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Our File No.: 05497-0226-0000

June 12, 2014

BY EMAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

**Attention: Erica M. Hamilton,
Commission Secretary**

Dear Sirs/Mesdames:

Re: FortisBC Inc. – Application for Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Enclosed please find the Reply Submission of FortisBC Inc. (**FBC**) dated June 12, 2014, with respect to the Non-PBR methodology portions of the above-noted matter. Sixteen hard copies will follow by courier. Please also find attached one legal authority, which is referenced in the Final Submission.

The enclosed Reply Submission is one of three Reply Submissions being filed contemporaneously by FBC and FortisBC Energy Inc. (**FEI**). In addition to this Final Submission, FBC and FEI will be filing a separate Joint Reply Submission on PBR Rate Design and FEI is filing a separate Reply Submission on Non-PBR methodology.

Yours truly,

FARRIS, VAUGHAN, WILLS & MURPHY LLP

Per: LB Herbst

Ludmila B. Herbst

LBH/ECM
Enclosure
c.c.: Registered Interveners
Boughton Law Corporation – Attention: Paul R. Miller
FortisBC Inc. – Attention: Dennis Swanson

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF
the *Utilities Commission Act*, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc. Application for
Performance Based Ratemaking Revenue Requirements 2014-2018

REPLY SUBMISSIONS OF FORTISBC INC. ON NON-PBR METHODOLOGY June 12, 2014

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PART 1 - INTRODUCTION

1. FortisBC Inc. (**FBC** or the **Company**) sets out below its reply to the submissions of the various Interveners delivered on May 22, 2014. This submission (the **FBC Non-PBR Reply**) is organized in accordance with the framework set out in FBC's main submission on Non-PBR issues, dated April 25, 2014 (the **FBC Non-PBR Submission**). Capitalized terms used herein are as defined in the FBC Non-PBR Submission.

2. Generally, where Interveners have either accepted or not expressed opposition to elements of the FBC Non-PBR Submission, or where FBC's response is fully set out in the FBC Non-PBR Submission, those elements are not addressed herein.

3. As with the FBC Non-PBR Submission, the FBC Non-PBR Reply addresses aspects of the Application other than the methodology of the PBR Plan. FBC's reply with respect to the methodology of the PBR Plan is addressed in a separate submission (the **PBR Reply**) that is being filed as a joint submission by FBC and FEI. The FBC Non-PBR Reply should be read in conjunction with the PBR Reply.

PART 2 - 2014 REVENUE REQUIREMENTS

A. <u>O&M Expenses</u>

(1) The Determination of 2013 Base O&M

(a) 2013 Approved O&M

4. The British Columbia Pensioners' and Seniors' Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC and Tenant Resource and Advisory Centre (**BCPSO**) submits in its Final (FBC-related) Submission on Non-PBR Issues

(the **BCPSO FBC Non-PBR Submission**) that using 2013 Approved O&M as the starting point for the determination of 2013 Base O&M "is reasonable in this case".[1] FBC agrees with this statement, for the reasons set out in the FBC Non-PBR Submission.[2]

5. However, BCPSO continues to suggest that a "perhaps preferable" approach would be to use the actual O&M expense for 2013 (**2013 Actual O&M**) as the starting point for 2013 Base O&M.[3]

6. Similarly, in the CEC Final Submission on FBC Non-PBR Base O&M (the **CEC FBC Non-PBR O&M Submission**), CEC questions the use of 2013 Approved O&M as the starting point for the determination of 2013 Base O&M,[4] at least with respect to certain O&M departments.[5] In contrast to BCPSO, CEC suggests that it is the 2012 actual O&M expense (**2012 Actual O&M**) that should be given "considerable attention" when developing 2013 Base O&M.[6]

7. FBC disagrees with using either 2012 Actual O&M or 2013 Actual O&M as the starting point for determining 2013 Base O&M, for the reasons set out below and confirms that only the use of 2013 Approved O&M would be appropriate.

8. In determining the preferable starting point for 2013 Base O&M, it was important to the Company to begin with a figure that had been <u>approved</u> by the Commission, by way of a recent and thorough regulatory process.[7] This approach was not only successfully used by the Company for the 2007 PBR

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1 BCPSO Final Submission on Non-PBR Issues (**BCPSO FBC Non-PBR Submission**), s. 1.1.

2 FBC Non-PBR Submission, para. 19 and Part 2(D)(1)(a).

3 BCPSO FBC Non-PBR Submission, s. 1.1.

4 CEC Final Submission on FBC Non-PBR Base O&M (**CEC FBC Non-PBR O&M Submission**), para. 12.

5 For example, with respect to the Operations Department, CEC looks to 2012 Actual O&M (CEC FBC Non-PBR O&M Submission, para. 60), but does not reference 2012 Actual O&M with respect to the Communications and External Relations Department (CEC FBC Non-PBR O&M Submission, para. 77).

6 CEC FBC Non-PBR O&M Submission, para. 18.

7 Exhibit B-1 – FBC Application, p. 51.

Plan,[8] but it was also endorsed by FBC's expert, B&V, as reasonable.[9] With this approach in mind, the Company looked to the most recently Commission approved figure for O&M expenses, which was set out in the 2012-13 RRA Decision for the year 2013. The suggestions of BCPSO and CEC to look to 2012 Actual O&M and 2013 Actual O&M are inconsistent with the approach of starting with an approved figure.

9. While CEC critiques the use of 2013 Approved O&M on the basis that it "was not approved by the Commission with the intention that it would be used as the basis of a subsequent PBR process",[10] this does not alter the fact that 2013 Approved O&M represents the most recent Commission approved O&M figure for the Company, or the fact that the figure was determined following a thorough regulatory process.

10. Ultimately, CEC misconstrues the use of 2013 Approved O&M and the concern it raises is irrelevant. 2013 Approved O&M is never used as "the basis of a subsequent PBR process",[11] but rather it is only ever used as a Commission approved O&M figure that represents an appropriate <u>starting point</u> for determining 2013 Base O&M. The Company has not proposed that 2013 Approved O&M itself is the appropriate figure to incorporate into the PBR formula, but it has instead adjusted the figure to reach an appropriate 2013 Base O&M. These adjustments, and the resulting 2013 Base O&M, are being scrutinized as a part of this regulatory process.

11. Further, while CEC implies that a different 2013 Approved O&M would have been approved by the Commission if the PBR Plan had been contemplated at the time of the 2012-13 RRA Decision,[12] it has not provided any evidence to

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[8] Ibid.

[9] Ibid.

[10] CEC FBC Non-PBR O&M Submission, para. 13.

[11] Ibid.

[12] Ibid.

support this suggestion. Further, it has not provided any evidence as to how the 2013 Approved O&M would have varied.

12. The Company does not suggest that 2013 Base O&M has somehow already been approved by the Commission. Rather, it is in this proceeding that FBC seeks to have the Commission approve 2013 Base O&M, with 2013 Approved O&M being the appropriate starting point for this determination, for all the reasons it has set out in the FBC Non-PBR Submission and this FBC Non-PBR Reply.[13]

13. As further justification for reliance on 2012 Actual O&M, CEC states that it was closely in line with 2011 actual O&M expenses (**2011 Actual O&M**), as well as the projected expenses for 2013 (**2013 Projected O&M**), when these figures are each analyzed on the basis of a per customer O&M cost.[14] However, this analysis ignores the reason why 2012 Actual O&M was lower than both 2012 Approved O&M and 2013 Approved O&M and is not sustainable in future years. The lower level of 2012 Actual O&M arose as a result of the timing of the release of the 2012-13 RRA Decision in August 2012. With respect to certain of the expenses proposed in the 2012-13 RRA, the Company postponed spending the funds while it awaited the Commission's decision on whether the expenses would be approved. As the 2012-13 RRA Decision was released three-quarters of the way through 2012, certain expenses that were planned for 2012 (and thus included in 2012 Approved O&M) were not incurred. This resulted in a lower level of spending in 2012, though these "savings" incorporated in 2012 Actual O&M do not represent a sustainable reduction in expenditures.[15]

14. While CEC acknowledges FBC's statement that the unspent 2012 O&M was required in 2013 and will be required in future years,[16] it ignores the effect of

[13] See FBC Non-PBR Submission, Part 2(D)(1).
[14] CEC FBC Non-PBR O&M Submission, para.16-17.
[15] Exhibit B-7 - FBC Response to BCUC IR 1.98.3.
[16] CEC FBC Non-PBR O&M Submission, para. 14.

that statement by suggesting that 2012 Actual O&M represents the "most accurate" representation of FBC's business.[17]

15. Unlike 2012 Actual O&M, 2013 Projected O&M was not affected by the timing of the 2012-13 RRA Decision, as it was not increased to incorporate the expenses planned for 2012.[18] However, there are also several issues with the use of 2013 Actual O&M. One is that it is not a figure that has been considered through this regulatory process; this figure is not on the record in this proceeding. Further, while BCPSO submits that it is "perhaps preferable" to use 2013 Actual O&M,[19] this would not be a simple change to make. As 2013 Base O&M is determined through making several adjustments to 2013 Approved O&M, 2013 Actual O&M could not simply be substituted for 2013 Approved O&M. Instead, each of the proposed adjustments would need to be re-analyzed and modified for 2013 Actual O&M to be used as the starting point.

16. In any event, such a substitution of 2013 Actual O&M is completely unnecessary, as FBC has already made a "sustainable savings" adjustment to 2013 Approved O&M. This has a similar effect of updating key information to account for the Company's actual experience during 2013.[20] Given all the above, the Company disagrees that 2013 Actual O&M would represent a better starting point than 2013 Approved O&M, and again emphasizes BCPSO's submission that starting with 2013 Approved O&M is "reasonable".[21]

17. In all of these circumstances, FBC reaffirms its submission that 2013 Approved O&M is the appropriate starting point for determining 2013 Base O&M.

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17 Ibid, para. 18.
18 Exhibit B-7 - FBC Response to BCUC IR 1.101.2.
19 BCPSO FBC Non-PBR Submission, s. 1.1.
20 Exhibit B-11 – FBC Response to BCPSO IR 1.36.1.
21 BCPSO FBC Non-PBR Submission, s. 1.1.

(b) Adjustments to Approved O&M

18. As was described in the FBC Non-PBR Submission, three types of adjustments were made to 2013 Approved O&M to arrive at 2013 Base O&M: an adjustment to represent net sustainable savings, a re-basing adjustment and an adjustment representing incremental O&M.[22]

19. Two of the Interveners, CEC and BCPSO, have raised concerns with certain of the adjustments proposed by FBC. Further, CEC has suggested that several additional adjustments should be made, particularly with respect to the net sustainable savings adjustment. FBC believes that the adjustments proposed in its Application are appropriate to convert 2013 Approved O&M to 2013 Base O&M. This section of the FBC Non-PBR Reply deals with the concerns expressed by CEC and BCPSO.

(i) <u>Net Sustainable Savings Adjustment</u>

20. As was set out in the FBC Non-PBR Submission, the net sustainable savings adjustment accounts for $452,000 in net cost reductions over the 2013 Approved O&M amount.[23] Additionally, each of the savings and costs that make up the net savings are expected to be <u>sustainable</u> in future years.[24] These net sustainable savings were realized across various different departments at FBC, with certain departments incurring incremental costs over the 2013 Approved O&M and other departments realizing savings over the 2013 Approved O&M. These departmental savings and costs were combined to arrive at the aggregate, net adjustment of $452,000 in savings.[25]

21. Both BCPSO and CEC suggest that certain of the costs incorporated by FBC into the net sustainable savings adjustment should be removed, with CEC also

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[22] FBC Non-PBR Submission, para. 29. See Part 2(D)(1)(b) of the FBC Non-PBR Submission for a discussion of the adjustments.

[23] FBC Non-PBR Submission, para. 31.

[24] Exhibit B-1 – FBC Application, p. 51.

[25] See Ex. B-1 – FBC Application, Table C4-2, p. 113 for the Productivity (Sustainable Savings) adjustment breakdown by Department.

proposing that some additional savings should be incorporated into the adjustment.

22. In total, BCPSO submits that a sustainable savings adjustment of $587,000 should be made, rather than the adjustment of $452,000 sought by FBC. BCSPO states that "the explainable variances represented a reduction in O&M of $587 k while increases totalling $135 M [*sic*] across the various Departments were attributed to "No Specific Activity".[26] It is unclear to FBC how BCPSO calculated the $587,000 and $135,000 figures incorporated into its proposal. The referenced IR lists $107,000 of the adjustment as being attributable to "no specific activity", and ($559,000) as being attributable to specific activities.[27] FBC has assumed that BCPSO has made a calculation error, and that it is suggesting that the sustainable savings adjustment proposed by FBC be modified from $452,000 to $559,000 (rather than the $587,000 it states). In any event, as is returned to below, FBC disagrees with BCPSO's recommended sustainable savings adjustment, whether it is $559,000 or $587,000.

23. In the CEC FBC Non-PBR O&M Submission, CEC also addresses the sustainable savings adjustment, recommending that the following portions of the adjustment be removed:

a. Generation Department: $64,000;[28]

b. Operations Department: $122,000;[29]

c. Information Technology (**IT**) Department: $14,000;[30] and

d. Engineering Services and Project Management (**ES&PM**) Department: $31,000.[31]

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26 BCPSO FBC Non-PBR Submission, section 1.1.
27 Exhibit B-7 – FBC Response to BCUC IR 1.96.2.
28 CEC Non-PBR O&M Submission, para. 34.
29 Ibid, para. 53.
30 Ibid, para. 87.
31 Ibid, para. 98.

24. With respect to the Generation Department, under item (a) above, CEC suggests that the $64,000 adjustment for sustainable costs proposed by FBC be removed.[32] It states that this removal is appropriate as "FBC has provided two differing explanations for this cost overrun", specifically that the Company attributed the adjustment to additional crane inspections, maintenance and documentation required by WorkSafeBC in its Application, but to legislative dam safety requirements in an IR response.[33] CEC further argues that the WorkSafeBC requirements have not been confirmed to be recurring, and that thus the expense should be excluded from the sustainable savings adjustment.[34]

25. These arguments are incorrect for two reasons. First, the Company has not provided inconsistent explanations for the adjustment related to the Generation Department, and second, the identified reason is expected to be recurring.

26. In its Application, the Company indicates that its 2013 Projected O&M for Generation is estimated to be slightly higher than 2013 Approved O&M for Generation, due to additional WorkSafeBC crane requirements.[35] However, the Application also references legislative changes, such as the dam safety regulations which increased the frequency of dam safety reviews in its Application as a reason for increased expenses.[36] While each of these activities caused additional expenses for the Company in 2013, when FBC was asked to provide a breakdown of the activities resulting in the sustainable savings adjustment, it was the second change ("increased efforts to meet legislative dam safety requirements") that is described by the Company as being the <u>sustainable activity</u> that resulted in the additional expenses beyond

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[32] Ibid, para. 34.
[33] Ibid, para. 32.
[34] Ibid, para. 34.
[35] Exhibit B-1 – FBC Application, p. 124.
[36] Ibid, p. 123.

2013 Approved O&M.[37] Accordingly, the Company has consistently provided that the adjustment was made to account for legislative changes made in 2013.

27. As the Company considers the cost of new legislative dam safety requirements to continue into the future (which is described further in Part 2(A)(2)(b) below), the $64,000 sustainable cost included in the sustainable savings adjustment for the Generation Department is appropriate and should be incorporated in 2013 Base O&M.

28. In addition to CEC's submission on the Generation Department, both BCPSO and CEC submit that the full sustainable savings adjustment should not be made for the Operations Department, the IT Department and the ES&PM Department, on the basis that FBC has not explained or justified these numbers.[38] FBC disagrees with this reduction, and submits that the net sustainable savings adjustment should remain at $452,000 for the following reasons.

29. Ultimately, each of the incremental savings and costs incorporated into the net sustainable savings adjustment is considered by the Company to be sustainable going forward, regardless of whether or not it may be attributed to one single item. As all of the savings and costs are expected to continue to be realized during the PBR Term, they are appropriately embedded into 2013 Base O&M.[39]

30. Further, one of the fundamental premises of the PBR Plan is that annual O&M expenses are to be determined on an <u>aggregate level</u> across all departments, by applying the PBR formula to 2013 Base O&M. 2013 Base O&M needs to reflect a reasonable starting point, in the aggregate, for the PBR formula.[40]

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[37] Exhibit B-7 – FBC Response to BCUC IR 1.96.2.

[38] BCPSO FBC Non-PBR Submission, section 1.1; CEC Non-PBR O&M Submission, paras. 53, 87 and 95.

[39] Exhibit B-24 – FBC Response to BCUC IR 2.10.1.

[40] Exhibit B-7 – FBC Response to BCUC IR 1.98.1; Ex. B-24 – FBC Response to BCUC IR 2.21.1.

31. By embedding the $452,000 net sustainable savings adjustment in 2013 Base O&M, the Company has committed to sustaining these savings over the PBR Term.[41] However, if the adjustment is increased beyond the required level for 2013, as has been proposed by CEC and BCPSO, 2013 Base O&M will be artificially too low and will no longer reflect a reasonable starting point. Instead, it will impede the Company's ability to earn a fair return.

32. Further, CEC is inconsistent in its position, in that it suggests that FBC should not be allowed to make an adjustment for the sustainable <u>costs</u> that are not directly attributable to a certain activity, but that it should continue to embed all proposed sustainable <u>savings</u> into 2013 Base O&M, even where they are not directly attributable to an activity. CEC's position in this regard is evident from the fact that it has not recommended removal of the net sustainable savings adjustments made for the Customer Service Department[42] or Communications and External Relations Department,[43] even though these items were described by FBC as resulting from "no specific activity".[44]

33. By incorporating those portions of the net sustainable savings adjustment that reduce 2013 Base O&M while simultaneously seeking to exclude those portions that increase it, CEC is attempting to accept what it likes while rejecting what it dislikes. This approach is both inconsistent and illogical. The purpose of the net sustainable savings adjustment is to recognize all sustainable changes from 2013 Approved O&M, whether they are a saving or a cost. While the Company agrees with CEC that it is appropriate for the sustainable savings recognized by the Customer Service Department and Communications and External Relations Department to be incorporated in the adjustment, it disagrees with CEC's suggestion that the corresponding sustainable costs in the Operations, IT and ES&PM Departments should be excluded. For the reasons set out above, the

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[41] Exhibit B-24 – FBC Response to BCUC IR 2.10.1.

[42] CEC Non-PBR O&M Submission, para. 68-69.

[43] Ibid, para. 75.

[44] Exhibit B-7 – FBC Response to BCUC IR 1.96.2.

Company submits that the full net sustainable savings adjustment of $452,000 should be made in determining 2013 Base O&M.

34. In addition to recommending that certain sustainable costs be excluded from the net sustainable savings adjustment, CEC has also recommended that the adjustment be increased to account for additional savings in the following departments:

a. Generation Department: Add a sustainable savings adjustment of $49,000 (in addition to removing FBC's proposed sustainable costs of $64,000, as was discussed above), to "acknowledge that the non-routine 2013 O&M approved amount is projected to be underspent";[45]

b. Operations Department: Add a sustainable savings adjustment of $190,000 (in addition to removing FBC's proposed sustainable costs of $122,000, as was discussed above), as "the Operations Department under spent the 2012 approved O&M budget by $190 thousand, or 1%";[46]

c. Customer Service Department: Increase the sustainable savings adjustment by $152,000 (from the $31,000 proposed by FBC, to $183,000), to bring the total cost per customer to the amount "originally provisioned in the 2013 Approved amount";[47]

d. Environmental, Health and Safety (**EH&S**) Department: Add a sustainable savings adjustment of $31,000 to compensate for short term changes to non-labour and temporary labour adjustments included in the 2013 projection;[48] and

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45 CEC Non-PBR O&M Submission, para. 46.
46 Ibid, para. 55, 61.
47 Ibid, para. 69.
48 Ibid, para. 115.

e. <u>Finance and Regulatory (**F&R**) Department:</u> Increase the sustainable savings adjustment by $100,000 (from the $191,000 proposed by FBC to $291,000) to "more realistically represent staffing levels identified as required".[49]

35. Much like declining to incorporate costs that will be sustainable in future years, adding additional savings that are <u>not sustainable</u> will result in a 2013 Base O&M that is artificially low and does not reflect an appropriate starting point for the Company's O&M calculations. The additional adjustments recommended by CEC do not represent sustainable savings. Further, in some instances CEC's proposed adjustments do not represent savings at all, and are merely an attempt to reduce the Company's O&M costs, without any basis.[50] Accordingly, CEC's proposed increases should not be incorporated into the sustainable savings adjustment or into 2013 Base O&M.

