasonable to its customers who would be faced with an inordinate cost burden and risk, nor is it economically efficient and in the public interest.

FFPC agreed with the proposal of Board staff that 2014 capital expenditures be reduced from $820,316 to $402,929 and proposed to bring forward the issue of its LTLT project in a future application, once the Board has completed its policy review on the topic. FFPC suggested that the costs of this project could be dealt with in a future Incremental Capital Module submission as part of FFPC's annual IRM submission.

FFPC stated that it made the LTLT expansion proposal both to be in compliance with the Distribution System Code by June 30, 2014 and to be consistent with its belief that under the Agreement, all residents of the Town of Fort Frances, including the 14 residents who are currently served by Hydro One, are entitled to the benefits flowing from that Agreement.

FFPC noted that both Board staff and VECC had commented in their final submissions that FFPC's capital plan with respect to transformers might be aggressive and would benefit from more specific customer feedback. FFPC expressed its general agreement with this point and stated that it was committed to further improving its customer engagement activities. FFPC also accepted Board staff's recommended approach for pacing transformer replacements.

Where FFPC's proposed LTLT is concerned, the Board first notes that the situation described by FFPC is not a typical load transfer arrangement because these 14 customers are not billed by FFPC which is the geographic distributor, nor do they pay FFPC's distribution rates. Hydro One is the physical distributor for these customers (i.e. owns and operates the assets that connect them) and has been billing them since the time they were connected. The Board also notes that in response to a Board staff teleconference question, FFPC confirmed that these customers are in FFPC's service territory.

FFPC was asked during this proceeding why it did not install its own meters for these customers. FFPC explained that at the time the LTLT homes were electrified, its distribution system was not in close proximity to most of the homes and the legal dispute over the Agreement was not resolved until 1983, when the Supreme Court of Canada issued its decision on the Agreement confirming FFPC's perpetual right to call for delivery of the low cost power.[2] FFPC stated that it does not believe that it has ever

[2] *Supreme Court of Canada Decision ([1983] 1 SCR 171)*

had the consent from stakeholders, including Hydro One and the Board, to proceed with replacing the metering assets of Hydro One with its own.

FFPC was asked during the proceeding to quantify the annual savings for these customers were they to begin paying FFPC's distribution and commodity rates. FFPC estimated that for a residential customer consuming 1,000 kWh monthly in 2013, the savings would be close to 50% of the total bill.

Given the magnitude of these savings, the Board does not consider it necessary to await the completion of its policy review of long-term load transfers before making a decision on FFPC's LTLT proposal. The Board also notes that the policy review would not cover the unique circumstances of FFPC, given this is not a load transfer agreement per se, that no amendment is required to the service area, as based on the evidence provided by FFPC these customers are already within FFPC's service area, and due to the existence of the Agreement with respect to commodity prices. In addition the Board notes that FFPC stated that the completion of this project will unlock access to approximately 25.4% of its service territory that is not developed, while also offering considerably improved access for potential renewable generation facilities. A further benefit would be that the implementation of this project would provide an alternate supply of electricity in close proximity to the Fort Frances Airport.

The Board agrees with FFPC that all the customers in its service area should have the benefit of the Agreement and accordingly finds that this project is approved with one qualification. The Board notes that FFPC has stated that it believes it could extend its plant to only 13 of the 14 customers by the end of 2014. The financial impact for FFPC if it is unable to connect one of the 14 customers by the end of 2014 is between $30,000 and $46,446. The Board will approve funding of this project sufficient to allow for the connection of 13 customers in 2014. Accordingly, the Board will disallow $40,000 from the proposed capital budget. As part of the draft rate order process, the Board will expect FFPC to provide adjusted capital expenditure and operating expense levels to reflect this adjustment along with all necessary explanations. Given the magnitude of the LTLT project compared to the total capital expenditures of FFPC, the Board will establish a variance account to track the expenditures to be reviewed in a future application. FFPC shall file a draft accounting order in its draft rate order to reflect this finding.

The Board considers that overall FFPC's proposed DSP may be somewhat aggressive and finds Board staff's recommended approach for pacing transformer investments is reasonable. The Board will accordingly approve $50,000 of 2014 capital expenditures for transformers.

The Board therefore finds that it will reduce FFPC's 2014 capital expenditures request from $820,316 to an approved level of $734,668.

Capital Contributions

VECC submitted that as FFPC was using a 'net' form of capital expenditure accounting it had not properly accounted for capital contributions.

The Board notes that in response to a Board staff teleconference question[3] FFPC confirmed that its treatment of capital contributions will be consistent with Article 430 of the *Accounting Procedures Handbook* (APH").

The Board finds that FFPC's confirmation that its treatment of capital contributions will conform to the APH adequately addresses the concerns raised by VECC. FFPC should include in its draft rate order filing confirmation that the treatment of capital contributions in the 2014 Test year is in conformity with the APH.

Working Capital Allowance

FFPC proposed a $1.1 million Working Capital Allowance based on the Board's default rate of 13%.

VECC submitted that a rate of 12% would be more appropriate because FFPC bills its customers on a monthly basis. VECC submitted that the Board's default rate was established when most utilities offered bi-monthly billing and that monthly billing utilities have a lower need for cash than bi-monthly utilities. VECC referred to a lead-lag study completed by London Hydro, a monthly billing utility, which indicated a lower working capital requirement close to 11%. Board staff took no issue with FFPC's proposal.

[3] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014*, p. 15, 4.2-Staff-43.

The Board has considered the arguments of VECC but finds no compelling reason to depart from its default rate. The Board does not consider it appropriate to adopt the results of a lead-lag study from another utility without a thorough analysis concluding that the two utilities are comparable.

Renewable Enabling Improvement ("REI") Plan

FFPC does not have any planned investments specific only to achieving smart grid objectives, but is proposing $50,000 in 2014 investments related to its development of a REI plan. This is stated by FFPC as being aimed at safely and reliably accommodating the connection of renewable energy generation facilities through improvement to its transformer station "FFMTS," which presently cannot accommodate 2-way or reverse electrical flow at any level.

FFPC is also proposing to recover $53,757 for all renewable energy generation ("REG") costs that FFPC incurred up to the end of the 2013 calendar year, including capital, OM&A and carrying charges booked in the Board established deferral accounts.

Board staff accepted FFPC's proposed REG plan as reasonable, along with the proposed allocation percentages, but expressed some concerns about the extent to which FFPC's proposed REI expenditures may also be considered as normal distribution system expenditures. Board staff argued that FFPC should provide a stronger rationalization in future applications as to how it distinguishes expenditures included in its REG plan from normal expenditures.

VECC supported the submissions of Board staff on this issue.

The Board accepts FFPC's proposals regarding its REI and REG costs as appropriate expenditures for recovery under these plans. The Board agrees with VECC and Board staff that FFPC should provide stronger rationalizations in future applications as to how it distinguishes expenditures included in its REG plan from normal expenditures.

FFPC should include in its draft rate order filing a draft accounting order for account 1533, Renewable Generation Connection Funding Adder Deferral account, "Sub-account Provincial Rate Protection Variances". In accordance with this Decision and Order, FFPC should also specify the amount that it would be expecting to receive from the IESO on a monthly and annual basis for the 2014 rate year commencing September 1, 2014.

COST OF CAPITAL AND FINANCIAL PERFORMANCE

FFPC's application included the following cost of capital parameters:

Table 4: Proposed Cost of Capital Parameters

Cost of Capital Parameter	FFPC's Proposal
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	2.11%
Long-Term Debt	4.88%
Return on Equity (ROE)	0%
Weighted Average Cost of Capital	2.82%

FFPC stated that since it operates under a 0% rate-of-return, it does not have a profit margin buffer of up to 9.8% per year to absorb unforeseen expenses or the financial impact of not achieving expected efficiency gains. FFPC confirmed that it maintains a current cash investment level of $2.1 million for future capital expenditures, as a matter of policy at the direction of its Board of Directors.

Board staff submitted it would be desirable that any rate relief received by FFPC as a result of this Application be sufficient to allow it to avoid developing another accumulated deficit similar to the one that has precipitated this application during the normal 5-year period between cost of service applications.

Board staff supported FFPC's cost of capital proposal. It submitted that given FFPC's unique circumstances, including cash reserves presently exceeding $2 million, its proposed cost of capital parameters would be a sufficient buffer for FFPC in the years ahead, while resulting in considerable savings for its customers. Board staff also argued that its position is consistent with the Board's endorsement of FFPC's rate minimization strategy in 2006.

VECC submitted that nothing precluded FFPC from earning a rate of return sufficient to enable stable long-term operations. VECC argued that FFPC's proposed 0% return for rate-setting purposes was not prudent since simply based on variations in demand induced by weather a utility will over earn in some years and under earn in others. VECC submitted that while FFPC has been able to build up a considerable reserve, this is because rates recover the Board approved debt costs, while FFPC is actually debt free.

VECC submitted that it is unlikely the Agreement would be threatened by having rates calculated with the inclusion of a modest return (1-3%) since in the long run such a return would equate to zero. VECC also suggested that if FFPC was to do so under an order of the Board, it would have the added protection of a regulatory defence.

VECC argued that with respect to FFPC's long-term debt, it would be prudent for FFPC to restructure so as to have affiliated debt issued by its shareholder, through the declaration of a dividend which would then be lent back in whole or in part to FFPC. VECC pointed out that this was the common structure of municipally owned utilities in Ontario.

VECC concluded that since the overall cost of capital is significantly below the allowable amount, it supported the current cost consequences of FFPC's proposal.

The Board accepts FFPC's proposals with regard to its cost of capital as the Board is of the view that FFPC should not take any risks which could endanger the Agreement, which the Board understands is for the benefit of the residents of the Town of Fort Frances on condition power is distributed on a non-commercial basis. As noted above, the benefit to residential ratepayers who consume approximately 1000 kWh is that their total bills are approximately half of those in surrounding areas served by Hydro One. The Board does not believe that there is any reason to require FFPC to depart from its 0% rate of return policy.

COST ALLOCATION AND RATE DESIGN

Cost Allocation

FFPC stated that it has filed its application using the cost allocation model that reflects the findings in the *Report on the Review of Electricity Distribution Cost Allocation Policy,* *March 31, 2011.* ("Cost Allocation Policy Review") The following table summarizes FFPC's current and proposed revenue-to-cost ratios compared to the Board's target range for each customer class.

Table 5: Revenue-to-Cost Ratios

Customer Class	2006 Board Approved %	Cost Allocation Model %	Proposed 2014 %	Board Target Range %
Residential	91.60	83.44	97.50	85 – 115
GS < 50 kW	105.79	86.40	97.50	80 - 120
GS 50 to 4,999 kW	126.30	227.47	120.0	80 - 120
Street Lighting	89.56	94.69	97.50	70 - 120
Unmetered Scattered Load	117.05	119.68	119.31	80 - 120

VECC and Board staff accepted FFPC's cost allocation proposals as appropriate for the purposes of setting 2014 rates.

The Board finds that FFPC's proposed cost allocation is appropriate for the purpose of setting 2014 rates as all of the proposed 2014 ratios are within the Board target ranges.

Monthly Service Charges

FFPC is proposing to increase its monthly service charges as well as its volumetric charges for four of its five classes. The exception is the GS 50 to 4,999 kW class for which the fixed charge would decrease from $242.06 to $165.98 and the volumetric charge from $3.59 to $2.51.

The table below shows the current and proposed fixed charges for each class, along with the ceiling values:

Table 6: Monthly Service Charge

Rate Classes	Current	Proposed	Ceiling	Floor
Residential	$12.05	$18.79	$22.94	$9.18
GS < 50 kW	$29.03	$43.62	$33.19	$16.08
GS 50 to 4,999 kW	$242.06	$165.98	$72.00	$44.24
Street Lighting (per connection)	$1.17	$1.60	$8.93	$0.75
Unmetered Scattered Load (per customer)	$29.03	$38.24	$19.14	$7.00

VECC submitted that for a number of FFPC's customer classes, the current 2013 fixed charge is already higher than the "ceiling" as established by the cost allocation model and that for these classes, the Board should consider keeping the 2014 fixed charge at the 2013 level.

Board staff noted that the fixed charges for the GS<50kW and USL customer classes are proposed to either move further away from the ceiling or to exceed the ceiling having been below it before. In the case of the GS 50-4,999 kW class the existing monthly charge was already above the ceiling and the proposed charge moves it closer to the ceiling.

Board staff submitted that in the normal course, it would suggest to revise the fixed/variable splits in order to avoid raising the fixed charges in the GS<50 kW and USL classes. However, this would mean raising the variable component of the inter class allocation for each of these classes, one of which is a class which may continue to be impacted by the economic situation faced by the Town of Fort Frances.

Board staff accepted FFPC's decision to maintain the current fixed/variable splits at the present time noting that for typical rate class consumption levels, the total bill impacts for all rate classes are below the 10% level.

FFPC submitted that it would not be appropriate to hold the fixed charge to the 2013 level as proposed by VECC since as business closures and housing vacancies increase in the Town of Fort Frances due to the recent mill closure, the 2014 proposed fixed charge is an appropriate safeguard to protect the financial viability of FFPC.

The Board accepts FFPC's and Board staff's arguments and approves the fixed charges proposed in the application.

DEFERRAL AND VARIANCE ACCOUNTS

Balances Proposed for Disposition

FFPC is requesting disposition of the Group 1 and Group 2 deferral and variance account principal balances as at December 31, 2012 and the forecasted interest to April 30, 2014, over a two year period. FFPC stated that the default disposition term of one year would create hardship for FFPC.

Table 7: Proposed Group 1 and 2 Account Balances for Disposition

Account #	Account Description	Disposition Amount[4]
1580	RSVA – Wholesale Market Service Charge	($99,297)
1584	RSVA – Retail Transmission Network Charge	$1,588
1586	RSVA – Retail Transmission Connection Charge	($156)
1588 – Pwr	RSVA – Power (excluding Global Adjustment)	$56,077
1589 – GA	RSVA –Global Adjustment	($224,583)
1508	OEB Cost Assessment	$8,451
1508	IFRS Transition	$27,183
1531	Renewable Generation Connection	$1,966
1582	RSVA One Time	$6,891
2425	Other Deferred Credits	($6,144)
1568	LRAM Variance Account	$27,572
	Total Proposed for Disposition excluding Global Adjustment	**$24,131**
	Total Proposed for Disposition	**($200,454)**

With the exception of the balance in the LRAM Variance Account 1568 which Board staff argued should only include the LRAMVA balance of $5,050, Board staff stated that it did not have any concerns with the balances proposed for disposition. FFPC had also included an LRAM amount of $22,523 in this account relating to a period prior to the establishment of the LRAMVA which Board staff submitted it should not be recorded in the account.

[4] Debit amounts are recoverable from FFPC's customers and credit amounts are refunded by FFPC back to its customers.

FFPC confirmed in its reply submission that it would amend the LRAMVA balance in Account 1568 to $5,050, as proposed by Board staff and proposed that the LRAM amount of $22,523 would be recovered through separate rate riders.

Board staff noted that as part of the disposition request of -$200,454, FFPC had proposed disposition of its IFRS Transition Costs of $27,183 which includes forecasted interest to April 30, 2014. FFPC has also stated that it is deferring implementation of IFRS until January 1, 2015, and that costs may be incurred in the future as FFPC completes its transition to IFRS. FFPC has also requested continuation of IFRS transition costs sub-account 1508.

Board staff noted that the Board's general policy and practice is not to dispose of the Account 1508 Sub-account IFRS Transition Costs until the distributor has completed its adoption of IFRS for financial and regulatory purposes and so has a complete record of such costs to review. Board staff submitted that it did not have any issues with FFPC's proposal to dispose of the balance in Account 1508, Sub-account IFRS Transition Costs, but that it was not clear whether FFPC has any more costs booked in this account for the 2013 calendar year. Board staff recommended that FFPC identify the 2013 costs, if any, in its reply submission and if the Board was to be satisfied with the nature and quantum of these costs they could be added to the overall balance to be recovered on a final basis. FFPC confirmed in its reply submission that it did incur $12,000 in audited 2013 IFRS transition expenses which it wished to recover at this time.

VECC supported the submissions of Board staff except for the issue of disposition of Account 1508 Sub-account IFRS Transition Costs. VECC did not agree with Board staff's submission that 2013 amounts should be included in the disposition of this account. VECC submitted that FFPC should either dispose of the 2012 actuals or defer the disposition until it has completed all IFRS related spending and has a final balance for the account.

FFPC disagreed with VECC's position, submitting that it should be permitted to include the audited 2013 Account 1508 Sub-account IFRS transition costs for disposition, as it has completed the majority of the IFRS transition in 2013 and therefore, does not foresee incurring any material additional expenses related to completing the IFRS transition.

The Board accepts FFPC's proposals for disposition of the Group 1 and 2 deferral account balances. The Board agrees with Board staff that the APH should be followed, and cautions FFPC to this effect, but will accept the departures noted by FFPC in its application on the basis that the amounts involved are immaterial.

The Board will permit the disposition of the 2013 amounts in Account 1508 Sub-account IFRS Transition Costs as FFPC completed the majority of its IFRS transition in 2013 and if the balance is not disposed of now, it would be carried forward until FFPC's next cost of service application which could be in 2018 or even later.

Stranded Meters

FFPC is seeking disposition of its stranded meter costs. The net book value of the stranded conventional meters at December 31, 2013 was $80,186. FFPC proposed a one-year recovery of this amount from the Residential, GS<50 kW and GS>kW classes to align with the cost recovery approved in FFPC's EB-2012-0327 rate order. The proposed Stranded Meter Disposition Rate Riders ("SMRR") per customer are outlined in the table below:

Table 8: Proposed Stranded Meter Rate Riders

Rate Class	SMRR ($/month)
Residential	$0.86
GS < 50 kW	$6.99
GS > 50 kW	$19.63

Board staff and VECC supported FFPC's proposal for recovery of stranded meter costs.

The Board approves FFPC's proposal for the recovery of the stranded meter costs as it is aligned with the cost recovery approved in FFPC's EB-2012-0327 smart meter rate order.

CDM & LRAMVA

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on April 26, 2012 outline the information that is required when filing an application for lost revenues in relation to both pre-2011 CDM activities (i.e. LRAM) and 2011-2014 CDM activities (i.e. LRAMVA). FFPC requested approval for an LRAM recovery in relation to pre-2011 CDM program savings of $22,523 arising from the recovery of lost revenues from persisting CDM savings from 2006-2010 CDM programs in 2011, 2012 and 2013.

FFPC also requested approval of an LRAMVA recovery in account 1568, specifically $5,050 in relation to energy savings from new programs deployed in 2011 and 2012 that will contribute to FFPC's 2011-2014 CDM Targets.

VECC and Board staff supported FFPC's requests.

The Board approves FFPC's requests for LRAM and LRAMVA recovery as they comply with the Board's CDM guidelines.

IMPLEMENTATION

The Board has made findings in this decision which change the proposed 2014 revenue requirement and therefore change the distribution rates from those proposed by FFPC. In filing its draft Rate Order, the Board expects FFPC to file detailed supporting material, including all relevant calculations showing the impact of this decision on FFPC's revenue requirement, the allocation of the approved revenue requirement to the classes of customer and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form Excel spreadsheet. If as a result of these calculations the total bill increase for any customer class would exceed 10%, the Board requires FFPC to file a mitigation plan as contemplated by the Board's Filing Requirements.

THE BOARD ORDERS THAT:

1. FFPC's new distribution rates shall be effective and implemented on **September 1, 2014**.

2. FFPC shall file with the Board, and serve on VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **14 days** of the date of the issuance of this Decision.

3. VECC and Board staff shall file any comments on the draft Rate Order with the Board and serve them on the parties within **7 days** of the date of filing of the draft Rate Order.

4. FFPC shall file with the Board and serve on VECC responses to any comments on its draft Rate Order within **4 days** of the date of receipt of VECC's and Board staff's comments.

COST AWARDS

1. The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Act. In this proceeding VECC is eligible for a cost award. In determining the amount its cost award, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards* and the maximum hourly rates set out in the Board's Cost Awards Tariff. VECC shall file with the Board and serve on FFPC, its cost claim within **7 days** from the date of issuance of the final Rate Order.

2. FFPC shall file with the Board and serve on VECC any objections to the claimed costs within **17 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and serve on FFPC any responses to any objections for cost claims within **24 days** of the date of issuance of the final Rate Order.

4. FFPC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2013-0130, and be made through the Board's web portal at www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, August 14, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2016-0152

Ontario Power Generation Inc.

Application for payment amounts for the period from January 1, 2017 to December 31, 2021

DECISION ON DRAFT PAYMENT AMOUNTS ORDER AND PROCEDURAL ORDER NO. 10

March 12, 2018

Ontario Power Generation Inc. (OPG) filed an application with the Ontario Energy Board (OEB) on May 27, 2016 under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes in payment amounts for the output of its nuclear generating facilities and most of its hydroelectric generating facilities. The request sought approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request sought approval for hydroelectric payment amounts to be effective January 1, 2017 to December 31, 2017 and approval of the hydroelectric payment amount setting formula for the period January 1, 2017 to December 31, 2021.

The OEB issued its Decision and Order (the Decision) on December 28, 2017. The OEB approved an effective date of June 1, 2017 for new payment amounts. The OEB directed OPG to file a draft payment amounts order that includes "… the final revenue requirement and final production forecast for the nuclear facilities, and the final hydroelectric rate setting mechanism and 2017 and 2018 parameters, as reflected in the findings made by the OEB in this Decision. OPG shall include supporting schedules and a clear explanation of all the calculations and assumptions used in deriving the amounts used, and final unsmoothed payment amounts." OPG was directed to propose smoothing for three implementation date scenarios, and to propose recovery periods for disposition of deferral and variance accounts and forgone revenue.

The Draft Payment Amounts Order (DPAO) was filed on January 17, 2018. OEB staff, the Association of Major Power Consumers in Ontario (AMPCO), Canadian Manufacturers & Exporters (CME), School Energy Coalition (SEC), Sustainability-Journal and Vulnerable Energy Consumers Coalition (VECC) filed submissions on the DPAO on January 26, 2018. OPG filed its reply submission on February 5, 2018.

The OEB has reviewed the DPAO, including the appendices, the submissions of parties and OPG's reply. The OEB finds that revisions to nuclear revenue requirement appendices are required. The OEB does not accept OPG's smoothing proposal and requires further changes to the appendices. OPG shall re-file the DPAO and the appendices in accordance with the OEB's findings in this Decision on Draft Payment Amounts Order and Procedural Order No. 10 (Decision on DPAO). Following the OEB's review of the re-filing, a final payment amounts order will be issued.

A. Revenue Requirement and Payment Amounts

A.1 2017 Nuclear Revenue Requirement

At Table 1 of Appendix A of the DPAO, the OEB approved 2017 nuclear revenue requirement is listed as $2,973.0 million. SEC states that the approved revenue requirement is $266.1 million lower given the approved effective date of June 1, 2017. SEC submitted that OPG should be required to amend Table 1 of Appendix A (and any other related tables) with a footnote. In SEC's view, some of the Decision's adjustments must be applied on an annualized basis, but not all. VECC supported the SEC submission on 2017 revenue requirement.

OPG argued that the approval of a June 1, 2017 effective date is not a revenue requirement reduction, but a requirement that OPG forgo collection of that revenue requirement for five months. OPG noted that the effective date was determined independently of the findings on revenue requirement. Further, the effective date for the previous cost based proceeding, EB-2013-0321, was later than the date requested by OPG. The revenue requirement in the EB-2013-0321 payment amounts order was not adjusted to reflect the approved effective date.

Findings

The OEB finds that OPG has complied with the Decision regarding the June 1, 2017 effective date in the DPAO. In accordance with the Decision, OPG will forgo collection of the revenue requirement approved in the Decision for the period January 1, 2017 to May 31, 2017.

The OEB will not require OPG to revise the presentation of revenue requirement in Appendix A of the DPAO on the basis put forward by SEC. The approved effective date for the EB-2013-0321 proceeding was later than the date requested by OPG. In the case prior, EB-2010-0008, OPG applied for a March 1, 2011 effective date, which was approved. The revenue requirement in the payment amounts orders for both EB-2013-0321 and EB-2010-0008 is presented on a full year basis, with no adjustments and no footnotes. The OEB requires this presentation to continue for the payment amounts order for the current proceeding.

A.2 Continuity of Property, Plant and Equipment

The Decision directed a 10% reduction on the nuclear operations and support services in-service capital additions. OPG calculated the depreciation impact of the 10% reduction in DPAO on the basis of the remaining service life of Darlington. OEB staff submitted that the weighted average depreciation rate based on the proportional asset mix underpinning in-service additions, other than those related to the Darlington Refurbishment Program (DRP), should be used as the Decision did not specify that the 10% reduction would apply to Darlington only. OPG replied that the historical performance related to Darlington operations in-service capital is the driver of the OEB's findings and that Darlington operations in-service capital drives the capital additions in the test period. OPG further noted that it has less flexibility to adjust the Pickering capital plan as that station approaches end of life.

The OEB ordered permanent disallowances associated with in-service additions for the Auxiliary Heating System (AHS) and Operations Support Building (OSB). OEB staff observed that OPG allocated the majority of the disallowance to the gross plant opening balance, and the rest to the forecast 2017 in-service amount. OEB staff submitted that the disallowances should be allocated on a pro-rated basis across the in-service dates as that better reflects the OEB's findings that poor performance and management issues for the projects occurred across the entirety of the projects. OPG argued that the DPAO is aligned with the disallowance set out in the Decision. The DPAO reflects 50% of difference between the actual in-service amount and the amount identified in the first execution business case summary for 2016 and for 2017, for both the AHS and OSB.

Findings

The OEB found that a 10% reduction each year (2017-2021) to the non-DRP nuclear operations and support services in-service capital additions was appropriate.[1] The

[1] Decision and Order, EB-2016-0152, page 18.

finding did not exclude Pickering operations. OPG shall revise the related nuclear revenue requirement tables in Appendix A to reflect the OEB's finding.

The OEB accepts OPG's explanation regarding the implementation of the permanent disallowances related to the AHS and OSB.

A.3 Capitalization and Cost of Capital

The short-term debt rates were agreed to by the parties in the settlement process and subsequently approved by the OEB. The Decision noted that the costs for debt components of the capital structure would depend on the final determination on capital structure and rate base. OEB staff observed that the short-term debt principal presented in the DPAO varied over the test period. OEB staff submitted that this was not consistent with the Decision. OPG replied that the allocation of short-term debt was to the total regulated operations. In determining the cost of capital for nuclear payment amounts, the short-term debt allocated to the regulated hydroelectric operations was deducted. The amount of short-term debt allocated to the nuclear operations was adjusted in the DPAO to reflect the Decision with respect to rate base and capital structure.

Findings

The OEB finds that OPG's explanation is sufficient and that the DPAO reflects the Decision with respect to capitalization and cost of capital.

A.4 Income Tax

SEC submitted that there is an issue with calculation of taxes and application of tax loss carryforwards given the June 1, 2017 effective date and a reduction in taxable income for 2017. SEC also sought further explanation of the impact of the Decision on depreciation and capital cost allowance.

OPG replied that no element of revenue requirement is based on actual results for 2017, including income taxes. Consistent with OPG's reply noted in section A.1, there was no revenue requirement reduction related to the June 1, 2017 effective date and there is no impact on the forecast of taxes or tax losses. OPG filed further detail on the calculation of test period capital cost allowance with the reply submission.

Findings

Consistent with section A.1, the OEB finds that OPG has complied with the Decision regarding income tax.

A.5 General

VECC noted differences between the Exh N3-1-1 proposed nuclear revenue requirement for the test period and the DPAO summary of proposed revenue requirement and submitted that the differences should be explained. OPG replied that the differences are explained in Table 6a of Appendix A of the DPAO which summarizes adjustments to revenue requirement including those arising from the approved settlement proposal. Tables 6 and 6a establish the revenue requirement on which the findings in the Decision are applied.

SEC stated that it was unclear why OPG's working capital was unchanged in the DPAO given the substantial changes in components of revenue requirement resulting from the Decision. OPG replied that the three components of nuclear working capital, materials and supplies, fuel inventory and cash working capital, are not affected by the Decision. SEC questioned the presentation of deferral and variance account balances in Tables 1 to 5 of Appendix A. SEC submitted that the tables should clearly state that the presentation is an OPG proposal.

Findings

The OEB finds that OPG's explanation regarding Table 6 of Appendix A general revenue requirement matters and working capital are sufficient.

The OEB notes that OPG's presentation of deferral and variance account balances in Tables 1 to 5 of Appendix A is consistent with the payment amounts orders of previous proceedings. However, OPG shall revise the deferral and variance account amortization to reflect the OEB's findings on smoothing in section D.

A.6 Payment Amounts

No submissions were filed regarding the determination of the base payment amounts for regulated hydroelectric operations for 2017 and 2018. The 2017 and 2018 base hydroelectric payment amounts, as set out in the DPAO on line 6 of Table 1 of Appendix B, are approved.

The OEB has considered all the submissions filed on test period nuclear revenue requirement. With the exception of the implementation of the 10% reduction to the non-DRP nuclear operations and support services in-service capital additions, the OEB finds that the nuclear revenue requirement presented in the DPAO on line 1 of Table 1 of Appendix C reflects the findings of the Decision.