36. With respect to the Generation Department, CEC proposes that the sustainable savings adjustment be increased to reflect the fact that FBC was projected to underspend with respect to non-routine O&M when compared to the 2013 O&M approved amount for non-routine work.

37. While this type of O&M work is classified as "non-routine", it is only non-routine to the extent that the frequency is not pre-set but rather is a function of equipment age and condition. When the net effect of varying types of work, occurring at different frequencies, on various projects and types of equipment are considered together, the result is more "routine" than may be expected from the term "non-routine". The annual value included for these activities in the 2013 Base O&M represents an averaged value over a long-term period of time.[51] As is acknowledged by CEC, "the projected reduction in non-routine

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[49] Ibid, para. 128.

[50] For example, with respect to CEC's proposal to increase the sustainable savings adjustment for the Finance and Regulatory Department, which is discussed in more detail below.

[51] Exhibit B-7 – FBC Response to BCUC IR 1.113.1.1.

work is be [sic] based on known factors".[52] Overall, while expenses incurred in any given year with respect to this "non-routine" work may vary, they are averaged over time and the figure included in 2013 Base O&M represents an appropriate levelized annual value. [53]

38. As has been previously described, it is the aggregate level of O&M expenses that is important,[54] rather than individual department expenses. Reducing the amount included in 2013 Base O&M for the Generation Department based on one year of lower projected expenditures would inappropriately skew the net effect of the levelized expenditures for these "non-routine" activities.

39. CEC makes a similar argument with respect to FBC's Operations Department, recommending that an additional savings adjustment of $190,000 be made to represent that the amount approved for O&M in 2012 was underspent by 1%.[55] For the reasons discussed above, this adjustment does not represent a sustainable savings and should not be incorporated into 2013 Base O&M.

40. As was described above in Part 2(A)(1)(a), as well as in Part 2(D)(1)(a) of the FBC Non-PBR Submission, FBC submits that the Commission should determine 2013 Base O&M from 2013 Approved O&M and not by reference to variances between 2012 Approved O&M and 2012 Actual O&M. While CEC argues that FBC's underspending of 2012 Approved O&M should be embedded into 2013 Base O&M, this unspent O&M was the result of uncertainty while awaiting the 2012-13 RRA Decision. It does not represent savings that will continue into the future, and should not be embedded into 2013 Base O&M.[56]

41. CEC attempts to refute the Company's explanation for the lower 2012 Actual O&M by pointing to the fact that 2012 Actual O&M was higher than 2011 Actual O&M. While this is correct, it does not change the fact that 2012 Actual O&M

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[52] CEC Non-PBR O&M Submission, para. 47.
[53] Exhibit B-7 – FBC Response to BCUC IR 1.113.1.1.
[54] Exhibit B-7 – FBC Response to BCUC IR 1.98.1.
[55] CEC Non-PBR O&M Submission, para. 55, 62.
[56] Exhibit B-7 - FBC Response to BCUC IR 1.98.3.

spending would have been even higher, but for the delays which occurred while waiting for the 2012-13 RRA Decision, and that it is incorrect for CEC to assume that this lower spending is sustainable. There have been a number of factors, including labour cost increases, increased costs to enhance the PLT apprenticeship program to attract and retain sufficient PLTs, increased substation maintenance expenditures and increased vegetation management costs that have driven an increase in O&M costs in recent years.[57]

42. The Company submits that the Commission should reject CEC's argument to add additional savings to the net sustainable savings adjustment for the Operations Department, as it is not appropriate to make this adjustment to 2013 Base O&M based on variances in 2012.

43. With respect to the Customer Service Department, CEC submits that the sustainable savings adjustment should be increased from $31,000 to $183,000.[58] To justify this change, CEC notes that the total number of customers for 2013 is projected to be lower than was anticipated when determining 2013 Approved O&M, and that O&M should also be reduced to keep the projected cost per customer in line with the amount "originally provisioned in the 2013 Approved amount".[59]

44. While the number of customers in 2013 was lower than initially projected, the costs for the Customer Service Department did not decline commensurately. For example, the call volumes actually experienced for the Customer Service Department were higher than anticipated for 2012 and 2013, increasing one of the main drivers for costs in the department: labour.[60] These increased call volumes have related to the RCR, increased bill estimates due to the labour disruption and several large outages.[61] Call volumes are further expected to

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57 Exhibit B.7 – FBC Response to BCUC IR 1.115.3.

58 CEC Non-PBR O&M Submission, para. 69.

59 Ibid, para. 69.

60 Exhibit B-1 – FBC Application, p. 129; Ex. B.7 – FBC Response to BCUC IR 1.118.2.

61 Exhibit B.7 – FBC Response to BCUC IR 1.118.2.

increase during the PBR Term.[62] Accordingly, given the increased per-customer costs incurred in Customer Service, it would be inappropriate to artificially adjust 2013 Base O&M in an attempt to keep the Customer Service O&M per customer at the 2013 Approved level.

45. CEC also suggests an adjustment to the O&M for the EH&S Department, to account for the fact that 2012 Actual O&M incorporated a short-term increase due to making an application for a Certificate of Recognition recognized by WorkSafeBC.[63] As 2013 Base O&M is based on 2013 Approved O&M, it is a flaw in logic for CEC to adjust 2013 Approved O&M on this basis.

46. Finally, CEC recommends an additional sustainable saving adjustment of $100,000 to the F&R Department.[64] Again, this adjustment is based on a consideration of the difference between 2012 Approved O&M and 2012 Actual O&M for the F&R Department. As FBC's proposed sustainable savings adjustment is based on savings found in 2013, not 2012, it would be inappropriate to make this adjustment.

47. Further, CEC's calculation of the dollar amount attributable to the remaining 2012 vacant positions in the F&R Department is incorrect and, as such, CEC's basis for suggesting a reduction in 2013 Base O&M is misinformed. The following explanations and clarifications have been added to the reconciliation provided in the CEC Non-PBR O&M Submission[65] as follows:

Finance dept[(a)]	($000s)	positions
2012 Labour Underspent[(b)]	465	3.5
less:		
Transferred to IT department[(c)]	84	1.0
Position not Filled[(d)]	124	1.0
Attributed to Remaining Vacant Positions[(e)]	257	1.5

62 Exhibit B-1 – FBC Application, p. 130.
63 CEC Non-PBR O&M Submission, para. 114.
64 Ibid, para. 128.
65 Ibid, para. 127.

48. The Company responds as follows to the various headings in this table, based on explanations and principles previously provided as part of FBC's evidence:

a. CEC has incorrectly stated that the labour amounts attributable to the Finance vacant positions are excessive; this criticism has failed to acknowledge that when comparing the variances between the Actual, Approved and Projected amounts, all such labour expenses include a general benefit loading rate applied to the base salary expenses. This general benefit loading rate is applied to all employees and includes pension and OPEB expenses, short-term incentives and other benefits.[66]

b. The $465,000 variance between the 2012 Approved O&M and 2012 Actual O&M for Finance labour is representative of the base salaries plus general benefit loadings attributable to 2.5 vacant positions and the reallocation of one position to the IT Department.[67]

c. In the CEC FBC Non-PBR Capital Submission, it states that the allocation from the Finance department to the IT Department is valued at $84,000.[68] However the $84,000 ignores the application of general benefit loadings and therefore the fully loaded salary transferred from the F&R department to the IT department is actually higher than $84,000.

d. Due to the challenges in recruiting candidates with the relevant financial skills and experience to address the increasing financial complexities arising from accounting guidance and regulatory requirements, the Finance department was left with a vacant position, representative of a fully loaded salary, during 2012. After reviewing the resources available to meet the evolving business requirements, it was determined that the

[66] Exhibit B-7 – FBC Response to BCUC IR 1.105.1 and 1.144.7.
[67] Exhibit B-7 – FBC Response to BCUC IR 1.134.2.
[68] CEC Non-PBR O&M Submission, para. 126.

vacancy was not sustainable over the long-term and the F&R Department was successful in recruiting for one of the 2012 vacant positions during 2013.[69]

e. CEC has incorrectly represented that $257,000 should be attributed to 1.5 vacant positions in 2012. The fully loaded labour transfer from the F&R Department to the IT Department is actually higher than what was included in CEC's table and as such, the remaining fully loaded labour should be less than $257,000 attributable to 1.5 vacant positions. Half of a position was attributable, not to a specific position, but rather to the turnover in various positions in 2012 and the time lag to fill those positions.[70] The decrease in fully loaded labour resulting from turnover and time lag occurred only during 2012 and therefore was appropriately excluded from the 2013 Projected O&M labour costs. The remaining fully loaded vacant position was not filled in 2012 and in 2013 it was determined that this one full time position vacancy was an efficiency savings that could be included in the 2013 Base O&M and carried over into the PBR term.[71]

49. Accordingly, if an appropriate calculation were completed (comparing all fully loaded amounts), the amount attributed to the remaining 1.5 vacancies would be lower, and would be an appropriate figure to attribute to the fully loaded labour cost of 1.5 employees. It is not appropriate to reduce 2013 Base O&M on account of a temporary decrease in labour for one year, especially when this decrease occurred as a result of recruitment challenges and re-evaluating whether all of those vacancies would need to be filled over the long-term while meeting FBC's business requirements. Instead it should be acknowledged that the FBC F&R Department has found long-term efficiencies resulting in the elimination of a position and that those avoided costs have been embedded in

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69 Exhibit B-1 – FBC Application, p. 159; Ex. B-7 – FBC Response to BCUC IR 1.134.2.

70 Exhibit B-7 – FBC Response to BCUC IR 1.135.4

71 Exhibit B-7 – FBC Response to BCUC IR 1.134.2.

2013 Base O&M, through the $191,000 sustainable savings Finance O&M adjustment proposed by FBC, over the PBR Term.

50. The Commission should reject CEC's proposal that an additional $100,000 be deducted from 2013 Base O&M, and should instead adopt the $191,000 sustainable saving adjustment for the to F&R Department proposed by FBC.

51. Overall, CEC has proposed its modifications to the sustainable savings adjustment by "cherry-picking". For example, it recommends making adjustments to the 2013 Approved O&M for only certain departments on the basis of variances between 2012 Approved O&M and 2012 Actual O&M, but does not make similar recommendations for other departments. For some departments, it looks to achieving consistent O&M costs per customer, while this is ignored for other departments. Similarly, it seeks to exclude sustainable costs that are not precisely attributed to a certain activity, while submitting it is appropriate to include similar sustainable savings. The Company submits that the rationale for CEC's proposed adjustments is flawed.

52. CEC's piecemeal approach is also clear when its proposed adjustments for FBC O&M departments are compared with the adjustments proposed for FEI. There is no overriding logic behind CEC's proposals, and they are clearly aimed at reducing 2013 Base O&M through any means. The Company submits that CEC's proposed modifications to the net sustainable savings adjustment should be rejected by the Commission in its determination of 2013 Base O&M.

(ii) Re-Basing Adjustments

53. In additional to the 2013 sustainable savings adjustment, FBC made three "re-basing" adjustments to 2013 Approved O&M to account for non-controllable expenses related to the MRS program, PST and pension and OPEB expense.[72]

[72] Exhibit B-1 – FBC Application, p. 52.

54. The only Intervener to comment on the re-basing adjustments in its Final Submission was BCPSO, which submitted that the re-basing adjustment was reasonable.[73]

(iii) Incremental O&M

55. The final adjustment made to 2013 Approved O&M accounts for incremental changes to O&M that occurred in 2013. Specifically, these adjustments relate to the lease payment for the Trail office and recurring expenses related to maintaining FBC's generating units.[74]

56. BCPSO submitted that both of these incremental O&M adjustments are reasonable.[75] CEC submitted that the expenses related to the generating units were not appropriate, as is discussed in more detail below in Part 2(A)(2)(b). No other Interveners made submissions with respect to the incremental O&M adjustment.

(2) Specific O&M Issues

(a) Impact of AMI

57. In the CEC Submission on PBR Methodology (the **CEC PBR Submission**), CEC notes that "there is no process to ensure that all AMI O&M benefits are captured and excluded" from the PBR formula, possibly creating a misalignment with customer interests.[76]

58. This concern is unfounded. The Company believes that it has taken an appropriate approach in forecasting the costs and benefits associated with the AMI Project, and to ensuring that they will be accurately reflected in the PBR formula. The forecasts utilized in this Application were considered by the Commission as part of the AMI CPCN application process, with the Commission

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[73] BCPSO FBC Non-PBR Submission, section 1.1.

[74] Exhibit B-1 – FBC Application, p. 52.

[75] BCPSO FBC Non-PBR Submission, section 1.1.

[76] CEC Final Submission on PBR Methodology (**CEC PBR Submission**), para. 324.

recognizing in Order C-7-13 that the level of forecast O&M reductions was "[r]easonable over the life of the project". The Commission accepted these forecasts.[77]

59. Further, in that decision, FBC was directed to file an Annual Cost/Benefit Tracking Report on the AMI Project for each of the first five years following the end or substantial completion of the AMI Project.[78] In any event, if the forecast O&M changes from the AMI Project change over the course of the PBR term, FBC confirms that it will update its forecasts.[79]

60. Further, the alleged concern raised by CEC remains the same under either a PBR or cost of service approach. In response to the alleged concern, CEC requests only that "the Commission should ensure that all benefits of CPCN projects like the AMI project are closely reviewed to ensure that perverse consequences are not slipping into the PBR formula".[80] This is an alarmist approach, and is unhelpful: CEC does not propose any alternative for how AMI O&M should be treated.

(b) Exclusions from the O&M Formula

61. In the BCPSO FBC Non-PBR Submission, BCPSO submits that FBC's proposal to track Pension and OPEB expense outside of the PBR methodology is reasonable and consistent with the fact that this expense varies according to factors beyond FBC's control.[81] No other Interveners made submissions with respect to the Pension and OPEB exclusion.

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77 Exhibit B-11 – FBC Response to BCPSO IR 1.31.1.
78 Exhibit B-11 – FBC Response to BCPSO IR 1.39.3.
79 Exhibit B-11 – FBC Response to BCPSO IR 1.39.1.
80 CEC PBR Submission, para. 396.
81 BCPSO FBC Non-PBR Submission, section 1.1.

62. In the CEC Non-PBR O&M Submission, CEC submits that Major Unit Inspections over $50,000 should be processed via the "flow-through process" rather than being determined by way of the PBR methodology.[82] This submission is based on the argument that they are "non-controllable" items, "since the need to complete major inspections is determined by industry standards and it is reasonable to expect that the costs of inspections, for the most part, are determined by the type and condition of the unit and the work required per industry standards".[83]

63. While Major Unit Inspections are required by industry standards, they are existing requirements that FBC must meet as part of its mandate to provide safe and reliable service to customers.[84] The expenditures associated with meeting these requirements have been determined based on the Company's experience and knowledge in this area and the costs are, to a certain extent, controllable in that they are not unforeseen, incremental expenses.[85]

64. In any event, FBC disagrees with CEC's submission that the expenses of completing Major Unit Inspections will vary depending on the type and condition of the unit. The Generation Department at FBC has estimated that the annual cost of the Major Unit Inspections will be $350,000.[86]

65. CEC has not submitted any evidence, only its own speculation, to suggest that the estimate of $350,000 per year for Major Unit Inspections is inaccurate, or to demonstrate that the cost per year will fluctuate by any amount. In any event, even if there is some fluctuation in the expense from year to year, O&M expenses are determined by the PBR formula on an aggregate level.[87] As is described in the FBC Non-PBR Submission, while a 15-year inspection schedule is anticipated, the maintenance schedule is guided by a condition-

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[82] CEC Non-PBR O&M Submission, para. 20-21.

[83] CEC Non-PBR O&M Submission, para. 30.

[84] Exhibit B-7 – FBC Response to BCUC IR 1.113.2.

[85] Exhibit B-7 – FBC Response to BCUC IR 1.156.1.

[86] Exhibit B-1 – FBC Application, p. 125.

[87] Exhibit B-7 – FBC Response to BCUC IR 1.98.1.

based interval philosophy, pursuant to which the actual schedule will be guided by condition, risk and operational priority.[88] This will allow the Company to prioritize required maintenance.

66. Further, CEC speculates that the cost of Major Unit Inspections will fluctuate based on the "condition" of the equipment. As the Company has just completed a ULE program, upgrades have recently been completed on 11 of the Company's 15 generating units, making the condition of the various units relatively consistent.[89] Further, the historical cost to maintain the units has remained fairly constant in recent years,[90] despite the fact that the ULE program was occurring with respect to various units. This demonstrates that the annual maintenance costs do not vary significantly between the units, despite potential differences in condition or work.

67. CEC also proposes that Dam Safety Inspections should be tracked outside of the PBR methodology as a non-controllable cost, as the need for the inspections is determined by regulation, and "the cost of the inspection is determined by the work required to comply the regulations and the type of Dam to be inspected".[91] However, as with the cost of Major Unit Inspections, CEC has not submitted any evidence to support its assertions, and there is nothing on the record to suggest that the costs will vary as suggested by CEC.

68. While Dam Safety Inspections are required by regulation, they are existing regulatory requirements that FBC must meet as part of its mandate to provide safe and reliable service to customers.[92] The expenditures associated with meeting these requirements have been determined based on the Company's experience and knowledge in this area and the costs are, to a certain extent,

[88] FBC Non-PBR Submission, para. 48.
[89] FBC Non-PBR Submission, para. 45.
[90] Exhibit B-1 – FBC Application, p. 123.
[91] CEC Non-PBR O&M Submission, para. 40.
[92] Exhibit B-7 – FBC Response to BCUC IR 1.113.2.

controllable in that they are not unforeseen, incremental expenses.[93] If new, unanticipated changes were to come into effect, these changes would be treated as exogenous factors and dealt with outside of the PBR formula.[94]

69. Accordingly, the Company disagrees with CEC's suggestion that the Major Unit Inspections or Dam Inspections should be excluded from the PBR formula.

(c) Summary on 2013 Base O&M

70. As was described above in detail, the submissions by CEC and BCPSO with respect to altering the use of 2013 Approved O&M as the starting point, changing the adjustments made or modifying the inclusions in 2013 Base O&M are not appropriate. None of the other Interveners made submissions with respect to 2013 Base O&M.

71. In summary, the Company reaffirms its submission that 2013 Base O&M should be approved by the Commission, as proposed in the Application.

B. <u>Capital Expenditures</u>

(1) The Determination of 2013 Base Capital

(a) 2013 Approved Capital

72. Much like the Company's determination of 2013 Base O&M, the Company has used a similar methodology to determine 2013 Base Capital. More specifically, the Company started with 2013 Approved Capital, and then made certain adjustments to reach an appropriate figure for 2013 Base Capital. This process is described in more detail in Part 2(E)(2) of the FBC Non-PBR Submission.

73. Unlike with respect to utilizing 2013 Approved O&M in the determination of 2013 Base O&M, none of the Interveners questioned FBC's reliance on 2013

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93 Exhibit B-7 – FBC Response to BCUC IR 1.156.1.
94 Exhibit B-1 – FBC Application, p. 63.

Approved Capital to determine 2013 Base Capital, and the Company submits that this methodology should be approved.

(b) Adjustments to Approved Capital

(i) Adjustment for Non-Recurring Major Projects

74. In the Submission of the Industrial Customers Group (**ICG**) on Both PBR Methodology and Non-PBR Issues (the **ICG Submission**), ICG raises some concerns with respect to the Major Project adjustment made to 2013 Approved Capital.[95] While this submission was raised in the portion of the ICG Submission on non-PBR issues, given the nature of that submission, the Company has replied to it in the PBR Reply.