The nuclear production forecast was approved in the Decision.[2] The OEB notes that the approved nuclear production forecast is used throughout the DPAO except for Appendix I (OPG's Rate Smoothing Proposal). In Appendix I, OPG uses production with two decimal places that results in a production forecast that is approximately 0.1 TWh lower in the test period than the approved production forecast. OPG shall use the approved nuclear production forecast, i.e. one decimal place, throughout the appendices.

B. Deferral and Variance Accounts

The Decision directed OPG to provide a full description of each deferral and variance account as part of the DPAO and to file accounting orders for the new accounts approved in the Decision.

B.1 Continuing Deferral and Variance Accounts

Descriptions for continuing deferral and variance accounts were provided in Appendix G of the DPAO. OEB staff proposed some revisions to account descriptions and submitted that it should be clear that the descriptions are effective June 1, 2017. SEC submitted that OPG should be required to provide the entries to the accounts for the period January 1, 2017 to May 31, 2017, as well as reference amounts for that period. SEC submitted that the impact of the June 1, 2017 effective date should be clear in the description for each individual account.

OPG filed revised descriptions of the continuing deferral and variance accounts with its reply submission. OPG replied that reference amounts are only applicable on and after the effective date. OPG argued that SEC's request for deferral and variance account information prior to the effective date is not an appropriate part of the current payment amounts order.

SEC questioned whether the reference amounts for the Capacity Refurbishment Variance Account (CRVA) for the hydroelectric facilities before and after the June 1,

[2] Decision and Order, EB-2016-0152, pages 11-12.

2017 effective date are appropriate. OPG argued that the operation of the CRVA for the hydroelectric facilities prior to June 1, 2017 was unchanged. Beginning on June 1, 2017, and the implementation of IRM, the CRVA will record entries on a monthly basis relative to the monthly allocation of the annual reference amount, if the monthly allocation of the annual funding amount threshold has been exceeded.

Findings

The OEB has reviewed the deferral and variance account descriptions and finds that the revisions regarding the June 1, 2017 effective date are appropriate. The OEB notes that the revision at page 8 of Appendix G should state, "… on the effective date of new payment amounts established in this [proceeding] for each year from 2017 to 2021."

The OEB finds that the reference amounts in the description for the CRVA for the hydroelectric facilities are appropriate. The OEB notes that reference amounts have also been included in the reply submission for the CRVA for the nuclear facilities. The OEB directs OPG to provide the source information for these reference amounts in a footnote in Appendix G.

The Decision approved recovery of 2015 year end audited deferral and variance account balances, less the amortization amounts approved in previous proceedings. The deferral and variance account riders are reviewed in section D of this Decision on DPAO.

B.2 Pension and OPEB Cost Variance Account

The Pension and OPEB Variance Account was first approved in the motion proceeding, EB-2011-0090, to record the variance between pension and OPEB costs underpinning payment amounts and actual pension and OPEB costs, as determined on an accrual basis. In the EB-2012-0002 deferral and variance account proceeding, the OEB approved a settlement proposal to recover the year end 2012 balances. In the EB-2014-0370 deferral and variance account proceeding, the OEB approved a settlement proposal to recover the year end 2014 balances in the Pension and OPEB Cost Variance Account (Post 2012 Additions).

SEC noted that at page 9 of Appendix G of the DPAO, it states that the Pension and OPEB Cost Variance Account (Post-2012 Additions) was previously authorized by the OEB to be recovered by June 30, 2021. SEC submitted that OPG should explain how recovery of this account remains consistent with the original terms of the account.

OPG replied that in the normal course the balance in the Pension and OPEB Cost Variance Account (Post-2012 Additions) would have been recovered by June 20, 2021. The EB-2014-0370 settlement proposal set out recovery over 72 months commencing July 1, 2015. Under OPG's rate smoothing proposal, no portion of the balance would be recovered in 2017 and 2018. OPG argued that, "… while the total elapsed time period from July 1, 2015 may exceed 72 months, as a result of the 24-month 'break' in recovery, the actual recovery can still occur over the OEB-authorized recovery period of 72 months." The description of the account in the filing with the reply submission was revised to reflect recovery over 72 months, rather than by June 30, 2021.

Findings

The OEB notes that the settlement proposal approved by the OEB in EB-2014-0370 states that, "The Parties have agreed that the amounts in the Pension and OPEB Cost Variance Account that have accrued since December 31, 2012 are appropriate and shall be cleared over a 72-month period from July 1, 2015 to June 30, 2021." The OEB finds that the approved settlement proposal is clear. It contains a time period for clearance of balances, i.e. 72 months, including a clear end date. The signatories to the settlement proposal have not agreed to an extension as proposed by OPG and there is no guarantee that they would.

In the Decision, the OEB approved the disposition of $86.8 million from regulated hydroelectric deferral and variance accounts and $217.9 million from nuclear deferral and variance accounts. Those amounts include some disposition from the Pension and OPEB Cost Variance Account (Post 2012 Additions). The Decision did not approve a mid-term review, but stated that OPG may file to dispose of deferral and variance account balances at the same time as its application for 2019 hydroelectric payment amounts. The OEB expects OPG to set out a proposal in that application for the remaining balance in the Pension and OPEB Cost Variance Account (Post 2012 Additions) that is compliant with the EB-2014-0370 settlement proposal.

B.3 New Accounts

Accounting orders for the new accounts ordered in the Decision were provided in Appendix H of the DPAO: the Rate Smoothing Deferral Account, Fitness for Duty Deferral Account and SR&ED ITC Variance Account.

There were no submissions filed expressing any concern with the first two new accounts. SEC noted that there was no description in the accounting order for the

SR&ED ITC Variance Account of the method by which the net tax impact would be grossed up. OPG replied that it had revised the accounting order to include the information requested by SEC.

Findings

OPG revised the description of the SR&ED ITC Variance Account to state "including the tax on the difference". The OEB has no concerns with the description of the SR&ED ITC Variance Account.

In the DPAO, OPG provided accounting orders for two additional accounts that were not ordered in the Decision. These accounts are reviewed in section C of this Decision on DPAO.

C. Forgone Revenue

C.1 Production Basis

In the DPAO, OPG proposed that forgone revenue be determined using actual hydroelectric and nuclear production for the period June 1 to December 31, 2017 and forecast hydroelectric nuclear production for the period January 1 to February 28, 2018. OPG and the parties assumed an implementation date of March 1, 2018 for the submissions, however, OPG provided supporting information for implementation dates of April 1, 2018 and May 1, 2018 in Appendix I of the DPAO.

Under OPG's smoothing proposal, $21.1 million of hydroelectric forgone revenue and $700.6 million of nuclear forgone revenue will be recovered over the three year period 2019 to 2021.

While the Decision set out the determination of forgone revenue on the basis of forecast production, OEB staff submitted that it had no concerns with using actual production for 2017 and forecast production values for 2018. The use of actual production for the seven months of 2017 represents the real revenue that would have been generated had the payment amounts been in place on June 1, 2017 and is consistent with the determination in EB-2007-0905.[3]

[3] EB-2007-0905 Payment Amounts Order, December 2, 2008, page 3 – "...the Board directs that the new payment amounts be set using the forecast production for the test period and that the interim period shortfall be calculated using the actual production during the interim period".

SEC submitted that using either actual production or forecast production for the seven months of forgone revenue in 2017 can be justified. However, SEC submitted that whichever is chosen should be applied to consistently, e.g. the payment amounts for the interim period, as using different assumptions produces unfair results. OPG replied that there is no mismatch as its proposal is what would have happened if the payment amounts had been implemented on the effective date. The payment amounts would have been based on forecast production and revenue would have been determined on actual production.

Findings

The OEB accepts OPG’s proposal to use actual production for 2017 to determine forgone revenue. Actual information where parties have it is the best information. The OEB accepts forecast production for 2018 in lieu of actual, since actual information is not available

The determination of forgone revenue and the forgone revenue riders are reviewed in section D of this Decision on DPAO.

C.2 Variance Accounts

OPG proposed two new variance accounts in the DPAO: the Hydroelectric Interim Period Shortfall Over/Under Recovery Variance Account and Nuclear Interim Period Shortfall Over/Under Recovery Variance Account. The variance accounts would record the difference between the approved amounts of forgone revenue and the amounts recovered based on actual production.

OEB staff submitted that the two new accounts should not be approved. While similar accounts were approved in the first OPG proceeding, EB-2007-0905, OEB staff noted that this is not the typical practice. OEB staff referred to five proceedings in which forgone revenue was not trued up. Without the accounts, OEB staff submitted that OPG would be at risk for recovery of forgone revenue in the same way it is at risk for revenue requirement in general.

In OPG’s view, the variance accounts are fairer to customers in the event production exceeds forecast, and to OPG as the purpose of forgone revenue is to put OPG in the position it would have been in if new payment amounts had been implemented on the effective date. OPG stated that using actual production to calculate forgone revenue and to recover forgone revenue means that OPG is subject to production risk twice.

OPG argued that the variances could be significant as OPG's revenues are fully variable with production, the amount of forgone revenue is large and the recovery period will span several years.

OPG disagrees with the OEB staff comparison with other proceedings requiring forgone revenue. In OPG's view, none of the proceedings are equivalent to the circumstances for OPG. The forgone revenue amounts were not significant, i.e. less than $15 million, and the recovery period was usually in months but no more than one year. OPG also noted that Uniform Transmission Rates and electricity and gas distributor fixed rates mean that these utilities are subject to less revenue recovery risk than OPG. It is OPG's view that the OEB should approve the variance accounts, as it did in the EB-2007-0905 proceeding.

Findings

The OEB will not accept the creation of two additional accounts. The Decision did not approve the addition of these two accounts. With respect to the Nuclear Interim Period Shortfall Over/Under Recovery Variance Account, the Decision accepted OPG's nuclear production forecast on the basis that it was an accurate reflection of the production OPG stated that it would achieve. Nowhere in the discussion of nuclear production forecast did the OEB contemplate the use of new variance accounts as it related to production. The OEB also specifically rejected a mid-term review to deal with possible changes to the nuclear production forecast.

The OEB does not approve the Hydroelectric Interim Period Shortfall Over/Under Recovery Variance Account to true up the recovery of $21.1 million of hydroelectric forgone revenue. In order to establish a new account, causation, materiality and prudence criteria must be met. The OEB finds that the proposed account would not meet the materiality criterion.

D. Payment Amount Smoothing

D.1 OPG Payment Amount Smoothing Proposal

The smoothing proposal filed with the application on May 27, 2016 was based on nuclear payment amounts smoothing as required by O. Reg. 53/05. The regulation was subsequently amended on March 2, 2017 to require smoothing based on the weighted average payment amount (WAPA) as determined by base hydroelectric and nuclear payment amounts and deferral and deferral and variance account riders. OPG filed an amended smoothing proposal in Exh N2-1-1. That proposal was based on a constant 2.5% annual increase in WAPA.

With the implementation of the Decision findings in the DPAO, OPG filed a revised smoothing proposal. OPG adjusted its methodology for smoothing by allowing the change in WAPA to vary between years. OPG has also considered the total bill impact of the smoothing proposal, i.e. WAPA and the impact of the forgone revenue riders.[4] OPG proposes to defer implementation of deferral and variance account riders and forgone revenue riders to January 1, 2019 in order to minimize customer bill impacts in 2018. The OPG proposal targets a consistent $0.65 year over year change in residential customer bills. In OPG's view, the proposal satisfies the O. Reg. 53/05 requirement that WAPA be more stable. The test period additions to the Rate Smoothing Deferral Account (RSDA) would be $732 million, and carrying charges would be $21 million. OPG proposed straight line recovery of deferral and variance account riders and forgone revenue riders over the period 2019 to 2021. The forgone revenue has been determined to be $721.7 million. The OPG DPAO proposal is summarized in section A of Table 1.

D.2 OEB Staff Submission and Payment Amount Smoothing Proposal

In its submission, OEB staff set out an alternate smoothing proposal. Unlike OPG's proposal which sets smoothed nuclear payment amounts in 2017 and 2018 that are higher than the unsmoothed nuclear payment amounts, the OEB staff proposal did not adjust the unsmoothed nuclear payment amounts in 2017 and 2018. Only the 2019 and 2020 nuclear payment amounts are smoothed. OEB staff submitted that its proposal was more advantageous to ratepayers as the quantum of forgone revenue ($626.5 million) was lower, the test period additions to the RSDA were lower ($515 million) and the average bill impact for residential customers ($0.53) was lower. However, OEB staff did note that its proposal resulted in higher carrying charges ($40 million) in the test period. The OEB staff proposal starts deferral and variance account riders and forgone revenue riders on March 1, 2018. Instead of straight line recovery, the OEB staff proposal uses a 15%, 50% and 35% recovery over the 2018, 2019 and 2020 period. The OEB staff proposal is summarized in section B of Table 1.

D.3 SEC Submission and Payment Amount Smoothing Proposal

SEC submitted that the OPG proposal does not consider the impacts on non-residential customers who do not have beneficial effects of the Fair Hydro Plan. SEC submitted

[4] O. Reg. 53/05 does not include forgone revenue riders in the determination of WAPA.

that actual 2017 WAPA was $50.67/MWh and actual January-February 2018 WAPA was $50.72/MWh. Using these actual WAPA instead of the 2016 WAPA of $60.97/MWh significantly changes the bill impacts. SEC determined that the effect of OPG’s proposal is an increase of 27.05% in 2018 in the largest part of the non-residential customer bill, followed by increases of 1.96% in 2019, 10.64% in 2020 and 2.15% in 2021. In SEC’s view this does not qualify as smoothing. SEC estimated that the Toronto District School Board will pay $1,880,000 more in 2018 than it did in 2017 under the OPG proposal. SEC acknowledges that the 2017 WAPA is lower than the 2016 WAPA, however, most companies and institutions are unlikely to have set those savings aside, and prepare budgets based on the most recent information.

SEC also submitted that OPG’s smoothing proposal assumes no rate riders beyond those considered in this proceeding. In deferring riders from this application to 2019, and assuming no future riders, OPG’s proposal will result in substantial rate increases in 2020.

SEC set out an alternate smoothing proposal in its submission. The proposal was supported by AMPCO and CME. The SEC smoothing proposal sets a smoothed 2018 nuclear payment amount of $63.00/MWh (vs. $83.10 in the OPG proposal). The SEC proposal starts the deferral and variance account riders and forgone revenue riders on March 1, 2018 and continues the riders on a straight line basis to December 31, 2019. SEC has determined that the impact of its proposal is to reduce the 2018 increase from 27.05% to 20.77%. SEC noted that there are consequences to it proposal, namely $2 billion of deferred revenue. SEC submitted that its proposal was more realistic and more in keeping with the intent of the regulation. The SEC proposal is summarized in section C of Table 1.

Table 1
Payment Amount Smoothing Proposals

	A. OPG Draft Payment Amounts Order	2016	2017	2018	2019	2020	2021	Total/Ave	Notes
1	Hydroelectric Payment Amount ($/MWh)	40.72	41.67	42.05	42.43	42.81	43.20		
2	Hydroelectric DVA Rider ($/MWh)	3.83			0.96	0.96	0.96		Amortization of $86.8M
3	Forgone HE Rider				0.23	0.23	0.23		Recovery of $21.1M
4	Nuclear Revenue Requirement ($M)		2973.0	3032.3	3116.7	3579.1	3173.8		
5	Production Forecast (TWh)	46.8	38.10	38.47	39.03	37.36	35.38		
6	Unsmoothed Nuclear Payment ($/MWh)	59.29	78.03	78.82	79.85	95.80	89.71		
7	Smoothed Nuclear Payment ($/MWh)	59.29	80.65	83.10	76.17	79.70	83.67		
8	Nuclear DVA Rider ($/MWh)	13.01			1.95	1.95	1.95		Amortization of $217.9M
9	Forgone Nuclear Rider				6.27	6.27	6.27		Recovery of $700.6M
10	WAPA Unsmoothed ($/MWh) - 1,2,6,8	60.97	61.16	61.85	64.21	72.44	68.74		
11	WAPA Smoothed ($/MWh) - 1,2,7,8	60.97	62.56	64.15	62.21	63.89	65.62		
12	Total (WAPA Smoothed + Forgone) ($/MWh) - 1,2,3,7,8,9	60.97	62.56	64.15	65.72	67.33	68.97		
13	Bill Impact of Total Payments ($/month)		0.65	0.65	0.65	0.65	0.65	0.65	
14	RSDA Additions - Smoothed ($M)		-62	-165	144	602	214	732	$21M interest in test period

Note: The production forecast at line 5 is reproduced from Appendix I of the DPAO. However, the Decision approved production forecast at the one decimal level which will affect the final determination of nulcear payment amounts and riders.

	B. OEB Staff Submission	2016	2017	2018	2019	2020	2021	Total/Ave	Notes
1	Hydroelectric Payment Amount ($/MWh)	40.72	41.67	42.05	42.43	42.81	43.20		
2	Hydroelectric DVA Rider ($/MWh)	3.83		0.52	1.44	1.01			Amortization of $86.8M
3	Forgone HE Rider			0.13	0.35	0.24			Recovery of $21.1M
4	Nuclear Revenue Requirement ($M)		2973.0	3032.3	3116.7	3579.1	3173.8		
5	Production Forecast (TWh)	46.8	38.10	38.47	39.03	37.36	35.38		
6	Unsmoothed Nuclear Payment ($/MWh)	59.29	78.03	78.83	79.85	95.80	89.71		
7	Smoothed Nuclear Payment ($/MWh)	59.29	78.03	78.83	77.00	85.00	89.71		
8	Nuclear DVA Rider ($/MWh)	13.01		1.05	2.79	2.04			Amortization of $217.9M
9	Forgone Nuclear Rider			2.90	7.76	5.67			Recovery of $605.4M
10	WAPA Unsmoothed ($/MWh) - 1,2,6,8	60.97	61.16	62.66	64.89	72.51	67.27		
11	WAPA Smoothed ($/MWh) - 1,2,7,8	60.97	61.16	62.66	63.34	66.78	67.27		
12	Total (WAPA Smoothed + Forgone) ($/MWh) - 1,2,3,7,8,9	60.97	61.16	64.27	67.70	69.90	67.27		
13	Bill Impact of Total Payments ($/month)		0.08	1.28	1.41	0.89	-1.03	0.53	
14	RSDA Additions - Smoothed ($M)		0	0	111	404	0	515	$40M interest in test period

	C. SEC Submission	2016	2017	2018	2019	2020	2021	Total/Ave	Notes
1	Hydroelectric Payment Amount ($/MWh)	40.72	40.72	42.05	42.43	42.81	43.20		
2	Hydroelectric DVA Rider ($/MWh)	3.83		1.50	1.50	2.45	2.45		SEC assumed riders 2020-2021
3	Forgone HE Rider			0.37	0.37				
4	Nuclear Revenue Requirement ($M)		2973.0	3032.3	3116.7	3579.1	3173.8		
5	Production Forecast (TWh)	46.8	38.10	38.47	39.03	37.36	35.38		
6	Unsmoothed Nuclear Payment ($/MWh)	59.29	78.03	78.82	79.85	95.80	89.71		
7	Smoothed Nuclear Payment ($/MWh)	59.29	59.29	63.00	67.00	75.00	80.00		
8	Nuclear DVA Rider ($/MWh)	13.01		3.05	3.05	7.93	7.93		SEC assumed riders 2020-2021
9	Forgone Nuclear Rider			9.65	9.65				
10	WAPA Unsmoothed ($/MWh) - 1,2,6,8	60.97	60.72	64.18	65.05	76.32	72.56		
11	WAPA Smoothed ($/MWh) - 1,2,7,8	60.97	50.67	55.66	58.09	65.27	67.53		
12	Total (WAPA Smoothed + Forgone) ($/MWh) - 1,2,3,7,8,9	60.97	50.67	61.25	63.49	65.27	67.53		
13	Bill Impact of Total Payments ($/month)							0.39	Lines 13&14 calculated by OPG
14	RSDA Additions - Smoothed ($M)							2,705	$313M interest in test period

D.4 OPG Reply Submission

OPG included a summary of the outcomes of the OPG smoothing proposal, the SEC proposal and the OEB staff proposal in Chart 3 of the reply submission. For the period beyond 2021, Chart 3 assumed an average WAPA increase of 8% in the 2022-2026 period for the alternative proposals, consistent with the OPG proposal. Chart 3 is reproduced in Table 2 below, with the addition of line numbers.

Table 2

	OPG Proposal	SEC Proposal	OEB staff Proposal
1-2017-2021 Average Change in WAPA	2.7%	9.2%	2.0%
2-2022-2026 Average Change in WAPA	8.0%	8.0%	8.0%
3-2027-2036 Average Change in WAPA	(1.5)%	(1.1)%	(2.4)%
4-Peak RSDA Balance ($B)	$2.7	$4.9	$1.9
5-2017 - 2021 RSDA Additions ($M)*	$732	$2,705	$515
6-2017 - 2021 Interest ($M)*	$21	$313	$41
7-Total Interest ($B)	$1.1	$2.7	$0.5
8-Interest Cost / Deferred Revenue Ratio	0.4	0.6	0.2
9-FFO Interest Coverage > = 3 (2017-2021) & (2022-2026)	4.3 / 4.6	2.6 / 3.9	4.2 / 5.0
10-DEBT to EBITDA < = 5.5 (2017-2021) & (2022-2026)	6.5 / 5.4	7.0 / 6.3	6.7 / 5.4
11-Nuclear Payment Amount Transition Impact ($/MWh)	($0.19)	($13.28)	$12.27
12-Average Annual Bill Impact (2017-2021) in %	0.4%	0.3%	0.3%
13-Average Annual Bill Impact (2017-2021) in $	$0.65	$0.39	$0.52
14-Average Annual Bill Impact (2017-2036) in %	0.3%	0.3%	0.2%
15-Average Annual Bill Impact (2017-2036) in $	$0.45	$0.45	$0.29

In OPG’s view, the OPG proposal produces better value than the OEB staff proposal for customers by maintaining constant year over year increases in monthly bills for residential customers. OPG stated that the OEB staff proposal is a reasonable alternative that trades off lower overall cost, i.e. deferring less revenue requirement and incurring less interest (lines 4, 5, 6 and 7 of Table 2), for greater year over year volatility. OPG noted that the 2018 and 2019 residential customer impacts of the OEB staff proposal were twice as high as the OPG proposal (line 13 of sections A and B in Table

1). OPG also noted that the transition impact at the end of the recovery period in 2037 is $12/MWh and much greater than the OPG transition impact (line 11 of Table 2).

OPG replied that the long term costs of the SEC proposal more than outweigh the short term benefit of reducing 2018 bill impacts. OPG calculated that the total RSDA carrying costs for the SEC proposal will be $2.7 billion, an increase of $1.6 billion over the OPG proposal and $2.2 billion over the OEB staff proposal (line 7 of Table 2). In OPG's view, smoothing requires the OEB to consider a long-term view. The SEC proposal focuses on a small period of time around the implementation date of payment amounts and riders from this proceeding. OPG submitted that the SEC proposal results in poor value for customers in the long term.

OPG argued that the SEC submission refers to WAPA and bill impacts as if they were equivalent, but they are not. Further, SEC cited an increase of 27.05% in the commodity portion of the non-RPP customers' bills. OPG provided year over year bill impacts for medium/large customers and industrial customers in three service areas in the DPAO at Appendix I. The bill impacts were presented on the basis of percent change on monthly bills. OPG argued that the SEC submission used selective annualized examples that do not reflect bill impacts on customers across Ontario and do not consider the impacts in the context of total bills. OPG also argued that SEC's method of calculating bill impacts ignores the decrease in payment amounts from which customers have benefitted since January 1, 2017.

The SEC smoothing proposal assumed riders for future recovery of deferral and variance account balances. In OPG's view, it is not appropriate or consistent with the definition of WAPA in O. Reg. 53/05 to determine deferral amounts on the basis of speculative riders for future periods. OPG submitted that the OEB will have the tools to address bill impacts of any future riders in the proceeding where they are approved.

D.5 Bill Impacts

The test period bill impacts for the typical residential customer are summarized for each smoothing proposal on line 13 in sections A, B and C of Table 1. The bill impacts for the test period as well as the full deferral and recovery period from 2017 to 2036 are summarized in lines 12 to 15 of Table 2.

As noted in section D.4, OPG disagreed with SEC's method of calculating bill impacts. The SEC approach focuses on the difference between payment amounts on February

28, 2018 and March 1, 2018. OPG argued that SEC creates the inaccurate impression that OPG's payment amounts are increasing by 27%.

OPG provided a bill impact analysis, under the OPG smoothing proposal, on a cumulative basis in Chart 4 of the reply submission. That chart is reproduced below.

Table 3

Line No.	Customer Class	Measure	2017	2018		2017 & 2018 Average Impact
				Jan - Feb	Mar - Dec	
1	Residential Customers	($/Month)	-$4.20	$0.00	$4.59	$0.65
2		(%)	**-2.8%**	**0.0%**	**3.0%**	**0.4%**
3	Non-RPP Customers	($/Month)	-$14,200	$0	$15,500	$2,200
4		(%)	**-3.3%**	**0.0%**	**3.6%**	**0.5%**

D.6 Findings

The OEB recognizes that the nuclear revenue requirement will change as a result of the findings in this Decision on DPAO. However, the changes are limited and do not affect the OEB's findings on smoothing.

O. Reg. 53/05 requires the OEB to determine the portion of nuclear revenue requirement for each year that is to be recorded in the RSDA with a view to making more stable the year-over-year changes in WAPA over each calculation period.

In reviewing the OPG proposal, the OEB staff proposal and the SEC proposal, the OEB has considered the cost of the proposals to ratepayers. In the OEB's view, the smoothing must be done at a reasonable cost. As noted in the Decision, rate stability is important to the OEB, but it does not necessarily follow that changes in WAPA, or total payment amounts, or bill increases need to be constant. The OEB considers that the OEB staff proposal meets the requirements of the regulation, does so at a more reasonable cost than the other proposals, and minimizes rate shock in 2017. On this basis, the OEB does not accept the proposals put forward by OPG or by SEC, but rather finds the rate smoothing proposal by OEB staff to be preferable.

Cost of Smoothing Proposals

As noted above, the OEB is required to determine the portion of nuclear revenue requirement for each year that is to be recorded in the RSDA. The regulation relates the

RSDA additions to changes in WAPA and requires that the RSDA balance earn interest at OPG's long-term debt rate compounded annually.

The OEB was assisted by the summary of outcomes prepared by OPG and included in this Decision on DPAO at Table 2. While there are assumptions underpinning the summary of outcomes, it is clear from lines 4 to 7 of the Table 2 that the SEC proposal results in significant cost to ratepayers. The test period interest costs of the SEC proposal are an order of magnitude higher than the other proposals. OPG estimates that the total interest costs for the SEC proposal are $2.7 billion and much higher than the total interest costs for the OPG proposal and OEB staff proposal. The OEB agrees with OPG that the short term bill impact benefits of the SEC proposal are dwarfed by the long term costs of the SEC proposal. While the increase from 2017 to 2018 is significant for commercial and industrial customers, it results from the 2017 rates being lower than historical trends. Given the much higher long term costs of SEC's proposal, the OEB finds that it is not reasonable to use the lowest point in several years as the base for smoothing.

With the exception of test period interest costs, the OEB staff proposal is less costly than the OPG proposal. The OEB finds that the lower total interest, $0.5 billion for the OEB staff proposal vs $1.1 billion for the OPG proposal, is a significant future saving for ratepayers. The OEB notes that OPG submitted that the OEB staff proposal is a reasonable alternative to the OPG proposal.

Stable Year-Over-Year Changes

O. Reg. 53/05 refers to WAPA, which does not consider the recovery of forgone revenue. As summarized in Table 1 at lines 11 and 12, the OEB staff proposal and the SEC proposal reflect increasing year-over-year smoothed WAPA and increasing total payment amounts (WAPA and forgone revenue riders) in the period 2017 to 2021.

The OPG proposal does not reflect increasing year-over-year smoothed WAPA, but does have increasing year-over-year total payment amounts. The OPG proposal results in a constant $0.65/month increase in monthly bills for residential customers. The OEB finds that all of the proposals have utilized additions to the RSDA and recovery mechanisms for deferral and variance account balances and forgone revenue in an effort to stabilize year-over-year changes. However, the OEB is of the view that recovery of deferral and variance account balances and forgone revenue should begin when the payment amounts order is implemented. Both the OEB staff proposal and the SEC proposal start riders on March 1, 2018, while the OPG proposal starts riders on

January 1, 2019. Further, the OEB finds that constant year over year increases in monthly bills, as proposed by OPG, is not a strict requirement for smoothing.

The OEB also accepts that a three year recovery period (from March 1, 2018 to December 31, 2020), as proposed by OEB staff is a reasonable time period over which to collect deferral and variance account balances and forgone revenue. The OEB is not of the view that it should be on a straight line basis, but rather as proposed in the OEB staff submission, with a significantly lesser amount in year 1 to alleviate rate shock.

While the bill impacts of the OEB staff proposal are more variable (line 13 of Table 1), the average bill impact of the OEB staff proposal is lower than the other proposals (lines 12 to 15 of Table 2). The OEB accepts this variability as there is a smoothing component to the OEB staff proposal, and the cost outcomes for the ratepayer are more positive. The OEB also notes that the OEB staff proposal resulted in lower forgone revenue than the OPG proposal.

O. Reg. 53/05 refers to stable year-over-year changes in WAPA over each calculation period. The calculation period "means each period for which the Board determines the approved revenue requirement under subparagraph 12ii of subsection 6(2) together with the year immediately prior to that period;" In the OEB's view, bill impacts according to this definition (with the addition for forgone revenue) are summarized on line 13 of Table 1.

SEC submitted that the bill impact for non-RPP customers on March 1, 2018 should be considered. The OEB is assisted by the total bill impact analysis filed by OPG and included as Table 3 in this Decision on DPAO. This analysis is based on the OPG smoothing proposal. The bills of non-RPP customers decreased by 3.3% in 2017, were unchanged in January and February of 2018, and will increase by 3.6% in the period March to December of 2018. The average 2017 and 2018 impact is 0.5%. Non-RPP customers have benefitted from lower bills since January 1, 2017. The OEB finds that the long-term cost to keep those bills low, as proposed by SEC, is unreasonable.

The SEC submission and smoothing proposal also included estimates of future riders for deferral and variance accounts. The OEB agrees with OPG that future disposition of deferral and variance accounts and the impacts of the disposition will be considered in those applications and not in the current proceeding.

Implementation of Smoothing Findings and Implementation Date

OPG shall re-file the DPAO and appendices in accordance with the findings in this Decision on DPAO. OPG shall reflect the smoothing findings as follows:

- There will be no RSDA additions for 2017, 2018 and 2021.
- The nuclear payment amounts for 2019 and 2020 shall be smoothed in accordance with the OEB staff smoothing proposal, subject to any minor variations to account for the minor revisions to the unsmoothed amounts that may result from the OEB's findings in Section A.2 of this Decision on DPAO (concerning the 10% reduction on the nuclear operations and support services in-service capital additions). That is, the smoothed amounts may be slightly more or less than the $77.00/MWh for 2019 and $85.00/MWh for 2020 proposed by OEB staff, so long as the variance from OEB staff's proposed numbers is reasonably proportional to any variance to the underlying unsmoothed amounts.
- The deferral and variance account balances and the forgone revenue will be recovered in riders over the period March 1, 2018 to December 31, 2020. In the first 10 months 15% will be recovered, in the next 12 months 50% will be recovered and in the last 12 months 35% will be recovered.

The OEB approves an implementation date of March 1, 2018. The OEB is making provision for re-filing of DPAO appendices in accordance with the findings in this Decision on DPAO, as well as a brief period for submissions on the re-filing. The submissions on the re-filing will be limited to comments on the compliance with the OEB's findings. It will not be an opportunity to argue for a different smoothing proposal. It is the OEB's understanding that, with the timelines set out in this Decision on DPAO, the IESO will be able to implement March 1, 2018 through its billing processes.

THE ONTARIO ENERGY BOARD THEREFORE ORDERS THAT:

1. OPG shall file with the OEB, with a copy to the intervenors, a revised draft Payment Amounts Order and appendices that reflect the OEB's findings in this Decision on Draft Payment Amounts Order by **March 19, 2018**.

2. OEB staff and intervenors shall file with the OEB, with a copy to OPG, any comments on the revised draft Payment Amounts Order and appendices by **March 21, 2018**.

3. OPG shall file with the OEB, with a copy to the intervenors, a response to any comments by **March 23, 2018**.

All filings to the OEB must quote the file number, **EB-2016-0152** and be made electronically through the OEB's web portal at http://www.pes.ontarioenergyboard.ca/eservice/ in searchable/unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at https://www.oeb.ca/oeb/_Documents/e-Filing/RESS_Document_Guidelines_final.pdf. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a USB flash drive in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Violet Binette at violet.binette@oeb.ca and OEB Counsel, Michael Millar at michael.millar@oeb.ca and Ian Richler at ian.richler@oeb.ca.

ADDRESS

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DATED at Toronto, **March 12, 2018**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

COURT OF APPEAL FOR ONTARIO

CITATION: Union Gas Limited v. Ontario Energy Board, 2015 ONCA 453
DATE: 20150622
DOCKET: C58756

Hoy A.C.J.O., and Simmons and Tulloch JJ.A.

BETWEEN

Union Gas Limited

Appellant

and

Ontario Energy Board

Respondent

Patricia D.S. Jackson, Crawford Smith and Alex Smith, for the appellant

Michael Millar, for the respondent

Heard: December 16, 2014

On appeal from the order of the Divisional Court (Justices Colin D.A. McKinnon and Susan G. Himel, Justice Herman J. Wilton-Siegel dissenting) dated December 20, 2013, with reasons reported at 2013 ONSC 7048, 316 O.A.C. 218, affirming the decision of the Ontario Energy Board, dated November 19, 2012.

Simmons J.A.:

A. INTRODUCTION

[1] Union Gas Limited appeals with leave from an order of the Divisional Court dismissing Union's appeal from a decision of the Ontario Energy Board. The

main issue on appeal is whether the Board's decision contravened the principle against retroactive ratemaking.

[2] In April 2012, Union applied to the Board for an order amending the rates it would charge to its customers for natural gas as of October 2012. A primary purpose of the application was to adjust rates as a result of allocating a portion of Union's 2011 utility earnings between Union and its ratepayers under the terms of an Earnings Sharing Mechanism ("ESM") contained in an Incentive Regulation Mechanism Settlement Agreement (the "IRM Agreement").

[3] In 2007, Union entered into the IRM Agreement with parties representing its major stakeholders and constituents (the "interveners") to provide for a five-year period of incentive regulation. By order made in January 2008, the Board approved the IRM Agreement. The IRM Agreement contained the ESM, under which Union agreed to share utility earnings greater than two per cent above its regulated rate of return with ratepayers.

[4] As part of the IRM Agreement, Union agreed to reduce its revenue requirement by $4.3 million. In exchange for this reduction, four deferral accounts previously established by the Board were eliminated.

[5] Deferral accounts allow a regulator to separately accumulate certain amounts (costs or revenues) before deciding by order, at specified intervals, to what extent, if at all, such costs or revenues will be charged to ratepayers as part

of rates. Because it is contemplated from the outset that amounts in deferral accounts will be disposed of in a manner that affects rates, deferral accounts do not offend the principle against retroactive ratemaking.

[6] At least one of the four eliminated deferral accounts tracked upstream transportation optimization revenues. Union generated upstream transportation optimization revenues through transactions with third parties in which Union disposed of upstream transportation services.

[7] In the past, the Board had directed that Union share the upstream transportation optimization revenues in the eliminated deferral accounts with ratepayers based on a 75/25 split in favour of ratepayers.

[8] As a result of the elimination of the four deferral accounts, under the IRM Agreement, Union was able to keep net revenues that would previously have been recorded in those accounts, subject to the ESM.

[9] Union's April 2012 application for a rate order included a request to share with ratepayers $22 million in 2011 revenues Union had earned using TransCanada Pipelines Limited's ("TCPL") Firm Transportation Risk Alleviation Mechanism ("FT-RAM") program under the ESM.

[10] Under the FT-RAM program, utilities earned credits for unused firm[1] transportation services, which the utilities could then use to purchase cheaper interruptible transportation services. Union was able to monetize the credits it earned under the FT-RAM program through various assignment and exchange transactions with third parties.

[11] Union classified its 2011 FT-RAM earnings as upstream transportation optimization revenues – that is, as utility earnings that would previously have been recorded in one of the eliminated deferral accounts. In a procedural order in Union's application, the Board directed that Union's classification of its 2011 FT-RAM revenues be dealt with as a preliminary issue in the proceeding.

[12] In its decision on the preliminary issue, the Board rejected Union's classification of its 2011 FT-RAM revenues as utility earnings and concluded instead that the disputed $22 million should be classified as "gas supply cost reductions". As such, the revenues would ordinarily be passed through to ratepayers, and Union would not be entitled to any portion of them.

[13] The Board found that Union had used the FT-RAM program to generate profits on its upstream transportation portfolio on a planned basis – whereas Union's past upstream transportation optimization activities had occurred on an unplanned basis. Because upstream transportation costs are passed through

[1] Firm transportation refers to the quality of upstream transportation. Firm transportation cannot be interrupted by the transportation supplier, whereas interruptible transportation can be interrupted.

entirely to ratepayers, the Board found that Union's planned profit-making on its upstream transportation portfolio was inconsistent with the IRM Agreement and the regulatory principle imbedded in it that a utility "cannot profit from the procurement of gas supply for its customers."

[14] The Board concluded that it was entitled to reclassify the FT-RAM revenues because it was part of its mandate to ensure that revenues were being properly characterized under the IRM Agreement and in a manner that resulted in just and reasonable rates.

[15] While acknowledging that gas supply costs (and gas supply cost reductions) are ordinarily passed through entirely to ratepayers, the Board directed that 90 per cent of the $22 million should be credited to ratepayers and that 10 per cent should be credited to Union as an incentive for generating the revenues. In a subsequent rate order, the Board directed that the funds should be recorded in a newly created deferral account.

[16] Union appealed the Board's decision on the preliminary issue to the Divisional Court.

[17] Before the Divisional Court, Union argued that the Board had already approved the gas supply cost reductions to be credited to ratepayers for 2011 through final rate orders made in Quarterly Rate Adjustment Mechanism ("QRAM") proceedings, which disposed of deferral accounts relating to upstream

gas and transportation costs. Accordingly, Union maintained that by reclassifying Union's 2011 FT-RAM revenues as gas supply cost reductions, the Board engaged in impermissible retroactive ratemaking.

[18] In a split decision, the Divisional Court found that the Board's reclassification of the 2011 FT-RAM revenues did not amount to impermissible retroactive ratemaking. The majority concluded that the revenues at issue were not dealt with in the 2011 QRAM proceedings. Moreover, because the revenues were brought forward as part of the ESM proceeding, they were effectively "encumbered", and therefore subject to further disposition by the Board. The majority held that the Board's statutory rate-making authority is broad and "[does not] in any manner constrain the Board from making orders respecting matters which arose in a previous year but had not been specifically dealt with as a discrete item in the rate-setting process."

[19] Union now appeals to this court with leave and argues that the Board acted unreasonably in reclassifying Union's 2011 FT-RAM revenues as gas supply cost reductions for two reasons.

[20] First, it says the reclassification was an unauthorized departure from the terms of the IRM Agreement, which the Board had approved as the mechanism for setting rates during the IRM period. Second, it says the reclassification amounted to impermissible retroactive ratemaking. This is because gas supply

cost deferral accounts had already been disposed of through final orders in the 2011 QRAM proceedings and because there was no separate deferral account for FT-RAM revenues in relation to which the Board could make a further disposition. According to Union, the Board's decision is thus a classic impermissible attempt to remedy past rates the Board later concluded were excessive.

[21] For the reasons that follow, I would dismiss Union's appeal.

B. BACKGROUND

(1) Union

[22] Union is an Ontario corporation that sells, distributes, transmits and stores natural gas. It does not produce natural gas. From its head office in Chatham, Union services approximately 1.4 million residential, commercial and industrial customers across northern, southwestern and eastern Ontario.

(2) The Board and its Authority

[23] The Board is a statutory tribunal governed by the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B. Among other powers, the Board has authority to set rates for the sale, transmission, distribution and storage of gas in the natural gas sector: s. 36(1).[2] The Board carries out its rate-setting function by

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[2] The text of relevant provisions under the Act is included in Appendix "A".

issuing orders: s. 19(2). In making orders, the Board is not bound by the terms of any contract: s. 36(1).

[24] Under s. 36(2) of the Act, 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" (emphasis added).

[25] Just and reasonable rates permit a utility to recover its prudently incurred costs and earn a fair return on invested capital: see, for example, *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario (Energy Board)*, 2013 ONCA 359, 116 O.R. (3d) 793, at paras. 13, 30-32, leave to appeal to S.C.C. granted, [2013] S.C.C.A. No. 339, appeal heard and reserved December 3, 2014; *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186, pp. 192-3.

[26] Under s. 36(3) of the Act, "[i]n approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate."

[27] Deferral accounts are not defined in the Act. However, under ss. 36(4.1) and (4.2), the Board must dispose of the balances in deferral accounts at specified intervals. Deferral accounts relating to the commodity of natural gas are to be reflected in rates within a maximum of three months, and deferral accounts

relating to other items, including transportation costs, are to be reflected in rates within a maximum of 12 months.

(3) The Board's Practice in Setting Union's Rates

[28] Historically, the Board set Union's natural gas rates following an annual cost of service hearing at which the Board established Union's revenue requirement, consisting of a forecast of Union's costs, including a return on equity, over a future year or test period. As part of the rate-setting process, typically the Board established various deferral accounts to allow it to defer consideration of revenues and expenses that could not be forecast with certainty.

[29] Between 2008 and 2012, Union's natural gas rates were set through a Board-approved Incentive Regulation Mechanism – the IRM Agreement.

[30] During incentive regulation, a utility's base rates are set initially through a cost of service proceeding and then adjusted annually using a pre-approved pricing mechanism intended to encourage productivity or efficiency improvements. If a utility is able to increase revenues or reduce costs during incentive regulation, it is permitted to retain its "over-earnings" in excess of its regulated return on equity – but subject to the terms of any earnings sharing mechanism under which the utility has agreed to share its earnings with its ratepayers.

[31] I will return later to the terms of the IRM Agreement.

(4) Upstream Transportation Optimization

[32] To ensure a consistent supply of gas to its customers, Union holds a portfolio of upstream transportation contracts that provide gas transportation on a firm basis from supply basins across North America to Union's storage, transmission and distribution system in Ontario.

[33] Because it is difficult to predict with accuracy how much firm transportation capacity is required in any given year, as part of maintaining a conservative gas supply plan that will ensure a consistent supply of natural gas, a utility may, from time-to-time, have excess firm transportation capacity.

[34] Traditionally, the Board has passed through the cost of upstream transportation entirely to ratepayers through the use of deferral accounts. However, where a utility was able to generate revenue by disposing of unused transportation capacity through transactions with third parties, the Board has generally permitted the utility to retain some portion of the revenues generated from these transactions to encourage the utility to dispose of the unused capacity. The transactions themselves are generally referred to as "optimization activities" or "transactional services".

[35] Prior to the IRM Agreement, revenue earned from upstream transportation optimization activities was recorded in various deferral accounts. In the past, the Board had ordered that these accounts be cleared at least annually on the basis

that ratepayers receive 75 per cent of the revenues through a rate reduction and Union retain the remaining 25 per cent of revenues.

(5) The IRM Agreement

[36] As indicated above, for the period 2008 to 2012, Union entered into the IRM Agreement with the interveners. In January 2008, the Board approved the IRM Agreement as an acceptable incentive regulation program.

[37] The following aspects of the IRM Agreement are significant for the purposes of this appeal:

- The IRM Agreement identified so-called “Y factors”, which are costs incurred by Union that would be passed through entirely to customers during the term of the IRM Agreement. Items treated as “Y factors” in the IRM Agreement included upstream gas and transportation costs.
- The IRM Agreement eliminated four deferral accounts, which had been previously maintained. In return for closing these accounts, Union increased the optimization margin built into rates from $2.6 million to $6.9 million. Put another way, Union agreed to fund a $4.3 million annual decrease in rates and assumed the risk of earning sufficient optimization revenue to offset that decrease.

- The IRM Agreement included the ESM, which initially provided that utility earnings greater than two per cent above Union's regulated rate of return would be shared 50/50 with ratepayers.
- The IRM Agreement permitted the parties to re-open it if Union's earnings exceeded its regulated return on equity by more than three per cent.

[38] When Union's earnings for 2008 did exceed three per cent, the parties to the IRM Agreement entered into a further Settlement Agreement amending the terms of the IRM Agreement (the "Amending Agreement"). Among other things, the Amending Agreement provided that earnings over three per cent of Union's regulated rate of return were to be shared 90/10 in favour of ratepayers. The Board approved this amendment by order.

(6) QRAM Proceedings

[39] As indicated above, depending on the type of deferral account, the Act requires that they be cleared at least quarterly or annually. Given the frequency with which deferral accounts must be cleared, the Board developed QRAM proceedings. They provide an abbreviated and mechanistic hearing process used to clear some, but not all, deferral accounts.

[40] In 2011, Union brought five deferral accounts forward for disposition every quarter through QRAM proceeding. Some of these accounts included gas

transportation related costs. Union did not bring the disputed $22 million in FT-RAM revenues forward for disposition in any of the 2011 QRAM proceedings.

(7) Union's April 2012 Application

[41] The application giving rise to this appeal was brought in April 2012. As indicated above, Union filed an application at that time seeking an order amending or varying the rates charged to customers as of October 2012. A key purpose of the application was to dispose of 2011 utility earnings in accordance with the ESM.

[42] In its application, Union included as utility earnings total optimization revenues for 2011 of $31.7 million, $22 million of which was attributable to FT-RAM optimization.

(8) Union's 2013 Cost of Service Proceeding

[43] On November 10, 2011, Union filed an application with the Board for an order approving or fixing its rates effective January 1, 2013. The appropriate treatment of FT-RAM revenues was an issue in that proceeding. The cost of service decision is relevant because the Board incorporated the evidentiary record from the 2013 cost of service proceeding as part of the record on the preliminary issue.

C. DECISIONS BELOW

(1) The Board's decision on the Preliminary Issue

[44] Prior to dealing with Union's application, the Board determined that it would address Union's treatment of upstream transportation optimization revenues in 2011 as a preliminary issue.

[45] The Board described the preliminary issue as follows: "Has Union treated the upstream transportation optimization revenues appropriately in 2011 in the context of Union's existing IRM framework?"

[46] In its decision on the preliminary issue, the Board accepted the argument of several interveners that TCPL's FT-RAM program allowed Union to create revenue opportunities by planning to replace higher cost firm upstream transportation services paid for by ratepayers with lower cost upstream transportation arrangements:

> The Board agrees with the submissions of parties that *the utilization of TCPL's FT-RAM program by Union allows Union to manage its upstream transportation arrangements on a planned basis* by leaving pipe empty and flowing gas on a different and cheaper path. The Board finds that *the effect of this activity is that higher upstream transportation costs that are paid for by Union's customers, have been substituted with lower cost upstream transportation arrangements*. [Emphasis added.]

[47] As noted by the Divisional Court, the Board used even stronger language in its companion decision on the related 2012 cost of service proceeding in describing Union's actions. For example, the Board said:

> The Board finds that the record in this proceeding is clear that firm assets are being made available for transactional services on a planned basis, with releases occurring prior to the commencement of the heating season and with capacity being assigned for up to a full year. …
>
> … the record in this proceeding suggests that Union's optimization activities have, in their own right, become a driver of the gas supply plan and are no longer solely a consequence of it.
>
> *The Board finds that Union's ability to "manufacture" optimization opportunities undermines the credibility of Union's gas supply planning process, the planning methodology, and the resulting gas supply plan.*
>
> As submitted by various parties to this proceeding and Board staff, *Union has had an incentive to contract excessive upstream gas transportation services to the detriment of the ratepayer. Union has not filed convincing evidence that the amount and type of upstream gas transportation contracts procured on behalf of ratepayers reflects the objective application of its gas supply planning principles.* [Emphasis added.]

[48] In the light of its finding that Union had acted on a planned basis, the Board concluded that treating FT-RAM revenues as utility earnings was "inconsistent" with the IRM Agreement – and contrary to the regulatory principle inherent in it – that the cost of upstream transportation is a pass-through item from which Union is not entitled to profit:

> The Board finds that Union has used TCPL's FT-RAM program to create a profit from the upstream transportation portfolio and has treated this profit as utility earnings, subject only to the provisions of the earnings sharing mechanism.
>
> *The Board finds that this treatment is inconsistent with the Settlement Agreement on the IRM Framework and contrary to long standing regulatory principle inherent in the IRM Framework that the cost of gas and upstream transportation are to be treated as pass-through items, and therefore that Union cannot profit from the procurement of gas supply for its customers*. [Emphasis added.]

[49] Instead, the Board determined that the monies generated from FT-RAM activities should be treated as gas supply costs savings:

> As such, the Board finds that Union's upstream transportation FT-RAM optimization revenues are gas cost reductions, and are properly considered Y factor items in accordance with Union's IRM Framework.

[50] However, although gas supply cost reductions would normally be passed through completely to ratepayers, the Board noted that "absent an incentive, [Union] may not have undertaken these [optimization] activities."

[51] Accordingly, the Board directed that ratepayers would be entitled to 90 per cent of the $22 million net revenue amount related to Union's 2011 FT-RAM activities in the form of an offset to gas supply costs and that Union would be entitled to receive a 10 per cent incentive for having generated the net revenues.

[52] In the course of its reasons, the Board rejected Union's arguments that reclassifying the FT-RAM revenues would undo the IRM Agreement and amount to retroactive ratemaking.

[53] The Board noted that it was reclassifying revenues based on evidence filed in Union's 2013 cost of service proceeding, which the Board incorporated by reference. The Board stated that the reclassification of revenues "[was] consistent with the IRM Framework".

[54] Moreover, the Board found that it had "an ongoing responsibility to determine whether activities undertaken during the IRM term [were] being characterized in accordance with the IRM Framework and have been characterized in a manner which results in just and reasonable rates."

[55] Accordingly, "the annual disposition of deferral accounts, earnings sharing, and other accounts that are part of Union's IRM Framework is not merely a mechanical exercise." Instead, "it is a process that is informed by evidence relating to the balances in those accounts and whether those balances reflect the appropriate application of the IRM Framework and the regulatory principles inherent in it."

[56] The Board also rejected Union's arguments that its FT-RAM activities were no different than optimization activities or transactional services in which Union had engaged in the past and that treating its FT-RAM activities as gas supply

cost reductions would be inconsistent with the descriptions and historical use of deferral accounts.

[57] The Board found that evidence in prior proceedings led to the conclusion that upstream optimization opportunities were generally only available on an *unplanned* basis. Further, Union had not pointed to any evidence filed prior to the concurrent cost of service proceeding that fully explained how the FT-RAM revenues were being generated.

[58] In this regard, the Board noted that an “information asymmetry … exists” between Union and its ratepayers and that Union had an obligation to make “a much higher level of disclosure than was produced in prior proceedings” concerning “departures or potential departures … from regulatory principle inherent in the IRM Framework”.

[59] Despite its findings concerning the 2011 FT-RAM revenues, the Board rejected submissions from some of the interveners that it should address FT-RAM revenues earned prior to 2011.

[60] The Board directed Union to advise it of the gas supply related deferral account(s) in which the reduction to ratepayers would be recorded and to file a draft accounting order for the account(s).

[61] The Board subsequently issued a decision and rate order on February 28, 2013, under which the revenues from the 2011 FT-RAM optimization activities were to be recorded in a newly created deferral account.

(2) The Divisional Court's Decision

[62] Union appealed the Board's decision on the preliminary issue to the Divisional Court. Before the Divisional Court, Union argued that all 2011 gas supply related costs had been dealt with through final orders in 2011 QRAM proceedings. Accordingly, by reclassifying the utility revenues as gas supply cost reductions to be passed through to ratepayers, the Board varied what were final rate orders and engaged in impermissible retroactive ratemaking.

[63] The majority dismissed the appeal, holding that the Board's findings were clear that the disputed $22 million had not been dealt with as part of the 2011 QRAM proceedings and that Union had not met its disclosure obligations concerning the FT-RAM revenue. Because the "true scope and nature of the FT-RAM program" was only revealed during the 2012 rate hearing, that revenue could only be properly classified following the 2012 hearing. It followed that the $22 million was "encumbered" because "Union, in accordance with the statutory framework and Board policy, was bringing forward its 2011 accounts for review and approval."

[64] During the course of their reasons, the majority stated, “the provisions of section 36 of the Act are liberal in construction and do not in any manner constrain the Board from making orders respecting matters which arose in a previous year but had not been specifically dealt with as a discrete item in the ratesetting process”.

[65] In the dissenting judge’s view, the elimination of the deferral accounts when the IRM Agreement was entered into led to the conclusion “that the intended Y factor under the [IRM Agreement] was gross transportation costs”.

[66] In other words, because the upstream transportation optimization deferral accounts were eliminated, the Y factor described as upstream transportation costs in the IRM Agreement referred to the costs associated with Union’s firm transportation contracts “without regard for any netting or pass-through of profits or losses on the sale of any such contracts.”

[67] Accordingly, under the terms of the IRM Agreement, the FT-RAM revenues were to be treated as utility revenues subject to the ESM because there was “no other account or provision that would mandate different treatment” for them.

[68] The dissenting judge also rejected the Board’s conclusion that a meaningful distinction could be made under the terms of IRM Agreement between FT-RAM revenues and other transactional services revenues. In his view, the Board’s conclusion that a distinction existed between planned and

unplanned upstream transportation optimization activities was not justified. He concluded, “[T]he concept of ‘transactional services revenues’ does not, by itself, provide a basis for the re-classification of FT-RAM related revenues as gas supply costs.”

[69] Having concluded that the Y factor described in the IRM Agreement referred to gross transportation costs – and therefore that FT-RAM revenues were subject to the ESM – the dissenting judge turned to the question of the Board’s authority to reclassify such revenues as gas supply cost reductions. He rejected the Board’s submission on appeal that the amounts brought forward by Union were “encumbered” and questioned how, in the absence of an applicable deferral account, that condition could arise.

[70] The dissenting judge concluded that neither the IRM Agreement nor the Act authorized the Board to reclassify Union’s FT-RAM revenues. Rather, the Board’s reclassification of Union’s 2011 FT-RAM related earnings for the purposes of the ESM constituted retroactive ratemaking, and was, “by definition, unreasonable”.

D. ANALYSIS

(1) Standard of Review

[71] Under s. 33(2) of the Act, an appeal lies to the Divisional Court from an order of the Board “only upon a question of law or jurisdiction”.

[72] The parties agree that decisions of the Board are reviewable on appeal to the Divisional Court on a standard of reasonableness. I agree. (See, for example, *Power Workers'*).

(2) Discussion

[73] Union submits that the Board's decision to reclassify the FT-RAM revenues as gas supply cost reductions is unreasonable because it is an unauthorized departure from the terms of the IRM Agreement, which the Board had approved as the mechanism for setting just and reasonable rates during the incentive regulation period, and because it constitutes impermissible retroactive ratemaking.

[74] Union points out that, under the terms of the IRM Agreement, it reduced its revenue requirement in exchange for the elimination of the upstream transportation optimization deferral accounts. Union contends that its FT-RAM optimization activities were no different than other optimization activities in which it had previously engaged and that it is undisputed that, absent the IRM Agreement, such revenues would have fallen within the one of the eliminated upstream transportation optimization deferral accounts. By reclassifying FT-RAM revenues as gas supply cost reductions, the Board effectively unwound the IRM Agreement. Moreover, the reclassification is inconsistent with the Board's past treatment of such revenues.

[75] In any event, all permissible 2011 rate adjustments based on gas supply cost reductions had already been made through final orders in the QRAM proceedings. In the absence of a deferral account that segregated specified amounts for future disposition, reclassifying the FT-RAM revenues from utility earnings to gas supply cost reductions was nothing more than an impermissible attempt to adjust rates that had been previously set based on unanticipated circumstances – namely, the unanticipated amount of revenue Union was able to generate by using the FT-RAM program. By definition, the Board's decision constitutes impermissible retroactive ratemaking.

[76] I would not accept these submissions.

[77] As a starting point, contrary to Union's position, the Board made an explicit finding that monies generated by Union's 2011 FT-RAM activities would not have fallen into one of the deferral accounts eliminated under the IRM Agreement. In the Board's view, this was because Union was using the program to create optimization opportunities on a planned basis, whereas the deferral accounts recorded optimization activities carried out on an unplanned basis:

> The Board notes that *Union has classified the revenues generated from its upstream transportation FT-RAM optimization activities as transactional service revenues because it believes that these activities are no different than its traditional transactional service activities.* However, *the Board finds that a review of the evidence* filed by Union in previous proceedings to answer the

> question: "what are transactional services" *does not lead to this conclusion*.
>
> …
>
> The Board finds that *Union's evidence* in the RP-2003-0063 / EB-2003-0087 proceeding, when taken as whole, *does not support the conclusion that the planned optimization of gas supply related assets would be considered a transactional service. The evidence* in the above noted proceeding *explicitly speaks to the fact that with a balanced gas supply portfolio there will be few, if any, firm assets available to support transactional services on a future planned basis. In the Board's view, this statement speaks to the fact that the portion of utility gas supply assets that is available to support transactional service activities is only the portion of those assets that is temporarily surplus to the gas supply plan as a result of factors beyond Union's control. Therefore, a clear distinction can be made between Union's transactional services (including exchanges) and Union's FT-RAM related activities*. [Emphasis added.]

[78] In my view, the Board's findings that monies generated by Union's 2011 FT-RAM activities were generated on a planned basis, and were thus distinguishable from upstream transportation optimization revenues that would have fallen within the eliminated deferral accounts, are findings of fact that were not subject to review on appeal to the Divisional Court.

[79] In the result, rather than being a departure from the IRM Agreement that had the effect of unwinding the IRM Agreement, the Board's decision was nothing more than a review of the nature of the revenues brought forward for sharing under the ESM and a determination that some of such revenues did not

qualify for that treatment. Accordingly, in my view, the Board's decision cannot be seen as unreasonable on the basis that it was a departure from the IRM Agreement. Nor was its conclusion that the FT-RAM revenues did not qualify for sharing under the ESM unreasonable.