(ii) Adjustments for Non-Controllable Items

75. None of the Interveners made any submissions with respect to FBC's adjustment to 2013 Approved Capital for non-controllable items. Accordingly, the Company submits that the Commission should accept this adjustment, as proposed.

(2) Specific Capital Issues

(a) Inclusion of Capital in the PBR Plan

76. In the CEC Final Submission on FBC Non-PBR Base Capital (the **CEC Non-PBR Capital Submission**), CEC submits that all capital expenditures should be excluded from the PBR formula.[96] The Company has responded to this argument in the PBR Reply. No other Interveners have made this suggestion, or raised concerns with respect to the inclusion of Regular Capital in the PBR Plan.

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[95] Final Submission of ICG on Both PBR Methodology and Non-PBR Issues (the **ICG Submission**), para. 48.

[96] CEC Final Submission on FBC Non-PBR Base Capital (the **CEC Non-PBR Capital Submission**), para. 2.

(b) Deferred Capital Expense Account

77. In the BCPSO FBC Non-PBR Submission, BCPSO suggests that a deferred capital expense account should be established to capture capital spending that has been carried over, to recognize that ratepayers have already "paid" for this deferred spending. BCPSO recommends that this deferral account then be drawn down in 2014 and 2015 to offset the increase in revenue requirements in those years.[97]

78. With respect to capital expenditures, in its Evidentiary Update FBC proposed an additional adjustment of $27,542,000 in 2014 and $9,997,000 in 2015, in order to allow the approved 2012 and 2013 capital expenditures to be completed in 2014 and 2015.[98] 2013 Base Capital and the PBR formula for capital are not changed as a result of this adjustment.[99]

79. While BCPSO suggests that the deferred capital spending account should incorporate the capital spending that was approved in 2012 but not spent, BCPSO has overstated the amount. It is not the Company's total capital spending that has been "paid" for by ratepayers already, but rather only the cost of service (depreciation, debt, equity and the resulting income taxes) associated with this spending.[100] Any amount captured through a deferral account would be considerably less than the $30 million proposed by BCPSO.

80. BCPSO's submission, in effect, amounts to unlawful retroactive ratemaking. Pursuant to the UCA, the Commission has jurisdiction to set <u>prospective</u> rates. This involves only a matching of future costs to future rates. In *Northwestern Utilities Ltd. v. The City of Edmonton*, [1979] 1 S.C.R. 684, Estey J. (for the Supreme Court of Canada) said the following with reference to the equivalent Alberta legislation:

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[97] BCPSO FBC Non-PBR Submission, s. 1.2.
[98] Exhibit B-1-6 – Evidentiary Update, pp. 57-58.
[99] Exhibit B-24 – FBC Response to BCUC IR 2.90.14.
[100] Exhibit B-1 – FBC Application, p. 277, demonstrates costs included in revenue requirements.

> The statutory pattern is founded upon the concept of the establishment of rates *in futuro* for the recovery of the total forecast revenue requirement as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of the *Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the Act which make this clear ….[101]

81. An attempt to recoup funds from past periods by adjusting future periods effectively amounts to retroactive ratemaking, and the approach suggested by BCPSO should be rejected by the Commission.

C. Load and Resulting Revenues

82. In the BCPSO FBC Non-PBR Submission, BCPSO raises a concern that the calculation used by the Company to forecast load does not accurately account for rate-driven savings.

83. As BCPSO acknowledges, the rate-driven savings estimate of 9.7 GWh for 2014 is very small relative to the total gross load forecast of 3,519 GWh for the same period.[102] Total rate-driven savings amount to only 0.27 percent of the total gross load forecast. BCPSO suggests that more consideration should be given as to how to appropriately estimate rate-driven savings in the future,[103] but does not propose any changes to the present load forecast for 2014.

D. Power Purchase Expense

84. The only Intervener to comment on FBC's PPE forecast was BCPSO, which submitted that the Commission should approve the PPE forecast for 2014.[104]

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[101] At p. 691 [emphasis added]. Available online at: http://scc.lexum.org/en/1978/1979scr1-684/1979scr1-684.html.

[102] BCPSO FBC Non-PBR Submission, s. 1.3.

[103] Ibid.

[104] Ibid, s. 1.4.

E. Other Income

85. Similarly, BCPSO was the only Intervener to comment on the Company's Other Income forecast, to submit that the Commission should approve the forecast for 2014. [105]

F. Financing & Return on Equity

86. BCPSO submitted that the Commission should approve the Company's financing costs (consisting of both debt costs and depreciation) and return on equity, as is proposed in the Application, subject to any changes in the Company's forecast rate base.[106]

87. No other Interveners made any submissions with respect to the Company's financing or return on equity.

G. Taxes

88. Finally, BCPSO was the only Intervener to make submissions with respect to taxes. It submitted that it had no concerns with the Company's proposed approach to calculating forecast income taxes and property taxes, and that they should be approved for 2014.[107]

89. No other Interveners made any submissions with respect to the Company's tax forecasts.

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[105] Ibid, s. 1.5.
[106] Ibid, s. 1.6.
[107] Ibid, s. 1.7.

PART 3 - ACCOUNTING POLICIES

A. Generally Accepted Accounting Principles

90. In its Application, FBC seeks approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports.[108] The justification for this request is set out in Part 3(A) of the FBC Non-PBR Submission.

91. In Final Submissions, BCPSO was the only Intervener to comment on this request. It submitted that it is supportive of FBC's request, as the reconciliation will become less informative each year, while becoming simultaneously more expensive to prepare, shifting the cost/benefit ratio of performing it.[109] The Company agrees and submits the reconciliation should be discontinued.

B. Net-of-Tax Treatment of Pension/OPEB Funding

92. Submissions on the Net-of-Tax Treatment of pensions and OPEB expense are discussed below in Part 4 on Deferral Accounts.

C. Sharing of Services

93. ICG "supports the use of the Massachusetts formula for the allocation of shared service costs between FEI and FBC".[110]

94. No other Interveners addressed this approach in Final Submissions, and the Company submits that the Commission should approve its request to allocate Executive costs between FEI and FBC by way of the Massachusetts Formula, consistent with the accepted approach used for the Board of Directors.[111]

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[108] Exhibit B-1 – FBC Application, p. 10.
[109] BCPSO FBC Non-PBR Submission, s. 2.
[110] ICG Submission, para. 63.
[111] Exhbiit B-23 – FBC Response to BCPSO IR 2.8.1.

D. Capitalized Overhead

(1) Continuation of 20 Percent Capitalization Rate

95. In its Application, FBC seeks approval to continue to utilize a capitalized overhead rate of 20 percent of O&M expenses during the PBR Period.[112]

96. In the BCPSO FBC Non-PBR Submission, BCPSO submits that 20 percent is too high.[113] Similarly, ICG raises concerns with FBC's capitalization policies, and recommends that "FBC be directed to capitalize overhead at 8% of capital expenditures instead of 20% of O&M during the PBR Plan".[114]

97. The ICG Submission contains a section titled "Capitalization of Overhead" in which ICG makes a variety of submissions on both direct overhead and capitalized overhead.[115] As was described in the FBC Non-PBR Submission, these are two distinct concepts: capitalized overhead is the process by which a certain portion of total O&M costs that are indirectly related to capital are attributed to capital,[116] while direct overhead allows the Company to attribute in a more efficient manner certain O&M costs that are directly related to capital.[117] In its Application and the FBC Non-PBR Submission, the Company has done its best to keep these two concepts distinct, in accordance with the Commission's recognized concern "with respect to the need to differentiate between capitalized and direct loadings" in the 2012-13 RRA Decision.[118] The related, but distinct nature of these two concepts is depicted in the following diagram from the KPMG Review:[119]

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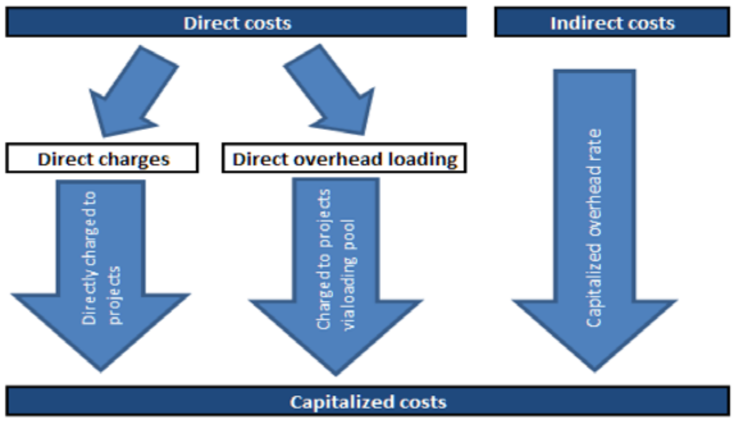
[112] Exhibit B-1 – FBC Application, p. 10.
[113] BCPSO FBC Non-PBR Submission, s. 2.
[114] ICG Submission, para. 99.
[115] Ibid, para. 83-99.
[116] FBC Non-PBR Submission, para. 166.
[117] Ibid, para. 191.
[118] 2012-13 RRA Decision, p. 72.
[119] Exhibit B-1-1 – FBC Application Appendices, Appendix F3 – KPMG Review, p. 12.

Diagram 1: Capital cost allocation overview



98. The Company has done its best to identify when ICG's submissions relate to capitalized overhead, direct overhead, or both.

99. With respect to capitalized overhead, ICG submits that further scrutiny is needed with respect to FBC's overhead capitalization policy. In support of this, it looks to the increase over the past ten years of <u>both</u> capitalized overhead and direct overhead, as a percentage of unloaded gross capital expenditures, as well as a comparison with Newfoundland Power Inc.[120] The Company refers to paragraphs 171 to 175 of the FBC Non-PBR Submission, in which it has responded to the concerns outlined by ICG.

100. Further, while ICG submits that the above concern demonstrates that further scrutiny of FBC's overhead capitalization policy is necessary, "as was directed by the Commission Panel in the 2012-2013 RRA Decision",[121] this further scrutiny has already been conducted by way of the KPMG Review. In the 2012-13 RRA Decision, the Commission directed FBC to "provide an external audit opinion on the appropriateness of its capitalized overhead methodology".[122] As part of this Application, the Company included the KPMG Review,[123] the scope

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[120] ICG Submission, para. 88.
[121] Ibid, para. 89.
[122] 2012-13 RRA Decision, p. 72.
[123] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review.

of which specifically addressed the directives made by the Commission in the 2012-13 RRA Decision.[124]

101. While ICG submits that FBC's overhead capitalization policy should be changed "given that KPMG can only support a capitalization rate of approximately 15% of O&M",[125] this is not correct. Rather, KPMG found that the Company's overhead capitalization policy was a "reasonable basis for capitalization of costs related to capital activities that have not been directly charged to projects" that were "consistent with internally generated evaluation criteria and practice established by the external guidance".[126]

102. While KMPG selected a Survey Model to estimate capitalized overhead at approximately 15 percent,[127] it acknowledged that "[n]o single regulatory guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes the types of indirect costs ... that should be considered for capitalization".[128] It also considered another mathematical model that suggested a figure of 17 percent would be appropriate, and reviewed an industry comparison which demonstrated a range of 4 percent to 59.2 percent.[129]

103. With the guidance of the KPMG Review, as well as for the reasons described in paragraph 168 of the FBC Non-PBR Submission, the Company determined that its capitalization rate should remain at its current level of 20 percent of O&M for the PBR Period.[130]

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124 Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 7.
125 ICG Submission, para. 89.
126 Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 5.
127 Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 5.
128 Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 4.
129 Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, pp. 27, 37.
130 Exhibit B-1 – FBC Application, p. 255.

104. While ICG seeks a Commission direction that the Company "implement immediate changes to its capitalization policies",[131] FBC submits that there is no reason to do so, for the reasons explained below.

105. First, as was described in more detail in the FBC Non-PBR Submission, using a percentage of forecast capital expenditures as an overhead capitalized allocator would introduce high variability into customer rates.[132] While ICG states that this variation only arises when annual capital expenditures are forecast incorrectly,[133] the fluctuations are not linked to inaccurate forecasts. As can be seen from the following table, rates vary in a range of 3.30% to 3.60% when capitalized overhead is calculated as a percentage of O&M, while fluctuating between -1.20% to 6.30% when calculated as a percentage of capital expenditures:[134]

	($000s)				
	Forecast				
	2014	**2015**	**2016**	**2017**	**2018**
Capitalized Overhead calculated as 20% of O&M Expense	12,277	12,349	12,192	12,476	12,660
Capitalized Overhead calculated as 22.3% (response to BCUC IR 2.50.1.1) of Base Capital Expenditures (response to BCUC IR2.50.1)	22,906	17,936	12,194	11,825	12,702
Rate Increase with Capitalized Overhead calculated as 20% of O&M Expense	3.30%	3.60%	3.60%	3.60%	3.60%
Rate Increase (Decrease) with Capitalized Overhead calculated as 22.3% (response to BCUC IR 2.50.1.1) of Base Capital Expenditures (response to BCUC IR 2.50.1)	(1.20%)	6.30%	6.20%	3.90%	3.30%

106. These fluctuations will occur due to changes in capital expenditure levels, not with discrepancies in forecasting.

107. Further, while ICG suggests that a rate of 8 percent of capital expenditures should be used,[135] it has provided no support for why this percentage is

[131] ICG Submission, para. 90.
[132] Exhibit C10-7 - ICG Response to BCUC IR 1.6.
[133] ICG Submission, para. 97.
[134] Exhibit B-24 - FBC Response to BCUC IR 2.50.1.2.
[135] ICG Submission, para. 99.

appropriate. While the figure of 8 percent of capital expenditures was derived as being equivalent to 13.3 percent of O&M expense,[136] Mr. Pullman has previously acknowledged that this figure was arrived at by way of an arbitrary reduction that is not supported by a calculation.[137]

108. With respect to ICG's contention that FBC has dismissed Mr. Pullman's contention that certain assets such as trucks and furniture should not be included in capitalized overhead, the Company refers to its previous submission set out in the FBC Non-PBR Submission at paragraph 189.

109. Given all of the above, the Company reiterates its submission that, based on all the circumstances set out in paragraph 168 of the FBC Non-PBR Submission, capitalized overhead should continue to be calculated as 20 percent of O&M.

E. <u>Direct Overhead</u>

FBC's Direct Overhead Methodology

110. As was described above, as well as in Part 3(E) of the FBC Non-PBR Submission, the Company's use of a direct overhead methodology is distinct from its capitalization of indirect overhead. Direct overhead recovers supervisory and administrative costs that are not easily allocated to a specific capital project, but that are still directly attributable to T&D capital projects.[138] As can be seen from the above KPMG diagram, direct overhead involves direct costs that could be directly charged to capital (though inefficiently), if the direct overhead approach were not to be used. Efficiency gains are the difference between using the direct overhead methodology and directly charging the costs.[139]

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[136] Exhibit C10-5 – Pullman Evidence, p. 12.
[137] FBC Non-PBR Submission, para. 183; Ex. C10-7 – ICG Response to BCUC IR 1.8.1.
[138] Exhibit B-1 – FBC Application, p. 255.
[139] Ibid, pp. 255-256.

111. In the ICG Submission, ICG adopts Mr. Pullman's recommendation that "the Commission Panel accept the [direct loading] methodology pro-tempore and direct FBC to review it again prior to the end of the PBR Period".[140] While the Company agrees with ICG's recommendation that its Direct Overhead methodology be approved, it disagrees that a further review of the methodology is necessary.

112. In the 2012-13 RRA Decision, the Commission directed FBC to "ensure that the direct overhead loading methodology is commented upon as part of the external audit opinion" on capitalized overhead and to provide a "more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification".[141] Further, FBC was directed to "meet with Commission staff" following the preparation of the external audit report to review the report and options.[142]

113. This has all been completed, in accordance with the Commission's directives. The Company engaged KPMG to prepare a report with a detailed explanation, reconciliation and external audit opinion on the Company's direct overhead methodology.[143] Following receipt of drafts of the KPMG Review, the Company meet with Commission staff on two occasions to discuss the KPMG Review.[144] Further, the Company included a detailed explanation of its direct overhead methodology in the Application,[145] through the IR process, and in the FBC Non-PBR Submission.[146]

114. Given the recent nature of the KPMG Review, and that it was prepared specifically for the purposes of this Application, in accordance with directives of

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[140] ICG Submission, para. 83.
[141] 2012-13 RRA Decision, p. 77.
[142] 2012-13 RRA Decision, p. 75.
[143] See Ex. B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review.
[144] Exhibit B-1 – FBC Application, p. 254.
[145] See Exhibit B-1 – FBC Application, pp. 255-257.
[146] FBC Non-PBR Submission, Part 3(E).

the Commission, it is not necessary for there to be an additional review of the Company's direct overhead policy.

115. Further the concerns raised by Mr. Pullman and ICG to support the alleged necessity for further review of the direct overhead methodology are unfounded.

116. In the ICG Submission, ICG adopts Mr. Pullman's statement that "the KPMG Review provides only lukewarm support for FBC's Direct Overhead methodology".[147] This is not correct: in the KPMG Review, KPMG found FBC's direct overhead methodology was "a reasonable basis for capitalization of costs related to capital activities" and also that "[t]hese methodologies are consistent with FBC's internally generated evaluation criteria and available accounting guidance".[148]

117. Further, Mr. Pullman and ICG rely on the following KPMG statement from the KPMG Review:[149]

> That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association which is clearly related to capital activity.

118. ICG recommends that a more rigorous analysis should be performed to develop suitable direct overhead loading rates, as there is evidence that direct overhead is not causally linked to capital activity.[150]

119. With respect, ICG has again conflated the distinct concepts of direct overhead and capitalized overhead. The KMPG quote relied on speaks of the assignment of <u>indirect costs</u> to capital projects, which are the costs allocated by way of a capitalized overhead rate.[151] In contrast, as previously discussed, the direct overhead methodology is used to charge <u>direct costs</u> that are not directly

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[147] ICG Submission, para. 84.
[148] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, pp. 5-6.
[149] ICG Submission, para. 84.
[150] ICG Submission, para. 85-86.
[151] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 5.

charged to specific capital projects but are directly attributable to T&D capital projects".[152]

120. In any event, FBC submits that the direct costs that it allocates by way of its direct overhead methodology are appropriately allocated from the direct overhead cost pool to specific capital projects. The direct overhead loading rate is determined by a ratio of the total direct overhead cost pool to the total unloaded T&D capital costs.[153] In the KPMG Review, KPMG summarized FBC's internal criteria for direct overhead as ensuring that:[154]

> The identified driver, being it work effort or investment, has a direct correlation to the cost of the service or goods and also have a direct effect on the level of service for that capital project.

121. In its findings, KPMG determined that FBC's direct overhead methodology was "<u>consistent with FBC's internally generated evaluation criteria</u>".[155] Accordingly, ICG's stated concern is not an appropriate basis to justify further review of the direct overhead methodology.

122. In the ICG Submission, ICG suggests that the Company has somehow inaccurately attributed a concern to Mr. Pullman, that it may be inappropriate to charge direct overhead to a direct overhead capital loading pool.[156] For clarity, this section of the argument was in no way attributed to being a response to Mr. Pullman. As was stated in this section, the "enumerated list of why this practice should continue",[157] was intended to summarize why the Company has reached the view "that its direct overhead loading methodology is appropriate, and ... should be continued during the PBR".[158]

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[152] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 12.
[153] Exhibit B-2 – FBC Application, p. 255.
[154] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 18.
[155] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, pp. 5-6 [emphasis added].
[156] ICG Submission, para. 86.
[157] ICG Submission, para. 86.
[158] FBC Non-PBR Submission, para. 193.