[80] Moreover, I am not convinced that the fact that the FT-RAM revenues were not segregated in a special deferral account relating specifically to gas supply cost reductions means that the Board engaged in impermissible retroactive ratemaking by reclassifying them as gas supply cost reductions. Rather, I conclude that the FT-RAM revenues brought forward by Union for disposition as part of the ESM proceeding were effectively "encumbered" and subject to further disposition by the Board.

[81] This issue requires a discussion of the principle against retroactive ratemaking.

[82] It is well established that an economic regulatory tribunal, such as the Board, operating under a positive approval scheme of ratemaking must exercise its rate-making authority on a prospective basis. Generally speaking, absent express statutory authorization, such a regulator may not exercise its rate-making authority retroactively or retrospectively.

[83] As noted by the Divisional Court majority, the classic explanation for the general presumption against the retroactive operation of statutes is set out in *Young v. Adams*, [1898] A.C. 469, at p. 476:

> [I]t manifestly shocks one's sense of justice that an act legal at the time of doing it should be made unlawful by some new enactment.

[84] In *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722, ("*Bell Canada 1989*"), at p. 1749, Gonthier J. writing for the court, characterized retroactive ratemaking as ratemaking the purpose of which "is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive."

[85] At p. 1759 of the same case, Gonthier J. explained that "the power to review its own previous final decision on the fairness and reasonableness of rates would threaten the stability of the regulated entity's financial situation."

[86] From the ratepayers' perspective, retroactive ratemaking may create unfairness because it "redistributes the cost of utility service by asking today's customers to pay for the expenses incurred by yesterday's customers": *Atco Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2014 ABCA 28, 566 A.R. 323, at para. 51.

[87] Nonetheless, courts have recognized qualifications on the principle against retroactive ratemaking.

[88] In *Bell Canada 1989*, at pp. 1752-1761, the Supreme Court concluded that the power to make interim orders necessarily implies the power to modify, by final order, the rates created under an interim order.

[89] In *Bell Canada v. Bell Alliant Regional Communications*, 2009 SCC 40, [2009] 2 S.C.R. 764, ("*Bell Alliant*"), the Supreme Court noted, at para. 54, that deferral accounts are "accepted regulatory tools" that "'enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year'".

[90] Although *Bell Alliant* involved the disposition of funds in a deferral account, at paras. 61 and 63, Abella J. also used the term "encumbered" to explain why the disposition of funds in a deferral account for one-time credits to ratepayers did not constitute impermissible retroactive ratemaking. A key feature of her reasoning was that it was known from the beginning that funds accumulated in the deferral accounts at issue were subject to further disposition by the regulator in the form of credits to ratepayers. She said:

> [61] In my view, because this case concerns encumbered revenues in deferral accounts … we are not dealing with the variation of final rates. As Sharlow J.A. pointed out, [the principle from] *Bell Canada 1989* [that retroactive or retrospective ratesetting is impermissible] is inapplicable because *it was known from the outset in the case before us that Bell Canada would be obliged to use the balance of its deferral account in accordance with the CRTC's subsequent direction*.

…

> [63] In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since *these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates always remained subject to the deferral accounts mechanism established in the Price Caps Decision*. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting [Citations omitted and emphasis added.]

[91] More recently in *Atco Gas,* the Alberta Court of Appeal explained that "[s]lavish adherence to the use of interim rates and deferral accounts should not prohibit adjustments" in a proper case: at para. 62. Moreover, "[s]imply because a ratemaking decision has an impact on a past rate does not mean it is an impermissible retroactive decision": at para. 56. Rather, "[t]he critical factor for determining whether the regulator is engaging in retroactive ratemaking is the parties' knowledge [that the rates were subject to change]": at para. 56.

[92] In that case, the regulator directed Atco to remove certain surplus assets from its rate base and revenue requirement, and backdated the effective date of the removal to an earlier date. The earlier date was the day after the Alberta

Court of Appeal issued a decision indicating that Atco did not require the regulator's consent to remove the asset from its rate base. Removal of the assets from the rate base and revenue requirement caused a decrease in rates, and since the regulator backdated the effective date of the removal, rates were decreased after the fact.

[93] On appeal to the Alberta Court of Appeal, Atco argued that the regulator could only change the rates by using an interim order or deferral account. The Alberta Court of Appeal rejected that argument. The court found, at para. 53, that "the utility must also be taken to know that the rates will be subject to change as a result of the non-inclusion of those assets in the rate base."

[94] In this case, Union does not dispute that, under the terms of the IRM Agreement, following its year-end, it was obliged to bring forward for the Board's review and approval amounts it classified as utility earnings that were subject to sharing under the ESM. Union also knew, from the outset of the IRM Agreement, that the Board's ESM determination would impact rates. The ESM determination under the IRM Agreement was thus inherently retrospective – and Union always knew that.

[95] Further, on the Board's findings, the manner in which Union generated its 2011 FT-RAM revenues and its classification of those revenues as utility earnings was inconsistent with the IRM Agreement and violated the regulatory

principle inherent in the IRM Agreement that the cost of upstream transportation is a pass-through item and that a utility "cannot profit from the procurement of gas supply for its customers."

[96] Although Union argued that its 2011 FT-RAM activities were no different than its previous upstream optimization activities, the Board made a specific finding that "a clear distinction can be made between Union's [unplanned] transactional services … and Union's [planned] FT-RAM activities."

[97] Significantly, prior to the 2012 hearings, the fact that the 2011 FT-RAM revenues were generated on a planned basis – and thus in a fashion inconsistent with regulatory principle and the IRM Agreement – was uniquely within Union's knowledge.

[98] In this regard, the Board found that Union had an obligation to "be mindful of the information asymmetry that exists between it and [its] ratepayers" and "to disclose departures or potential departures that it intends to make from regulatory principle inherent in the IRM Framework."

[99] In circumstances where Union knew that it was generating its 2011 FT-RAM revenues on a planned basis, Union must be fixed with knowledge, as of the date it generated those revenues, that the Board would be obliged to characterize them as a Y factor, or pass-through item, under the IRM Agreement.

[100] Although the Board had permitted profit-taking on optimization activities in the past, on the Board's findings, the prior optimization activities involved disposing of unplanned surpluses of firm transportation. The 2011 FT-RAM activities were qualitatively different because they involved disposing of planned surpluses of firm transportation. Prior to the 2012 hearings, Union was the only party in a position to know that – and must also be taken to have known that – its actions were inconsistent with the regulatory principle inherent in the IRM Agreement.

[101] In these circumstances, where the ESM determination was inherently retrospective, and where Union failed to disclose in advance the true nature of its intended 2011 FT-RAM activities, it was not unreasonable for the Board to treat Union's 2011 FT-RAM revenues as encumbered and therefore subject to further disposition by the Board in the form of a credit to ratepayers.

[102] Union argues that the Board never made an express finding that Union was acquiring excess firm transportation during 2011. While the Board may not have said so expressly, on a fair reading of their decision on the preliminary issue in combination with their decision on the 2012 cost of service proceeding, in my view, that message is very clear.

[103] Having regard to all the circumstances, I am not persuaded that the majority of the Divisional Court erred in characterizing the 2011 FT-RAM

revenues that Union brought forward in its 2012 application as encumbered or that the Board's decision to reclassify those revenues as gas supply cost reductions was unreasonable.

E. DISPOSITION

[104] Based on the foregoing reasons, the appeal is dismissed.

[105] Neither party requested costs and none are awarded.

Released:

"AH"	"Janet Simmons J.A."
"JUN 22 2015"	"I agree Alexandra Hoy A.C.J.O."
	"I agree M. Tulloch J.A."

Appendix "A"

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B.

19. (2) The Board shall make any determination in a proceeding by order.

33. (1) An appeal lies to the Divisional Court from,

(a) an order of the Board …

(2) An appeal may be made only upon a question of law or jurisdiction and must be commenced not later than 30 days after the making of the order or rule or the issuance of the code.

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.

…(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.

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

…

(4.1) If a gas distributor has a deferral or variance account that relates to the commodity of gas, the Board shall, at least once every three months, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates.

(4.2) If a gas distributor has a deferral or variance account that does not relate to the commodity of gas, the Board shall, at least once every 12 months, or such shorter period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2013-0119

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Chapleau Public Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION and RATE ORDER

March 13, 2014

Chapleau Public Utilities Corporation ("Chapleau PUC") filed an application with the Ontario Energy Board (the "Board") on September 10, 2013 under section 78 of the Act, seeking approval for changes to the rates that Chapleau PUC charges for electricity distribution, effective May 1, 2014 (the "Application").

The Application met the Board's requirements as detailed in the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") dated October 18, 2012 and the *Filing Requirements for Electricity Distribution Rate Applications* dated July 17, 2013. Chapleau PUC selected the Price Cap Incentive Rate-Setting ("Price Cap IR") option to adjust its 2014 rates. The Price Cap IR methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between cost of service applications. Chapleau PUC last appeared before the Board with a full cost of service application for the 2012 rate year in the EB-2011-0322 proceeding. In this proceeding, Chapleau PUC also seeks approval for its request to recover amounts related to a billing error from Hydro One Networks Inc. ("Hydro One") for Low Voltage Service and adjustments to its Low Voltage Service rates.

The Board conducted a written hearing and Board staff participated in the proceeding. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was granted intervenor status and cost eligibility with respect to the proposals regarding Low Voltage Service. No letters of comment were received.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Rate Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Revenue-to-Cost Ratio Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Hydro One Billing Error for Low Voltage Service; and
- Proposed Adjustments to Low Voltage Service Rates.

Price Cap Index Adjustment

The Board issued the *Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the "Price Cap IR Report") which provides the 2014 rate adjustment parameters for distribution companies selecting either the Price Cap IR or Annual IR Index option.

Distribution rates under the Price Cap IR option are adjusted by an inflation factor, less a productivity factor and a stretch factor. The inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group Research, LLC, the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned Chapleau PUC a stretch factor of 0.45%.

As a result, the net price cap index adjustment for Chapleau PUC is 1.25% (i.e. 1.7% - (0% + 0.45%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. The price cap index adjustment does not apply to the components of delivery rates set out in the list below.

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Electricity Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFit Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

The Board issued a Decision and Rate Order (EB-2013-0396) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2014. The Board determined that the RRRP charge to be paid by all rate-regulated distributors and collected by the Independent Electricity System Operator shall be increased to $0.0013 per kWh effective May 1, 2014, from the current $0.0012 per kWh. The draft Tariff of Rates and Charges flowing from this Decision and Rate Order reflects the new RRRP charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges for electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy,* dated March 31, 2011. Pursuant to the Board's Decision in its 2012 cost of service application EB-2011-0322, Chapleau PUC proposed to increase the revenue-to-cost ratio for its Sentinel Lighting and Street Lighting classes, offset by a reduction in that of the GS >50 kW class.

The table below outlines the proposed revenue-to-cost ratios.

Current and Proposed Revenue-to-Cost Ratios

Rate Class	Current 2013 Ratio	Proposed 2014 Ratio
Residential	0.97	0.97
General Service Less Than 50 kW	1.04	1.04
General Service 50 to 4,999 kW	1.23	1.22
Street Lighting	0.78	0.80
Sentinel Lighting	0.61	0.68
Unmetered Scattered Load	1.19	1.19

Board staff submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in Chapleau PUC's 2012 cost of service proceeding.

The Board agrees that the proposed revenue-to-cost ratios are consistent with the decision arising from the 2012 cost of service proceeding and therefore approves the revenue-to-cost ratios as filed.

Retail Transmission Service Rates

Electricity distributors are charged for transmission costs at the wholesale level and then pass on these charges to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

The Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline") which outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2014. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Uniform Transmission Rates ("UTR") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors must adjust their RTSRs to reflect any changes to the applicable Sub-Transmission RTSRs of their host distributor(s), e.g. Hydro One Networks Inc.

Chapleau PUC is a partially embedded distributor whose host is Hydro One Networks Inc.

The Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2014, as shown in the following table:

2014 Uniform Transmission Rates

Network Service Rate	$3.82 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.82 per kW $1.98 per kW

The Board also approved new rates for Hydro One Networks' Sub-Transmission class, including the applicable RTSRs, effective January 1, 2014 (EB-2013-0141), as shown in the following table.

2014 Sub-Transmission RTSRs

Network Service Rate	$3.23 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.65 per kW $1.62 per kW

The Board finds that these 2014 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Chapleau PUC's 2012 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2014 is a credit of $108,948. This amount results in a total credit claim of $0.0041 per kWh, which exceeds the preset disposition threshold.

Low Voltage Billing Error

Chapleau PUC recorded a principal debit balance of $93,387 and interest of $1,831 in Account 1550 and proposed recovery within its 2012 Group 1 balances to reflect adjusted low voltage charges resulting from a billing error by Hydro One. Chapleau PUC received an invoice for $93,387 from Hydro One in September 2013, which adjusted the billed demand quantity (kW) from January 28, 2009 to April 3, 2013. Chapleau PUC proposed to recover the debit balance with its 2012 deferral and variance account balances to offset the credit balance of $108,948, reducing the total credit balance for disposition to $13,730. This would result in a total credit claim of $0.0005, which does not meet the preset disposition threshold.

Chapleau PUC confirmed that the $93,387 consists of two components:

- $34,296 related to transactions subsequent to December 31, 2011, where the account balance has not yet been disposed on a final basis; and
- $59,091 related to transactions prior to December 31, 2011, where the account balance was approved by the Board and disposed on a final basis in Chapleau PUC's 2013 IRM rate proceeding EB-2012-0114.

Chapleau indicated that it had an internal process for checking the accuracy of amounts payable and that it had questioned Hydro One's billed amounts on three occasions since 2009. Hydro One assured Chapleau PUC that the invoiced amounts were correct. In early 2013, Chapleau PUC again questioned the invoice received and was informed by Hydro One that there was indeed an error.

Board staff submitted that Chapleau PUC's 2011 deferral and variance account balances had been disposed of on a final basis in Chapleau PUC's 2013 IRM decision, and that the proposal to recover the adjustment of $59,091 relating to this period from Chapleau PUC's customers would result in retroactive ratemaking[1].

Board staff submitted that both the Retail Settlement Code and Hydro One's Conditions of Service addressed under-billing situations, limiting the amount of time over which a distributor must be repaid. Specifically, Board staff noted that Section 7.7.7 states the following:

> Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid is 2 years. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid is 2 years.

Board staff also noted in its submission that Hydro One's Conditions of Service provide for recovery of billing errors, as follows:

> Where a billing error, from any cause, has resulted in a Customer or Retailer being under-billed, and where Measurement Canada has not become involved in the dispute, the Customer or Retailer shall pay to Hydro One the amount that was not previously billed. In the case of an individual Customer who is not responsible for the error, the allowable period of time for which the Customer may be charged is two (2) years for residential customers, including seasonal and farm residence, and all other customers[2].

Board staff submitted that Chapleau PUC may choose to consider the Retail Settlement Code and Hydro One's Conditions of Service as a basis by which to pursue further discussions with Hydro One.

VECC submitted that, based on past Board decisions, it would be inappropriate for Chapleau PUC to include an out-of-period adjustment and that the Board should not approve Chapleau PUC's request.

Chapleau PUC included Hydro One's comments in its reply submission. Therein, Hydro

[1] EB-2013-0022, Decision and Order, Veridian Motion to Review, April 25 2013, p. 10

[2] Hydro One Networks Inc. Conditions of Service, May 21, 2013, s. G. Billing Errors, p. 71c

One indicated that its settlement practices with its embedded distributors are consistent with the approach used by the Independent Electricity System Operator with market participants, which incorporates the correction of billing errors without regard to any time limitation. Failure to mirror this approach would result in cross-subsidization and improper allocation of costs among the parties involved.

Chapleau PUC submitted that the disputed amount of $59,091 represents 7.3% of its distribution revenue, and that failure to recover this amount from customers would create a serious cash flow risk. Chapleau PUC submitted that it should not be penalized for Hydro One's error. Chapleau PUC requested that the Board allow it to recover the full amount of $93,387, or the Board should not allow Hydro One to pass on its billing errors, if a distributor is unable to recover those costs from its customers.

The Board cannot approve the proposal to recover the adjustment of $59,091 relating to Chapleau PUC's 2011 deferral and variance account balances. The 2011 account balances were disposed on a final basis in Chapleau PUC's 2013 IRM decision. To subsequently adjust the balances would result in retroactive ratemaking. The courts have made it very clear that retroactive rate-making, the adjustment to rates after a final rate order has been issued, is not allowed. Rather, the principles of certainty and finality are a necessary component of effective rate regulation.

The Board approves the disposition of a debit amount of $34,296 as the account balance has not yet been disposed on a final basis.

Chapleau did not ask for disposition of its Group 1 balances in this proceeding. However, with the exclusion of the $59,091 the disposition threshold is met. In making this decision, the Board is mindful of the efforts made by Chapleau PUC to rectify the Hydro One billing error beginning in 2009. It is through no fault on the part of Chapleau PUC that it is faced with a significant adjustment to its past low voltage payments that cannot be recovered by way of a rate application to the Board.

The Board notes that both the Retail Settlement Code and Hydro One's Conditions of Service in effect during the period of overbilling, and when the invoice was dated, appear to provide some remedy for this situation; however, the onus is on Chapleau to pursue these options. The Board's opinion is that neither Chapleau PUC nor its current customers should pay for costs that go back as far as 2009, given it was solely the result of Hydro One's billing error.

The Board approves the disposition of a credit balance of $73,980 as of December 31, 2012, including interest as of April 30, 2014 for Group 1 accounts. This credit balance includes the additional debit amount of $34,295 in Account 1550 as discussed above. Under normal circumstances, the default period for the disposition of deferral and variance account balances is one year. In this case, in order to mitigate the impact on Chapleau's cash flow, these balances are to be disposed over a two-year period from May 1, 2014 to April 30, 2016.

The table below identifies the principal and interest amounts approved for disposition for Group 1 accounts.

Group 1 Deferral and Variance Account Balances

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$19,399	($41)	$19,358
RSVA - Wholesale Market Service Charge	1580	($36,071)	($1,512)	($37,583)
RSVA - Retail Transmission Network Charge	1584	$7,449	$507	$7,956
RSVA - Retail Transmission Connection Charge	1586	$635	$413	$1,048
RSVA - Power	1588	($6,511)	($2,766)	($9,277)
RSVA - Global Adjustment	1589	$34,451	$950	$35,401
Recovery of Regulatory Asset Balances	1590	0	0	0
Disposition and Recovery of Regulatory Balances (2008)	1595	0	$135	$135
Disposition and Recovery of Regulatory Balances (2010)	1595	0	($3)	($3)
Disposition and Recovery of Regulatory Balances (2011)	1595	($88,552)	($2,462)	($91,014)
Total Group 1 Excluding Global Adjustment – Account 1589		**($103,651)**	**($5,729)**	**($109,381)**
Total Group 1		**(69,200)**	**($4,779)**	**($73,980)**

The balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the transfer must be the same as the effective date for the associated rates, generally, the start of the rate year. Chapleau PUC should ensure these adjustments are included in the reporting period ending June 30, 2014 (Quarter 2).

Low Voltage Rates

Chapleau PUC withdrew its request to change its low voltage rates, and stated that it would address these changes in its next cost of service application.

Rate Model

With this Decision and Rate Order, the Board is providing Chapleau PUC with a rate model, applicable supporting models and a draft Tariff of Rates and Charges (Appendix A). The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2013 Board-approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Chapleau PUC's new distribution rates shall be effective May 1, 2014.

2. Chapleau PUC shall review the draft Tariff of Rates and Charges set out in Appendix A and shall file with the Board, as applicable, a written confirmation of its completeness and accuracy, or provide a detailed explanation of any inaccuracies or missing information, within **7 days** of the date of issuance of this Decision and Rate Order.

3. If the Board does not receive a submission from Chapleau PUC to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Rate Order will become final. Chapleau PUC shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

4. If the Board receives a submission from Chapleau PUC to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the Board will consider the submission of Chapleau PUC prior to issuing a final Tariff of Rates and Charges.

5. Chapleau PUC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

COST AWARDS

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Chapleau PUC shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Chapleau PUC any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Chapleau PUC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2013-0119,** be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 13, 2014
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Rate Order

Draft Tariff of Rates and Charges

Board File No: EB-2013-0119

DATED: March 13, 2014

Ontario Energy Board

Commission de l’énergie de l’Ontario

Ontario

EB-2013-0022

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Veridian Connections Inc. for an order or orders approving or fixing just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2012.

AND IN THE MATTER OF a Motion to Review and Vary by Veridian Connections Inc. pursuant to the Ontario Energy Board’s *Rules of Practice and Procedure* for a review by the Board’s Decision and Order in proceeding EB-2012-0247.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER
ON MOTION TO REVIEW
April 25, 2013

INTRODUCTION

On January 23, 2013, Veridian Connections Inc. (“Veridian”) filed with the Ontario Energy Board (the “Board”) a motion for request to review and vary (the “Motion”) the Board’s Decision and Order dated October 25, 2012 (the “Decision”) in respect of Veridian’s smart meter application (EB-2012-0247) (the “Final Disposition Proceeding”). The Board assigned the Motion file number EB-2013-0022.

The Motion sought to extend the time for filing the Motion with the Board and vary the

Board's EB-2012-0247 Decision to permit Veridian to recover an additional $478,224 in revenue requirement related to 2009 amortization expenses associated with smart meter capital expenditures made in 2006, 2007, and 2008. The recovery is to be made through amendment of the existing Smart Meter Disposition Riders ("SMDRs") commencing on May 1, 2013 and continuing until April 30, 2014.

The Board issued its Notice of Motion to Vary and Procedural Order No. 1 on March 6, 2013. The Board granted intervenor status and cost award eligibility to the Vulnerable Energy Consumers Coalition ("VECC"), as it was the only intervenor in Veridian's smart meter rate proceeding under EB-2012-0247. The Board also determined that the most expeditious way of dealing with the Motion was to consider concurrently the threshold question of whether the matter should be reviewed, as contemplated in the Board's *Rules of Practice and Procedure* (the "Rules"), and the merits of the Motion.

The Board established a timetable for Veridian to file any additional material in support of the Motion, followed by written submissions by VECC and Board staff, and a reply submission by Veridian.

Veridian submitted additional material in support of its Motion on March 13, 2013. Board staff filed its submission on March 22, 2013. Veridian filed its reply submission on April 3, 2013. VECC did not file any submission.

For the reasons that follow the Board grants the extension of time for filing the Motion and finds that the threshold test has been met. The Board has reviewed the Motion materials and the Decision, and for the reasons set out below has determined that it will not grant the relief requested.

BACKGROUND

On October 2, 2009 Veridian applied to the Board for approval of 2010 rates on a Cost of Service basis (EB-2009-0140) (the "Interim Disposition Proceeding"), within which Veridian applied for interim disposition of smart meter-related revenue requirement amounts. As part of the Interim Disposition Proceeding, the capital expenditures associated with smart meter investments up to December 31, 2008 were included in Veridian's rate base effective January 1, 2010. Accordingly, going forward from January 1, 2010, the revenue requirement associated with smart meter capital expenditures up to December 31, 2008 was included in base rates.

Even after taking into account the interim clearance of smart meter amounts as approved by the Board in the Interim Disposition Proceeding, the 2009 amortization amounts related to smart meter capital investments made prior to January 1, 2009 were neither: a) included in base rates; nor b) recovered as part of the interim clearance.[1]

The Smart Meter Model (the "Model") issued by the Board along with Guideline G-2011-0001: Smart Meter Meter Funding and Cost Recovery – Final Disposition, issued December 15, 2011, and used by Veridian in its smart meter application EB-2012-0247 did not specifically address the fact that the 2009 amortization related to the pre-2009 smart meter capital expenditures remained outstanding and unrecovered either through an earlier rate rider or through approved distribution rates.

On May 31, 2012, Veridian applied for final disposition of smart meter-related amounts under Board file number EB-2012-0247. As part of that proceeding Veridian used the Board's Model to calculate the revenue requirement to be cleared.

The application sought approval for the final disposition of Account 1555 and 1556 related to smart meter expenditures. Veridian requested SMDRs and Smart Meter Incremental Revenue Requirement Rate Riders ("SMIRRs") effective November 1, 2012.

On October 25, 2012, the Board issued its Decision in the EB-2012-0247 proceeding and found that Veridian's documented costs, as revised in responses to interrogatories, related to smart meter procurement, installation and operation were reasonable. The Board approved the recovery of the costs for smart meter deployment and operation as of December 31, 2011. The Board directed Veridian to establish the SMDRs based on an 18-month recovery period to April 30, 2014, and to accommodate within the SMDR the applicable SMIRR amount related to the period from May 1, 2012 to October 31, 2012.

Veridian filed its Draft Rate Order and provided the following summary table outlining the SMDR and SMIRR rate riders as originally filed, as revised as per interrogatories and as recalculated pursant to the Board's Decision.

[1] Motion for Request for Review and Variance filed by Veridian, January 23, 2013, paragraphs 5 & 6

Class	SMDR ($/month for 18 months)			SMIRR ($/month until new rates set under rebasing)		
	As Filed	Update-Board Staff IR#13	Update - Board Decision	As Filed	Update-Board Staff IR#13	Update - Board Decision
Residential	$0.97	$0.83	$0.55	$0.98	No Change	$ 1.25
GS < 50 kW	$2.45	$4.15	$3.45	$2.46	No Change	$ 3.17

Board staff filed comments on the draft Rate Order on November 5, 2012 and agreed that Veridian had appropriately reflected the Board's findings in its draft Rate Order and proposed Tariff of Rates and Charges.

The Board issued Veridian's final Rate Order on November 15, 2012.

Veridian is now asking the Board through its Motion to allow for recovery of smart meter capital expenditures in the amount of $478,224, inclusive of Payment In Lieu of Taxes ("PILs") impacts, through the amendment of the existing SMDR. The amended SMDR is proposed to commence on May 1, 2013 and to continue until April 30, 2014.

Issues Before the Board

1. Extension of time

As noted by Veridian in its Motion materials, Veridian discovered the gap in recovery of smart meter expenses on January 9, 2013 during preparation of its regular year-end accounting working papers. It was during this process that Veridian realized that, with respect to the costs incurred by Veridian in relation to smart meter implementation it had not yet recovered the 2009 amortization expense related to pre-2009 smart meter capital expenditures, totalling $528,859 (before accounting for PILs impacts) and recorded in Account 1556.

As a result of the timing of Veridian's discovery of this amount for which it had not sought recovery it was not in a position to file its Motion within the prescribed 20 days specified in the Rules, which expired on or about November 14, 2012. Accordingly, Veridian asks that the Board use its discretion to extend the time period for filing a request for review.

The Board notes that parties are expected to respect the Board's deadlines and comply with the Rules, however the Board understands that the error was not identified by Veridian until after the 20 day period had expired and Veridain filed its motion immediately after becoming aware of the error. The Board therefore will use its discretion to hear the Motion, despite the timelines being exceeded.

2. Motion to Review and Vary

Veridian's Motion seeks to vary the Decision so that Veridian may recover an additional $478,224 in revenue requirement related to 2009 amortization expense of $528,859 associated with smart meter capital expenditures made in 2006, 2007, and 2008, less a credit to Grossed-up Taxes/PILs of $50,635.

Veridian requests revisions to its SMDR as outlined below.

Rate Class	Currently Approved Rate Rider	Requested Revision to Rate Rider effective May 1, 2013
Residential	$0.55	$0.83
Residential – Urban Year Round	$0.55	$0.83
Residential – Suburban Year Round	$0.55	$0.83
General Service Less Than 50 kW	$3.45	$4.59

Veridian bases its Motion on the following grounds:

1. There is an identifiable error in the Decision and that there are inconsistent findings in the Decision. The error is material and relevant to the outcome of the Decision. The omission of the 2009 amortization is a calculation error that should be remedied through a variance of the original Decision.

2. Veridian also notes that as part of the EB-2012-0247 proceeding, Veridian completed the Board's Model to calculate the revenue requirement to be recovered. However, the Model, in its design, did not anticipate any gap (i.e., unrecovered amounts from a reviewed and approved interim recovery, and final disposition of smart meter-related amounts in relation to amortization expense of installed smart meters.

The Threshold Test

The application of the threshold test was considered by the Board in its Decision on a Motion to Review the Natural Gas Electricity Interface Review Decision (the "NGEIR Review Decision"). The Board, in the NGEIR Review Decision, stated that the purpose of the threshold question is to determine whether the grounds put forward by the moving party raise a question as to the correctness of the order or the decision, and whether there is enough substance to the issues raised such that a review based on those issues could result in the Board varying, cancelling, or suspending the decision. Further, in the NGEIR Decision, the Board indicated that in order to meet the threshold question there must be an "identifiable error" in the decision for which review is sought and that "the review is not an opportunity for a party to reargue the case".

In addition to the test set out in the NGEIR Review Decision, Rule 45.01of the Board's Rules provides that, with respect to a motion for review the Board may determine, with or without a hearing, a threshold question whether the matter should be reviewed before conducting any review on the merits.