123. The Company accepts and agrees with ICG's submission that it is appropriate to charge direct overhead to a direct overhead capital loading pool.[159] However, it disagrees with Mr. Pullman's suggestion that the methodology should be reviewed "for the reasons related to direct charging of costs that should be allocated, and the possibility that the residual costs of the three identified departments will be capitalized".[160]

124. With respect to Mr. Pullman's suggestion that certain costs are being inappropriately directly charged when they should be allocated, each department estimates the amount of time by position and expenses that should be charged to T&D projects via the direct overhead methodology, rather than being directly charged to the project. The direct overhead loading rate is then determined as a ratio of the total direct overhead cost pool to the total unloaded T&D capital costs.[161] These estimates are being made by individuals in each department, who are in the best position to know the nature of their work. The data is then compiled by management in order to determine the total direct overhead loading pool.[162] In contrast, Mr. Pullman's concern is founded only on the suggestion that "the amounts are being directly charged which should really be allocated, such as time spent in administration and management".[163] As was stated in the FBC Non-PBR Submission, Mr. Pullman has not provided any explanation for why such a conclusion would follow.[164]

125. The second concern identified by Mr. Pullman as allegedly giving rise to a need to further review FBC's direct overhead methodology is "the possibility that the residual costs of the three identified departments will be capitalized".[165] Mr. Pullman submits that the three departments (EH&S, Finance and Procurement

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[159] ICG Submission, para. 86.
[160] ICG Submission, para. 87.
[161] Exhibit B-1 – FBC Application, p. 255.
[162] Exhibit B-1-1 – FBC Application Appendices, Ex. F3 – KPMG Review, p. 19.
[163] Exhibit C10-5 – Pullman Evidence, pp. 6-7.
[164] FBC Non-PBR Submission, para. 198.
[165] ICG Submission, para. 87.

& Material Handlings) are not sufficiently linked to FBC's T&D function, and that this may give rise to a double-counting of expenses in both direct overhead and capitalized overhead.[166]

126. As was already addressed in the FBC Non-PBR Submission, not only has Mr. Pullman failed to properly distinguish between direct overhead and capitalized overhead in raising this concern, but the KPMG Review specifically confirmed that the Company's direct overhead methodology does not result in duplication.[167]

127. For these reasons, the Company submits that the Commission should reject ICG's suggestion that FBC's direct overhead methodology should be further reviewed.

PART 4 - DEFERRAL ACCOUNTS

A. Deferral Account Financing

128. In the Application, FBC seeks Commission approval for changes to the rate base treatment and financing of certain deferral accounts, as was described in Section D3.2 of the Application.[168] This request requires the Commission to revisit the decision of the Commission Panel in the 2012-13 RRA Decision, which the Company respectfully submits was incorrect with respect to this issue. In the FBC Non-PBR Submission, the Company set out detailed submissions in this regard in Part 4(A).[169]

129. Two interveners, ICG and BCPSO, have submitted that the approval sought by the Company should not be granted, and that the approach used in the 2012-13 RRA Decision should be maintained.[170]

[166] Exhibit C10-5 – Pullman Evidence, p. 7.
[167] FBC Non-PBR Submission, para. 200-201.
[168] Exhibit B-1 – FBC Application, pp. 7-10.
[169] FBC Non-PBR Submission, para. 207-234.
[170] ICG Submission, para. 109; BCPSO FBC Non-PBR Submission, s. 3.1.

130. In addition to adopting the arguments in Part 4(A) of the FBC Non-PBR Submission, the Company responds to certain additional arguments raised by ICG and BCPSO in this section of the FBC Non-PBR Reply.

131. In the ICG Submission, ICG submits that FBC's request for a change in deferral account financing "has a single purpose, that is, to increase returns to the shareholder at the expense of an increase to cost of capital and related income taxes to be borne by ratepayers".[171] This misstates the Company's intentions: in the FBC Non-PBR Submission, the Company summarizes seven different concerns that it has with the financing ordered in the 2012-13 RRA Decision.[172] At the forefront of these concerns is the inconsistency created amongst FBC's deferral accounts. The Company is not simply seeking to increase returns to the shareholder at the expense of ratepayers, but rather to ensure that the way that the deferral accounts are treated for regulatory purposes is consistent among its various deferral accounts, and with other rate base items.

132. ICG is incorrect to suggest that excluding the deferred charges from rate base would necessarily have the effect of reducing the Company's revenue requirements. As can be seen from Table 1-B in Part E of the Evidentiary Update, the total of the deferred charges that were excluded from rate base by virtue of the 2012-13 RRA Decision was a credit of $6.8 million as at December 31, 2012 (which represents the mid-point of the time period of the 2012-2013 RRA Decision).[173] Inclusion of these amounts in rate base, as proposed by FBC, would have the effect of lowering revenue requirements and would serve to reduce FBC's return rather than increase its return.

133. FBC's proposal to include the RSDM as a credit to rate base that reduces earned return and mitigates rate increases further demonstrates that increasing shareholder return is not the motivation behind its proposed treatment of deferred accounts. The RSDM will have a credit balance of $24 million at the

171 ICG Submission, para. 101.

172 See FBC Non-PBR Submission, para. 207-234.

173 Exhibit B-1-6 – Evidentiary Update, p. 286, l. 77.

end of 2014,[174] which again results in lower revenue requirements over the PBR Period than if it were excluded from rate base. The Company's proposal for deferral account financing seeks a consistent and principled treatment of its deferral accounts, which accurately reflects the nature of how these amounts are financed, consistent with other rate base items.

134. Additionally, while ICG acknowledges that FBC has sought approval on the basis that the 2012-13 RRA Decision was incorrect,[175] it later states that the Company is basing its request on the distinction between investments and deferred operating costs/current period expenses and states this request should be denied on the basis that the 2012-13 RRA has already directly addressed the issue.[176] The Company acknowledges that this issue was addressed in the 2012-13 RRA Decision, but reiterates its submission that the decision was incorrect. In any event, section 75 of the UCA states that "[t]he commission must make its decision on the merits and justice of the case, and <u>is not bound to follow its own decisions</u>". The Commission may reach a different decision on this issue now, just as it had done prior to the 2012-13 RRA, despite its decision in the 2012-13 RRA Decision.

135. ICG suggests that FBC rejects the distinction between "investments" and "deferred operating costs/current period expenses". The Company agrees that it does, in fact, reject this distinction <u>for the purposes of determining how the costs are to be financed</u>, for the reasons set out in section D3.2 of the Application.[177] Further, the Company also agrees that the Commission must conclude that "once an item is placed into a deferral account, it immediately ceases to be an operating cost ... and it becomes akin to a capital item", again <u>for the purposes of how it is financed</u>. As was described in the Application, "there is no distinction to be drawn between deferrals and capital in terms of the

[174] Exhibit B-1-6 – Evidentiary Update, p. 287, l. 5.
[175] ICG Submission, para. 102.
[176] ICG Submission, para. 104.
[177] Exhibit B-1 – FBC Application, pp. 246-249.

utility's financing costs or its right to a fair return".[178] This is because the entirety of rate base is financed in the same manner, through the combination of debt and equity that is reflected in the WACC.

136. While the Commission Panel in the 2012-13 RRA Decision disagreed, for the reasons set out in the Application and the FBC Non-PBR Submission the Company submits that this Commission Panel should agree with this principle and revisit the issue.

137. ICG submits that the Company "fails to expressly mention the other electric utility", in discussing deferral rate financing.[179] This is incorrect, as the Company responded directly to a question posed by ICG in IRs on the treatment of deferral accounts for other electric utilities in the province. The Company's response to this IR included a discussion of BC Hydro.[180] ICG also submits that the Commission should conclude that the Company's deferral accounts "should be financed in a similar manner to how BC Hydro deferral accounts are financed".[181] While ICG states that there is "no reason to provide an investor-owned electric utility in British Columbia with WACC to finance all deferral accounts, when similar deferral accounts of BC Hydro are financed at WACD",[182] the Company strongly disagrees. For all of the following reasons, FBC does not believe that it is appropriate to make a comparison between the practices used by FBC and BC Hydro:[183]

a. BC Hydro's status as a Crown corporation, while FBC is an investor-owned electricity utility;

b. BC Hydro's status as a non-taxable entity;

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[178] Exhibit B-1 – FBC Application, p. 247.
[179] ICG Submission, para. 105.
[180] Exhibit B-15 - FBC Response to ICG IR 1.41.1.
[181] ICG Submission, para. 105.
[182] ICG Submission, para. 106.
[183] Exhibit B-15 - FBC Response to ICG IR 1.41.1.

c. BC Hydro's access to low-cost financing as a government entity;

d. BC Hydro's ROE has at times included a risk premium to the benchmark ROE, over and above that allowed to FBC, set at the direction of the Provincial government;

e. BC Hydro's capital structure is established and revised at the direction of the Provincial government, including a deemed equity component that is higher than the actual equity in BC Hydro's books, and at times including both a debt and equity return on the difference between the deemed and book equity;

f. BC Hydro's deferral accounts are recorded and financed on a gross basis, while FBC's and FEI's deferral accounts are recorded net-of-tax; and

g. the government sets the rate of return it receives from its investment in BC Hydro, and there are many ways in which that return can be modified or affected. It is not appropriate to compare to an investor-owned utility.

138. For these reasons, looking to BC Hydro's deferral account practice is less informative for FBC than comparing FBC's practice to other investor-owned utilities. In contrast to BC Hydro, FBC's proposed treatment changes are consistent with the practices used by other investor-owned utilities in this and other jurisdictions. This is described in more detail at Part 4(A)(2)(e) and (f) of the FBC Non-PBR Submission.

139. Overall, while the ICG submits that there is "no compelling reason for the Commission to reverse itself" from the 2012-13 RRA Decision,[184] the Company submits that it has provided numerous compelling reasons in the FBC Non-PBR Submission and herein, that demonstrate that deferred expenditures and

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[184] ICG Submission, para. 109.

revenues should be included in rate base and attract a WACC rate of return, or, where timing requires,[185] held in non-rate base deferral accounts where they attract a rate of return reflective of WACC.

140. BCPSO also makes submissions with respect to the financing of FBC's deferral accounts. It suggests that the Company's request should be denied on the basis that the 2012-13 RRA Decision is inconsistent with a methodology approved by the Ontario Energy Board in November 2006 (the **OEB Methodology**).[186] The Company submits that the Commission should disregard the evidence with respect to the OEB Methodology, as this evidence is not on the record. The record in this matter has been closed since April 11, 2014, and yet the BCPSO Final Non-PBR Submission is the first time that the OEB Methodology has been raised in this proceeding. Further, the OEB Methodology itself is still not on the record. As a result, the parties to the proceeding have not had the opportunity to consider the OEB Methodology, or to submit evidence to respond to it. Given that the OEB Methodology dates from November 2006, there is no reason why BCPSO could not have submitted this evidence in the normal course. The Commission should refuse to allow this additional evidence.

141. Even if the OEB Methodology operates in the manner suggested by BCPSO, it would still be subject to all the same concerns that FBC outlined in Part 4(A) of the FBC Non-PBR Submission.

B. <u>Specific Deferral Accounts</u>

(1) New Deferral Accounts

142. BCPSO was the only Intervener to make submissions with respect to the new deferral accounts proposed by FBC. It submits that it has "no particular

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[185] As explained in Ex. B-1 – FBC Application, p. 249.
[186] BCPSO FBC Non-PBR Submission, s. 3.1.

concerns with the BCUC approving the RSDM or ESM deferral accounts".[187] Of the remaining eight new proposed deferral accounts, BCPSO submits it would be appropriate for all of them to have a one-year amortization period.[188]

143. There are only two of these eight accounts with a proposed amortization period of over one year: the Interest Expense Variance deferral account and the Property Tax Variance deferral account. While the Company has selected amortization periods that are consistent with the periods approved for FEI, this is not the sole or primary rationale for these periods, as is suggested by BCPSO.[189]

144. With respect to both accounts, the Company believes that the proposed amortization period of three years provides a reasonable balance between a long enough period to smooth the customer impact for any potential large variances that may arise in a given years, with a short enough period in which customers are still paying for the true cost of service in a timely manner.[190] As was recognized by BCPSO, variation from a one-year recovery period may be appropriate where "there is a significant balance that is likely to create material rate instability".[191] Given the potential for large variances in interest expense and property taxes, the Company believes that moving from a one-year period to a three-year period is appropriate.

145. The Company submits that the amortization periods for the proposed new deferral accounts should be approved as submitted.

(2) Changes to Deferral Accounts

146. The only Intervener to make submissions with respect to the changes in deferral accounts proposed by FBC was BCPSO.

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187 BCPSO FBC Non-PBR Submission, s. 3.2.
188 Ibid.
189 Ibid.
190 Exhibit B-7 – FBC Response to BCUC IR 1.190.6 and 1.191.4.
191 BCPSO FBC Non-PBR Submission, s. 3.2.

147. With respect to the six deferral accounts approved by Commission Order G-23-13 (in which the determination of the applicable financing rate and amortization periods was left to this proceeding), BCPSO submits that "the proposed amortization periods are reasonable". BCPSO also notes that the "two year amortization period for the BCUC Generic Cost of Capital Proceeding Account is consistent with the termination date of the Automatic Adjustment Mechanism approved by the BCUC".[192]

148. BCPSO also supports the approval of changes in the amortization period of the DSM Deferral account, On-Bill Financing Pilot Program Deferral account, the 2014-2018 PBR Application deferral account, the two City of Kelowna Acquisition-related deferral accounts, the On-Bill Financing Participant Loans deferral account and the 2014 debt issues cost deferral account.[193]

149. With respect to the 2014-2018 Capital Expenditure Plan deferral account, BCPSO proposes a four year amortization period be used, rather than the two-year period proposed by the Company.[194] The Company has specifically addressed why it used a shorter amortization period for this account. When asked about the two year amortization period in IRs,[195] the Company adopted its response given in another IR response. In the referenced response, FBC confirmed that the amortization period was selected based on:[196]

a. the size of the balance in the deferral account;

b. the nature of the deferral;

c. any applicable benefit period of the deferral; and

d. the impact on customer rates.

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[192] BCPSO FBC Non-PBR Submission, s. 3.3.
[193] Ibid, s. 3.4.
[194] Ibid, s. 3.4.
[195] Exhibit B-7 – FBC Response to BCUC IR 1.197.1.
[196] Exhibit B-7 – FBC Response to BCUC IR 1.194.2.

150. It was in weighing these factors that the Company determined that a two-year amortization period was appropriate for the 2014-2018 Capital Expenditure Plan deferral account. The Company submits that its proposed amortization period should be approved by the Commission.

C. Net-of-Tax Treatment

151. One of the approvals sought by FBC in the Application is to discontinue the net-of-tax treatment that it utilizes in recording the difference between amounts funded by ratepayers for pensions/OPEB and amounts actually paid out by the Company in a deferral account.[197] This request is described at paragraphs 264-266 of the FBC Non-PBR Submission.

152. The only Intervener to make submissions with respect to this request was BCPSO, which submitted "that the going-in rate must be adjusted to reflect the change from recording the deferral account on a net of tax basis to include the income tax impact in tax expenses". BCPSO submitted that if this change is made, that ratepayers should be indifferent to the change proposed by FBC.[198]

153. It is not clear as to what BCPSO refers to as the "going-in rate" since income tax is reforecast each year as part of an Annual Review process and is not set by the PBR formula. FBC interprets "going-in" rate as being relevant for cost of service components that use a base level and then are adjusted in subsequent years by the PBR formula. This is not what FBC is proposing regarding the discontinuation of the net-of-tax treatment for pension and OPEB funding differences.[199]

154. FBC's proposed methodology for taxes related to pensions and OPEBs results in an estimated $55,000 difference in the determination of 2014 income tax expense.[200] The primary intent of discontinuing the net-of-tax treatment for

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[197] Exhibit B-1 – FBC Application, p. 242.
[198] BCPSO FBC Non-PBR Submission, s. 2.
[199] Exhibit B-1 – FBC Application, p. 242.
[200] Exhibit B-7 – FBC Response to BCUC IR 1.215.2, 1.215.2.1.

pension and OPEB funding differences is to address the issue of how pension and OPEB balances are not being drawn down in the same manner as other deferral accounts and their related net of tax deferral balances.[201] Further, this proposed treatment will align with FEI,[202] as well as a majority of taxable entities within the rate-regulated utility industry.[203]

PART 5 - DEMAND SIDE MANAGEMENT PROGRAM

155. Three Interveners filed Final Submissions on the Company's DSM Plan: ICG, B.C. Sustainable Energy Association and Sierra Club British Columbia (**BCSEA**) and BCPSO. In the BCPSO FBC Non-PBR Submission, BCPSO submits that "the BCUC should approve the reduced 2014-2018 DSM spending".[204]

156. In contrast, ICG and BCSEA submit that the DSM Plan should not be approved, and that the Commission should direct the Company to file revised expenditure schedules.[205] As it did earlier in the FBC Non-PBR Reply Submission, the Company has responded to the concerns raised by ICG and BCSEA using the same format as the FBC Non-PBR Submission.

A. The Proposed DSM Plan

(1) Expenditures excluded from PBR Formula

157. As was described in the FBC Non-PBR Submission, while the Company is seeking approval of the DSM Plan as part of the PBR Application, the DSM program costs are not included within the PBR structure, and all direct DSM program costs are to be recovered under cost-of-service principles.[206] BCSEA was the only Intervener to address this point in its Final Submission, and it

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[201] Exhibit B-1 – FBC Application, pp. 242-243.
[202] Exhibit B-1 – FBC Application, pp. 242-243.
[203] Exhibit B-7 – FBC Response to BCUC IR 1.215.1, 1.215.3.
[204] BCPSO FBC Non-PBR Submission, s. 4.1.
[205] ICG Submission, para. 120; Written Argument of BCSEA (**BCSEA Submission**), para. 11.
[206] FBC Non-PBR Submission, para. 281-286; Ex. B-12 – FBC Response to BCSEA IR 1.33.1.1.

indicated that it “support[s] the concept that the DSM program costs should be excluded from the PBR structure”.[207]

(2) Program Funding Transfer Rules

158. FBC also seeks approval of program funding transfer rules applicable to the DSM Plan, which will provide the Company with the flexibility to respond and react to changes in circumstances during the five-year expenditure period requested.[208]

159. In the BCSEA Submission, BCSEA supports Commission approval of the proposed program funding transfer rules.[209]

160. BCPSO similarly supports the proposed program funding transfer rules, with one caveat. BCPSO submits that the Company should not be allowed to reduce the funding approved for programs that specifically respond to adequacy requirements set out in section 3 of the DSM Regulation, without prior approval of the Commission. BCPSO makes this caveat with respect to transfers of funds either between program areas, or from existing to new programs within the same approved program area.[210]

161. As proposed, the program funding transfer rules allow the Company to make funding transfers of under 25 percent between approved program areas without prior Commission approval, while Commission approval is required for transfers of over 25 percent.[211] The Company submits that this 25 percent limit is an appropriate threshold for Commission involvement in program funding transfers and that the proposal to require Commission approval for smaller amounts is unwarranted and inefficient. The program funding transfer rules are intended to allow the Company to adequately react to changing market conditions, as well

[207] BCSEA Submission, para. 17.
[208] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, p. 10.
[209] BCSEA Submission, para. 14(c)-(d).
[210] BCPSO Submission, s. 4.3.
[211] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, p. 11.

as customer responses to programs, input from stakeholders and changes in the political environment in which the Company operates.[212]

162. Balanced with this flexibility, the current constraints on the Company are more than sufficient to ensure that the Commission is aware of any changes being made to the DSM portfolio, without the need for a formal review. These constraints include approved budgets, the cost-effectiveness tests, annual reporting requirements and the 25 percent limit on transfers between program areas.[213]

163. Accordingly, allowing the Company to make transfers without the need for a full Commission review will allow the Company to take advantage of unforeseen opportunities, which, in turn, ensures that cost-effective DSM opportunities are initiated within a timely manner. Given the five year term of the DSM expenditure schedules, this flexibility is particularly important.[214] The flexibility is also balanced with protections to ensure that the Commission remains aware of changes.[215] Accordingly, the Company submits that its program funding transfer rules should be approved as proposed.

164. In addition, BCPSO submits that expenditure transfers should be included within the scope of the Annual Review.[216] The Company agrees that transparency is important with respect to the use of the program funding transfer rules, and it confirms that this will be achieved through including the details of any new programs adopted under the program funding transfer rules in the year-end Annual DSM Report.[217]

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[212] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, p. 10.
[213] Exhibit B-24 – FBC Response to BCUC IR 2.114.1.
[214] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, p. 10-11.
[215] Exhibit B-24 – FBC Response to BCUC IR 2.114.1.
[216] BCPSO Submission, s. 4.3.
[217] Exhibit B-7 – FBC Response to BCUC IR 1.262.1.