Rule 44.01(a) sets out some of the grounds upon which a motion may be raised with the Board:

> Every notice of motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> > (a) Set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
> > i. error in fact;
> >
> > ii. change in circumstances;
> >
> > iii. new facts that have arisen;
> >
> > iv. facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

The Board also notes that in the NGEIR Review Decision it was established that the Board has the necessary discretion to supplement the above list of grounds upon which a motion to review and vary may be raised in an appropriate case.[2]

[2] EB-2006-0322/EB-2006-0338/EB-2006-0340, Motions to Review the Natural Gas Electricity Interface Review Decision, May 22, 2007, page 15

The Board received submissions from Veridian and Board staff. Board staff submitted that the threshold test has not been met arguing that none of the grounds listed in Rule 44.01 had been established. Veridian argued that the threshold had been met and that the Motion had merit.

The Board discusses each of the grounds set out in Rule 44.01 below with respect to the facts as presented in this Motion.

i. Error in fact

Veridian argued that a combination of what it would characterize as unusual circumstances relating to the multi-proceeding approach to the recovery of its smart meter-related revenue requirement led to an error in the calculation of the rider that was intended to fully compensate Veridian for costs incurred in the deployment and operation of smart meters. Veridian also submitted that the error related to the failure of the SMDR to compensate Veridian for 2009 Amortization Expenses related to 2006, 2007, and 2008 smart meter Capital Expenses in the amount of $478,223.79.

Veridian stated that the error it is seeking to have corrected is not related to the omission of evidence that, had it been before the Board prior to the Decision may or may not have influenced the exercise of the Board's discretion or judgment with respect to the prudence of Veridian's smart meter-related expenditures. Veridian noted that it is asking the Board to correct a clear error in the calculation of the recovery that necessarily follows from the Board's analysis of the prudence of Veridian's spending.

Board staff submitted that in demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. Board staff submitted that the Board's Decision is consistent with the evidence provided by Veridian.

Veridian argued in its reply submission that Board staff has admitted that there is an error in the Decision when it accepted that the $478,223.79 amount should have been factored into the SMDR calculation as it is an outcome of the smart meter capital expenditures approved by the Board.

The Board finds that Veridian has failed to demonstrate that the findings are contrary to the evidence that was before the Panel, that the Panel failed to address a material issue or that the Panel made inconsistent findings. The Board finds that the Decision was correct based on the evidence presented by Veridian in its pre-filed materials and during the proceeding.

ii. Change in circumstances

The Board finds no change in circumstances and notes that neither Veridian nor Board staff made any submissions with respect to this aspect of the threshold test.

iii. New facts that have arisen

Both Board staff and Veridian acknowledged that the review of accounting year-end working papers did result in the discovery of the amount of $478,224 now claimed by Veridian. The amortization expenses claimed in this Motion are for the previously installed and approved smart meters for the discrete time period of 2009. The Board notes that these amounts were at the time both unaudited and outside of the test year for 2010 rates.

In its submission Board staff noted that Veridian is asking the Board to address a calculation error that was made when implementing the Board's approval of Veridian's smart meter capital expenditures through an SMDR.

Board staff acknowledged that the Model did not explicitly contemplate Veridian's circumstances, but submitted that the use of the Model does not preclude the need for other calculations to accommodate the special circumstances of any particular distributor or its application. Further, Board staff submitted that Veridian should have been aware that there was an amount missing prior to filing its application, as the expenses documented in the Model would have been diferent than the principal balances in Account 1556 for OM&A, and specifically, depreciation. Veridian was in the best position to identify the missing depreciation expense during that proceeding and it should not be incumbent on the Board, Board staff, or VECC as the intervenor to recognize this oversight.

Veridian stated that it only discovered the gap in recovery of smart meter expenses on January 9, 2013 during preparation of its regular year-end accounting working papers. It was during this process that Veridian realized that, with respect to the costs incurred by Veridian in relation to smart meter implementation it had not yet recovered the 2009 amortization expense related to pre-2009 smart meter capital expenditures, totalling $528,859 (before accounting for PILs impacts) and recorded in Account 1556.

Veridain submitted that the omission of the 2009 amortization is a calculation error that constitutes a new fact and that the omission of the $478,224 should be remedied through a variance of the original Decision.

The Board finds that this is a new fact for the purpose of the threshold test. This amount was not previously in evidence, nor was the fact that amortization for 2009 had never been addressed nor that the total amount in the account was not cleared. The Board therefore finds that the threshold test for reviewing the Decision has been met.

The Merits of the Motion

Both Board staff and Veridian agree that the amount of $478,224 that Veridian is now seeking recovery of in its Motion is both material and is not in dispute. It is also submitted by Veridian and agreed to by Board staff that the amount should have been factored into the SMDR calculation as it is an outcome of the smart meter capital expenditures approved by the Board.

The Board notes that it has been consistent in allowing for the full recovery of the prudently incurred revenue requirement for approved smart meters deployed in accordance with the Government's regulations.[3] However, the Board finds that the failure to include the $478,224 for recovery in the EB-2012-0247 proceeding was an error on the part of Veridian. Veridian itself submitted that it was an omission to not include the 2009 amortization expenses.

Previous decisions of the Board when dealing with distributors' errors in calculations have resulted in disallowance of the correction, when in the distributor's favour. For example, in the North Bay Hydro decision[4] the Board found that "[t]he utility has control of its books and records and has the responsibility to ensure mistakes do not occur." As a result, the Board in that decision denied the application of North Bay Hydro.

The Board finds some parallels in this situation. Veridian should have been aware of

[3] EB-2012-0081, Cambridge and North Dumfries Hydro Inc., July 26, 2012, page 9
[4] EB-2009-0113, North Bay Distribution Ltd., September 8, 2009

the correct amount of the smart meter expenditures, including amortization expenses. The Board's Guideline G-2011-0001 and Smart Meter Model make it clear that it is the responsibility of the distributor to amend the models as appropriate.[5] The Board expects a utility to provide the Board with accurate accounting for rate setting purposes. Veridian has control of its books and records and has the responsibility to ensure mistakes do not occur. The Board will not adjust for this error.

A second very important factor is with respect to retroactive rate-making. If the Board were to allow recovery this would result in retroactive ratemaking in that Veridian is asking to recover an additional $478,224 in revenue requirement related to 2009 amortization expense through revisions to the SMDR which were established in a Final Rate Order. The courts have made it very clear that retroactive rate-making, the adjustment to rates after a final rate order has been issued, is not allowed. Rather, the principles of certainty and finality are a necessary component of effective rate regulation. To allow Veridian to correct a calculation error after a final rate order was issued would require the Board to engage in retroactive ratemaking, which is contrary to the legal principles upon which the Board performs its legislated mandate.

DATED at Toronto, April 25, 2013
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

[5] Guideline G-2011-0001 and the associated Board-issued models contemplate that a smart meter cost recovery application will cover all costs up to and including the prospective test year to appropriate calculate the SMDR and SMIRR to recover all historical and prospective costs until the distributor's next cost of service application. This thus consists of both audited and unaudited actuals historically and to the bridge year, and forecasts for part of the bridge and test years. This avoids the need for a further application to review audited stub period costs.

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

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

1.2 OPG's Application

Section 78.1 of the *OEB Act* requires that the payment amounts set by the regulation stay in effect until the later of (i) March 31, 2008, and (ii) the effective date of the Board's first order.

In its application, which was filed November 30, 2007, OPG requested that the Board set new payment amounts based on a 21-month test period from April 1, 2008 to December 31, 2009. The new payment amounts proposed by OPG are based on a forecast cost-of-service methodology. OPG also sought an interim order from the Board for increased payment amounts effective April 1, 2008.

In February 2008, the Board held a hearing on OPG's request for an interim order. The Board did not grant OPG's request for increased payments on an interim basis but it did order that the current payment amounts be made interim as at April 1, 2008. Given the provisions of Section 78.1 of the *OEB Act* and the related regulation O. Reg. 53/05, a direct result of the Board's decision to make the current payment amounts interim was that the effective date of the Board's first order under Section 78.1 would be April 1, 2008.[1] Although that decision set the effective date as April 1, 2008, it was not necessary at that time for the Board to determine whether the new payment amounts would be the same as, or different from, the existing payment amounts. The issue of the implementation for new payment amounts remained outstanding and is addressed in Chapter 10.

OPG's proposed revenue requirement and revenue deficiency are summarized in Table 1-2. OPG's proposed revenue requirement is approximately $6.4 billion for the 21-month test period. If the current payment amounts were to stay in place until December 31, 2009, OPG estimated that the prescribed facilities would generate $5.4 billion of revenue for the 21-month period, about $1 billion less than OPG claims it requires. OPG has asked for increases in the payment amounts for the prescribed facilities to offset a large part, but not all, of that revenue deficiency. The company proposed a mitigation measure that would reduce the deficiency by $228 million, and asked for new payment amounts that would cover the remaining estimated deficiency of $798 million.

[1] The Board's oral decision is at pages 111 to 118 of the transcript, "EB-2007-0905, Motion for Interim Order, February 7, 2008" and is reproduced in Appendix C.

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BY E-MAIL

December 7, 2017

To: All Licensed Electricity Distributors
All Other Interested Parties

Re: Applications for 2019 Electricity Rates

This letter sets out a list of cost of service filers under the Price Cap Incentive Rate-setting method for the 2019 rate year based on the dates of distributors' last cost of service applications and other supporting information (the 2019 Rebasing List). At this time, 18 electricity distributors are scheduled to file a cost of service application for 2019 rates. The 2019 Rebasing List is set out in Appendix A to this letter.

This letter also sets out the deadlines by which notice must be given to the OEB in respect of various other matters relating to the setting of 2019 rates, and by which cost of service applications for 2019 rates are expected to be filed. The deadlines are summarized in Appendix B to this letter.

Background

As set out in the *Handbook for Utility Rate Applications* issued by the OEB on October 13, 2016, three incentive rate-setting (IR) methods are available to electricity distributors: Price Cap IR; Custom IR; and the Annual IR Index.

Inclusion on the 2019 Rebasing List and Cost of Service Application Deadline

Most of the distributors that have been included on the 2019 Rebasing List are those whose rates were last set based on a cost of service application for rates effective May 1, 2014, as well as distributors that were scheduled to have their rates rebased for the 2018 rate year but whose rate rebasing was deferred by one year.

Distributors that are on the 2019 Rebasing List and that intend to file for rates effective January 1 or May 1 are expected to file their 2019 rate applications on a cost of service basis no later than **April 27, 2018** or **August 31, 2018**, respectively. Distributors whose current rate years commence on May 1 that plan on requesting a change to a January 1 rate year should notify the OEB of this intent no later than **March 1, 2018**. Any distributor which intends to select to have its rates set using either the Custom IR or the Annual IR Index method must refer to the sections below.

Selection of Custom IR or Annual IR Index Methods

Any distributor that has been included on the 2019 Rebasing List and that intends to select either the Custom IR or the Annual IR Index method for 2019 rates must, if it has not already done so, notify the OEB as soon as possible and in any event no later than **March 1, 2018**.

Distributors that have filed Annual IR Index applications for 2018 rates have not been included on the 2019 Rebasing List unless they have indicated that they plan to file a cost of service application. These distributors can choose to move to the Price Cap IR method, but would only be eligible to rebase for 2019 if their last cost of service application was for May 1, 2014 rates[1] or earlier. Distributors that choose to move to the Price Cap IR method and rebase their rates for 2019 must notify the OEB no later than **March 1, 2018**. If a distributor's rates were rebased after May 1, 2014, the early rebasing approach discussed below would apply and notice must be given as set out below. Distributors on the Annual IR Index that wish to choose the Custom IR option for 2019 must so notify the OEB no later than **March 1, 2018**.

Adjustments to the 2019 Rebasing List

Requests to Defer Rebasing Beyond the 2019 Rate Year

Any distributor that has been included on the 2019 Rebasing List but wishes to request deferral of rebasing beyond the 2019 rate year must, if it has not already done so, send a letter to the OEB as soon as possible and in any event no later than **March 1, 2018**. That letter should include the reasons for which deferral of rebasing is being sought. The OEB will consider, among other relevant factors, the distributor's scorecard performance results.

Distributors that Intend to File an Early Rebasing Application

A distributor that is not included on the 2019 Rebasing List but wishes to have its 2019 rates set on a cost of service basis under the Price Cap IR option must so notify the OEB in writing as soon as possible and in any event no later than **March 1, 2018**. In keeping with the OEB's approach to early rebasing as set out in its April 20, 2010 letter, a distributor that seeks to have its rates rebased earlier than scheduled must clearly demonstrate, 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 remaining years of its Price Cap IR plan term.

---

[1] Distributors that rebased effective January 1, 2014 (or earlier) had rate plan terms of four years. Distributors rebasing effective May 1, 2014 and later had five year terms.

Distributors Filing Custom IR annual updates

A distributor filing a Custom IR annual update should do so by **August 31, 2018**.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A
Electricity Distributors Scheduled to Apply for Rebasing for 2019 Rates

	Distributor	Current Rate Year
1	Greater Sudbury Hydro Inc.	Jan. 1
2	Kitchener - Wilmot Hydro Inc.	Jan. 1
3	Oakville Hydro Electricity Distribution Inc.	Jan. 1
4	Attawapiskat Power Corporation	May 1
5	Burlington Hydro Inc.	May 1
6	Bluewater Power Distribution Corporation	May 1
7	COLLUS Power Corporation	May 1
8	Energy + Inc.	May 1
9	Fort Albany Power Corp.	May 1
10	Fort Frances Power Corp.	May 1
11	Kashechewan Power Corp.	May 1
12	Lakeland Power Distribution Ltd.	May 1
13	Midland Power Utility Corporation	May 1
14	Niagara-on-the-Lake Hydro Inc.	May 1
15	Orangeville Hydro Ltd.	May 1
16	Orillia Power Distribution Corporation	May 1
17	Peterborough Distribution Inc.	May 1
18	Veridian Connections Inc.	May 1

APPENDIX B
Summary of Deadlines

Action	OEB Deadline
Notification from any distributor on the 2019 Rebasing List that will be selecting either the Custom IR or Annual IR Index method and therefore will not be filing a cost of service rate application for 2019 rates	March 1, 2018
Notification from any distributor that is currently on Annual IR Index but that plans to file a cost of service rate application under the Price Cap IR method or a Custom IR application for 2019 rates	March 1, 2018
Letter from any distributor included on the 2019 Rebasing List that wishes to submit a request to defer rebasing beyond 2019	March 1, 2018
Notification from any distributor that is not included on the 2019 Rebasing List but that plans to file a cost of service application for 2019 rates under the Price Cap IR method (early rebasing)	March 1, 2018
Notification from any distributor that plans to file a cost a service application for 2019 rates and that wishes to convert its rate year from May 1 to January 1	March 1, 2018
Deadline for cost of service applications for January 1, 2019 rates including those distributors that wish to convert from May 1 rates to January 1 rates	April 27, 2018
Deadline for cost of service applications for May 1, 2019 rates and for Custom IR annual update applications	August 31, 2018

SUMMARY OF APPLICATION

OVERVIEW

This is an application for an order of the Ontario Energy Board approving payment amounts for OPG's prescribed hydroelectric and nuclear generating facilities effective March 1, 2011 based on a January 1, 2011 – December 31, 2012 test period. The revenue requirement requested in this application is based on forecast costs from January 1, 2011 through December 31, 2012. However, OPG is not requesting to make the new payment amounts effective until March 1, 2011 because of the timing of the application. As a result, OPG is foregoing recovery of the forecast increase in costs for January and February of 2011. The basis for the application can be found in Ontario Regulation 53/05 and section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act")

OPG's prescribed generating facilities consist of five hydroelectric generating stations and three nuclear generating stations. These stations offer their output into the IESO - administered electricity market in accordance with the Ontario Market Rules. Further detail on the prescribed facilities is provided in Ex. A1-T4-S2 and Ex. A1-T4-S3. In 2009, approximately 29 per cent of the output from the prescribed facilities was produced by hydroelectric generation and 71 per cent by nuclear generation. Together, the output from prescribed hydroelectric and nuclear facilities equalled approximately 48 per cent of Ontario primary demand in 2009.

OPG is subject to a Memorandum of Agreement with its shareholder, the Province of Ontario, as well as directives from its shareholder which substantially influence the nature and manner of OPG's operation of the prescribed facilities. Information with respect to the Memorandum of Agreement is found at Ex. A1-T4-S1. OPG is mandated by the Memorandum of Agreement to operate as a commercial enterprise in accordance with the highest corporate standards, including corporate governance, social responsibility, and corporate citizenship, as well as environmental stewardship.

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

Ontario

EB-2011-0286

Filing Guidelines for Ontario Power Generation Inc.

Setting Payment Amounts for Prescribed Generation Facilities

Issued: July 27, 2007 (EB-2006-0064)
Revised: November 27, 2009 (EB-2009-0331)
Revised: November 11, 2011

Table of Contents

1. PART 1: INTRODUCTION **1**

1.1 OVERVIEW OF LEGISLATIVE CONTEXT AND REGULATORY METHODOLOGY 1
1.2 REQUIREMENTS OF O. REG. 53/05 2
1.3 BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS DECISIONS* 2

2. PART 2: FILING GUIDELINES **5**

2.1 INTRODUCTION 5
2.1.1 Key Planning Parameters 6
2.1.2 Confidential Information 8
2.2 EXHIBIT A ADMINISTRATIVE DOCUMENTS 8
2.2.1 Administration 8
2.2.2 Overview/Summary 9
2.2.3 Background Financial Information 9
2.3 EXHIBIT B RATE BASE 10
2.3.1 Gross Assets – Property, Plant and Equipment and Intangible Assets 11
2.3.2 Accumulated Depreciation and Amortization 11
2.3.3 Working Capital Calculation 11
2.4 EXHIBIT C COST OF CAPITAL AND RATE OF RETURN 11
2.4.1 Capital Structure – Amounts & Ratios 11
2.4.2 Component Costs of Debt 12
2.4.3 Calculation of Return on Equity 12
2.4.4 Nuclear Waste Management and Decommissioning Costs 12
2.5 EXHIBIT D CAPITAL PROJECTS 13
2.6 EXHIBIT E PRODUCTION FORECAST 15
2.7 EXHIBIT F OPERATING COSTS 16
2.7.1 Operating, Maintenance & Administration and Other Costs 16
2.7.2 Taxes 18
2.8 EXHIBIT G OPERATING REVENUE 18
2.8.1 Energy Revenue 19
2.8.2 Other Revenues 19
2.9 EXHIBIT H DEFERRAL AND VARIANCE ACCOUNTS 19
2.10 EXHIBIT I DETERMINATION OF PAYMENT AMOUNTS 20

1. PART 1: INTRODUCTION

This document provides the filing guidelines for Ontario Power Generation Inc. ("OPG") regarding the setting of payment amounts for OPG's prescribed generation facilities. The Board expects that OPG will comply with these filing guidelines. This document is not a statutory regulation, rule or code issued under the Board's authority and does not preempt the Board's discretion to make any order or give any direction as it determines necessary concerning any matters raised in relation to the setting of payment amounts for the prescribed generation facilities, including in relation to the production by OPG of additional information which the Board on its own motion or at the request of a party considers appropriate.

This document sets out specific filing guidelines for purposes of the setting of payment amounts for certain of Ontario Power Generation Inc.'s ("OPG") generation facilities under section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act").[1] The generation facilities in question are identified in the *Payments Under Section 78.1 of the Act Regulation*, O. Reg. 53/05 ("O. Reg. 53/05") and are: Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generation Station, De Cew Falls I, De Cew Falls II (all of the foregoing being hydroelectric generating stations located in the Regional Municipality of Niagara), the R.H. Saunders hydroelectric generating station on the St. Lawrence River, Pickering A nuclear generating station, Pickering B nuclear generating station and Darlington nuclear generating station (collectively the "prescribed generation facilities").

1.1 OVERVIEW OF LEGISLATIVE CONTEXT AND REGULATORY METHODOLOGY

Section 78.1 of the Act authorizes the Ontario Energy Board (the "Board") to set payments to be made to OPG with respect to the output of the prescribed generation facilities. Under O. Reg. 53/05, the Board's authority in that regard commenced on April 1, 2008.

In addition to identifying the prescribed generation facilities, O. Reg. 53/05 empowers the Board to establish the form, methodology, assumptions and calculations to be used in making an order that determines payment amounts for the purpose of section 78.1 of

[1] The working assumption reflected in this version of the guidelines is that OPG will be filing a payment amounts application in 2012 for test years 2013 and 2014. The prior test years for which the Board set OPG's payment amounts were 2011 and 2012. It is assumed that actuals will be available for 2009, 2010 and 2011 as well as the most recent forecast for the 2012 (current) bridge year. Accordingly, the term "historical" refers to 2009, 2010 and 2011 actuals and "Board-approved" refers to the numbers which support the payment amounts approved by the Board for 2011 and 2012.

the Act. It also contains rules that must be followed by the Board in setting those payment amounts.

These filing guidelines are informed by the previous two proceedings on OPG payment amounts (EB-2007-0905 and EB-2010-0008) and reflect directions contained in the decisions of these proceedings.

1.2 REQUIREMENTS OF O. REG. 53/05

O. Reg. 53/05 affects the setting of payment amounts for the prescribed generation facilities in three principal ways: first, by requiring that OPG establish certain deferral and variance accounts and that the Board ensure recovery of the balance in those accounts subject to certain conditions being met; second, by requiring that the Board ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG; and third, by setting certain financial values that must be accepted by the Board when it makes its first order under section 78.1 of the Act. The last item has now been addressed.

1.3 BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS DECISIONS*

Directives and Undertakings Include	EB-2010-0008 Decision with Reasons Page Number
Niagara Tunnel - The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.	28
Nuclear Benchmarking - The Board directs OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application. The methodology and report format will be consistent with that filed in EB-2010-0008.	45
Nuclear Staffing – The Board will direct OPG to conduct an examination of staffing levels as part of its next benchmarking study.	46
The Board expects to review the initiatives OPG has taken and intends to take to improve the Forced Loss Rate.	46
Pickering B Continued Operations – The Board expects OPG to address the specifics of the benefits analysis including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate, more fully in its next application.	52

Directives and Undertakings Include	EB-2010-0008 Decision with Reasons Page Number
Nuclear Fuel Procurement – In the next proceeding, the Board will examine the program to determine whether OPG is optimizing its contracting. The Board will therefore direct OPG to file an external review as part of its next application.	55
Nuclear Rate Base – In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts. The separate presentation of data related to ARC will assist in this regard.	59
Darlington Refurbishment – The Board expects OPG to file updated information on its progress for examination in the next proceeding.	71
Darlington Refurbishment – As DRP is a multi-year project, the Board expects that in future payments cases, the business case will be updated.	72
Compensation – The Board will therefore direct OPG to file on a FTE basis in its next application and to restate historical years on that basis.	84
Compensation – The Board expects to examine the issue of overtime more closely in the next proceeding. The Board expects OPG to demonstrate that it has optimized the mix of potential staffing resources.	84
Compensation – The Board directs OPG to conduct an independent compensation study to be filed with the next application.	88
Pension and OPEB – OPG is directed to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rate in its next application.	91
The Board will direct OPG to file an independent depreciation study at the next proceeding.	97
The Board directs OPG to re-address the hydroelectric incentive mechanism ("HIM") structure in its next application.	148
IRM – Following a preliminary Board review, the Board expects OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application.	156

Directives and Undertakings Include	EB-2011-0090 Decision and Order on Motion Page Number
Pension and OPEB Variance Account – The Board expects OPG to provide an independent actuary's report and an audit opinion.	14

* Only indicates Board direction for filing purposes

2. PART 2: FILING GUIDELINES

2.1 INTRODUCTION

OPG's application to the Board should provide sufficient detail to enable the Board to make a determination as to whether the proposed payment amounts are just and reasonable. The material presented is OPG's evidence and the onus is on OPG to prove the need for and the basis for the proposed new payment amounts. A clearly written application that advocates the need for the proposed payment amounts, complete with sufficient evidence and justification for the proposed payment amounts, is essential to facilitate an efficient regulatory process and a timely decision.

In the previous proceeding, the Board observed that at times the analysis was complicated by the fact that data was presented in ways which were not always comparable. The Board expects OPG to present data on a consistent basis so that comparisons are accurate.

The 2013-2014 payment amounts application will be OPG's third cost of service application. To the extent that materials are the same or substantially the same as those filed in previous applications, OPG shall indicate this to improve the efficiency of the review.

The Board remains cognizant of the large number of interrogatories that a rate (or in this case payment) setting process can generate. The requirement for a large number of interrogatories in the previous cases suggests that OPG and the interested parties do not have a common understanding of the information required to support the application. OPG should strategically consider the clarity and materiality of the evidence, with the goal of providing a clear and concise narrative of its filing. The evidence should be designed to increase the understanding of the parties with the overall objective of reducing the number and scope of interrogatories required. The Board also advises parties to carefully consider the relevance of their interrogatories when assessing an application and whether the issue being explored is material.

In determining what evidence to file, OPG should consider what information the Board and the intervenors are likely to request, and provide that information in the filed evidence rather than waiting for the request to be made at the hearing. This will ensure a better use of hearing time, and a more focused and informed cross examination.

In order to facilitate an efficient review of interrogatories and responses, the filing of interrogatories and responses must be sorted by issue.

The filing shall contain the following nine exhibits:

Exhibit A Administrative Documents
Exhibit B Rate Base
Exhibit C Cost of Capital and Capital Structure
Exhibit D Capital Projects
Exhibit E Production Forecast
Exhibit F Operating Costs
Exhibit G Operating Revenue
Exhibit H Deferral and Variance Accounts
Exhibit I Determination of Payment Amounts

Each exhibit shall provide the identified data for each category of prescribed generation facility (nuclear and hydroelectric). Each exhibit shall also explain how allocations have been made from total corporate to the prescribed generation facilities as a whole and the non-prescribed generation facilities as a whole, and then from the prescribed generation facilities as a whole to each of the nuclear and hydroelectric classes of prescribed generation facilities.

Excel spreadsheets shall be provided as appropriate to the data in question. Generally, formulae indicating on-sheet calculations shall be provided. As a minimum, OPG shall file an Excel spreadsheet summarizing production forecast (as noted in section 2.6), compensation and benefits (as noted in section 2.7.1) and a Revenue Requirement Work Form ("RRWF") in Excel format. The RRWF will generally replicate the data and tables that OPG files to support the payment amounts order. The RRWF will be filed with the application and will reflect the payment amounts for which OPG is seeking approval.

2.1.1 Key Planning Parameters

The key planning parameters listed below form the basis of how the detailed guidelines provided in this document should be interpreted or applied.

The filing should be made in accordance with:

- International Financial Reporting Standards ("IFRS"), on the understanding that OPG is required to adopt IFRS for 2012.

  For the historic years, actuals will be filed on the basis of Canadian Generally Accepted Accounting Principles ("CGAAP"). OPG should refer to the *Report of the Board: Transition to IFRS;* dated July 28, 2009 ("Board Report"), and subsequent amendments and addendum for guidance on IFRS. While this Board Report was directed to electricity and gas distributors, the Board will consider OPG's transition to IFRS in the context of the policies established in the Board Report.

OPG is required to identify in its application the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. This is consistent with requirements set out in the Board Report.

As OPG is expected to adopt modified IFRS for financial reporting in 2012, OPG is required to present all historical years up to 2010 on a CGAAP basis, historical year 2011 on both CGAAP and modified IFRS basis, bridge year 2012 and test years 2013 and 2014 on a modified IFRS basis. Where there are differences in information between CGAAP and modified IFRS for the historical year 2011, the presentation of the information must clearly show the differences.

In addition, OPG shall meet the following guidelines in preparing its filing:

- Six years of data shall be submitted, as a minimum. The years are defined as:
  - Test Years = prospective payment years (typically 2 years)
  - Bridge Year = current year
  - Historic Years = last 3 complete years of actuals (as a minimum)
- Multi-year data showing data for all of the Historic Years, Bridge Year and Test Years shall be presented on the same sheet for the summary/main schedules

- Where applicable, for the each of the Historic Years, a detailed variance analysis shall also be provided **comparing Board-approved to actual costs and production**. The use of the phrase "Board approved" in these filing guidelines refers to the set of data used by the Board as the basis for approving the most recent payment amounts. It does not mean that the Board, in fact, "approved" any of the data, but only that the final approved payment amounts were based on that data.

- A detailed variance analysis for costs and production shall be provided for each historic and bridge year compared to the prior year. This analysis shall explain the reasons for the variance, the drivers of the variance and the contribution of each towards the total year-over-year variance.

- Written direct evidence shall be presented before the data schedules

- With respect to the claimed revenue sufficiency/deficiency, OPG shall provide a summary of the drivers of the sufficiency/deficiency for each of the Test Years, along with how much each driver contributes

- OPG shall file twelve paper copies and a copy in electronic form. The electronic form, including appendices and attachments, shall be in searchable/unrestricted

PDF format. OPG shall also file a single consolidated file of the application on CD or USB flash drive.

A filing that includes all documentation detailed in this document will be considered complete for purposes of further processing by the Board.

2.1.2 Confidential Information

Unless otherwise directed by the Board, any request for confidential treatment of information by OPG must be made at the time of the filing and in accordance with the Board's *Practice Direction on Confidential Filings.* The onus is on OPG or the entity requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted. It is the expectation of the Board that OPG or any other entity requesting confidential treatment will make every effort to limit the scope of their requests for confidentiality to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure, and to prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record.