(3) DSM Reporting Period

165. Both BCPSO and BCSEA support the Company's request to discontinue the current semi-annual DSM reporting period, and to move to submitting annual reports on the DSM program.[218]

B. Legal Framework

(1) British Columbia's Energy Objectives

(a) GHG Emissions

166. Section 44.2(5)(a) of the UCA requires the Commission to consider the "applicable of British Columbia's energy objectives" in determining whether to approve FBC's submitted DSM expenditures. BCSEA submits that FBC has not complied with this GHG energy objective.[219]

167. The Company confirms that it has, indeed, considered GHG energy objectives in its DSM Plan. As was summarized in Table H-1 of the Application,[220] several of the British Columbia energy objectives are being met by the Company's DSM activities. This includes measures that encourage customers to switch to energy sources that decrease GHG emissions (CEA, s. 2(h)), as well as measures that encourage communities to reduce their GHG emissions, more generally (CEA, s. 2(i)).

168. Additionally, the Company notes that the Commission must only consider the applicable of British Columbia's energy objectives.[221] In the 2012-13 RRA Decision, when referencing its requirement to consider the applicable energy objectives, the Commission identified several of the energy objectives set out in section 2 of the CEA that were "most relevant" to the 2012-13 RRA. While these "most relevant" objectives included section 2(i), encouraging communities

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[218] BCSEA Submission, para. 14(b), BCPSO Submission, s. 4.2.
[219] BCSEA Submission, para. 123.
[220] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, pp. 3-4.
[221] UCA, s. 44.2(5).

to reduce GHG emissions and use energy efficiently, it did not include section 2(g), which refers to reducing GHG emissions by set levels up until 2050.[222] In contrast, objective 2(g) was discussed by the Commission in the 2012-13 RRA Decision as being a relevant objective in the context of considering whether to approve the proposed 2012 LTRP.[223] FBC confirms that the objective in section 2(g) of the CEA applies to FBC in the context of its long-term resource planning, and that it was considered by the Company in the development of the 2012 LTRP.[224]

169. Consistent with the 2012 LTRP, the Company has confirmed that its proposed conservation measures (which include DSM and the RCR) will result in offsetting more than 50 percent of annual load growth. As a result, this will also tend to reduce GHG emissions, in accordance with section 2(g) of the CEA.[225] While BCSEA states that reducing load growth is not the appropriate consideration, the Company disagrees.

170. Overall, a key objective of the DSM Plan is to mitigate load growth via DSM measures.[226] It is within this context of mitigating load growth that the CEA energy objectives must be considered. Accordingly, the Commission should look to the effect on load growth when assessing whether the proposed DSM measures are in alignment with BC's energy objectives.

171. Additionally, in the 2012-13 RRA Decision, the Commission determined that the 2012 LTRP met the requirements of the UCA, which included the energy objective in section 2(g) of the CEA on reducing GHG emissions.[227] As the proposed DSM Plan is consistent with the 2012 LTRP (as was described in Part 5(D)(2)(a) of the FBC PBR Submission, and as is set out below in the next

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[222] 2012-13 RRA, p. 91.
[223] 2012-13 RRA Decision, p. 145.
[224] Exhibit B-12 – FBC Response to BCSEA IR 1.21.
[225] Exhibit B-21 – FBC Response to BCSEA IR 2.39.1.
[226] Exhibit B-21 – FBC Response to BCSEA IR 2.45.6.
[227] 2012-13 RRA Decision, pp. 148-149.

section), the DSM Plan is also consistent with the applicable of British Columbia's energy objectives.

(2) Long-Term Resource Plan

172. BCSEA submits that the DSM Plan is not in the public interest, as it is contrary to the 2012 LTRP.[228] The Company disagrees, and refers to its submissions on this point in Part 5(D)(2)(a) of the FBC Non-PBR Submission.

173. Further, the Company notes that BCSEA has acknowledged both that the 2012 LTRP "is not legally 'cast in stone'" and that the "approved resource stack can be modified if circumstances change."[229] The Company agrees that its actual resource stack can, and should, be modified as circumstances change,[230] and submits that this has occurred with respect to the change in the Company's LRMC, as is described in detail in Part 5(E) of the FBC Non-PBR Submission and Part 5(C) of the FBC Non-PBR Reply.

174. Despite noting that the 2012 LTRP is not cast in stone, BCSEA seems to suggest that it must be strictly followed as the Company did not specifically "provide evidence or argument concerning the likelihood or possibility of a substantial drop in the LRMC occurring within three years" at the time of approval of the 2012 LTRP.[231] However, the Company could not have predicted future changes in circumstances at the time the 2012 LTRP was submitted for approval, nor was it obliged to attempt to gaze into a crystal ball and reference every possible change. Further, such an expectation is not consistent with the nature of the 2012 LTRP as a planning document.[232]

175. Finally, while the LRMC may have changed since the time of the 2012 LTRP, the proposed DSM Plan continues to achieve the approved target in the 2012

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[228] BCSEA Submission, para. 112-115.
[229] BCSEA Submission, para. 115.
[230] Exhibit B-12 – FBC Response to BCSEA IR 1.12.7.
[231] BCSEA Submission, para. 114.
[232] Exhibit B-12 – FBC Response to BCSEA IR 1.12.7.

LTRP of mitigating 50 percent of annual load growth using DSM and other conservation measures.[233]

176. The Company submits that the proposed DSM Plan remains consistent with the 2012 LTRP.

(3) Cost-Effectiveness of Expenditures

177. In the BCSEA Submission, BCSEA quotes from the GEEG Evidence[234] that "[i]t does not appear that FBC actually used the TRC or UCT to design its proposed DSM portfolio".[235] The Company submits that this assertion is completely unfounded, and notes that it has indicated many times in this proceeding that the TRC and mTRC tests formed the basis of the proposed DSM Plan.[236] More specifically, the Application supported its request for approval of the DSM expenditure schedules based on a schedule that demonstrated first and foremost that the proposed DSM Plan passed the required cost-effectiveness tests.[237]

178. BCSEA includes a table in the BCSEA Submission, which lists measures that BCSEA suggests should have been included in the proposed DSM Plan.[238] While BCSEA states that previous levels of expenditure from the 2012-13 DSM Plan could be included in the DSM Plan, the Company has confirmed that their inclusion would not be viable, and would lead to the total mTRC expenditure exceeding the 10 percent cap on the mTRC portfolio.[239] If the DSM Plan were to continue at the previous expenditure levels, it would also not be viable as the

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[233] 2012-13 RRA Decision, pp. 145, 147; Ex. B-24 – FBC Response to BCUC IR 2.100.1, 2.106.1.1.

[234] Exhibit C8-9 – Direct Testimony of Green Energy Economics Group, Inc (**GEEG**) and Resource Insight, Inc, dated December 20, 2013 (the **GEEG Evidence**).

[235] BCSEA Submission, para. 125.

[236] See FBC Non-PBR Submission at Part 5(D)(4)(b) and para. 374 and 385; Ex. B-7 – FBC Response to BCUC IR 1.236.3.1; Ex. B-21 – FBC Response to BCSEA IR 2.65.2, 2.65.6, 2.66.3

[237] Exhibit B-1-1 – FBC Application Appendices, Attachment H1 – DSM Plan, p. 4

[238] BCSEA Submission, para. 125.

[239] Exhibit B-21 – FBC Response to BCSEA IR 2.64.2.1.

residential program would fail the cost-effectiveness test.[240] Further, even if all programs (including those that pass the TRC but not the mTRC) were included, there would only be a modest improvement to the overall portfolio TRC, the customer sector TRC, and the DSM target savings.[241]

179. While BCSEA submits that FBC designed the DSM Plan “simply to remove measures and program components that were not cost-effective until the portfolio achieved the minimum level of TRC cost-effectiveness”,[242] this is mere conjuncture on BCSEA’s part, and is not supported by any evidence. The Company confirms that the proposed DSM Plan includes all DSM measures that have been identified by the Company as being cost-effective, with only some minor and prudent exceptions.[243]

180. BCSEA suggests that the DSM portfolio should be redesigned and rebalanced. While BCSEA denies that the GEEG Evidence ignores the topic of equity,[244] it concludes that there is nothing “inherently unfair about acquiring cost-effective efficient resources disproportionately from large customers”.[245] While BCSEA may not have “ignored” the topic of equity, it has certainly disregarded its application. This is inconsistent with FBC’s stated concern with the disparity in the PCT ratios between the commercial and industrial programs versus the residential program. The DSM Plan considers a variety of factors, including key-end uses, the cost-effectiveness tests, customer payback period and the take-up rate for customers, in determining the appropriate mix of customer DSM programs.[246]

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[240] Exhibit B-12 – FBC Response to BCSEA IR 1.21.1.
[241] Exhibit B-21 – FBC Response to BCSEA IR 2.64.2.2.
[242] BCSEA Submission, para. 127.
[243] Exhibit B-21 - FBC Response to BCSEA IR 2.66.4.
[244] BCSEA Submission, para. 133.
[245] Exhibit C8-9 – GEEG Evidence, p. 45.
[246] Exhibit B-42 – FBC Rebuttal Evidence to BCSEA, p. 1.

181. BCSEA also states that "FBC justifies the proposed DSM spending reduction in part by consideration of rate impacts".[247] The Company has consistently confirmed that the RIM Test was one of its considerations when designing the DSM portfolio, but that it does not screen DSM measures on the basis of rate impact: while rate impacts are important, they are secondary to the cost-effectiveness tests prescribed in the DSM Regulation.[248] The Company does not have a "threshold" for what rate impact it considers to be "viable" when designing the DSM portfolio;[249] this decision is left for the Commission to determine, in the context of the entire Application.[250] The rate impact of the DSM Plan, while important, is a by-product of the individual assessment of DSM measures based primarily on TRC cost-effectiveness and secondarily on other considerations not related to rate impact.[251]

182. The Company re-affirms its position that the proposed DSM Plan is cost-effective pursuant to the DSM Regulation, and should be approved by the Commission.

C. Long-Run Marginal Cost

(1) Specific LRMC Issues

(a) Short-Run versus Long-Run Estimate

183. BCSEA challenges FBC's LRMC on the basis that it allegedly "estimates only a series of *short*-run marginal energy costs" rather than being a true long-run marginal cost.[252] The Company disagrees with this characterization.

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247 BCSEA Submission, para. 136.

248 Exhibit B-1-4 – FBC Application Appendices, Appendix H – Demand Side Management, p. 14; Ex. B-21 – FBC Response to BCSEA IR 2.66.3.

249 Exhibit B-21 – FBC Response to BCSEA IR 2.65.3.

250 Exhibit B-21 – FBC Response to BCSEA IR 2.65.4.

251 Exhibit B-21 – FBC Response to BCSEA IR 2.65.6.

252 BCSEA Submission, para. 36.

184. As the Company described in the FBC Non-PBR Submission, the LRMC in the Application is not a short-run market price estimate, but is rather based on a 30 year forecast of market prices delivered to British Columbia.[253] While BCSEA refers to FBC's confirmation that the avoided-cost computation is "based on the simplifying assumption that the alternative to additional DSM is a series of short-term purchases from the Mid-Columbia energy market",[254] these short-term purchases occur at the estimated 30 year forecast of market prices. As such, an expected cost over the long term is arrived at and a fair comparison can be made.

(b) Exchange Rate

185. In the BCSEA Submission, BCSEA criticizes the exchange rate utilized to convert the Mid-C prices from US dollars to Canadian dollars in the LRMC estimate, and suggests that it will result in an underestimation of LRMC.[255] BCSEA suggests that FBC has prioritized using a forecast that is publicly available and consistent between gas and electricity price forecasts, rather than an assumption that is "actually accurate".[256]

186. In making its submissions, BCSEA misses the important point that it is the natural gas forecast price that is the primary driver in FBC's calculation of the Mid-C market price forecast, and therefore the LRMC. The conversion of the Mid-C price forecast from US dollars to Canadian dollars is just one small step in the process.[257] Given this, it is entirely appropriate that the exchange rate assumptions used to convert the Mid-C prices from US dollars to Canadian dollars come from the same source and be based on the same information as the underlying natural gas market price forecast. This position is reinforced by the fact that since the 2012 LTRP, the principal factor in the reduction of FBC's

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[253] FBC Non-PBR Submission, para. 348; Ex. B-24 – FBC Response to BCUC IR 2.98.3.
[254] BCSEA Submission, para. 37.
[255] Ibid, para. 41, 60.
[256] Ibid, para. 42.
[257] Exhibit B-1-1 – FBC Application Appendices, Attachment H4 – Midgard Memorandum, pp. 1-2.

estimate of LRMC has been the major shift downward in the long term natural gas price forecast.[258]

187. Further, BCSEA is ignoring the fact that forecasts are inherently uncertain. FBC is not claiming that the long-term exchange rate forecasts that it has relied on will turn out to be accurate, only that they are reasonable based on the interpretation and application of the information available at the time they are prepared and for their intended purpose.[259]

188. GLJ Petroleum Consultants prepares its quarterly price and market forecasts after a comprehensive review of information available to it at the time the forecast is prepared from a wide range of sources including government agencies, industry publications, Canadian oil refiners and natural gas marketers. As GLJ states:[260]

> The forecasts presented herein are based on an informed interpretation of currently available data. While they are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change.

189. Again, FBC believes that it is entirely appropriate to use the exchange rate assumptions that are based on the same review of market and economic information that is incorporated in the commodity price forecast used to determine FBC's avoided cost.[261]

190. BCSEA says that FBC was incorrect in concluding that GEEG believes that a better forecast would be to use the exchange rate futures.[262] However, BCSEA then proceeds to use foreign currency future prices as the sole point of

[258] Exhibit B-24 – FBC Response to BCUC IR 2.98.1.

[259] Exhibit B-21 – FBC Response to BCSEA IR 2.48.1.

[260] Exhibit B-21 – FBC Response to BCSEA 2.48.1 [Emphasis Added].

[261] Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 2.

[262] BCSEA Submission, para. 53.

comparison in an attempt to undermine both the GLJ forecasts.[263] BCSEA also ignored the information FBC provided in response to a BCSEA IR which illustrated the sometimes wide disparity between forward exchange rate information available at different points in time to actual rates.[264] For example, on January 2, 2009 the value of the Canadian dollar one year out based on the forward rate was 0.8303 USD per CAD while the actual rate on January 4, 2010 was 0.9636.[265]

191. BCSEA states that FBC has retreated from its criticism of using forwards to estimate future exchanges rates,[266] as in an IR response the Company indicated that it had "not made any assertion on the fallibility of forwards" and that they remained "a useful tool when used appropriately".[267] FBC stands by both of its statements: the forward rate is <u>not</u> a good predictor of long-term future exchange rates,[268] as is evidenced by the historical information provided in the FBC's responses to BCSEA's own information requests but this does not mean that forwards are fallible in nature or that they are not useful in the appropriate application.[269]

192. As the Company described in its Rebuttal Evidence to BCSEA, changes in the exchange rate forecast will have an impact on the LRMC.[270] BCSEA argues that the difference between an exchange rate of 1.00 and 0.90 corresponds to approximately 22% of the change in the LRMC used in the 2012-13 DSM Plan ($84.94/MWh) and the LRMC in the DSM Plan ($56.61/MWh).[271] BCSEA's assumption of a linear relationship between LRMC and DSM in order to determine the effect of exchange rate on DSM savings is less than "only roughly

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263 BCSEA Submission, para. 47.
264 Exhibit B-49 – FBC Response to BCSEA Rebuttal IR 1.3.4.
265 Exhibit B-49 – FBC Response to BCSEA Rebuttal IR 1.3.4.
266 BCSEA Submission, para. 56.
267 Exhibit B-49 – FBC Response to BCSEA Rebuttal IR 3.1.
268 Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 2.
269 Exhibit B-49 – FBC Response to BCSEA Rebuttal IR 1.3.4.
270 Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 2.
271 BCSEA Submission, para. 59.

illustrative".[272] In addition, the calculated impacts would also have to take into account other changes that occurred during the time period, which could have offset the effect of changes in the exchange rate.[273]

193. FBC is satisfied that the GLJ natural gas commodity forecast and associated exchange rate assumptions used in determining LRMC is reasonable and appropriate for their intended purpose.[274]

(c) Firm vs. Non-Firm Resources

194. BCSEA argues that the use of non-firm prices to estimate avoided costs is not adequate, and that it results in an excessive reduction in avoided cost.[275]

195. While BCSEA submits that DSM savings are generally as firm as FBC's load,[276] this is inconsistent with the Company's evidence. The "nuanced" approach that the Company suggests needs to be taken when determining whether DSM is firm or not, simply recognizes that some DSM is firm, and some is not. While BCSEA states that this is contradictory to the Company's statement that "broad-based DSM programs will return reliable energy savings over time", this statement must be read in conjunction with the remainder of the sentence, that "... traditional DSM measures are non-firm resources".[277] Together, these statements reflect the nuanced approach that FBC proposes.

196. BCSEA also suggests that "FBC appears to define a 'firm' resource as one that can be shaped or dispatched, which is incorrect". The Company actually stated that non-firm resources cannot be shaped or dispatched, and not that firm resources can be shaped or dispatched.[278]

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[272] BCSEA Submission, para. 59.
[273] Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 3; Ex. B-49 – FBC Response to BCSEA Rebuttal IR 5.1.
[274] Exhibit B-21 - FBC Response to BCSEA IR 2.49.2.
[275] BCSEA Submission, para. 62, 80.
[276] BCSEA Submission, para. 65.
[277] FBC Non-PBR Submission, para. 355.
[278] FBC Non-PBR Submission, para. 355; Ex. B-7 – FBC Response to BCUC IR 1.241.2.1.1.

197. While BCSEA suggests that FBC should adjust the spot-market prices to reflect the avoided costs of obtaining firm supply,[279] this ignores the fact that the Mid-C LRMC forecast is for firm energy.[280]

198. Further, the GEEG Evidence suggests that FBC's approach of "ignoring the need for firm supplies until after the 2015 Resource Plan is not prudent".[281] The authors of the GEEG Evidence appear to create a false sense of urgency. FBC's after-savings load growth with its proposed DSM plan is 0.5 percent to 0.7 percent per year.[282] The 2012 LTRP states that FBC does not plan to build new resources in the short to medium term, and it will re-evaluate is long-term needs in future resource plans.[283]

(d) Avoided Shaped Load

199. BCSEA suggests that FBC's DSM avoided cost estimate is too low, as it is based on average energy prices instead of prices at the times of day and year that correspond to DSM savings.[284]

200. It is correct that FBC uses a LRMC that is based on annual average avoided cost, and does not distinguish between seasonal or time of day savings.[285] While this is a simplifying assumption in the calculation of LRMC, the fact that the Company does not apply time-of-use shaping factors to its calculation of the proxy for avoided cost is consistent with the fact that the Company also does not apply time-of-use shaping factors to screen DSM programs to favour winter peaks.[286] Further, while not applying load shaping is a simplifying assumption, it avoids the inefficiencies associated with conducting a detailed and complicated analysis. The GEEG Evidence refers to "weighting the spot energy

[279] BCSEA Submission, para. 70.
[280] Exhibit B-7 – FBC Response to BCUC IR 1.241.2.1.
[281] BCSEA Submission, para. 69.
[282] Exhibit B-1 – FBC Application, p. 80.
[283] Exhibit B-7 – FBC Response to BCUC IR 1.240.4.
[284] BCSEA Submission, para. 86.
[285] Exhibit B-12 - FBC Response to BCSEA IR 1.6.2.2.
[286] Exhibit B-12 – FBC Response to BCSEA IR 1.7.5.2.

prices to reflect the pattern of DSM savings over the day, week and year".[287] This suggestion would require a very detailed analysis, involving a large amount of resources and time. Further, the analysis would require hourly price forecasts and hourly DSM forecasts, which are presently not available.[288] Therefore, FBC's proposed approach is a reasonable one.

(e) Transmission Costs

201. As described in the FBC Non-PBR Submission, the LRMC proposed in the Application is intended to reflect the cost that FBC would face if it were to purchase electricity at Mid-C and wheel the power to the Canada-US border.[289] It is not meant to represent the cost of importing power into British Columbia, but rather to represent a proxy for the average price of electricity within British Columbia.[290]

202. BCSEA suggests that Midgard has understated the transmission charges associated with moving the electricity from the Mid-C market to FBC's service territory, as a result of congestion occurring in the BPA system.[291] To remedy this, the GEEG Evidence suggests that congestion costs on the BPA system and the full cost of wheeling should be incorporated into LRMC. While BCSEA suggests that FBC is ignoring all congestion charges "because not all energy purchases avoided by DSM would include congestion charges",[292] this is not correct. It is not appropriate for congestion costs to be incorporated into LRMC, as there are no congestion costs on the BPA system as BPA does not impose congestion charges.[293] While congestion can lead to paying higher prices to meet peak loads, this risk has justified obtaining new resources, such as WAX.

[287] Exhibit C8-9 - GEEG Evidence, p. 84.
[288] Exhibit B-12 – FBC Response to BCSEA IR 7.0 series.
[289] Exhibit B-1-1 - FBC Application Appendices, Attachment H4 - Midgard Memorandum, p. 2.
[290] Exhibit B-1-1 - FBC Application Appendices, Attachment H4 – Midgard Memorandum, p. 3.
[291] BCSEA Submission, para. 87-89.
[292] BCSEA Submission, para. 89.
[293] Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 4.

With WAX, FBC's peak loads are not at risk at this time or in the near future.[294] Should it become a risk in the future, FBC will deal with this through its future resource planning.[295]

203. BCSEA also suggests that the LRMC forecast by Midgard contains an understatement of the avoided T&D costs, relying on the GEEG Report's estimated load-growth incremental costs of $233/kW-year, compared to $35/kW-year figure used by FBC.[296]

204. After stating that the NPPC recommended value of $23/kW-year (for avoided transmission cost) and $25/kW-year (for avoided distribution cost) referenced as a comparable by FBC is "substantially higher" than FBC's figure of $35/kW-year,[297] BCSEA continues to recommend the figure of $233/kW-year figure put forward in the GEEG Evidence.[298] While BCSEA attempts to suggest that this figure falls into the range of avoided T&D costs calculated by FBC for 2013 through 2019, it relies on a chart that estimates FBC's annualized cost of load-related T&D. This chart is not comparable to the Company's avoided T&D figure, and should not be relied on in determining FBC's avoided costs.

(f) Avoided Cost of GHG Mitigation

205. BCSEA also argues that it would be prudent for FBC to include a "high" GHG cost adder forecast when determining the DSM avoided cost, rather than utilizing BC Hydro's "low" GHG cost adder from the 2011 draft BC Hydro IRP.[299]

206. In its utility resource planning, FBC must comply with its legislated GHG obligations, currently specified by the CEA and the GHG (Cap and Trade) Reporting Regulation. Neither section 2(c) nor section 6(4) of the CEA directs

[294] Exhibit B-42 - Rebuttal of FBC to BCSEA, p. 4.
[295] Exhibit B-12 – FBC Response to BCSEA IR 1.8.2.
[296] BCSEA Submission, para. 96; Ex. C8-14 – GEEG Evidence, p. 60.
[297] BCSEA Submission, para. 94.
[298] Ibid, para. 95.
[299] Ibid, para. 106

FBC to meet long-term firm load growth with long-term firm clean BC energy, nor does it prescribe DSM target levels. However, FBC considers these issues in its resource planning, as described in the 2012 LTRP, and it does plan to become self-sufficient in the long-term.[300]

207. The Company's use of the BC Hydro "low" GHG cost adder in the determination of LRMC was based on Midgard's opinion that "the low GHG price adder scenario is the most plausible scenario".[301] This opinion was reached based on a consideration of the precursor documents (such as Technical Advisory Committee reports and presentations) to the BC Hydro IRP, which had not yet been completed. Having considered these documents, Midgard determined that the low price adder scenario represented the prudent choice of scenarios. This opinion has since been corroborated by the release of the BC Hydro 2013 IRP.[302]

208. BCSEA argues that the Company "underestimates the carbon intensity of the market purchases it uses as a proxy for DSM avoided costs" by "using the average annual PNW CO_2e emission rate rather than the marginal CO_2e emission rate".[303] BCSEA's suggestion ignores the fact that the Mid-C Trading hub is complex and trades surplus energy generated by various resources, including hydro with storage, run of river hydro, wind, nuclear, gas and coal. The generation mix is impacted by time of day and season.[304] Accordingly, the LRMC should represent a mix of different types of resources.

209. Further, the flexibility of FBC's system enables energy to be purchased at times when non-thermal resources, such as wind or water, are often the marginal resources. The Company believes that it is most appropriate to use the

[300] Exhibit B-21 - FBC Response to BCSEA IR 2.45.6.
[301] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Midgard Memo, p. 3.
[302] Exhibit B-12 – FBC Response to BCSEA IR 1.13.3.
[303] BCSEA Submission, para. 101, footnotes omitted.
[304] Exhibit B-12 - FBC Response to BCSEA IR 1.1.2.2, 1.3.6.

average CO_2e emission rate related to its market purchases.[305] While BCSEA suggests that a weighting of the marginal emissions rates over the year would be more appropriate,[306] this is inconsistent with the Greenhouse Gas Cap and Trade Reporting Regulation, which requires the Company to report its carbon footprint associated with electricity imports based on the average emissions factor.[307]

(g) Self-Sufficiency

210. The Company disagrees with BCSEA's submission regarding the applicability of section 6 of the CEA to FBC's DSM Plan.[308]

211. Section 6(4) of the CEA requires a public utility to consider British Columbia's energy objective to achieve electricity self-sufficiency "in planning in accordance with section 44.1 of the Utilities Commission Act for the construction or extension of generation facilities and energy purchases". The language of this section is clear: it expressly applies only to "planning in accordance with section 44.1" of the UCA. There is no suggestion of it having any "implicit" application beyond this section of the UCA, nor to it applying to applications brought under section 44.2 of the UCA.

212. In any event, even if the self-sufficiency requirement were to apply to "implicit" proposals, which the Company denies, FBC submits that the DSM Plan, in conjunction with other conservation measures, continues to achieve the Company's target for mitigating annual load growth.[309]

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[305] Exhibit B-21 – FBC Response to BCSEA IR 2.45.13.
[306] BCSEA Submission, para. 111.
[307] Exhibit B-21 – FBC Response to BCSEA IR 2.45.13.
[308] BCSEA Submission, para. 109.
[309] Exhibit B-24 – FBC Response to BCUC IR 2.100.1.

D. Collaboration with Other Utilities and Government

213. As was described in the FBC Non-PBR Submission, FBC has worked to collaborate with both FEU and BC Hydro with respect to its DSM measures.[310] However, ICG submits that this collaboration is not enough and that "[t]he DSM programs offered to similar customers of BC Hydro and FBC should be similar".[311]

214. ICG's suggestion presumes that utilities in British Columbia should have the same DSM programs. This assumption is unfounded. While the Company does integrate and collaborate with other utilities where possible, in accordance with the Commission's encouragement in the 2012-13 RRA Decision,[312] there is no requirement in the UCA or the DSM Regulation for FBC to integrate or align its DSM Plan with BC Hydro. While the ICG describes the DSM Regulation as having the objective of providing "a consistent province-wide standard for program design in BC",[313] it does not provide a source for this objective. The Company disagrees that this is a requirement of the DSM Regulation.

215. Further, ICG's suggestion is not consistent with the Commission's finding in the 2012-13 RRA Decision that it was not prepared to direct FBC to implement the same DSM programs as BC Hydro, as they are "different utilities, operating in different contexts".[314] That finding is consistent with ICG's own acknowledgement that there are "significant differences between BC Hydro and FBC industrial sector load as a percentage of total load". While ICG suggests that these aggregate differences do not account for the fact that BC Hydro's incentive levels are approximately three times higher than FBC's for industrial customers, it fails to mention that BC Hydro's average industrial customer sales are actually ten times higher than for FBC (78.5 GWh/customer versus 7.5

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[310] FBC Non-PBR Submission, para. 362..
[311] ICG Submission, para. 78.
[312] 2012-13 RRA Decision, p. 141.
[313] ICG Submission, para. 79.
[314] 2012-13 RRA Decision, p. 139.

GWh/customer). When this is combined with the fact that few jurisdictions have as high a percentage of large industrial load as BC Hydro, this skews industrial DSM spending, as there are much larger DSM opportunities for BC Hydro customers.[315] The Company states that this difference more than adequately explains the different levels of DSM spending between the companies.

216. ICG also requested that the Commission provide “further clarification” of the finding made in the FBC 2012-2013 RRA Decision.[316] The Company submits that this is not necessary and would not be helpful. In the 2012-13 RRA, the Commission heard submissions from ICG that are very similar to those put forward in this proceeding.[317] The Commission did not accept ICG’s requests and, clearly concluded that BC Hydro and FBC were “different utilities, operating in different contexts”.[318] Nothing about this statement requires further clarification.

217. ICG has also requested that FBC be directed by the Commission to provide a response to BCUC IR 2.107.3,[319] in which FBC “refuses to provide a side by side comparison of DSM programs offered by BC Hydro and FBC”.[320] As was set out in the response to the IR, providing such a side-by-side comparison would be resource intensive.[321] Further, the exercise would have no utility, given the Commission’s recognition in the 2012-13 RRA Decision, of the differences between BC Hydro and FBC.[322]

218. ICG’s suggestion that FBC should file a DSM Plan that is consistent with BC Hydro’s program[323] also presumes that BC Hydro’s DSM program is the correct

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[315] Exhibit B-24 – FBC Response to BCUC IR 2.107.2.
[316] ICG Submission, para. 78.
[317] 2012-13 RRA Decision, p. 137.
[318] 2012-13 RRA Decision, p. 139.
[319] Exhibit B-24 – FBC Response to BCUC IR 2.107.3.
[320] ICG Submission, para. 77.
[321] ICG Submission, para. 77.
[322] 2012-13 RRA Decision, p. 139.
[323] ICG Submission, para. 79.

program, and that the program suggested by FBC is not. There is no evidence to support this assertion. Further, the Commission previously rejected this same suggestion from ICG in the 2012-13 RRA Decision, stating that "we are not persuaded that BC Hydro's level of incentive is necessarily optimal and that FBC should move to that level".[324]

E. Interveners Proposed Changes to DSM Expenditures

(1) Increasing DSM Spending Level

219. In the BCSEA Submission, BCSEA submits that the DSM Plan is not in the public interest, as BCSEA contends that it represents a drastic cutback in DSM savings from the 2012-13 DSM Plan.[325] BCSEA describes the expenditures under the DSM Plan as being "a gutting of the 2012-2013 DSM Plan".[326]

220. BCSEA's use of the word "gutting" creates a charged impression that does not conform to the reality. While the proposed expenditures under the DSM Plan are lower than FBC's previous DSM spending, the Company has described the reasons for this reduction in the Application and the FBC Non-PBR Submission.[327] As was described above, one of the predominant reasons for the reduction in the Company's proposed DSM expenditures, as compared to previously approved expenditure levels, is a decline in LRMC.[328]

221. ICG also challenges FBC's proposed reduction in DSM savings target, specifically with respect to Industrial DSM. ICG states that the Company justified its proposed reduction based on "a dramatic decrease in forecast savings for 2013", which ICG suggests did not materialize as forecast. In support of its argument, ICG refers to the 2013 Industrial Sector DSM savings forecast of 857 MWh (forecast as of November 2013), and compares it to the

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[324] 2012-13 RRA Decision, p. 139.
[325] BCSEA Submission, para. 21, 29.
[326] BCSEA Submission, para. 29.
[327] See, for example, FBC Non-PBR Submission at para. 280.
[328] See also FBC Non-PBR Submission,para. 362.

actual for 2013 of 2,520 MWh. ICG proposes that the savings target be increased to 2,500 MWh for the Industrial sector. [329]

222. As is acknowledged by ICG,[330] it relies on actual 2013 DSM savings from the FBC Annual DSM Report for December 2013, filed by FBC with the Company on March 31, 2014 (**December 2013 DSM Report**). The December 2013 DSM Report is not on the record in this proceeding.

223. The Company submits that ICG should not be able to rely on these figures. As the 2013 DSM Report is not on the record, ICG seeks to introduce the figures for industrial sector savings in isolation, without providing any of the surrounding context for the figures. Further, the parties in the proceeding have not had the opportunity to place evidence on the record with respect to the figures. Relying on the actual 2013 figures in isolation ignores the specific projects that contributed to the savings, and whether the savings were extraordinary or will continue into future years.

224. Instead, the Company states that the 2013 forecast for industrial savings of 857 MWh, which has been on the record since the November 2013 and has been subject to the regulatory process, should be preferred. The Company submits that setting the savings target for the industrial sector at 800 MWh for 2014-2018 is prudent. As was acknowledged by ICG, the Company confirms that the program funding transfer rules will provide the Company with the flexibility to respond to any extraordinary and unexpected opportunities that arise in the Industrial sector. While ICG states that FBC "will not do so for industrial customers unless directed to do so by the Panel in this decision",[331] this is simply an unfounded assumption. The Company has indicated that the entire purpose of the program funding transfer rules is to allow it to respond, where appropriate, to changing opportunities in a timely manner.[332]

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[329] ICG Submission, para. 75.
[330] ICG Submission, footnote 74.
[331] ICG Submission, para. 76.
[332] Exhibit B-1-1 – FBC Application Appendices, Appendix H – Demand Side Management, p. 11.

225. Additionally, FBC notes that ICG has based its recommendation on an examination of the proposed industrial savings in isolation, rather than considering the entire DSM Plan.[333] ICG's approach is inconsistent with the approach that the Company has requested that the Commission adopt. The Company has submitted that it is appropriate for the Commission to consider the proposed DSM portfolio as a whole, when determining cost-effectiveness. This is consistent with section 4(1) of the DSM Regulation, which provides that the Commission may compare the costs and benefits of the portfolio as a whole, and is consistent with the approach accepted by the Commission in the 2012-13 RRA Decision.[334] The Company's reasons for determining that a portfolio-level analysis is appropriate are described in more detail at paragraphs 326 to 327 of the FBC Non-PBR Submission.

(2) Amortization Period

226. ICG adopts the opinion of Mr. Pullman that, as of the end of 2013, FBC should no longer be capitalizing DSM expenses associated with Planning and Evaluation Expenditures, and that the amortization period for all remaining DSM expenses should remain at 10 years rather than the 15 year period requested by FBC. ICG has not provided any basis for this opinion, other than to suggest that BC Hydro's change to a 15 year amortization period was mandated by the government and that it is inconsistent with the US practice of expensing DSM expenses immediately.[335] The Company refers to Part 5(H) of the FBC Non-PBR Submission, in which it describes why the proposed 15 year amortization period should be approved.

227. Additionally, the Company notes that BCSEA supports Commission approval of the change to a 15 year amortization period, effective January 1, 2014.[336]

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[333] ICG Submission, para. 75.
[334] 2012-13 RRA Decision, p. 136.
[335] ICG Submission, para. 100.
[336] BCSEA Submission, para. 14(a).

PART 6 - CONCLUSION

228. In light of all of the above, FBC reaffirms its request for the relief set out in paragraph 1 of the FBC Non-PBR Submission.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Counsel for FortisBC Inc.:

[Original signed by Ludmila Herbst]

Ludmila B. Herbst

[Original signed by Erica Miller]

Erica C. Miller

Dated: June 12, 2014

AUTHORITY

Northwestern Utilities Ltd. v. The City of Edmonton, [1979] 1 S.C.R. 684, Estey J. (for the Supreme Court of Canada)

Northwestern Utilities Limited and The Public Utilities Board of the Province of Alberta *Appellants*;

and

The City of Edmonton *Respondent.*

1977: November 28; 1978: October 3.

Present: Laskin C.J. and Ritchie, Spence, Pigeon, Dickson, Estey and Pratte JJ.

ON APPEAL FROM THE SUPREME COURT OF ALBERTA, APPELLATE DIVISION

Public utilities — Application for interim rate increase — Order of Public Utilities Board permitting recovery of losses incurred before date of application — Board thereby offending provisions of s. 31 of The Gas Utilities Act, R.S.A. 1970, c. 158 — Application of s. 8 of The Administrative Procedures Act, R.S.A. 1970, c. 2, to proceedings — Matter returned to Board for continuation of hearing.

Commencing on August 20, 1974, the appellant company filed an application with the Alberta Public Utilities Board for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the company to its customers. The application made reference to the powers under s. 31 of *The Gas Utilities Act*, R.S.A. 1970, c. 158, by asking for an order "giving effect to such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility requirement at $72,141,000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

On August 20, 1975, the company filed with the Board an application for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by [the company] to its customers"; and on September 25, 1975, it filed an application for an interim order "approving changes in existing rates, tolls

Northwestern Utilities Limited et The Public Utilities Board de la Province de l'Alberta *Appelantes*;

et

La ville d'Edmonton *Intimée.*

1977: 28 novembre; 1978: 3 octobre.

Présents: Le juge en chef Laskin et les juges Ritchie, Spence, Pigeon, Dickson, Estey et Pratte.

EN APPEL DE LA DIVISION D'APPEL DE LA COUR SUPRÊME DE L'ALBERTA

Services publics — Requête visant une augmentation provisoire de tarifs — Ordonnance de The Public Utilities Board permettant le recouvrement de pertes subies avant la date de la requête — La Commission n'a pas respecté l'art. 31 de The Gas Utilities Act, R.S.A. 1970, chap. 158 — Application aux procédures de l'art. 8 de The Administrative Procedures Act, R.S.A. 1970, chap. 2 — Affaire renvoyée à la Commission pour qu'elle en poursuive l'audition.

Le 20 août 1974, la compagnie appelante a demandé à The Public Utilities Board de l'Alberta une ordonnance établissant une base de tarification et un rendement convenable et approuvant les tarifs et droits qu'elle voulait imposer à ses clients pour le gaz naturel qu'elle distribuait. Se référant aux pouvoirs prévus à l'art. 31 de *The Gas Utilities Act*, R.S.A. 1970, chap. 158, elle demandait une ordonnance «tenant compte de la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». En outre, elle demandait une ordonnance établissant des tarifs provisoires jusqu'à la fixation des «tarifs définitifs». En conséquence, plusieurs ordonnances provisoires ont été rendues entre le 15 novembre 1974 et le 30 juin 1975. En réponse à la requête du 20 août 1974, la Commission rendait, le 15 septembre 1975, une ordonnance qui établissait une base de tarification et un rendement convenable et fixait le revenu total nécessaire à l'entreprise à $72,141,000. Ces montants inclus dans l'ordonnance étaient calculés en fonction des «données réelles pour 1974» et des «prévisions pour 1975». La Commission a ensuite ordonné à la compagnie de produire un tarif «apte à produire le revenu total nécessaire à l'entreprise approuvé par la Commission».

Le 20 août 1975, la compagnie a présenté à la Commission une requête en vue d'obtenir une ordonnance «approuvant les modifications aux tarifs, taxes et droits actuellement perçus par [la compagnie] pour le gaz distribué et les services fournis à ses clients»; cette requête fut suivie d'une autre, datée du 25 septembre or charges for gas supplied and services rendered by [the company] to its customers pending final determination of the matter". The application of 1975 recited the history of the 1974 application and stated that the operating costs and gas costs of the company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application has awarded the applicant "interim refundable rates", the 1975 application went on to state that the "existing rates charged by the applicant for natural gas do not produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public". Therefore the company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the company to its customers. The company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". The 1975 application sought as well interim rates "pending the fixing of final rates".

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The City of Edmonton appealed from this interim order to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of *The Public Utilities Board Act*, R.S.A. 1970, c. 302. The majority of the Appellate Division set aside the order and remitted it to the Board for reconsideration on two grounds: (1) that the effect of the order was a contravention of s. 31 of *The Gas Utilities Act* in that the company was thereby granted recovery of losses incurred before the date of application, namely, August 20, 1975; and (2) that the Board failed to comply with s. 8 of *The Administrative Procedures Act*, R.S.A. 1970, c. 2, by reason of its failure to give reasons for its decision. The company and the Board appealed to this Court from the decision of the Appellate Division.