2.2 EXHIBIT A ADMINISTRATIVE DOCUMENTS

The administrative documents identified in this section provide the background and summary to the filing. There are three sections:

1) Administration;
2) Overview/summary of the filing; and
3) Background financial information.

The detailed guidelines for each section are shown below.

This exhibit should be treated as an administrative exhibit and should exclude all other information, such as production and revenue forecasts, cost of capital summary, rate base evidence and the operating, maintenance and administration (OM&A) budget. These topics should be addressed in the appropriate exhibits that follow.

This exhibit should, however, include a brief summary of OPG's filing regarding the specific directions set out in the previous proceedings (see section 1.3 above) and references to where the detailed evidence can be found.

2.2.1 Administration

- Table of Contents/Exhibit List
- Nature of filing
- List of specific approvals requested
- List of relevant statutory provisions (such as any provisions of, or regulations under, the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998*)

- Contact information
- Draft issues list – including preliminary prioritization of primary and secondary issues
- Procedural Orders/motions/correspondence
- Identification of areas where there has been deviation from IFRS
- Relevant maps (or provide link to webpage where maps can be found)
- Organization charts
- Planned changes in corporate or operational structure
- Relevant company policies and regulations
- List of witnesses and their curriculum vitae

2.2.2 Overview/Summary

- Summary of filing (purpose, need and timing of the filing)
- Budget directives and guidelines (capital and operating budgets), including economic assumptions used
- Changes in methodology (accounting including IFRS, etc.) that would affect any of the Historic, Bridge or Test Years
- Schedule of overall revenue sufficiency/deficiency
    - Numerical schedules detailing the causes of the sufficiency/deficiency
    - Complete and detailed references to the data contained in the detailed schedules and tables shall be provided so that parties can map the summary cost driver information to the evidence supporting it
    - A detailed narrative of the causes of the sufficiency/deficiency highlighting the significant issues.
- An overview of the allocation methodology for assets, costs and revenues to the prescribed and non-prescribed assets, and to the nuclear- and hydroelectric-specific businesses
- Summary and status of Board directives from the EB-2010-0008 and EB-2011-0090 Decisions. OPG should clearly indicate how these have been or are being addressed in the current application.
- Summary or copy of relevant orders from any federal or provincial agency, Ministerial Directives and Shareholder Directives.

2.2.3 Background Financial Information

- Audited OPG financial statements approved by OPG's Board of Directors for each of the Historic Years (or provide the webpage address of the location on SEDAR or EDGAR where these audited financial statements can be found)
- Audited OPG financial statements should be provided as soon as they are available. If the statements are not available at the time of filing, OPG should provide these as an update
- Most recent quarterly OPG financial reports
- Rating agency reports for each of the Historic Years and Bridge Year
- Audited prescribed generation facilities financial statements for the Historic Years
- An overview of how the provisions of O. Reg. 53/05 are reflected in the filing compared to data in the financial statements

- To address the concern of a potentially significant variance between the date of the audited financial statements and the date of filing, a detailed reconciliation of the financial results shown in the audited financial statements and the financial results contained in the filing shall be provided
- OPG Board of Directors approved 2012 – 2014 Business Plan for the regulated components of OPG, for the hydroelectric business, and for the nuclear business. Any previous business plans that include part of the test period should also be filed. If any claim for confidentiality is advanced with regard to any part of the Business Plan, a claim for confidentiality should be made in accordance with Board's *Practice Direction on Confidential Filings*.

2.3 EXHIBIT B RATE BASE

A description of the prescribed generation facilities, and of any financial assets, shall be provided. For nuclear rate base, a separate presentation of asset retirement costs ("ARC") associated with nuclear liability obligations is required.

Items used in the computations or derived shall include opening and closing balances of the net fixed assets, working capital, accumulated depreciation, changes in working capital, accrued deferred earnings, and annual amortization of accrued deferred earnings.

The information presented here shall cover three areas:

1) List of gross assets (property, plant and equipment), including capital budgets and intangible assets (e.g. Computer software) if any, included in rate base;
2) Accumulated depreciation and amortization;
3) Working capital including cash working capital calculation, Fuel Inventory (for the nuclear business), and Materials and Supplies.

For each of these areas there will be some common statements that shall be provided summarizing the rate base. The schedules for rate base should include all Historic Years, Bridge Year (actuals to date, balance of year as budgeted) and Test Years. Additional statements that should be provided for 1 and 2 include:

<u>Continuity statements</u>

The continuity statements must provide year-end balances and include directly attributable costs, for example, capitalized borrowing costs.

<u>Summary variance explanation</u>
A written explanation shall be provided to identify the drivers to the variance for rate base. This applies to OPG's rate base for the following comparisons:

- Board-approved vs. actual for each of the Historic Years
- Board-approved vs. Bridge Year

- Year over year analysis for the six year period

2.3.1 Gross Assets – Property, Plant and Equipment and Intangible Assets

Continuity statements should be provided as indicated above.

- Required statements and analysis should be broken down by function
- A detailed breakdown should be provided by major plant account for each functionalized plant item for each of the Historic Years, Bridge Year and Test Years. For the Test Years, each plant item should be accompanied by a written description
- Mid-year averages should be provided

2.3.2 Accumulated Depreciation and Amortization

Continuity statements and a summary variance explanation shall be provided as indicated above for each of the Historic, Bridge and Test Years by asset account. Continuity statements shall be reconcilable to calculated depreciation costs.

2.3.3 Working Capital Calculation

Working capital shall be provided for the each of the Historic, Bridge and Test Years. The results shall be provided on a single schedule for comparison. The basis for the calculation of cash working capital must be detailed.

2.4 EXHIBIT C COST OF CAPITAL AND RATE OF RETURN

OPG shall ensure that the total capitalization in the filing (debt and equity) equates to the total rate base.

2.4.1 Capital Structure – Amounts & Ratios

The following elements of the proposed capital structure shall be detailed, with the necessary schedules, for each of the Historic, Bridge and Test Years:

- Long-term debt
- Short-term/unfunded debt (to equate total capitalization with rate base)
- Preference shares
- Common equity

Justification for proposed capital structure is required, including an explanation of the following:

- Non-scheduled retirement of debt or preference shares and buy back of common shares
- Long-term debt, preference shares and common share offerings

- Since the establishment of the prescribed asset classes, the assumptions and methodology used:

  - to develop prescribed generation asset valuations
  - to allocate OPG's debt to the prescribed generation facilities as a whole
  - to allocate OPG's debt as between the prescribed nuclear and hydroelectric generation facilities

- A historic accounting of changes to OPG's capital structure including:
  - Non-scheduled retirement of debt or preference shares or buy-back of common shares
  - Issuances of long-term debt, preference shares and common shares
- Discussion of material changes in the capital structure (i.e. increased or decreased equity thickness) of OPG, and the reasons for these changes
- All internal or commissioned reports, studies or analysis, from 2009 to the date of filing, of how to value OPG's assets and how to allocate debt, by business unit or asset class.

2.4.2 Component Costs of Debt

The following shall be provided for each of the Historic, Bridge and Test Years:

- Calculation of the cost of each item
- Justification of forecast costs by item including key economic assumptions
- Profit or loss on redemption of debt
- Consensus Forecasts – latest interest rate forecast based on a selection of forecasters that are common to utilities (e.g., the major banks and the Bank of Canada).

2.4.3 Calculation of Return on Equity

Justification for the proposed return on equity is required, including the filing of supporting documentation, e.g. Global Insight reports.

2.4.4 Nuclear Waste Management and Decommissioning Costs

This section provides a summary of OPG's obligations for nuclear waste management and decommissioning. This exhibit shall also provide the funding responsibilities as described in the Ontario Nuclear Funds Agreement.

Any updates or revisions to the Ontario Nuclear Funds Agreement Reference Plan must be summarized and the financial impacts explained in appropriate detail, including a reconciliation with the Board-approved amounts for 2011 and 2012. If the reconciliation is summarized elsewhere in the application, the reference shall be provided in this section.

The information shall be disaggregated to present Darlington and Pickering separate from Bruce.

The information presented shall cover:
- the revenue requirement treatment of OPG’s liabilities for decommissioning its nuclear stations and nuclear used fuel and low and intermediate level waste management
- the revenue requirement treatment of OPG’s liabilities for decommissioning Bruce

Further, the exhibit shall include:
- A summary of net book values of OPG’s nuclear stations including Bruce, noting amounts of unamortized asset retirement cost, for Historic, Bridge and Test years.
- A summary of the forecast pre-tax charge in OPG’s income statement due to the nuclear liabilities and the segregated funds

2.5 EXHIBIT D CAPITAL PROJECTS

Capital Budget - Historic Years, Bridge Year and Test Years

- Policies

    - OPG’s capitalization policy and any changes to that policy should be presented as part of the capital budget evidence

    - Proposed accounting treatment, including the treatment of costs of funds for capital projects that have a project life cycle greater than one year, should be provided

- Capital Expenditures – Provide a summary of capital expenditures for the Historic, Bridge and Test years, including the Board-approved amounts for the Historic and Bridge years.

- Capital budget by project

For Capital Projects of:	Detail Required
$20 million or more	Name, description, need, start date, in-service date, and cost for each project Business Case for each project of $20 million or more Provide actual in service dates (month and year) for major capital projects that closed to rate base in historical years and provide projected in service dates (month and year) for the bridge and test years Total cost of all projects in this category
Between $5 million and $20 million	Name, description and cost for each project Provide actual in service dates (month and year) for capital projects between $5 million and $20 million that closed to rate base in historical years and provide projected in service dates (month and year) for the bridge and test years Total cost of all projects in this category
Less than $5 million	Number of projects in this category, total cost of all projects in this category and average cost of the projects in this category Provide the total cost related to projects that will close to rate base in the test years

OPG shall provide an overall summary table of the business cases filed. The summary table should include the title of the business case, date prepared, the project stage, and status of the business case (i.e. full, partial, developmental), for the current case. Where applicable, the table should also indicate the business case's status in the previous proceeding, EB-2010-0008. Note that all of the above is also applicable to OM&A business cases.

- Variance analysis for capital projects of $20 million or more
  - A written explanation of variances should be presented where the variance is 10% or more of the project budget. Variance explanations should be provided for

the following comparisons:

- Board-approved vs. actual for each of the Historic Years
- Board-approved vs. Bridge Year forecast

OPG shall provide a summary table for projects $5M and greater that were projected to go into service in 2011 and 2012 in the EB-2010-0008 application. The table should include the project stage as provided in the EB-2010-0008 application and the current status of the project.

2.6 EXHIBIT E PRODUCTION FORECAST

The production forecast and any normalization methodology shall be provided. A description of outage planning processes and production reliability initiatives shall also be provided.

- Explanation of causes and assumptions for the production forecast
- Production for all Historic, Bridge and Test Years
- Weather forecasting and hydrological forecasting methodologies
- All data used to determine the forecast should be presented in **MS Excel spreadsheet format**
- Comparison of historical data with the forecast data in regard to forecasting assumptions
- A variance analysis of energy output shall be provided for the following:

  - Board-approved vs. actual for each of the Historic Years
  - Board-approved vs. Bridge Year forecast
  - Year over year analysis for the six year period

- All economic assumptions and their sources used in the preparation of the production forecast shall be included in this section

- Where available, actual and forecast generation losses due to spill shall be filed.

HYDROELECTRIC INCENTIVE MECHANISM (“HIM”)

An analysis of the HIM shall be provided. The analysis shall include an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of potential alternative approaches.

2.7 EXHIBIT F OPERATING COSTS

This exhibit should include information that summarizes the total operating, maintenance and administration costs, including asset service fees and taxes.

This exhibit shall include benchmarking studies that update studies filed in previous applications or new benchmarking studies. Further, this exhibit shall include a consolidation of the benchmarking information so that comparisons are evident, e.g. TGC, nuclear capacity factors, and other safety, reliability and value for money measures.

The benchmarking shall note whether the basis is a forecast or actual results.

2.7.1 Operating, Maintenance & Administration and Other Costs

The required statements for each of the components of this section include trend data for operating costs by major item.

a) Operating, Maintenance & Administration Costs

Details of the budgets for each of the Historic, Bridge and Test Years shall be provided.

The OM&A statements for each year shall provide:

- A breakdown on a work basis of each major item that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million

- Detailed information is to be provided for each expense incurred through the purchase of services or products that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million. The information is to include, for each such expense:

  - a summary of the tendering process used
  - if a tendering process was not used, an explanation of why that was the case as well as a description of the pricing methodology used
  - the identity of the company transacting with OPG
  - a summary of the nature of the activity transacted

  In addition, the annual dollar value, in aggregate, for all such expenses shall be provided.

- A breakdown of the following by employee group: number of full time equivalents (“FTEs”) including contributions from part time employees; total salaries, wages and benefits; and salaries, wages and benefits charged to O&M. In addition, the following shall also be provided:

- Total compensation by employee group and average level per group
- Details of any pay-for-performance or other employee incentive program
- The status of pension funding and all assumptions used in the analysis

Information shall be presented in terms of FTEs. In some cases, OPG may choose to provide the information in terms of head count as well as FTEs. The basis for each breakout of compensation data will be specified:

- Head count or FTE
- Yearly average, mid year or year end

These data shall be provided in Excel spreadsheet table format.

- Employee benefit programs, including pensions, and costs charged to O&M shall include the following details:

  - historic actuarial reports
  - actuarial evidence to support pension and OPEB expense for the bridge year and test years including any educational notes or articles issued by the Canadian Institute of Actuaries on methods for determining discount rates used for reporting under CICA standards
  - CICA guidance, practice notes, etc. that provide information on approaches to selecting discount rates shall be filed
  - discussion and analysis on discount rates used for calculating pensions and OPEB benefit obligations, cost for the year and liabilities
  - a table that summarizes actual accounting expense compared to Board-approved expense and with amounts actually paid for pensions and OPEBs for the period April 1, 2008 to the end of the historical period
  - the most recent report filed with Financial Services Commission of Ontario
  - discussion on the impacts of the adoption of IFRS

- A variance analysis for OM&A, and components of OM&A (including Regulatory Affairs costs), shall be provided for the following:

  - Board-approved vs. actual for each of the Historic Years
  - Board-approved vs. Bridge Year forecast
  - Year over year analysis for the six year period

  A written explanation is required for any variance greater than or equal to 10% of category expenses.

b) Depreciation/Amortization/Depletion

- An independent depreciation study and summary of changes for depreciation, amortization and depletion by asset group shall be provided

- Details of provision for depreciation, amortization and depletion by asset group for each of the Test Years should be provided, as should comparative data for each of the Historic Years and Bridge Year, including asset amount and rate of depreciation

- An analysis of the impact on depreciation of the change from CGAAP to MIFRS

c) Corporate Cost Allocation

A summary of the corporate cost allocation shall be provided, including information showing the costs incurred at the corporate level, the methodology and assumptions used to allocate these costs to the prescribed and non-prescribed generation facilities and the methodology to allocate these costs to each of the prescribed nuclear and hydroelectric businesses. Details in relation to shared corporate services should include:

- type of service (IT, office space, etc.)
- total annual expense by service
- rationale and derivation of cost allocators used for shared costs, for each type of service (square footage/computers/headcount/etc.)
- any variances in 2011 and 2012 corporate cost allocation.

2.7.2 Taxes

OPG shall file information on its Historic, Bridge and Test years income tax and the detailed calculation supporting the data. The documentation shall include copies of the most recent tax returns and notice of assessment, re-assessment and statements of adjustments.

- A detailed tax calculation shall be provided for each of the Historic, Bridge and Test Years, including derivation of interest deducted, capital cost allowance showing differences from depreciation/amortization expense, all other differences from financial statement income, tax rates and payments in lieu of taxes included in deriving the revenue requirement.
- Details on the gross revenue tax applicable to the hydroelectric business shall be provided either separately or as part of the operating expenses for the hydroelectric business
- All reconciling items shall have supporting schedules and calculations.

2.8 EXHIBIT G OPERATING REVENUE

The revenue forecast, any normalization methodology and sales activities shall be provided here. The information presented shall include other revenue derived from the use of the prescribed generation facilities, broken down by revenue source.

2.8.1 Energy Revenue

This section shall include:

- Production and energy revenues for all Historic, Bridge and Test Years
- Schedule of production showing volumes, total revenues and unit revenues for each of the Historic, Bridge and Test Years

2.8.2 Other Revenues

Details of other revenue, broken down by revenue source, shall be provided. This shall include OPG's revenues and costs associated with the Bruce nuclear generating stations

- A variance analysis of other revenues shall be provided for the following:

  - Board-approved vs. actual for each of the Historic Years
  - Board-approved vs. Bridge Year forecast
  - Year over year analysis for the six year period

- A detailed explanation of how other revenues are attributed to the prescribed generation facilities shall be provided.

2.9 EXHIBIT H DEFERRAL AND VARIANCE ACCOUNTS

As described in Part 1, O. Reg. 53/05 contains a number of provisions regarding the establishment of deferral and variance accounts and the recovery of balances in those accounts. In this section, OPG shall include information necessary to enable the Board to deal with these accounts in the manner contemplated by O. Reg. 53/05, including OPG's proposals regarding the following:

- The end date for entries into the deferral and variance accounts
- Addressing timing differences between the end date for entries into the deferral and variance accounts and the effective date of the Board's order
- The number of years over which balances in the deferral and variance accounts should be recovered (subject to the maximum set out for each in O. Reg. 53/05)
- The interest rate for the nuclear liability deferral account referred to in section 5.2(1) of O. Reg. 53/05

OPG shall also identify any deferral or variance accounts that it may wish to have authorization to establish on and after the date of the Board's order.

In general, this exhibit should include:

- A listing and detailed description (including account definition) of all outstanding deferral and variance accounts - those specified by O. Reg. 53/05 as well as those established by the Board in previous decisions, including:

    - Hydroelectric Water Conditions Variance Account
    - Ancillary services Net Revenue Variance Account – Hydroelectric
    - Ancillary services Net Revenue Variance Account – Nuclear
    - Transmission Outages and Restrictions Variance Account
    - Pickering A Return to Service Deferral Account
    - Nuclear Liability Deferral Account
    - Nuclear Development Variance Account
    - Capacity Refurbishment Variance Account
    - Nuclear Fuel Cost Variance Account
    - Income and Other Taxes Variance Account
    - Bruce Lease Net Revenue Variance Account
    - Hydroelectric Interim Period Shortfall (Rider D) Variance Account
    - Nuclear Interim Period Shortfall (Rider B) Variance Account
    - Tax Loss Variance Account
    - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
    - Nuclear Deferral and Variance Over/Under Recovery Variance Account
    - Hydroelectric Surplus Baseload Generation Variance Account
    - Hydroelectric Incentive Mechanism Variance Account
    - Pension and OPEB Cost Variance Account

- Continuity statements listing opening balances, transaction details including recoveries where applicable, interest rates and carrying charges, and closing balances. The schedules shall reflect annualized data for the Historic and Bridge years. Notes shall be provided for any unusual transactions.
- A detailed proposal for recovery of the balance in the deferral and variance accounts, where applicable.

2.10 EXHIBIT I DETERMINATION OF PAYMENT AMOUNTS

This exhibit shall include the following:

- Calculation of Revenue Deficiency or Sufficiency
    - Determination of net income
    - Statement of rate base
    - Indicated rate of return
    - Gross and net deficiency or sufficiency in revenue.

- Proposed Payments Schedule and Analysis
    - Proposed payments and revenue adjustments
    - Detailed calculations of revenue under the current payments schedule and the proposed payment schedule
    - Detailed reconciliation of payment revenue and other revenue to the total

revenue requirement.
- Analysis of % change vs. current payment amounts
- Bill impact analysis

- Payment Design

  OPG shall, in addition to providing the existing design of payment amounts, include:

  - Analysis of the existing design of payment amounts and whether the design maximized efficient use of the generation facilities
  - Proposed payment design and rationale
  - Explanation of non-cost factors and their application to payment design.

- Payment Implementation

  OPG shall provide a description of the settlement process with the IESO, including a description of the timelines associated with the requested effective date.

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Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

June 7, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON, M4P 1E4

Dear Ms. Walli,

RE: EB-2017-0049 – Blue Page Update to Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application

Updates to Hydro One Networks Inc.'s ("Hydro One") five-year Distribution Custom IR Application for the period 2018-2022 ("Application") have been submitted using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System.

The updates include a number of adjustments including:

- replacing the 2016 forecasted results with 2016 audited financial results;
- adopting a reduced stretch factor (0.45% compared to 0.60%) in the proposed Custom IR formula, based on an updated analysis of Hydro One Distribution's total cost benchmarking performance;
- reducing OM&A pension costs and related tax credits beginning in 2017, reflecting an updated pension valuation report;
- increasing the external revenues forecast to reflect changes in miscellaneous service charges calculated using audited 2016 financial results and the modified stretch factor;
- eliminating the proposed disposition of the *Retail Settlement Variance* Account – Global Adjustment regulatory asset balance to reflect an anticipated refund from the IESO of approximately $121 million, as the IESO refines its global adjustment calculation; and
- filing the 2017 Team Scorecard, redacted for net income performance levels on the basis that this is material forward-looking financial information.

The appendix to this letter contains a table listing the revised evidentiary exhibits.

The adjustments result in: (a) a reduction of $4.9 million in Hydro One Distribution's 2018 revenue requirement from $1,504.7 million to $1,499.9 million; (b) a reduction of $16.9 million in regulatory assets to be recovered; and (c) a slight increase in external revenues, which reduces rates revenue requirement by $1 million in 2018. These changes result in a 1.6% reduction in the average 2018 distribution rate increase from 6.5% to 4.9%.

The updates were filed in a complete text-searchable, Adobe Acrobat version of the merged evidence from today's filing and the original March 31st filing (as subsequently revised or supplemented). Hydro One intends to post electronic copies of the updated Application and supporting evidence on its website for public access. Two paper copies of the the revisions will be sent to the OEB shortly on coloured paper.

Hydro One's points of contact for service of documents associated with the Application remain as listed in Exhibit A, Tab 2 Schedule 1.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

Encls.

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Ontario

BY E-MAIL

December 29, 2015

To: All Licensed Electricity Distributors
All Other Interested Parties

Re: Applications for 2017 and 2018 Electricity Rates

This letter sets out a preliminary list of cost of service filers for the 2017 and 2018 rate years based on the date of their last cost of service application and other supporting information (the Rebasing List). At this time, 31 electricity distributors are scheduled to file a cost of service application for 2017 rates and four are scheduled to file for 2018 rates. The 2017 Rebasing List is set out in Appendix A to this letter. The 2018 Rebasing List is set out in Appendix B of this letter.

In light of the imbalance in the number of distributors scheduled to file a cost of service application over the next two years, the OEB is inviting interested electricity distributors that are scheduled to file a cost of service application for 2017 rates to submit expressions of interest for a deferral to rebase for 2018 rates. As with deferral requests in the past, the OEB will assess requests based on the individual circumstances of the distributor and its past performance.

This letter also sets out the deadlines by which notice must be given to the OEB in respect of various other matters relating to the setting of 2017 rates, and by which cost of service applications for 2017 rates are expected to be filed.

Background

As set out in the *Report of the Board: A Renewed Regulatory Framework for Electricity* (the RRFE Report), three alternative rate-setting methods are available to electricity distributors: Price Cap Incentive Rate-setting (Price Cap IR); Custom Incentive Rate-setting (Custom IR); and Annual Incentive Rate-setting Index (Annual IR Index).

Inclusion on the 2017 Rebasing List and Cost of Service Application Deadline

The distributors that have been included on the 2017 Rebasing List are those whose rates were last set based on a cost of service application for the 2013 rate year, as well as distributors that were scheduled to have their rates rebased for the 2016 rate year but whose rate rebasing was deferred by one year.

Distributors that are on the 2017 Rebasing List and that intend to file for rates effective January 1 or May 1 are expected to file their 2017 rate applications on a cost of service basis no later than **April 29, 2016** or **August 26, 2016**, respectively. Any distributor which intends to select to have its rates set using either the Custom IR or the Annual IR Index method must refer to the sections below.

Adjustments to the 2017 Rebasing List

<u>Selection of Custom IR or Annual IR Index Methods</u>

Any distributor that has been included on the 2017 Rebasing List and that intends to select either the Custom IR or the Annual IR Index method for 2017 rates must, if it has not already done so, notify the OEB as soon as possible and in any event no later than **February 26, 2016**.

Distributors that have filed Annual IR Index applications for 2016 rates have not been included on the 2017 Rebasing List. These distributors can choose to move to the Price Cap IR method, but would only be eligible to rebase for 2017 if their last cost of service application was for 2013 rates or earlier. Distributors that choose to move to the Price Cap IR method and rebase their rates for 2017 must notify the OEB no later than **February 26, 2016**. If a distributor's rates were rebased since 2013, the early rebasing approach discussed below would apply and notice must be given as set out below. Distributors on the Annual IR Index that wish to choose the Custom IR option for 2017 must so notify the OEB no later than **February 26, 2016**.

<u>Distributors that Wish to Submit Expressions of Interest for Deferral of Rebasing</u>

Any distributor that has been included on the 2017 Rebasing List but wishes to submit an expression of interest to defer its application beyond the 2017 rate year must, if it has not already done so, send a letter to the OEB as soon as possible and in any event no later than **February 26, 2016**. In making its determinations on each request, the OEB will consider, among other relevant factors, the distributor's scorecard performance results. If a distributor has earned more than 300 basis points above the OEB-approved return on equity during the most recent historical reporting period, no deferral will be granted. The OEB will address deferrals from 2018 to 2019 at a later time.

Distributors that Intend to File an Early Rebasing Application

A distributor that is not included on the 2017 Rebasing List but wishes to have its 2017 rates set on a cost of service basis under the Price Cap IR option must so notify the OEB in writing as soon as possible and in any event no later than **February 26, 2016**. In keeping with the OEB's approach to early rebasing as set out in its April 20, 2010 letter and reaffirmed in the RRFE Report, a distributor that seeks to have its rates rebased earlier than scheduled must clearly demonstrate, 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 remaining years of its Price Cap IR plan term.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A
Electricity Distributors Scheduled to Apply for Rebasing for 2017 Rates

1	Attawapiskat Power Corporation
2	Atikokan Hydro Inc.
3	Bluewater Power Distribution Corporation
4	Brantford Power Inc.
5	Canadian Niagara Power Inc.
6	Centre Wellington Hydro Ltd.
7	COLLUS Power Corporation
8	E.L.K Energy Inc.
9	Enersource Hydro Mississauga Inc.
10	Essex Powerlines Corporation
11	Erie Thames Powerlines Corporation
12	Fort Albany Power Corp.
13	Greater Sudbury Hydro Inc.
14	Hydro 2000 Inc.
15	Hydro One Remote Communities Inc.
16	Innpower Distribution Systems Limited
17	Kashechewan Power Corp.
18	Lakefront Utilities Inc.
19	London Hydro Inc.
20	Midland Power Utility Corporation
21	Northern Ontario Wires Inc.
22	Orillia Power Distribution Corporation
23	Peterborough Distribution Inc.
24	P.U.C. Distribution Inc.
25	Sioux Lookout Hydro Inc.
26	Thunder Bay Hydro Electricity Distribution Inc.
27	Tillsonburg Hydro Inc.
28	Welland Hydro-Electric System Corp.
29	Westario Power Inc.
30	West Coast Huron Energy Inc.
31	Whitby Hydro Electric Company

APPENDIX B
Electricity Distributors Scheduled to Apply for Rebasing for 2018 Rates

1	Cooperative Hydro Embrun Inc.
2	Hydro Hawkesbury Inc.
3	Kitchener - Wilmot Hydro Inc.
4	Lakeland Power Distribution Ltd.

APPENDIX C
Summary of Deadlines

Action	OEB Deadline
Notification from any distributor on the 2017 Rebasing List that will be selecting either the Custom IR or Annual IR Index method and therefore will not be filing a cost of service rate application for 2017 rates	February 26, 2016
Notification from any distributor that is currently on Annual IR Index but that plans to file a cost of service rate application under the Price Cap IR method or a Custom IR application for 2017 rates	February 26, 2016
Letter from any distributor included on the 2017 Rebasing List that wishes to submit an expression of interest to defer rebasing beyond 2017	February 26, 2016
Notification from any distributor that is not included on the 2017 Rebasing List but that plans to file a cost of service application for 2017 rates under the Price Cap IR method (early rebasing)	February 26, 2016
Deadline for cost of service (and Custom IR) applications for January 1, 2017 rates	April 29, 2016
Deadline for cost of service (and Custom IR) applications for May 1, 2017 rates	August 26, 2016

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

EB-2013-0416/EB-2014-0247

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR APPROVAL OF DISTRIBUTION RATES FOR 2015 TO 2019

DECISION
March 12, 2015

EB-2013-0416/EB-2014-0247

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015, and each year thereafter to December 31, 2019.