Held: The appeal should be dismissed and the matter returned to The Public Utilities Board for continuation of the hearing of the company's application of August 20, 1975.

1975, pour obtenir une ordonnance provisoire «approuvant, jusqu'à ce qu'une décision définitive soit rendue, les modifications aux tarifs, taxes et droits actuellement perçus par [la compagnie] pour le gaz distribué et les services fournis à ses clients». La requête de 1975 fait l'historique de la requête de 1974 et souligne que les frais d'exploitation de la compagnie et le coût du gaz «ont considérablement augmenté comparativement aux montants indiqués dans la requête de 1974 et continuent d'augmenter». Après avoir mentionné qu'à la suite de la requête présentée en 1974, la Commission avait accordé à la requérante des «tarifs provisoires remboursables», la requête de 1975 allègue que «les tarifs actuellement perçus par la requérante pour son gaz naturel ne produisent pas un revenu suffisant pour lui permettre de faire face à ses dépenses actuelles et futures d'exploitation et d'amortissement et d'obtenir un taux de rendement convenable sur l'investissement utilisé au service du public». La compagnie a alors demandé une ordonnance qui établisse une base de tarification et un rendement convenable, et fixe et approuve les tarifs à percevoir par la compagnie pour la distribution de gaz naturel. La compagnie a également demandé une ordonnance tenant compte de «la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». La requête de 1975 demandait en outre une ordonnance fixant des tarifs provisoires applicables «jusqu'à l'établissement de tarifs définitifs».

Dans son ordonnance du 1er octobre 1975, la Commission a accordé une augmentation provisoire de tarifs permettant à la compagnie de percevoir un revenu supérieur de $2,785,000 à celui qu'elle aurait normalement perçu en 1975. La ville d'Edmonton a interjeté appel de cette ordonnance provisoire devant la Division d'appel de la Cour suprême de l'Alberta en vertu de l'art. 62 de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302. Par un jugement rendu à la majorité, la Division d'appel a infirmé l'ordonnance et a renvoyé l'affaire devant la Commission pour un nouvel examen en se fondant sur deux motifs: (1) l'ordonnance produit un résultat qui contrevient à l'art. 31 de *The Gas Utilities Act*, car elle permet à la compagnie de recouvrer des pertes subies avant la présentation de la requête, c.-à-d. le 20 août 1975; et (2) la Commission n'a pas respecté l'art. 8 de *The Administrative Procedures Act*, R.S.A. 1970, chap. 2, en ne consignant pas les motifs de sa décision. La compagnie et la Commission ont interjeté appel devant cette Cour de cette décision de la Division d'appel.

Arrêt: Le pourvoi doit être rejeté et l'affaire doit être renvoyée à The Public Utilities Board pour qu'elle poursuive l'audition de la requête de la compagnie présentée le 20 août 1975.

The word "losses" as it is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates.

The first of the two principal issues in this appeal, *i.e.*, whether the Board by its interim order of October 1, 1975, offended the provisions of s. 31 by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975, was very narrow. The issue was simply whether or not the company by not applying in the 1974 application for a further interim order caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the company will have the effect of recovering from future gas consumers revenue losses incurred by the company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates in a manner not authorized by s. 31.

The majority in the Court below observed that "*prima facie* the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year". This Court was not prepared to say that a *prima facie* case had been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. The test was not whether the "new tentative rate base includes an amount for revenue losses" but rather the question was whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The company submitted that a determination of what is or is not a 'past loss' is a pure question of fact and as such is not subject to appeal by reason of s. 62 of *The Public Utilities Board Act*, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involved a determination

Le mot «pertes» à l'art. 31 ne renvoie pas aux pertes comptables au sens d'une perte nette subie au cours d'une année d'imposition, mais plutôt à la perte de revenu subie par l'entreprise au cours d'une période précise en raison du retard à mettre en vigueur, durant cette période, les augmentations projetées.

La première des deux principales questions en litige dans ce pourvoi qui consiste à déterminer si l'ordonnance provisoire rendue par la Commission le 1[er] octobre 1975 contrevient à l'art. 31 en permettant, selon la Ville, le recouvrement de pertes subies avant la présentation de la requête, le 20 août 1975, est très limitée. Il s'agit uniquement de déterminer si, en ne demandant pas d'ordonnance provisoire supplémentaire dans sa requête de 1974, la compagnie a amené la Commission à répondre à la nouvelle requête de 1975 de manière à autoriser des tarifs qui auraient pour effet de faire supporter par les nouveaux consommateurs de gaz les pertes de revenu sur le gaz livré avant la date de la requête (soit le 20 août 1975) ou avant la mise en vigueur des tarifs du 1[er] octobre 1975, mais d'une façon qui n'est pas autorisée par l'art. 31.

La Cour d'appel, à la majorité, a fait remarquer que «*prima facie* la nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu subies depuis le début de 1975 jusqu'à la date de la présentation de la requête, en août, car les calculs ne répartissent pas la perte entre les deux périodes de l'année». Cette Cour n'est pas prête à dire qu'il est établi *prima facie* que l'imposition des tarifs provisoires à compter du 1[er] octobre 1975 permettait le recouvrement dans l'avenir de pertes de revenu subies avant le 20 août 1975. Au lieu de se demander si la «nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu», il faut se demander si l'imposition dans l'avenir des tarifs provisoires procurera un revenu excédant le revenu total requis selon les calculs pour la même période, suite à l'inclusion dans le calcul d'un montant destiné à couvrir les manques à gagner subis avant la date de la présentation de la requête, que ces derniers aient ou non été inclus, de quelque façon que ce soit, dans la base de tarification ou aient été inclus dans les dépenses d'exploitation prévues pour la période durant laquelle les nouveaux tarifs provisoires seront imposés, sous réserve évidemment du pouvoir limité de la Commission en vertu de l'art. 31.

La compagnie a plaidé que la détermination de ce qui constitue une «perte passée» est une question de fait, non susceptible d'appel en vertu de l'art. 62 de *The Public Utilities Board Act*; cet article limite l'appel des décisions de la Commission aux seules questions de «droit ou de compétence». Le présent pourvoi implique l'analyse of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to characterization of "the forecast revenue deficiency in the 1975 future test year" of the company involved a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which involved the Board in construing ss. 28 and 31 of *The Gas Utilities Act* raises a question of law and may well go to the jurisdiction of the Board.

However, it was not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board's order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order were so narrow in scope and of such extraordinary brevity that one was left without guidance as to the basis upon which the rates had been established for the period October 1, 1975, onwards. Hence this submission of the company failed.

As to the second issue, namely the application to these proceedings of s. 8 of *The Administrative Procedures Act*, which provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it, the Board in its decision allowing the interim rate increase failed to meet the requirements of this section. The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal were unable to determine whether or not in discharging its functions, the Board had remained within or had transgressed the boundaries of its jurisdiction established by its parent statute. The appellants were not assisted by the decision in *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.* (1976), 2 A.R. 453, aff'd [1977] 2 S.C.R. 822, to the effect that under s. 8 of *The Administrative Procedures Act* the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor could the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. The order of the

de l'intention du législateur relativement au pouvoir de la Commission de tenir compte des manques à gagner ou des dépenses excédentaires engagées avant la présentation d'une demande de nouveaux tarifs en vertu de la Loi. La décision de la Commission au sujet du «manque à gagner prévu pour 1975, l'année témoin», comporte la détermination de questions dont la Commission prend connaissance pour fixer les tarifs en vertu de la Loi. C'est là une question de droit susceptible d'appel en vertu de l'art. 62. Une décision relative à une requête qui oblige la Commission à interpréter les art. 28 et 31 de *The Gas Utilities Act*, soulève une question de droit pouvant mettre en cause la compétence de la Commission.

Cependant, les circonstances de la présente affaire ne permettent pas au tribunal qui examine l'ordonnance de la Commission d'établir si cette dernière a excédé sa compétence. Le libellé et le contenu de l'ordonnance de la Commission sont en effet d'une portée si limitée et d'une telle brièveté qu'il est impossible d'établir si les tarifs ont été fixés pour la période commençant le 1er octobre 1975. Cet argument de la compagnie ne peut donc être retenu.

La deuxième question en litige porte sur l'application de l'art. 8 de *The Administrative Procedures Act* aux présentes procédures; cette disposition oblige certains tribunaux administratifs à communiquer aux parties une décision écrite, exposant les conclusions de fait et les motifs sur lesquels elle est fondée; la décision de la Commission accordant l'augmentation provisoire de tarifs n'est pas conforme aux exigences de cet article. L'inobservation de l'art. 8 par la Commission comporte l'omission très grave d'exposer «les conclusions de fait sur lesquelles sa décision est fondée», de sorte qu'il est impossible pour les parties et pour le tribunal siégeant en révision de déterminer si, dans l'exercice de ses fonctions, la Commission a respecté ou excédé les limites de sa compétence qu'établit sa loi organique. Les appelantes ne trouvent aucun appui dans *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.* (1976), 2 A.R. 453, confirmé à [1977] 2 R.C.S. 822, où il fut jugé que pour être conformes à l'art. 8 de *The Administrative Procedures Act*, les motifs doivent être appropriés, pertinents et intelligibles, et doivent permettre à la partie concernée d'évaluer les possibilités d'appel. La Commission ne peut pas invoquer non plus le caractère particulier de l'ordonnance en question, savoir une ordonnance provisoire dont les dispositions prévoient la possibilité d'un remboursement des montants perçus sous son autorité, pour se soustraire

Board revealed only conclusions without any hint of the reasoning process which led thereto. The result was that a reviewing tribunal could not with any assurance determine that the statutory mandates bearing upon the Board's process had been heeded.

As for the participation of The Public Utilities Board in these proceedings, there is no doubt that s. 65 of *The Public Utilities Board Act* confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given *locus standi* as a participant in the nature of an *amicus curiae* but not as a party. That this is so is made evident by s. 63(2) under which a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself.

The policy of this Court is to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction.

Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142 (1973), 7 N.B.R. (2d) 41; *MacDonald v. The Queen* (1976), 29 C.C.C. (2d) 257; *Re Canada Metal Co. Ltd. et al. and MacFarlane* (1973), 1 O.R. (2d) 577; *Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Ltd.*, [1961] S.C.R. 72; *Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Ltd.*, [1947] S.C.R. 336; *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board* (1958), 18 D.L.R. (2d) 588; *Central Broadcasting Co. Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers, Local Union No. 529*, [1977] 2 S.C.R. 112; *Canada Labour Relations Board v. Transair Ltd. et al.*, [1977] 1 S.C.R. 772, referred to.

APPEAL from a judgment of the Supreme Court of Alberta, Appellate Division[1], setting aside an order of The Public Utilities Board of the Province of Alberta granting an interim increase in rates pursuant to s. 52(2) of *The Public Utilities Board Act*, R.S.A. 1970, c. 302. Appeal dismissed.

[1] (1977), 2 A.R. 317.

à son obligation de rendre une décision motivée. L'ordonnance de la Commission ne comporte que des conclusions et est muette quant au raisonnement suivi pour y arriver, de sorte que le tribunal siégeant en révision ne peut établir avec certitude si la Commission a observé les exigences légales dans l'élaboration de sa décision.

En ce qui concerne la participation de The Public Utilities Board aux présentes procédures, il est évident que l'art. 65 de *The Public Utilities Board Act* confère à la Commission le droit de participer à l'appel de ses décisions, mais en l'absence d'indication précise de l'intention du législateur, ce droit est limité. La Commission a un *locus standi* et son droit de participer aux procédures d'appel s'apparente à celui d'un *amicus curiae* et non à celui d'une partie. Cela ressort clairement du par. 63(2) qui fait une distinction entre les «parties» qui interjettent appel de la décision de la Commission ou qui étaient représentées devant la Commission, et la Commission elle-même.

Cette Cour, à cet égard, a toujours voulu limiter le rôle du tribunal administratif dont la décision est contestée à la présentation d'explications sur le dossier dont il était saisi et d'observations sur la question de sa compétence, même lorsque la loi lui confère le droit de comparaître.

Jurisprudence: *Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142* (1973), 7 N.B.R. (2d) 41; *MacDonald c. La Reine* (1976), 29 C.C.C. (2d) 257; *Re Canada Metal Co. Ltd. et al. and MacFarlane* (1973), 1 O.R. (2d) 577; *Labour Relations Board of the Province of New Brunswick c. Eastern Bakeries Ltd.*, [1961] R.C.S. 72; *Labour Relations Board of Saskatchewan c. Dominion Fire Brick and Clay Products Ltd.*, [1947] R.C.S. 336; *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board* (1958), 18 D.L.R. (2d) 588; *Central Broadcasting Co. Ltd. c. Conseil canadien des relations du travail et la Fraternité internationale des ouvriers en électricité, Section locale nº 529*, [1977] 2 R.C.S. 112; *Conseil canadien des relations du travail c. Transair Ltd. et autres*, [1977] 1 R.C.S. 772.

POURVOI à l'encontre d'un arrêt de la Division d'appel de la Cour suprême de l'Alberta[1] infirmant une ordonnance de The Public Utilities Board de la province de l'Alberta qui accordait une augmentation provisoire de tarifs en vertu du par. 52(2) de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302. Pourvoi rejeté.

[1] (1977), 2 A.R. 317.

T. Mayson, Q.C., for the appellant Northwestern Utilities Ltd.

W. J. Major, Q. C., and *C. K. Sheard*, for the appellant Public Utilities Board of the Province of Alberta.

M. H. Patterson, Q. C., for the respondent.

The judgment of the Court was delivered by

ESTEY J.—This is an appeal by The Public Utilities Board for the Province of Alberta and Northwestern Utilities Limited from a decision of the Appellate Division of the Supreme Court setting aside an order of the Board granting an interim increase in rates pursuant to s. 52(2) of *The Public Utilities Board Act*, R.S.A. 1970, c. 302.

The majority of the Court of Appeal set aside the order and remitted it to the Board for reconsideration on two grounds:

(1) That the effect of the order was a contravention of s. 31 of *The Gas Utilities Act*, R.S.A. 1970, c. 158, in that Northwestern Utilities Limited was thereby granted recovery of losses incurred before the date of application, namely, the 20th of August 1975; and

(2) That the Board failed to comply with s. 8 of *The Administrative Procedures Act*, R.S.A. 1970, c. 2, by reason of its failure to give reasons for its decision.

The appellant, The Public Utilities Board (herein referred to as 'the Board'), is constituted under *The Public Utilities Board Act* to "deal with public utilities and the owners thereof as provided in this Act" (s. 28(1)), and is given more specific duties and powers with respect to gas utilities under *The Gas Utilities Act*. The appellant, Northwestern Utilities Limited (herein referred to as 'the Company'), is a gas utility regulated under these statutes.

The Board is by the latter statute directed to "fix just and reasonable ... rates, ... tolls or charges ..." which shall be imposed by the Company and other gas utilities and in connection therewith shall establish such depreciation and

T. Mayson, c.r., pour l'appelante Northwestern Utilities Ltd.

W. J. Major, c.r., et *C. K. Sheard*, pour l'appelante Public Utilities Board de la province de l'Alberta.

M. H. Patterson, c.r., pour l'intimée.

Le jugement de la Cour a été rendu par

LE JUGE ESTEY—Ce pourvoi est interjeté par The Public Utilities Board de la province de l'Alberta et Northwestern Utilities Limited à l'encontre d'un arrêt de la Division d'appel de la Cour suprême de l'Alberta annulant une ordonnance aux termes de laquelle la Commission accordait une augmentation provisoire de tarifs en vertu du par. 52(2) de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302.

La majorité en Cour d'appel a infirmé l'ordonnance et renvoyé l'affaire devant la Commission pour deux motifs:

[TRADUCTION] (1) L'ordonnance produit un résultat qui contrevient à l'art. 31 de *The Gas Utilities Act*, R.S.A. 1970, chap. 158, car elle permet à Northwestern Utilities Limited de recouvrer des pertes subies avant la date de la requête, c.-à-d. le 20 août 1975; et

(2) La Commission n'a pas respecté l'art. 8 de *The Administrative Procedures Act*, R.S.A. 1970, chap. 2, en ne consignant pas les motifs de sa décision.

L'appelante, The Public Utilities Board (ci-après appelée la «Commission»), a été créée par *The Public Utilities Board Act* pour [TRADUCTION] «connaître des questions concernant les entreprises de services publics et leurs propriétaires, conformément à la présente loi» (par. 28(1)); *The Gas Utilities Act* lui confère en outre des devoirs et pouvoirs plus spécifiques à l'égard des entreprises de distribution de gaz. L'appelante Northwestern Utilities Limited (ci-après appelée la «Compagnie») est une entreprise de distribution de gaz régie par ces lois.

L'article 27 de *The Gas Utilities Act* habilite la Commission à [TRADUCTION] «fixer les tarifs, ... taxes ou droits ... justes et raisonnables» que la Compagnie et les autres entreprises de distribution de gaz seront autorisées à percevoir et, ce faisant, other accounting procedures as well as "standards, classifications [and] regulations . . ." for the service of the community by the gas utilities (s. 27, *The Gas Utilities Act*). In the establishment of these rates and charges, the Board is directed by s. 28 of the statute to "determine a rate base" and to "fix a fair return thereon". The Board then estimates the total operating expenses incurred in operating the utility for the period in question. The total of these two quantities is the 'total revenue requirement' of the utility during a defined period. A rate or tariff of rates is then struck which in a defined prospective period will produce the total revenue requirement. The whole process is simply one of matching the anticipated revenue to be produced by the newly authorized future rates to future expenses of all kinds. Because such a matching process requires comparisons and estimates, a period in time must be used for analysis of past results and future estimates alike. The fiscal year of the utility is generally found to be a convenient but not a mandatory period for these purposes. It is a process based on estimates of future expenses and future revenues. Both according to the evidence fluctuate seasonally and both vary according to many uncontrollable forces such as weather variations, cost of money, wage rate settlements and many other factors. Thus the rate when finally established will be such as the Board deems just and reasonable to allow the recovery of the expenses incurred by a utility in supplying gas to its customers, together with a fair return on the investment devoted to the enterprise. We are here concerned only with the rate establishing process and, hence, this summation of the Board's functions and powers is limited to that aspect of its statutory operations.

While the statute does not precisely so state, the general pattern of its directing and empowering provisions is phrased in prospective terms. Apart from s. 31 there is nothing in the Act to indicate any power in the Board to establish rates retrospectively in the sense of enabling the utility to recover a loss of any kind which crystallized prior to the date of the application (*vide City of*

à déterminer la méthode d'amortissement et autres procédures comptables de même que les [TRADUCTION] «normes, catégories [et] règlements» applicables aux entreprises de distribution de gaz en tant que services publics. Pour établir ces tarifs et droits, la Commission doit, en vertu de l'art. 28 de la Loi, [TRADUCTION] «établir une base de tarification [et] fixer un taux de rendement convenable». La Commission doit ensuite évaluer les dépenses totales d'exploitation de l'entreprise pendant la période considérée. Le total de ces deux éléments forme le «revenu total nécessaire» à l'entreprise pour une période donnée. Le tarif est alors établi pour la période à venir de façon à produire le revenu total nécessaire. En fait, il s'agit de faire correspondre les revenus que produiront les nouveaux tarifs autorisés pour la période à venir au total des diverses dépenses futures. Etant donné que ce calcul se fait sur la base de comparaisons et d'estimations, l'analyse des résultats obtenus dans le passé et des estimations faites pour l'avenir doit être fondée sur une période de temps précise. Sans être la règle, l'année d'imposition de l'entreprise est généralement considérée une base adéquate. Le processus est fondé sur une estimation des dépenses et revenus futurs. Selon la preuve, ces deux éléments varient d'une saison à l'autre et dépendent de facteurs incontrôlables tels les conditions météorologiques, le coût de l'argent, les ententes salariales, et ainsi de suite. Ainsi, le tarif établi par la Commission doit être celui qu'elle juge juste et raisonnable pour permettre le recouvrement des dépenses engagées par une entreprise de distribution de gaz pour desservir ses clients et la réalisation d'un taux de rendement convenable sur l'investissement dans l'entreprise. La seule question qui nous occupe en l'espèce est la méthode de détermination des tarifs et, en conséquence, cet aperçu des fonctions et pouvoirs de la Commission se limite à cet aspect du rôle que lui prescrit la loi.