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving an exemption from sections 7.5.1 and 7.5.2. of the Distribution System Code.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

Emad Elsayed
Member

DECISION

March 12, 2015

TABLE OF CONTENTS

1.0 INTRODUCTION AND SUMMARY 7

2.0 ORGANIZATION OF THE DECISION 11

3.0 ALIGNMENT WITH THE RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY 12

3.1 Inconsistency with outcome-based regulation 13
3.2 Lack of externally imposed incentives 14
3.3 Weak benchmarking evidence 15
3.4 Limited prospects for continuous improvement 17
3.5 Value to customers 18

4.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS 21

4.1 Compensation 22
4.2 Vegetation Management 25
4.3 Conservation and Demand Management (CDM) 27

5.0 DEPRECIATION AND AMORTIZATION 31

6.0 LEAP FUNDING 32

7.0 DISTRIBUTION SYSTEM PLAN, RATE BASE & CAPITAL EXPENDITURES 33

7.1 Distribution System Plan 33
7.2 Rate Base & Capital Expenditures 35
7.3 Working Capital 39

8.0 COST OF CAPITAL 40

9.0 REVENUE REQUIREMENT AND RATE SMOOTHING 41

10.0 LOAD FORECAST 42

11.0 COST ALLOCATION AND RATE DESIGN 43

11.1 Rate Class Review 43
11.2 Revenue to Cost Ratios 45
11.3 Increase in Fixed Charges 45
11.4 Seasonal Rate Class 46
11.5 Street Lighting Class Rates 49

11.6 Unmetered Scattered Load Class 50
11.7 Line Loss Study 50
11.8 Miscellaneous Service Charges 51

12.0 SMART METER COSTS 52

13.0 DEFERRAL AND VARIANCE ACCOUNTS 55
13.1 Restatement of balances 55

14.0 DISTRIBUTION SYSTEM CODE EXEMPTION (EB-2014-0247) 57

15.0 RECOVERY OF LOST REVENUES 60

16.0 SUMMARY OF DIRECTIONS FOR FILING 61

17.0 IMPLEMENTATION AND ORDER 63

18.0 APPENDICES 66

Appendix 1 –The Proceeding, Participants and Witnesses
Appendix 2 – Oral Decision on City of Hamilton motion, September 16, 2014

18.0 APPENDICES

Appendix 1 –The Proceeding, Participants and Witnesses
Appendix 2 – Oral Decision on City of Hamilton motion, September 16, 2014

APPENDIX 1
THE PROCEEDING, PARTICIPANTS AND WITNESSES

THE PROCEEDING

On December 19, 2013, Hydro One filed an application with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B for an order or orders approving distribution rates for a five year period, commencing January 1, 2015.

The OEB issued a Notice of Application on January 24, 2014. In response to the Notice, the OEB received 19 requests for intervenor status. The OEB approved 18 of these interventions.

The OEB also received 13 Letters of Comment from ratepayers across Ontario, the vast majority expressing concern with the high level of the proposed rate increases. In addition, the OEB received resolutions from 42 Ontario municipalities, expressing concern over electricity rate increases.

Hydro One updated its pre-filed evidence in this case on January 30, 2014 and provided a further update on May 30, 2014. At the applicant's suggestion, the OEB held a series of three transcribed technical conferences on April 1, 10 and 23 and also held a transcribed session on May 12, 2014 during which Hydro One senior management made a presentation on the application.

The OEB approved an issues list for this case on May 20, 2014. Following an interrogatory process, a further technical conference was held on July 21 and 22, 2014. A settlement conference was held on July 28, 2014 but no settlement was achieved.

Motion and Decision

On September 4, 2014, the City of Hamilton filed a motion requesting an order freezing the rates of Hydro One for the street lighting class at 2014 levels or setting these rates as interim in this proceeding. The OEB heard the motion on September 12, 2014 and on September 16, 2014 gave an oral decision denying the motion. A copy of this decision is attached as Appendix 2.

The oral hearing for this proceeding began on September 8, 2014. On that date the OEB granted an interim exemption from section 7.5.2 of the DSC. The evidentiary portion of the hearing concluded on September 18, 2014. Hydro One presented oral argument-in-chief on September 24, 2014. The OEB received submissions from OEB staff and fifteen intervenors. The record closed with receipt of reply argument from Hydro One on October 27, 2014.

Decision on Interim Rates

On December 18, 2014, the OEB acknowledged that the OEB's decision may not be issued until after the proposed effective date of January 1, 2015 and declared Hydro One's current approved distribution rates interim as of January 1, 2015 pending the Board's final decision on the application.

In the decision on interim rates, the OEB also granted Hydro One's request to discontinue collection of revenue through the Regulation 330/09 renewable connection funding adder from provincial ratepayers as of December 31, 2014.

PARTICIPANTS

A list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding is shown below. A complete list of intervenors is available at the OEB's offices.

OEB Counsel and Staff (OEB staff)	Jennifer Lea, Harold Thiessen, Lisa Brickenden, Leila Azaiez, Keith Ritchie, Stephen Cain
Hydro One Networks Inc. (Hydro One)	Don Rogers, Anita Varjacic
Society of Energy Professionals (SEP)	Bohdan Dumka, Vicki Power

ONTARIO POWER GENERATION

News
from Ontario Power Generation

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March 4, 2016

OPG REPORTS 2015 FINANCIAL RESULTS

Strong operating and financial results position OPG well for the refurbishment of the Darlington station

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $402 million for 2015, down from $561 million excluding extraordinary gain in 2014. The decreased earnings were mainly a result of the planned four-unit Vacuum Building Outage (VBO) at the Darlington Nuclear Generating Station (GS) in 2015, which reduced nuclear generation and increased operations, maintenance and administration (OM&A) expenses. The decrease in earnings in 2015 was partially offset by the new base regulated prices effective November 2014 and the newly in-serviced hydroelectric units.

"OPG's strong operating and financial performance over the last few years allows us to proceed with confidence in refurbishing our nuclear plant at Darlington," said Jeff Lyash, OPG President and CEO. "Over its additional 30-plus years of operating life, Darlington will provide a reliable supply of clean electricity and is expected to contribute approximately $50 billion in additional economic benefits to Ontario." Mr. Lyash also noted, "We currently produce about half of Ontario's electricity and our power costs customers approximately 40 per cent less than the rest of the market. Undertaking the Darlington Refurbishment project will allow us to keep moderating overall electricity prices for customers for decades to come and contributes to the Province's climate change goals."

"I am also pleased to continue our record of partnering with Indigenous communities in 2015 as the construction of the Peter Sutherland Sr. GS is being undertaken in partnership with the Taykwa Tagamou Nation."

Mr. Lyash added, "In 2015, OPG again achieved a strong safety performance. As one of the company's fundamental core values, safety is embedded in all that we do. Our goal is zero injuries."

In January 2016, OPG announced that it is ready to deliver on the Government of Ontario's decision to proceed with the refurbishment of the first of four units at Darlington and to pursue continued operations at the Pickering Nuclear GS to 2024, pending necessary approvals. Operating Pickering to 2024 will help provide a reliable supply of baseload electricity while the Darlington units and the units operated by Bruce Power L.P. undergo refurbishment.

Since 2010, OPG has invested more than $200 million in Pickering to ensure its safe and reliable operation. In 2015, the Pickering Station provided about 14 per cent of

Ontario's power and achieved its highest ever level of reliability. Operating Pickering to 2024 will save electricity customers up to $600 million, avoid eight million tonnes of greenhouse gas emissions and maintain approximately 4,500 jobs across Durham Region.

Generating and Operating Performance

OPG operates a diverse generation portfolio of nuclear, hydroelectric, and thermal plants that is virtually free of greenhouse gases and smog-causing emissions.

In addition to the impact of the Darlington VBO on generation and OM&A expenses, OPG's net income was lower in 2015 due to higher interest expense, lower electricity trading margins, and higher accretion expense related to fixed asset removal and nuclear waste management liabilities. These were partially offset by higher earnings in 2015 from the new hydroelectric units on the Lower Mattagami River and a write-off of $77 million in 2014 reflecting a regulatory disallowance of capital costs by the Ontario Energy Board.

Total electricity generated decreased in 2015 to 78.0 terawatt hours (TWh) from 82.2 TWh in 2014. Nuclear production of 44.5 TWh in 2015 represented a decrease of 3.6 TWh compared to 2014, primarily due to the VBO at the Darlington GS, which required the shutdown of all four units from Sep. 14, 2015 to Oct. 30, 2015.

Generation of 30.4 TWh in 2015 from the Regulated – Hydroelectric segment was lower than the 31.3 TWh generated in 2014, mainly due to lower water flows in eastern Ontario. Generation from the Contracted Generation Portfolio increased by 0.3 TWh as a result of higher production from the hydroelectric units on the Lower Mattagami River.

The Darlington Nuclear GS capability factor of 76.9 per cent in 2015 reflected the planned VBO in 2015. The capability factor at the Pickering Nuclear GS increased to 79.4 per cent in 2015 from 75.3 per cent in 2014 mainly due to improved station performance. The Pickering Nuclear GS achieved the best ever reliability performance in the station's history.

OPG's regulated hydroelectric stations achieved an availability factor of 91.2 per cent in 2015 which was comparable to 91.4 per cent in 2014. OPG's contracted hydroelectric stations achieved an availability of 88.6 per cent in 2015 compared to 90.2 per cent in 2014. The reduction mainly reflected a higher number of planned outage days at certain Lower Mattagami River stations. OPG's contracted thermal stations achieved an equivalent forced outage rate of 11.2 per cent in 2015 compared to 8.9 per cent in 2014, mainly due to an outage to perform repair work at the Lennox GS.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2015 were as follows:

Darlington Refurbishment

- The Darlington Refurbishment project is expected to extend the operating life of the station by approximately 30 years. The approved project budget for the four-unit refurbishment is $12.8 billion including capitalized interest and escalation. Refurbishment work on the first unit is scheduled to commence in October 2016, with the last unit completed by 2026. Life-to-date capital expenditures were $2,166 million as at Dec. 31, 2015.

- In December 2015, OPG received a ten-year operating licence for the Darlington GS from the Canadian Nuclear Safety Commission (CNSC) – the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which will span most of the refurbishment period, is effective from Jan. 1, 2016 to Nov. 30, 2025.

Peter Sutherland Sr. GS

- In March 2015, OPG's Board of Directors approved the construction of a new 28 MW generating station, the Peter Sutherland Sr. GS, on the Abitibi River, with a planned in-service date in the first half of 2018 and a budget of $300 million. Life-to-date capital expenditures were $95 million as at Dec. 31, 2015.

- During 2015, OPG executed a hydroelectric energy supply agreement for the station with the Independent Electricity System Operator, and completed financing for the project.

- The station will be constructed through a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation. This project is OPG's latest partnership with a First Nation community. Past successful partnerships included those with the Moose Cree First Nation for the Lower Mattagami River project and the Lac Seul First Nation for the Lac Seul GS.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2015**	**2014**
Revenue	**5,476**	4,963
Fuel expense	**687**	641
Gross margin	**4,789**	4,322
Operations, maintenance and administration	**2,783**	2,615
Depreciation and amortization	**1,100**	754
Accretion on fixed asset removal and nuclear waste management liabilities	**895**	797
Earnings on nuclear funds - (a reduction to expenses)	**(704)**	(714)
Regulatory disallowance related to the Niagara Tunnel project	**-**	77
Income from investments subject to significant influence	**(39)**	(41)
Other net expenses	**65**	47
Income before interest, income taxes, and extraordinary item	**689**	787
Net interest expense	**180**	80
Income tax expense	**92**	139
Income before extraordinary item	**417**	568
Extraordinary item	**-**	243
Net income	**417**	811
Net income attributable to the Shareholder	**402**	804
Net income attributable to non-controlling interest [1]	**15**	7
Income (loss) before interest, income taxes, and extraordinary item		
Electricity generation business segments	**912**	830
Regulated – Nuclear Waste Management	**(186)**	(76)
Services, Trading, and Other Non-Generation	**(37)**	33
Total income before interest, income taxes, and extraordinary item	**689**	787
Cash flow		
Cash flow provided by operating activities	**1,465**	1,433
Electricity generation (TWh)		
Regulated – Nuclear Generation	**44.5**	48.1
Regulated – Hydroelectric	**30.4**	31.3
Contracted Generation Portfolio [2]	**3.1**	2.8
Total electricity generation	**78.0**	82.2
Nuclear unit capability factor (per cent)		
Darlington Nuclear GS	**76.9**	92.1
Pickering Nuclear GS	**79.4**	75.3
Availability (per cent)		
Regulated – Hydroelectric	**91.2**	91.4
Contracted Generation Portfolio – hydroelectric stations	**88.6**	90.2
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**11.2**	8.9
Return on Equity Excluding Accumulated Other Comprehensive Income (AOCI) (%) [3]	**4.0**	8.5
Return on Equity Excluding AOCI and extraordinary gain in 2014 (%) [3]	**4.1**	6.0
Funds from Operations (FFO) Adjusted Interest Coverage (times) [3]	**5.0**	2.8

[1] Relates to the 25% interest of a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami LP.

[2] Includes OPG's share of generation from its 50% ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] ROE Excluding AOCI and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about these measures is provided in OPG's Management's Discussion and Analysis for the year ended Dec. 31, 2015, under the section, *Supplementary Non-GAAP Financial Measures*.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity that is 99.7 per cent free of greenhouse gas and smog-causing emissions. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open, environmentally responsible, and commercially sound manner.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended Dec. 31, 2015 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
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investor.relations@opg.com

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BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce lease agreement and associated agreements (collectively "Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations.

2.0 OVERVIEW

OPG leases the Bruce A (Units 1-4) and Bruce B (Units 5-8) Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Bruce lease agreement sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have entered into a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement ("Used Fuel Agreement"), the Amended and Restated Low and Intermediate Level Waste Agreement ("L&ILW Agreement"), and the Amended and Restated Bruce Site Services Agreement.

For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be ($66.1)M for 2017, ($74.3)M for 2018, ($85.9)M for 2019, ($82.1)M for 2020 and ($93.1)M for 2021 as shown in Ex. G2-2-1 Table 1. In accordance with O. Reg. 53/05 and the OEB's previous findings, these net amounts are applied towards the nuclear revenue requirement. Specifically, sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts. These revenues and costs are subject to the Bruce Lease Net Revenues Variance Account.

On December 3, 2015, the Province announced that an updated contract had been executed between the Independent Electricity System Operator ("IESO") and Bruce Power to enable the refurbishment of Bruce Units 3-8 (the Amended and Restated Bruce Power Refurbishment Implementation Agreement or "ARBPRIA").[1] In support of these planned refurbishments, an amended Bruce lease agreement was executed by OPG and Bruce Power on December 4, 2015 ("2015 Amendment") that extended the lease period in line with the estimated post-refurbishment end-of-life ("EOL") dates of the Bruce units. The negotiated amendments to the Bruce Lease cover several other areas including base rent, supplemental rent, low and intermediate level waste ("L&ILW") management fees, and related provisions that serve to limit OPG's financial risk exposure over the term of the lease.

The 2015 Amendment resulted from negotiations undertaken by OPG and Bruce Power in the context of the IESO and the Province's need to fully consider the economics of Bruce Power's proposed refurbishment of the Bruce units, which provided an opportunity for certain aspects of the lease arrangements between OPG and Bruce Power to be reassessed.

Key changes to the Bruce Lease resulting from the negotiations included:

- Extension of the lease renewal term by approximately 20 years;
- Elimination of the derivative liability embedded in the lease agreement;
- Changes in the supplemental rent and L&ILW management fees to align them more closely with the costs of managing used fuel and L&ILW generated by the Bruce units as determined under the Ontario Nuclear Funds Agreement ("ONFA"); and
- Provisions that serve to limit OPG's financial risk exposure over the term of the lease related to changes in nuclear used fuel and waste management costs arising from future updates to the ONFA reference plan.

[1] https://news.ontario.ca/mei/en/2015/12/ontario-commits-to-future-in-nuclear-energy.html

Ontario

ONTARIO REGULATION 353/15

made under the

ONTARIO ENERGY BOARD ACT, 1998

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AMENDING O. REG. 53/05

(PAYMENTS UNDER SECTION 78.1 OF THE ACT)

1. Subsection 0.1 (1) of Ontario Regulation 53/05 is amended by adding the following definitions:

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station;

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends;

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2;

2. The Regulation is amended by adding the following section:

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually.

3. (1) Paragraph 4 of subsection 6 (2) of the Regulation is amended by striking out the portion before subparagraph i and substituting the following:

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

. . . . .

(2) Subsection 6 (2) of the Regulation is amended by adding the following paragraph:

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the payment amount that is used in the determination of the undeferred payments made under section 78.1 of the Act with respect to the nuclear facilities,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment.

Commencement

4. This Regulation comes into force on the later of January 1, 2016 and the day it is filed.

STAKEHOLDER CONSULTATION

1.0 PURPOSE

This evidence provides a description of the stakeholder consultation process that OPG held while it was developing this 2017-2021 payment amounts application.

Given the novel elements of this application (in particular, the transition to incentive regulation), OPG found it beneficial to share its plans for the application with stakeholders while the filing was still under development.

2.0 BACKGROUND

OPG first held stakeholder consultation sessions in late 2014 and early 2015 regarding the company's potential 2016-2020 payment amounts application (the "initial consultation"). The consultation process consisted of three information sessions. While OPG did not ultimately file an application for 2016 payment amounts, the stakeholder feedback from that process was helpful in developing this application. OPG has included the agendas from the initial consultation as attachments to this schedule.

Following the initial consultation, OPG held a series of consultation sessions regarding the current application for 2017-2021 payment amounts.

This schedule provides an outline of the entire consultation process, including the initial consultation and the subsequent sessions. It includes a summary of material changes that OPG made to this application based on feedback from stakeholders.

3.0 OBJECTIVE

The objective of the consultation process was to inform stakeholders about the application and to seek input on OPG's transition to incentive regulation.

4.0 PROCESS

4.1 Initial Consultation

In the initial consultation, OPG held three stakeholder information sessions regarding its potential 2016-2020 application. These sessions were held on December 17, 2014, January 22, 2015, and February 18, 2015. Copies of the presentations that were made at the session and facilitator notes are posted on OPG's website at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's payment amounts, and other stakeholders who, in OPG's view, may have a material interest in the application. Funding was offered to participants who qualified under the funding guidelines.

The information sessions were held on a non-confidential, without-prejudice basis. Steve Klein, VP and Practice Manager at OPTIMUS | SBR was retained as a neutral, third-party facilitator and to document and report on the sessions.

The December 17, 2014 session highlighted the challenges and uncertainties inherent in OPG's operating environment for the five year period commencing in 2016. In addition, the session provided information on the Inflation Factor Analysis and Total Factor Productivity Study for OPG's hydroelectric operations prepared by London Economics International LLC. A copy of the session agenda is provided in Attachment 1.

At the January 22, 2015 session, OPG outlined proposed regulatory approaches for both hydroelectric and nuclear facilities. A copy of the session agenda is provided in Attachment 2.

At the February 18, 2015 session, OPG gave stakeholders another opportunity to request clarification or ask other questions about the materials presented at the second information session. OPG also presented updated plans on various aspects of the application, as they were developing. A copy of the session agenda is provided in Attachment 3.

4.2 2016 Consultation

Since OPG ultimately did not apply for new payment amounts in 2016, it held a further round of consultations on the current application in 2016. These sessions were held on February 8, 2016, March 21, 2016, and May 19, 2016. As it did in the initial consultation, OPG invited parties that participated in the previous application and retained OPTIMUS | SBR to facilitate and provide notes. Copies of the presentations that were made at the session and facilitator notes are posted on OPG's website at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

At the February 8, 2016 session, OPG presented the company's plan to file an application covering payment amounts for 2017-2021. A copy of the session agenda is provided in Attachment 4. OPG presented the structure and major elements of the company's planned application. The session included a keynote presentation by OPG President and CEO Jeffrey Lyash, as well as detailed updates on the Darlington Refurbishment Program ("DRP") and on the Pickering Life Extension program.

The March 21, 2016 session was held at the Darlington Energy Complex. Participants toured the reactor mock-up used to prepare for the DRP. While touring the Darlington site, stakeholders were given an overview of the Facility and Infrastructure Projects and Safety Improvement Opportunities. OPG briefed the participants on the scope of the DRP, the company's DRP contracting strategy, and provided an overview of the DRP-related evidence planned for the company's payment amounts application. A copy of the session agenda is provided in Attachment 5.

Following the consultations, OPG made a number of changes to the planned application, including:

i. Eliminating the proposal to establish hydro base rates using a 2017 forecast test year cost of service review – instead, the filed application escalates existing hydro payment amounts by the proposed price-cap index;

ii. Eliminating the proposed symmetrical earnings sharing mechanism for nuclear and hydro;

iii. Eliminating the situational off-ramp proposed for nuclear;

iv. Eliminating the New Cost of Capital Variance Account proposed to record differences in hydro return on equity during the incentive regulation ("IR") term;

v. Modifying the hydro x-factor, increasing the annual productivity adjustment from -1 per cent (as identified by the independent Total Factor Productivity study) to 0 per cent, reflecting OEB policy in the electric distribution sector;

vi. Expanding the application of nuclear stretch factor applied to include corporate support costs; and

vii. Expanding the proposed performance reporting metrics to include all of the key hydroelectric performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B) and all measures used in annual nuclear benchmarking.

OPG also held a briefing for stakeholders on the final application on May 19, 2016. A copy of the session agenda is provided in Attachment 6. Materials from this presentation are available at http://www.opg.com.

Stakeholder Consultation Session Notes

Second Information Session on Upcoming Applications

January 22, 2015
Main Auditorium
700 University Avenue

OPTIMUS | SBR
REGULATORY SERVICES

Table of Contents

1. Welcome and Introductions – Randy Pugh, Director, Regulatory Affairs and Steve Klein, VP and Practice Manager, OPTIMUS | SBR 3

2. OPG's Incentive Rate Mechanism Consultation – Overview of Regulated Hydroelectric Stations 3

3. OPG's Initial Hydro Incentive Regulation Plan Proposal 5

4. Hydroelectric Inflation Factor Assessment / Questions and Discussion 8

5. Hydroelectric TFP Study Report / Questions and Discussion 9

6. Nuclear Operations and Projects – 2016-2020 11

7. Initial Nuclear Multi-Year Cost of Service Regulation Plan Proposal 13

8. Closing Remarks 16

9. Session Agenda 17

10. Attendee List 18

1. Welcome and Introductions – Randy Pugh, Director, Regulatory Affairs and Steve Klein, VP and Practice Manager, OPTIMUS | SBR

Randy Pugh, Director, Regulatory Affairs at OPG welcomed participants and provided context for the day's second information session. The purpose of this information session is to help establish a rate making methodology for OPG's upcoming applications. Throughout the session, information would be provided on OPG's hydroelectric 2016-2020 operating environment, the inflation factor assessment and Total Factor Productivity (TFP) study report, as well as an overview of OPG's Nuclear 2016-2020 operating conditions. These presentations provide the foundation for discussing OPG's initial proposal for an incentive regulation recovery mechanism and nuclear multi-year cost of service plan, both in response to directives established by the Ontario Energy Board (OEB).

Steve Klein of OPTIMUS | SBR, in his capacity as Facilitator, outlined the logistics and round-table format for the session, particularly noting the keen desire on the part of OPG Regulatory Affairs to gain valued feedback and meaningful input from the participants to assist OPG in its efforts to establish the appropriate rate making methodology for its upcoming applications to the OEB. Brief self-introductions, i.e. name and affiliation, followed.

2. OPG's Incentive Rate Mechanism Consultation – Overview of Regulated Hydroelectric Stations

Mario Mazza, VP, Strategic Operations, Hydro-Thermal Operations (HTO) at OPG summarized the "Overview of Regulated Hydroelectric Stations" presentation from the previous December 17 stakeholder information session. Details of the study are available by accessing the presentation and notes from the previous session on the OPG website.

OPG's HTO assets are diverse in size, configuration, location, and vintage, among other factors. A variety of regulatory regimes are also involved, either through local communities and/or inter-provincial boundaries.

Over the next five years, OPG plans to invest about $1B in assets. Investments are generally dictated by asset condition and the position in their life cycle. In addition, there are a variety of risks that need to be incorporated in these plans which may impact investment profiles. In regards to energy production, OPG is forecasting to be in the 33 TWh range over the next five years with a 'sweet-spot' of 91%-93% availability for units. The difficulty of forecasting with hydroelectric assets due to the variability associated with 'Mother Nature' was highlighted.

There are a wide range of regulatory bodies that must be considered, as well as a regulatory framework in Ontario that dictates water management plans, which increases operating complexity. In this multi-stakeholder environment, OPG is only one user of these watersheds, and a variety of other activities must also be considered, such as navigation, boating and rafting.

Moving forward, there are risks related to future regulatory changes. With respect to the environmental landscape, potential changes are expected when it comes to fish habitat, bypasses and mitigation. Environmental acts, provincially and federally, that will impact OPG are currently being dealt with by operations, but may also require capital investments.

Dam safety regulations in Ontario are dictated by the Lakes and Rivers Improvement Act, rather than a formal and distinct regulation. These regulations are relatively imprecise, and there are technical guidelines and requirements that must be met, which generates potential future investment risk; such as through required physical enhancements.

Major capital investments expected over next five years include the Ranney Falls expansion project, where approvals are underway. OPG is also looking at optimizing the Sir Adam Beck 1 (SAB 1) facility which has two units that are presently deregistered with the IESO. Based on water forecasts and market conditions moving forward, there may be an opportunity to do a major frequency conversion of those assets which should provide about 100 MW capacity to the system and enhance usage of the Pump Generating Station. Remaining projects are primarily lifecycle focused projects where major mechanical and electrical work will be conducted to maintain performance.

OPG's five year average for the capital program is approximately $135M per year. Lumpiness in 2016 and 2017 is associated with geotechnical work on the Pump Generating Station reservoir to support safety and continued operations for the next 40-50 years. Plans are in place to start the project in 2016 which is going to require a major station shutdown.

For hydroelectric operating, maintenance and administration (OM&A), the biggest component is OPG's Gross Revenue Charge followed by base operating costs and then Project OM&A which is expected to remain fairly level over the next five years. A portion of the Project OM&A is partly tied to capital programs, such as when replacing various mechanical components which includes an overhaul. The overhaul part of the project is considered operating and maintenance when it comes to accounting rules. As a result, some projects are tied to refurbishment and operating programs, while others are tied to maintaining single assets due to lifecycle position and weather among other factors. In addition, another important issue is alkali-aggregate concrete growth activity in certain dams. In the program, mitigation has been provided for at the Otto Holden and R.H. Saunders plants, considered an operating and maintenance type project as opposed to capital.

Ensuring units are available as required is a critical component of supporting production. From an economic and system point of view, 91-93% availability for a fleet of assets appears optimal. With respect to operational benchmarking, about 72% - 82% of assets are in the optimal range. Cost benchmarking OPG against other utilities indicates quite a few assets are in the top quartile with 25 stations in top two quartiles. Smaller plants are frequently excluded from benchmarking efforts, as they are relatively less important to the system, although opportunities to include these are being explored.

Prior to discussing OPG's initial hydro incentive regulation plan proposal, Mr. Pugh highlighted the lumpiness of OM&A costs and that it is generally increasing over the 5 year period. The production forecast is expected to remain stable and capital expenditures are expected to average $135M per year over the 2016-2020 period based on current forecasts. These numbers are based on previous projections, and OPG is currently in the process of preparing its financial outlook. OPG's actual application will be informed by details gathered over the next couple of months. For benchmarking results, an overview of OPG's most significant plants' performance over a three year period indicates positive and in many cases, improving results. This presentation provides the backdrop for OPG's initial hydro incentive regulation plan proposal.

3. OPG's Initial Hydro Incentive Regulation Plan Proposal

Mr. Pugh highlighted that this consultation process is designed to gather feedback and inform proposal development. OPG is planning to apply for new rates, effective January 1 2016, with a targeted filing date of late Q2/early Q3. To inform proposal development, OPG considered where the OEB has explored rate making before, specifically the Renewed Regulatory Framework for Electricity (RRFE) Board Report for incentive regulation; see "Initial Hydro Incentive Regulation Plan Proposal" for details.

In the RRFE, the key components of incentive rate making plans are summarized, three options provided, and situations suggested in which a utility may use those particular options. Of the three approaches identified by the RRFE, OPG explained that the most appropriate approach to apply to the OPG hydro context is the Price Cap Index Approach. The Proposal Summary, in table format, outlines key RRFE planning parameters in the first column, RRFE methodology components under the RRFE Price Cap Index Approach column and OPG's initial proposal in the third column.

Each element of the RRFE Price Cap methodology was compared to OPG's initial proposal, to discuss similarities and differences as well as to gather feedback. For the Base Rate, in the RRFE it is determined in a forward test year cost of service review. Typically, for a distributor, in a bridge year a test year cost of service forecast is filed which becomes the base rate, using I-X to escalate over four years. OPG recently completed a similar "rebasing" review, with the Board's decision issued in November, 2014. The OEB established a base rate for 2014-2015, on a forward test year basis, which OPG intends to use as the base rate to be escalated for 2016-2020. The 2016-2020 timeline is designed in alignment with OPG's nuclear rate setting methodology which will allow for a broader review of common issues, such as corporate costs, at the same time.

With regards to the annual adjustment mechanism, a composite index is used for inflation under the RRFE. OPG is proposing to use a composite index with the same sub-indices, with weights that are specific to the generation industry's values. OEB developed an X–factor for distributors based on peer group X-factors, comprised of distribution industry TFP group potential and a stretch factor. OPG is proposing the same methodology with a peer group X-factor comprised of a generation industry TFP growth potential and a stretch factor, based on the results of an upcoming Benchmarking study.

The Role of Benchmarking in the RRFE covers two things: to establish the reasonableness of cost forecasts and to assign a stretch factor. The OEB has already used benchmarking to determine a just and reasonable rate for OPG's proposed base rate. As a result, benchmarking would only be used to establish a stretch factor.

Under the RRFE, Sharing of Benefits occurs through the stretch factor. OPG's initial proposal is a stretch factor of 0, as informed by LEI's TFP study. It is noted that the London Economics International LLC (LEI) study is not a benchmarking study, although OPG is planning to conduct a benchmarking study in the near future. For the other component of sharing benefits, similar to the gas industry's targeted incentive plan for transactional services, the OEB has targeted performance with respect to OPG's Hydroelectric Incentive Mechanism (HIM) which would continue to be used moving forward.

The proposed Term for OPG's initial proposal is the same as under the RRFE. The Incremental Capital Module will be applied for as under the RRFE. It is presumed that the OEB's recent report, "New Policy Options for the Funding of Capital Investments", issued September 18, 2014 will form the basis for this application.

The Treatment of Unforeseen Events under the RRFE is aligned with the EB-2007-0673 OEB report and OPG is proposing to adopt the same treatment except for an OPG-specific materiality threshold that reflects OPG's requirements.

OPG is proposing a similar Performance Reporting and Monitoring methodology as in the RRFE, using OPG's actual regulatory return after tax on rate base, with reviews initiated where performance erodes to unacceptable levels. The primary difference is that electricity distributors have specific performance metrics established by the OEB, while OPG would have to establish metrics that are relevant to a generation utility.

OPG is proposing a symmetrical Earnings Sharing mechanism. To the extent OPG performs below 100 basis points from established ROE, ratepayers would share in the cost difference, while performance above 100 basis points would allow ratepayers to share in revenue gains.

Additional information and context are then provided regarding the impact on OPG's proposed approach. In O. Reg. 53/05, OPG's hydroelectric rate prior to regulation was set at $33/MWh, while the combined rate for both newly and previously regulated hydroelectric rate from the EB-2013-0321 Order is $40.72/MWh. As a result, the average annual rate increase for the test period from 2007 to 2015, is approximately 2.5%. Under the proposed Index Price Cap, the published "I factor" value has been 1.63% over the period of OEB regulation and the TFP value recommended by LEI is -1%. Assuming a stretch factor of 0, the resulting X factor is still -1%. The resulting Index Price Cap value, based on historic values, is 2.63% which is comparable to the 2.5% average resulting from amounts previously approved by the OEB.

A question was raised about the Incremental Capital Module, regarding whether or not it is expected to be filed, or if it is to be made available as required. Mr. Pugh indicated that the planning process is currently underway and that a final answer is not available, although based on projected capital expenditures, it does not appear to meet the materiality threshold.

A general comment about maintaining consistent terminology in respect of OM&A and O&M operating costs was made. It was noted that the hydroelectric overview presentation, which included a slide on OM&A costs, reflected total operating costs including GRC. Benchmarking discussions were also based on

OM&A, and clarity regarding the specific OM&A components included was requested to provide a common ground for discussion and assessment.

Mr. Pugh replied that OPG compares its performance against industry benchmarks. Moving forward, external consultants will be engaged to advise what can and cannot be included in a benchmarking study. In particular, when comparing to other peers, it is important to recognize that all required benchmarking information may not be available.

An additional question was asked regarding OM&A costs, and whether it covered all of the regulated facilities. It was confirmed that these OM&A costs are related to all of the 54 regulated facilities, and that OM&A is presented on a consistent basis over time.

A stakeholder highlighted that the proposal summary reflected only one option of the RRFE, and asked if a rationale for the selection of that particular option would be included in the application.

Mr. Pugh clarified that the RRFE option presented was the one that best reflects OPG's current operating circumstances and constraints, and that the purpose of these consultation sessions is to gather stakeholder feedback around the proposed options. Key stakeholder concerns, where resolution or agreement cannot be achieved, will be considered open issues to be discussed at the next application.

Another question was asked regarding whether or not a hydroelectric incentive rate mechanism working group is to be setup by the OEB to guide the application process. Mr. Pugh highlighted that OPG's stakeholder information sessions would likely achieve the same outcome as an OEB working group and that forming such a working group was based on the intended filing schedule and activities planned two years ago. A specific working group may have been appropriate at the time, but a filing was not submitted that year. The goal of OPG's information sessions is to meet the OEB's needs for establishing a rate making methodology as well as ensuring intervenor concerns are expressed and addressed.

A stakeholder suggested that a symmetrical earning sharing mechanism may generate concerns among intervenors. Previous mechanisms have been asymmetrical.

An additional question was asked regarding performance reporting and monitoring, and what is defined by 'project management' capability. Mr. Pugh clarified that OPG's current performance scorecard approach includes three general categories of performance with some metrics oriented around project management. With respect to moving into a longer regulatory term, it is important to ensure that current initiatives are also supported by service performance metrics. It was noted that preliminary details on the type of metrics in consideration can also be made available at the next session for feedback.

A question was also raised regarding HTO OM&A expenditures, as they are forecasted out to 2020, although current business plans are for a three years. It was clarified that long-term planning efforts are also conducted, with lifecycle planning, to project long-term needs. Another stakeholder confirmed that the IRM term is five years, and highlighted a concern that historically the term is two years. Mr. Pugh clarified that the I-X component, applied to the base rate, goes from 2016 to the end of 2020. The duration of this term is identical to that of the nuclear proposal, which enables common costs as well as cost of capital and allocation to be reviewed together. Most utilities regulated by the OEB are on 5 year plans. As a result, it is important to consider the challenges associated with a five year forecast and to ensure those are addressed in planning efforts.

A final question was raised about incentive regulation and reporting, regarding whether or not clear incentives replace the need for frequent reporting. Transparency was urged. Mr. Pugh noted that a suite of service quality metrics would be developed, in consultation with stakeholders, to mitigate these risks.

A final question was raised regarding the suggested annual adjustment mechanism. Mr. Pugh noted that OPG is proposing that the same indices as distributors be used, but composite will be weighted based on generation industry data.

4. Hydroelectric Inflation Factor Assessment / Questions and Discussion

Julia Frayer of London Economics International (LEI) addressed the group by presenting highlights and key points from the December session. Details of the study are available by accessing the presentation and note from the previous session on the OPG website.

LEI has selected an index to reference the relevant inflation to be used within an I-X situation in the hydroelectric business, and is a reflection of a number of factors. The I-factor design being recommended is a composite index based on empirical research, and is consistent with the current forward-looking policy and OPG's expected future environment. This composite index has been selected because it met all six of the defined criteria, as described in the initial stakeholder engagement session. It includes factors exogenous to OPG, including Average Weekly Earnings (AWE) and the Gross Domestic Product (GDP) Input Price Index (IPI), which is a reflection of the economy as a whole; both indices are published through Statistics Canada and are readily available. Moving forward, computation for completing annual rate calculations will be straightforward given the conclusions of this work.

In addition to the criteria used in the evaluation of potential indices, LEI determined this I-factor has historically produced stable rates and will be greatly applicable to OPG's business. It was noted that the most empirically-intensive part of this investigation was determining the weightings. The weights that were used were reflective of average industry weights from the Total Factor Productivity study; from 2002-2012, the weights used were 81% on capital, 12% on labour, and 7% on non-labour, producing an I-factor of -1%.

LEI provided a response to a question from the December consultation regarding the difference in weights between the industry average and OPG, and the impact it would have on the study results. In lieu of the industry aggregate weights, if OPG's capital and O&M weights were used rather than industry average weights, the overall results would be quite comparable. For example, based on OPG's historical weights the composite I-factor results in an average value for the last ten years of historical data of 1.95% compared to the 1.97% (under industry weights).

Further details regarding the conclusions of this study are available by consulting the presentation by LEI, available on the OPG website. Stakeholders did not have any direct questions regarding the Inflation Factor study.

5. Hydroelectric TFP Study Report / Questions and Discussion

Ms. Frayer gave a second presentation to report on the Total Factor Productivity (TFP) Study. As the TFP study was presented in detail in the December stakeholder engagement session, the focus of this session was to provide a summary of the previous session and to build upon some questions that were brought up within that session.

Ms. Frayer discussed some challenges encountered throughout the TFP study, the first of which was the gap in available data. As the approach was empirical and required significant data inputs, data challenges impacted the time frames and variables used. The team took a pragmatic approach to addressing the concerns and highlighted early on in the process that data availability would be an issue and adjustments in methodology may be required. The second challenge, commonly identified for TFP studies, is the fact that such studies are based on historical data. This leads to questions of whether the historical trends are applicable to the future. However, because the industry is in a steady state environment, and this is common practice, the results are reasonable measures for the future.

LEI found that the industry as a whole has experienced a TFP trend of -1% over the 2002-2012 period. This time period was sufficiently long to obtain average trends, to address any data issues and to smooth any other environmental conditions that caused the year over year fluctuations in TFP index values. It was acknowledged, in response to a comment from a stakeholder, that if data previous to 2002 was used, or if certain US companies were used as comparators, the trend line may have been slightly different because of such changes. However, other TFP studies have found that about ten years is sufficient for reflecting the long term trend. In addition, it was noted that the variability in figures year on year is common for this industry, and that adding or removing a year would not impact the overall -1% TFP trend.

Negative TFP growth rate indicates that more inputs are required to maintain outputs over time. Although production capabilities should be stable across the life of the asset, OM&A costs may be expected to increase as one needs to spend more to maintain operating assets. These are long-lived assets and the industry peers specifically captured similar aged assets as those operated by OPG. In addition, the assets are designed to produce a target amount of energy (unlike network business that can expand to meet load growth from their customers). This sector has not seen any significant improvements in drivers of productivity, such as big scale technology-induced efficiencies in operations or economies of scale related to additional sales (given the design-based fixed nature of productive capability once an asset is installed).

A stakeholder inquired about the adjustments to the results, and LEI confirmed that there were no adjustments to the data per se, but adjustments were made by way of decisions taken with respect to the variables used and methodologies employed. It was noted that the swing in index values in 2006/2007 did not require adjustment.

Figures for 2013 are not included as the underlying data was not available at the time and were not an imperative for the study; Mr. Pugh explained that the effort and time required to gather the 2013 data. It is also not expected that adding 2013 data would not materially impact the results of the current study, as it would only add a twelfth data point to the existing eleven-year study period.

LEI explained that the study was not parametric or econometric; therefore, confidence intervals cannot be associated with these results. Differences in the results as observed in basis point differences should not be interpreted as indicating statistically significant differences. LEI conducted a regression of the TFP index values to further test the results, and specifically the choice of the start and end years of the study, and found that the results are unbiased, stable and reliable.

In regards to the index-based approach chosen, Ms. Frayer indicated that it was a well-established approach that the Board has relied on in previous studies for the purposes of rate making. Other options were considered, including the DEA analysis and stochastic frontier analysis, but for regulatory purposes, transparency and ease of implementation, the current method was chosen. There were also concerns that there would be insufficient data to complete the process using the other methods.

LEI used predefined criteria (comparable size, scale of operations, etc.) to distill an original list of 55 companies into a set of 16 appropriate comparables. LEI intended to include Canadian peers initially. However, Canadian peer data was not readily available for the time frames being studied, and many firms declined participation for a variety of reasons (i.e. they did not want to participate or they did not have the data). Sanity checks were completed to ensure that no particular firms were skewing results based on its unique circumstances over the study period; one firm was removed through this process. Firms were not excluded based on weather, geography or location, as it was determined through consultation with hydro operations that once a plant was designed and built, differences related to these factors would not be significant on the operational productivity of the plant, as the plant would be designed to fit within its environment.

The differences between centrally dispatched markets and those not centrally dispatched and the type of corporate ownership would also not affect the outcome of the TFP study. If the mix of asset types was different among peers, there would potentially be an impact if the study was looking at benchmarking efficiency related to cost and production levels, but such characteristics were not expected to affect the outcome of the TFP study, which was looking at trends over time in productivity rather than absolute efficiency levels. The age of the asset could also impact the results, and this was considered in the study – LEI looked at firms that had not recently built a large hydroelectric asset for comparability with respect to life cycle stage, showing similar productivity and growth rate spending. This is one of the reasons why the Niagara Tunnel was excluded (in addition, it was not operating during the study timeframe and therefore necessary historical data was not available for this project).

In terms of inputs and outputs, LEI explained that when choosing a monetary versus a physical approach for measuring capacity, MW ratings (in terms of physical-rated capabilities) were the best measure for the assets employed. If choosing a monetary approach, additional discussions about depreciation methods, etc., would be required. Capital input is not capital spending or expenditures, but is rather the physical quantity of capital employed by the business.

Regarding the question of input weights and how they are combined to create an input index, this process used actual data observed for input weights to estimate labour and non-labour components. An endogenous approach was used, as is common in TFP studies, to produce consistent results. Notably the weights did differ by year and across firms. There was some surprise that the industry aggregate capital weight was so high, but it was noted that this is normal for the industry.

In consideration of output measures, because OPG is expected to be remunerated under an I-X regime using MWh, LEI felt confident that this measure would be effective measures of output. And as noted in the December consultation, the study timeframe controlled for the year-on-year volatility in production.

A stakeholder stated that the study was well done given the limitations, but questioned the differences in productivity and efficiency that have occurred over the past 60 years, and how one can anticipate advances in our future. LEI indicated that we cannot expect a significant level of advancement to occur in the next five years for existing regulated hydro and thus it would be unnecessary to try and understand at this time how technology advancements may improve for example production at newer installations. Mario Mazza also commented on the fact that many large scale hydroelectric opportunities had been exhausted and therefore the opportunity for economies of scale efficiencies was limited.

AT THIS POINT, THE GROUP BROKE FOR A THIRTY (30) MINUTE LUNCH BREAK

6. Nuclear Operations and Projects – 2016-2020

Carla Carmichael, VP, Nuclear Finance at OPG provided a quick overview of OPG's nuclear operations and projects presentation from the previous session; see the "Nuclear Operations and Projects 2016-2020" presentation for details. Details of the study are available by accessing the presentation and note**s** from the previous session on the OPG website.

The Nuclear Strategic Framework illustrates the next 15 years of OPG's nuclear portfolio with respect to the Darlington and Pickering stations. The Framework shows the expected impact that upcoming work programs are going to have on generation and to inform future program design. OPG is embarking on a wide range of complex activities, all within a similar time frame, including Pickering shutdown in 2020, the refurbishment of four nuclear units at Darlington and planning for a deep geological repository. This Framework is filed with the OPG business plan to the OEB.

247K effective full power hours were originally used to plan against, which would have entailed some units shutting down before and after 2020. With the advent of a planning assumption of 261K, which occurred subsequent to last hearing, OPG now envisions that all units will go to the end of 2020; no early shutdowns or life management outages required.

Another important change occurred with the planned Darlington refurbishment outages. OPG's original plan was to overlap the first unit and second unit. Subsequent to discussions with shareholders, and looking at the associated risks to completing the first unit on schedule, a decision was made to unlap the first two units. Unlapping created concerns with unit sequencing, and required re-sequencing of which units to refurbish at what time.

OPG is confident it will be able to reach the end of the 2020 time frame for Pickering End of Commercial Operations. A wide range of work has been completed around fuel channel life management and life extension programs. With respect to Safe Store ONFA funding, analysis is being conducted to identify what costs would be covered under ONFA and what needs to be covered under OEB through application. A variety of costs will not be included under ONFA as it covers assets under the protected zone, and OPG has assets outside of this zone. Other costs such as severance, inventory and asset write-downs are being investigated. Post-2020 at Pickering there is also a lot of work required, including oversight and safety requirements that must be met until the fuel is taken out of the reactors and the bay, resulting in additional costs going beyond 2020.

The Clarington transformer station, which is expected to be in service in the fall of 2017, must be in service to enable Pickering shut down and to support grid stability. Around the same time, OPG will receive its final operating license and go to the Board of Directors for a decision on the final shutdown date. Shutdown approval will then be submitted to the CNSC, moving towards eventual decommissioning. A question was asked regarding costs associated with shutdown post 2020, and why there was not a plan to recover costs during Pickering's life of operation. Ms. Carmichael indicated that the ONFA fund is expected to cover most of these costs. Mr. Pugh added that a forecast has been developed, not just on ONFA, but also internally generated funds to address nuclear liabilities that are expected to be incurred in the period upon which rates are set.

With respect to production risks and opportunities, there are two key risks in nuclear planning: generation and costs. Operating nuclear stations creates exposure to a variety of risks that other generation types are not exposed to. Unique risks in the nuclear industry – such as with Fukushima – must also be taken into consideration during planning.

Additional factors such as aging of the units, and continuous testing of units and channels, may change assumptions of generation. For Darlington, the schedule could be modified as well as the lapping re-sequenced or unlapped entirely. Refurbishment of the first unit could be completed earlier or later than 2019 and the planned outage duration could be longer or shorter than expected. Unexpected conditions from first outage, such as equipment failures and obsolete components, may be identified and require incorporation in the subsequent refurbishment plans. There is also a risk at the end of the unit when it comes back online that there will be a higher than expected forced last rate. Base assumptions expect performance better than other refurbishments, although realities could differ.

With Pickering, a key risk is that the direction to shut down earlier than 2020 could be requested by stakeholders such as the Province. CNSC would still need to approve OPG's license based on OPG's ability to support a safe and reliable operation. Fuel channel life is the life limiting component of stations, and when OPG launched the fuel channel life program, it extended outages to do all required testing on the basis that the future generation from these units would be beneficial. However, there is a constant inspection process and things do sometimes come up which could change base planning assumptions.

A stakeholder raised a question comparing the vertical drop in generation associated with Pickering End of Commercial Operations with Darlington unit refurbishments which show changes in generation as a gradual slope. Ms. Carmichael advised that the Nuclear Strategic Framework is a pictorial illustrative slide designed to showcase all of the work that is happening, and the effect on generation.

Mr. Pugh clarified, with respect to Darlington refurbishment which starts in October 2016 for the first year, is not end of year. As such, there is a certain level of production up to October and then beyond. This graph considers revenue production by year and the associated graphing tool is designed to produce a smooth graph. The purpose of this table is illustrative, while the actual numbers will be reviewed by the OEB to set revenue requirement for the next five years, including a proposal for rate smoothing.

Ms. Carmichael highlighted additional generation planning cost risks and opportunities, with an emphasis on the higher forecast risks associated with the longer duration of the cost of service term. These concerns are particularly important in a non-steady state of operations. If there are changes in timing, OPG will not necessarily have all of the time required to mitigate those costs. Staffing levels, for example, must be considered by looking into the labour, resource and demand plan. There are also costs that are not covered by the ONFA fund, which may be expected to be covered, and these assumptions must be validated.

The impact of collective bargaining, attrition, and business transformation will also influence cost plans if any of those base assumptions change. The performance of contractors and suppliers also impacts cost. Finally, uncertainty with respect to pensions and other post-employment benefits, particularly with market changes, may impact assumptions and forecasts.

7. Initial Nuclear Multi-Year Cost of Service Regulation Plan Proposal

Within the context of Ms. Carmichael's industry overview, Mr. Pugh provided an overview of OPG's initial Nuclear Multi-Year Cost of Service Regulation Plan Proposal; see "Initial Nuclear Multi-year Cost of Service Regulation Plan Proposal" for details. OPG is trying to set rates for 2016-2020 and this initial proposal provides an opportunity to generate stakeholder feedback. The goal is to make an application in late Q2 or early Q3 2015. OPG has started long-term planning, and efforts are being conducted now to generate agreement on the methodology to guide efficient information gathering and support application development.

For 2016-2020 rate setting, a multi-year forecast test period application review will be used; similar to a two year cost of service review. OPG does not know the level of information that can be provided for the last three years, but they are looking into the level of detail that can be provided. Both distributor guidelines and OPG's current guidelines will inform OPG's filing requirements.

With the Annual Adjustment Mechanism in traditional custom IR, the OEB looks at the five year cost of service, layered with an efficiency factor as appropriate, and determines an annual revenue requirement for each of the five years. OPG is suggesting a modified approach, with the same revenue requirement review, similar to a two-year cost of service proposal, however OPG will also be proposing rate smoothing. OPG proposes that the OEB set an annual revenue requirement, an approved smoothed rate and approved production forecast. The OEB approved rate will be multiplied by the approved production forecast to generate a revenue forecast. The difference between the annual revenue requirement and annual forecast revenue will be captured in a deferral account. The deferral account will receive a carrying cost appropriate for the long-term nature of that account.

The Treatment of Unforeseen Events will apply the criteria of materiality, prudence and causation as described in the EB-2007-0673 Report of the Board.

OPG proposed that all OEB approved Deferral and Variance accounts will continue. These accounts will continue to record the difference in the annual revenue requirement approved by the OEB for that cost item and the actual cost. The revenue requirement for a particular item will become the benchmark for the deferral and variance account, and actual costs are recorded against the benchmark. There are three new Deferral and Variance accounts proposed, which include rate smoothing mid-term review, and Pickering End-of-Life to address factors that are unique to OPG's operating environment during the 2016-2020 period.

A mid-term review is being proposed in Q1 of 2018 to set rates in July 2018, where an application will be made to the OEB to forecast production and related fuel costs for the next 2.5 years. This application will be open to intervenors for comments and reviewed by the OEB for a decision regarding the production forecast. The difference between the updated production forecast multiplied by the smoothed rate and OPG's original forecast that underpins their revenue requirement multiplied by the smoothed rate will be recorded in the deferral account. The purpose of this account is to address the risk associated with a forecasting for a longer period than in historical applications.

For Performance Reporting and Monitoring, an approach similar to the RRFE and that proposed for hydro will be utilized. In addition, OPG service quality metrics for safety, reliability and project management will be incorporated and reviewed annually by the OEB and intervenors.

Similar to hydro, symmetric earnings sharing is being proposed. Due to increased volatility, the dead band would also increase to +/- 200 basis points. Situational off-ramps are also being proposed, such as those which may arise due to LTEP changes, which create fundamental planning challenges warranting a regulatory review.

The Nuclear Rate Smoothing Strategy is discussed, with the associated graph provided for illustrative purposes; OPG forecasts of cost over the Darlington refurbishment period are currently being developed. Rate smoothing over multiple rate setting periods is necessary to avoid price spikes during the Darlington Refurbishment period. The details of OPG forecasts and the smoothed rate will be considered in OPG's nuclear rate application. Costs that are not collected in rates and deferred, will include a carrying cost so there is no economic loss to the company.

A stakeholder inquired whether or not there is a production materiality threshold (i.e. MWh) that would trigger the mid-term review. Mr. Pugh indicated that it has not been determined, and materiality has always been considered a monetary as opposed to a production number, although it will be taken into account. Mr. Pugh added that one of the benefits of incentive regulation is to extract regulatory efficiencies, and to the extent that there is no material change as a result of production, this approach will be taken into consideration.

An additional question was asked regarding the expected rate smoothing period. Within the illustrative forecast, the large accumulation starts to reverse by 2024. After that time, the rate trajectory will be assessed, and the second term really depends on the size of the bucket of costs as well as the projected operating environment moving forward.

A stakeholder asked if the plan is to decide on the smoothing timeline in another application, not in the current application. Mr. Pugh noted that in this application, the OEB has to make a decision on smoothing.

It was asked whether any consideration was given to pre-loading a variance account to smooth rates due to the expected increase in costs. Mr. Pugh replied by outlining that for the first five years, rate smoothing allows you to incorporate most of the expectation variations. The next period where Darlington is in refurbishment and Pickering is shutdown, the unsmoothed rate begins to increase significantly.

Mr. Pugh suggested that the concept of rate smoothing reflects OPG’s requirements and will be included in a proposal. Consideration will also be given to variations in slope levels and trends during the planning process. The OPG has an expectation of smoothing, and the proposal will be consistent with the cost recovery proposal. If another option is considered optimal, the proposal can be prepared to help inform OPG’s planning efforts. The OEB will make a decision, incorporating stakeholder comments, to determine a specific smoothed rate and revenue requirement.

A stakeholder asked about the ‘Cost of service – Unconstrained Rate’ line as part of the Illustrative Nuclear Rate Forecast, which starts to increase once the first Darlington unit comes back to service. Mr. Pugh clarified that the primary driver behind the increase in rate is related to Pickering End of Commercial Operations.

Another question was asked regarding whether or not a rate increase could be expected following the first outage in 2016 when Darlington refurbishment starts due to generation reduction. It was clarified that the rates reflect the refurbishment plan. The costs incurred from 2016-2018 in refurbishment are capitalized and will be placed in service in 2019 when the unit comes back up. As a result, a large in-service amount for refurbishment arises in 2019.

A question was asked about why the OPG chose a five year term. Mr. Pugh mentioned that a lot of the plans approved by OEB commonly include similar terms. OPG’s goal is to make this application clear for the OEB to enable efficient resolution. As such, OPG will align its efforts with OEB’s traditional approach and gather stakeholder input to address the associated needs.

In addition, it was noted that OPG is not only a nuclear company, and includes many shared resources. One application on five years against another at three years would make it difficult to understand the broader picture for the OEB intervenors and ratepayers. This consideration supported the decision to choose a five year term, with the caveats that nuclear production requires unique factors to be included that reflect the nuclear operating environment. Mr. Pugh noted that a five year term will best facilitate review of common costs.

A stakeholder raised a concern regarding the five year term, due to the concerns associated with a large number of complex initiatives occurring during this time. Mr. Pugh highlighted that the five year term appeared to align with OPG's goals, and supported expediency as well as information gathering.

In regards to the deferral account, a stakeholder asked when OPG expects to start recording entries. Mr. Pugh noted that entries would be recorded every year.

Another stakeholder inquired about the Nuclear Strategic Framework, and asked if two things could impact estimates: costs in decommissioning and refurbishment, as well as the actual amount of generation during that time (i.e. costs rise or generation goes down).

Mr. Pugh highlighted that these are only forecasts, and that OEB decisions, the impact of business plans carried out over longer periods of time and a variety production assumptions based on updated information will be incorporated as it becomes available. It was confirmed that the drivers, numerator and denominator, are costs over generation. As those values change over time with OPG Pickering End of Life efforts and Darlington refurbishment, they drive the increase in costs in 2019. In addition, it was clarified that decommissioning costs will occur at a later stage, currently only safe storage and plant shut down costs are included.

An additional question was asked to define post-refurbishment forced loss rate risk. It was noted that, for units which have come back from refurbishment outages as well as return to service units such as Bruce and Pickering station, a significant increase in forced loss rates with the units is experienced. This experience will be reflected in OPG's forecast, as it is a big risk from an operating expenditure perspective that is commonly seen in refurbishment outages.

8. Closing Remarks

Mr. Pugh gathered feedback on the session format and advised that all relevant materials and notes will be posted to OPG's website. In addition, a letter will also be sent out to participants providing guidance on questions that may arise following the session, to voice concerns and clarify outstanding details. OPG is planning another information session in approximately four weeks, based on availability, to generate dialogue on the proposals discussed.

All presentations used at this Stakeholder Consultation are posted on the OPG Regulatory Affairs website at:

http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx

Any post session questions or comments from stakeholders should be directed to OPG's Regulatory Affairs email address at:

opgregaffairs@opg.com

9. Session Agenda

AGENDA

Information Session
January 22, 2015

Main Auditorium – 700 University Avenue, Toronto, ON

8:30 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:15 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:15 a.m. – 10:30 a.m.	- OPG's Initial Incentive Rate-making Proposal for Hydroelectric Operations
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 11:15 a.m.	- Hydroelectric Inflation Factor Assessment / Questions and Discussion
11:15 a.m. – 12:00 p.m.	- Hydroelectric TFP Study Report / Questions and Discussion
12:00 p.m. – 12:45 p.m.	- Lunch
12:45 p.m. – 2:00 p.m.	- OPG's Initial Multi-year Cost of Service Proposal for Nuclear Operations
2:00 p.m. – 2:15 p.m.	- Closing Remarks

10. Attendee List

INVITATIONS	
ORGANIZATION	**STAKEHOLDER**
AMPCO	Hamza Mortage
Canadian Manufacturers and Exporters	Emma Blanchard (by teleconference)
Enbridge Gas Distribution Inc.	Hulya Sayyan
Energy Probe	David MacIntosh Norm Rubin Dr. Larry Schwartz
Hydro One Networks Inc.	Jim Malenfant
IESO	Paula Lukan
Ministry of Energy	Raynier Ramasra
Ontario Energy Board	Violet Binette
Power Worker's Union	Alfredo Bertolotti
School Energy Coalition	Mark Rubenstein
Society of Energy Professionals	Joseph (Joe) Fierro Alex Saba
Ontario Power Generation	Deborah Alexson-Curley (a.m.) Colin Anderson (full day) David Barr (a.m.) Hamant Becharbhai (p.m.) Tom Bergen (full day) Mike Bilaniuk (full day) Carla Carmichael (p.m.) Lucy D'Avella (full day) Bryan Icyk (full day) Mike Jessop (full day) Alex Kogan (full day) Tom Ladanyi (full day) May Laureta Lapira (full day) John Mauti (p.m.) Mario Mazza (a.m.) Faye McDermid (full day) Sheila O'Neill (full day) Randy Pugh (full day)

	Sarbinder Singh (a.m.) Greg Towstego (p.m.)
London Economics International LLC	Ian Chow (a.m.) Julia Frayer (a.m.)
OPTIMUS | SBR	Steve Klein Sequin Martel Andrea Spencer