Bien que la Loi ne le dise pas expressément, ses prescriptions et dispositions habilitantes sont rédigées en termes prospectifs. Mis à part l'art. 31, rien dans la Loi n'indique que la Commission ait le pouvoir d'établir rétroactivement des tarifs de façon à permettre à l'entreprise de recouvrer des pertes d'aucun genre subies avant la date de la requête. (Voir l'arrêt *Ville d'Edmonton et autres*

Edmonton et al. v. Northwestern Utilities Limited[2], *per* Locke J. at pp. 401, 402).

The rate-fixing process was described before this Court by the Board as follows:

The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

The statutory pattern is founded upon the concept of the establishment of rates *in futuro* for the recovery of the total forecast revenue requirement of the utility as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the Act which make this clear and I take but one example, found in s. 35, which provides:

(1) No change in any existing rates . . . shall be made by a . . . gas utility . . . until such changed rates or new rates are approved by the Board.

(2) Upon approval, the changed rates . . . come into force on a date to be fixed by the Board and the Board

[2] [1961] S.C.R. 392.

c. Northwestern Utilities Limited[2], le juge Locke, aux pp. 401 et 402.)

Voici en quels termes la Commission a décrit à cette Cour sa méthode de détermination des tarifs:

[TRADUCTION]—La PUB approuve ou fixe pour les services publics des tarifs destinés à couvrir les dépenses et à permettre à l'entreprise d'obtenir un taux de rendement ou profit convenable. Le processus s'accomplit en deux étapes. Dans la première étape, la PUB établit une base de tarification en calculant le montant des fonds investis par la compagnie en terrains, usines et équipements, plus le montant alloué au fonds de roulement, sommes dont il faut établir la nécessité dans l'exploitation de l'entreprise. C'est également à cette première étape qu'est calculé le revenu nécessaire pour couvrir les dépenses d'exploitation raisonnables et procurer un rendement convenable sur la base de tarification. Le total des dépenses d'exploitation et du rendement donne un montant appelé le revenu nécessaire. Dans une deuxième étape, les tarifs sont établis de façon à pouvoir produire, dans des conditions météorologiques normales, «le revenu nécessaire prévu». Ces tarifs restent en vigueur tant qu'ils ne sont pas modifiés à la suite d'une nouvelle requête ou d'une plainte, ou sur intervention de la Commission. C'est également à cette seconde étape que les tarifs provisoires sont confirmés ou réduits et, dans ce dernier cas, qu'un remboursement est ordonné.

L'économie de la législation repose sur le principe que la détermination des tarifs pour l'avenir doit permettre à l'entreprise de percevoir intégralement le revenu nécessaire prévu calculé par la Commission. La détermination des tarifs consiste donc à faire correspondre le montant des revenus prévus produits par les tarifs projetés au revenu total nécessaire à l'entreprise. Il ressort clairement de plusieurs dispositions de *The Gas Utilities Act* que la Commission n'agit que pour l'avenir et ne peut fixer des tarifs qui permettraient à l'entreprise de recouvrer des dépenses engagées antérieurement et que les tarifs précédents n'avaient pas suffi à compenser. Plusieurs dispositions de la Loi le confirment d'ailleurs, notamment l'art. 35:

[TRADUCTION] (1) Les entreprises de distribution de gaz . . . ne doivent pas modifier les tarifs en vigueur . . . avant d'avoir obtenu l'approbation de la Commission.

(2) Après leur approbation, les tarifs modifiés . . . entrent en vigueur à la date fixée par la Commission et

[2] [1961] R.C.S. 392.

may either upon written complaint or upon its own initiative herein determine whether the imposed increases, changes or alterations are just and reasonable.

Section 32 likewise refers to rates "to be imposed thereafter by a gas utility". The 1959 version of the legislation before the Court in this proceeding was examined by the Alberta Court of Appeal in *City of Calgary and Home Oil Co. Ltd. v. Madison Natural Gas Co. Ltd. and British American Utilities Ltd.*[3] wherein Johnson J.A. observed at p. 661:

The powers of the Natural Gas Utilities Board have been quoted above and the Board's function was to determine "the just and reasonable price" or prices to be paid. It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.

Vide also *Regina v. Board of Commissioners of Public Utilities (N.B.), Ex parte Moncton Utility Gas Ltd.*[4], at p. 710; *Bradford Union v. Wilts*[5], at p. 616.

There is but one exception in this statutory pattern and that is found in s. 31 which is critical in these proceedings. It is convenient to set it out in full.

It is hereby declared that, in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by an owner of a gas utility after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of the application.

It should be noted that s. 31 has been amended by s. 5 of *The Attorney General Statutes Amendment Act, 1977*, 1977 (Alta.), c. 9, which received Royal Assent on May 18, 1977. However, s. 5(3) of that Act provides that s. 31 "as it stood immediately before the commencement of" s. 5 "... continues to apply to proceedings initiated ..." before

[3] (1959), 19 D.L.R. (2d) 655.
[4] (1966), 60 D.L.R. (2d) 703.
[5] (1868), L.R. 3 Q.B. 604.

cette dernière peut, à la suite d'une plainte écrite ou d'office, déterminer si les augmentations ou modifications accordées sont justes et raisonnables.

L'article 32 parle également de tarifs [TRADUCTION] «imposés à l'avenir par l'entreprise de distribution de gaz». La législation en cause devant cette Cour a fait l'objet, dans sa version de 1959, des remarques suivantes du juge Johnson de la Cour d'appel de l'Alberta dans l'arrêt *City of Calgary and Home Oil Co. Ltd. v. Madison Natural Gas Co. Ltd. and British American Utilities Ltd.*[3], à la p. 661:

[TRADUCTION] Les pouvoirs de The Natural Gas Utilities Board ont été précisés plus haut. La Commission a le devoir de fixer les «prix justes et raisonnables» à payer. Elle doit établir les tarifs pour l'avenir et, ceci fait, elle n'a plus compétence aux fins de cette requête. Pour que la Commission ait le pouvoir de prendre des mesures rétroactives, il faudrait que la Loi le prévoie expressément; or, rien en l'espèce ne révèle l'intention de conférer un tel pouvoir à la Commission.

Voir également *Regina v. Board of Commissioners of Public Utilities (N.B.), Ex parte Moncton Utility Gas Ltd.*[4], à la p. 710; *Bradford Union v. Wilts*[5], à la p. 616.

Il existe cependant une disposition importante qui se distingue du reste de la Loi sur cette question; il s'agit de l'art. 31, qui est capital en l'espèce. Il convient de le citer intégralement:

[TRADUCTION] Il est par les présentes déclaré qu'en fixant des tarifs justes et raisonnables, la Commission peut tenir compte de la partie des excédents de revenu perçus ou des pertes subies par le propriétaire d'une entreprise de distribution de gaz après sa demande de nouveaux tarifs, si la Commission estime que ces excédents ou pertes sont imputables à un retard indu à entendre et à trancher la demande.

Il convient de souligner que l'art. 31 a été modifié par l'art. 5 de *The Attorney General Statutes Amendment Act, 1977*, 1977 (Alta.), chap. 9, qui a reçu la sanction royale le 18 mai 1977. Cependant, le par. 5(3) de la Loi dispose que l'art. 31 [TRADUCTION] «existant avant l'entrée en vigueur de [l'art. 5] continue de s'appliquer aux

[3] (1959), 19 D.L.R. (2d) 655.
[4] (1966), 60 D.L.R. (2d) 703.
[5] (1868), L.R. 3 Q.B. 604.

May 18, 1977. Accordingly, this case stands to be determined in accordance with s. 31 as set out above.

The interpretative difficulties raised by s. 31 are manifold. For one thing, the word 'losses' which is not defined in the Act is employed with reference to the Board's power to establish rates with respect to the period after an application has been made and before the Board has fully disposed of the application by taking into account "excess revenues and losses" which the Board determines have been "due to undue delay in the hearing and determination of the application". It is in my view apparent once the statute is examined as a whole that 'losses' as the word is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates. The word in short is an abbreviation for 'lost revenue' which may indeed be suffered by a utility during a period when the utility is not in a net loss position in the accounting sense of that term. This Court had occasion to consider s. 31 collaterally in *City of Edmonton et al. v. Northwestern Utilities Limited, supra.* Locke J. writing on behalf of the whole Court on this point so interpreted and applied the word "losses" as it appears in this section.

Much of the difficulty encountered before the Board and again reflected in the judgment of the Court of Appeal has arisen by the use of the expression 'loss' sometimes to refer to a net loss for a period in the past and sometimes by applying the term to a shortfall of revenue in the sense in which I believe the Legislature uses the term in s. 31. This difficulty appears to have been obviated by the new s. 31 which is not now before the Court (*vide The Attorney General Statutes Amendment Act, 1977, supra*).

Section 52(2) of *The Public Utilities Board Act* should also be noted:

The Board may, instead of making an order final in the first instance, make an interim order and reserve

procédures instituées ...» avant le 18 mai 1977. Le présent litige doit donc être tranché en fonction de la version précitée de l'art. 31.

Les problèmes d'interprétation que soulève l'art. 31 sont nombreux. Par exemple, le mot «pertes», qui n'est pas défini dans la Loi, est utilisé dans le contexte du pouvoir de la Commission de fixer des tarifs pour la période qui suit la date de la demande et qui précède la décision finale de la Commission sur le sujet en tenant compte des «excédents de revenu et des pertes» qu'elle considère «imputables à un retard indu à entendre et à trancher la demande». Il est à mon avis évident, dans le contexte général de la Loi, que le mot «pertes» à l'art. 31 ne renvoie pas aux pertes comptables au sens d'une perte nette subie au cours d'une année d'imposition, mais plutôt à la perte de revenu subie par l'entreprise au cours d'une période précise en raison du retard à mettre en vigueur, durant cette période, les augmentations projetées. Il s'agit en fait d'une façon abrégée de décrire la «perte de revenu» que peut subir une entreprise durant une certaine période sans que pour autant elle subisse une perte nette au sens comptable de cette expression. Cette Cour a déjà eu l'occasion d'étudier incidemment le sens de l'art. 31 dans l'arrêt *Ville d'Edmonton et autres c. Northwestern Utilities Limited*, précité. Exposant l'opinion de la Cour à ce sujet, le juge Locke a interprété et appliqué de cette façon le mot «pertes» employé dans ledit article.

La difficulté éprouvée devant la Commission, qui se reflète aussi dans le jugement de la Cour d'appel, vient en grande partie du fait que le mot «perte» est parfois utilisé pour désigner une perte nette subie au cours d'une période antérieure, et parfois pour désigner un manque à gagner (sens que lui donne, à mon avis, le législateur à l'art. 31). Il semble que le texte du nouvel art. 31, non applicable en l'espèce, ait fait disparaître cette difficulté (voir *The Attorney General Statutes Amendment Act, 1977*, précitée).

Le paragraphe 52(2) de *The Public Utilities Board Act* mérite également d'être cité:

[TRADUCTION] La Commission peut prononcer une ordonnance provisoire, au lieu de rendre une ordonnance further direction, either for an adjourned hearing of the matter or for further application.

Section 54 provides in similar language the authority for the Board to make such interim orders *ex parte*. These interim orders are couched in the same terms as the final or basic orders establishing rates and tariffs and hence are likewise prospective.

Against this statutory background a brief outline of the historical facts of this proceeding and its origins bring the two issues now before the Court into sharper focus. Commencing on August 20, 1974, the Company filed an application for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the Company to its customers. The application made reference to the powers under s. 31 by asking for an order "giving effect to such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility revenue requirement at $72,141,-000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the Company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

The practice and terminology historically adopted by the Board in the discharge of its statutory functions are no doubt clear to the industry and to persons attending upon the Board in the discharge of its functions but leaves something to be desired in the sense that the terminology does not precisely fit that employed by the legislation to which reference has been made. It is clear, however, that in its order with respect to the August 1974 application,

définitive, et remettre sa décision à une audition ultérieure de la demande ou à la présentation d'une nouvelle demande.

L'article 54 habilite la Commission, en des termes semblables, à rendre de telles ordonnances provisoires *ex parte*. Ces ordonnances provisoires sont rédigées de la même façon que les ordonnances définitives ou initiales fixant les tarifs et, comme elles, ne s'appliquent que pour l'avenir.

Cet historique de la législation doit être complété d'un rappel des faits à l'origine de ce pourvoi afin de bien mettre en évidence les deux questions en litige devant cette Cour. Le 20 août 1974, la Compagnie demandait une ordonnance établissant une base de tarification et un rendement convenable et approuvant les tarifs et droits qu'elle voulait imposer à ses clients pour le gaz naturel qu'elle distribuait. Se référant aux pouvoirs prévus à l'art. 31, elle demandait une ordonnance [TRADUCTION] «tenant compte de la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». En outre, elle demandait une ordonnance établissant des tarifs provisoires jusqu'à la fixation des «tarifs définitifs». En conséquence, plusieurs ordonnances provisoires ont été rendues entre le 15 novembre 1974 et le 30 juin 1975. En réponse à la requête du 20 août 1974, la Commission rendait, le 15 septembre 1975, une ordonnance qui établissait une base de tarification et un rendement convenable et fixait le revenu total nécessaire à l'entreprise à $72,141,000. Ces montants inclus dans l'ordonnance étaient calculés en fonction des «données réelles pour 1974» et des «prévisions pour 1975». La Commission a ensuite ordonné à la Compagnie de produire un tarif [TRADUCTION] «apte à produire le revenu total nécessaire à l'entreprise approuvé par la Commission».

Je ne doute pas que les usages et le vocabulaire adoptés par la Commission dans l'exercice des devoirs que lui confère la Loi soient clairs pour les gens de l'industrie ou les personnes qui comparaissent devant la Commission, mais la terminologie employée suscite une certaine confusion car elle diffère de celle de la législation, à laquelle j'ai fait référence plus haut. Toutefois, il est clair que c'est en fonction de la période à venir que la Commisthe Board has attempted to establish in the prospective sense those rates which the Company will require to enable it to carry on its business as a gas utility in the future and until such further and other rates are established by the Board. Had the Company then responded to the September 15 order by filing a proposed schedule of rates the Board would no doubt in completion of its statutory response to the August 1974 application by the Company have established the appropriate schedule of rates to be brought into effect by the Company in its billings from and after a date prospectively prescribed by the Board.

The complication which gives rise to these proceedings occurred on August 20, 1975, when the Company filed with the Board an application (not to be confused with the application filed on August 20, 1974) for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers"; together with an application on September 25, 1975, for an interim order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers pending final determination of the matter". The application of 1975 recites the history of the 1974 application and states that the operating costs and gas costs of the Company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application had awarded the applicant "interim refundable rates", the 1975 application went on to state:

> The existing rates charged by the Applicant for natural gas do not produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public.

Therefore the Company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the Company to its customers. The

sion a essayé, dans l'ordonnance relative à la requête du 20 août 1974, de fixer les tarifs devant permettre à la Compagnie de poursuivre l'exploitation de son entreprise de distribution de gaz jusqu'à ce que la Commission fixe de nouveaux tarifs. Si la Compagnie avait produit un projet de tarif, en réponse à l'ordonnance du 15 septembre, la Commission se serait sans nul doute acquittée des devoirs que lui impose la Loi pour la requête d'août 1974 en fixant le tarif approprié que la Compagnie aurait pu commencer à appliquer dans sa facturation à partir d'une date prescrite par la Commission de façon prospective.

Le litige actuel remonte au 20 août 1975, date à laquelle la Compagnie a présenté à la Commission une requête (à ne pas confondre avec la requête produite le 20 août 1974) en vue d'obtenir une ordonnance [TRADUCTION] «approuvant les modifications aux tarifs, taxes et droits actuellement perçus par Northwestern Utilities Limited pour le gaz distribué et les services fournis à ses clients»; cette requête fut suivie d'une autre, datée du 25 septembre 1975 pour obtenir une ordonnance provisoire [TRADUCTION] «approuvant, jusqu'à ce qu'une décision définitive soit rendue, les modifications aux tarifs, taxes et droits actuellement perçus par Northwestern Utilities Limited pour le gaz distribué et les services fournis à ses clients». La requête de 1975 fait l'historique de la requête de 1974 et souligne que les frais d'exploitation de la Compagnie et le coût du gaz [TRADUCTION] «ont considérablement augmenté comparativement aux montants indiqués dans la requête de 1974 et continuent d'augmenter». Après avoir mentionné qu'à la suite de la requête présentée en 1974, la Commission avait accordé à la requérante des [TRADUCTION] «tarifs provisoires remboursables», la requête de 1975 allègue:

> [TRADUCTION] Les tarifs actuellement perçus par la requérante pour son gaz naturel ne produisent pas un revenu suffisant pour lui permettre de faire face à ses dépenses actuelles et futures d'exploitation et d'amortissement et d'obtenir un taux de rendement convenable sur l'investissement utilisé au service du public.

La Compagnie a alors demandé une ordonnance qui établisse une base de tarification et un rendement convenable, et fixe et approuve les tarifs à percevoir par la Compagnie pour la distribution de

Company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application", apparently paraphrasing s. 31 of *The Gas Utilities Act*. The 1975 application seeks as well interim rates "pending the fixing of final rates".

It is also relevant to note in passing that the 1974 application indeed had its own roots in a prior procedure before the Board initiated by the Board itself under s. 27 of *The Gas Utilities Act* in 1974. In June 1974, the Company applied for an interim rate increase and after a hearing in July 1974 the application was denied on August 19, 1974, and the application of August 20, 1974, was thereupon filed.

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the Company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The question immediately arises as to whether this sum represents increased expenses to be incurred by the Company for the period after the interim rates became effective (October 1, 1975) or whether it represents expenses incurred and unrecovered in the past. It was from this interim order that the City of Edmonton (herein referred to as 'the City') appealed to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of *The Public Utilities Board Act*:

(1) Subject to subsection (2) [the requirement of leave], upon a question of jurisdiction or upon a question of law, an appeal lies from the Board to the Appellate Division of the Supreme Court of Alberta.

The Appellate Division of the Supreme Court of Alberta set aside the Board order of October 1, 1975, and referred the matter to the Board "for further consideration and redetermination". One preliminary argument can be disposed of at the outset. It was argued in the Courts below, as well

gaz naturel. La Compagnie a également demandé une ordonnance tenant compte de [TRADUCTION] «la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande», paraphrasant apparemment l'art. 31 de *The Gas Utilities Act*. La requête de 1975 demandait en outre une ordonnance fixant des tarifs provisoires applicables [TRADUCTION] «jusqu'à l'établissement de tarifs définitifs».

Il est également pertinent de souligner ici que la requête présentée en 1974 résulte d'une procédure antérieure entamée la même année par la Commission elle-même en vertu de l'art. 27 de *The Gas Utilities Act*. En effet, en juin 1974, la Compagnie avait demandé à la Commission de fixer une augmentation provisoire de tarifs; après une audience tenue en juillet 1974, la Commission a rejeté cette requête, le 19 août 1974, et la Compagnie est revenue à la charge en déposant sa requête du 20 août 1974.

Dans son ordonnance du 1er octobre 1975, la Commission a accordé une augmentation provisoire de tarifs permettant à la Compagnie de percevoir un revenu supérieur de $2,785,000 à celui qu'elle aurait normalement perçu en 1975. Il faut immédiatement se demander si cette différence correspond à une augmentation des dépenses après la date d'entrée en vigueur de l'augmentation provisoire de tarifs (soit le 1er octobre 1975) ou à des dépenses déjà engagées mais non recouvrées. C'est précisément de cette ordonnance provisoire dont la ville d'Edmonton (ci-après appelée la «Ville») a interjeté appel devant la Division d'appel de la Cour suprême de l'Alberta en vertu de l'art. 62 de *The Public Utilities Board Act*, qui dispose:

[TRADUCTION] (1) Sous réserve du paragraphe (2) [l'autorisation d'appel], les décisions de la Commission sont susceptibles d'appel à la Division d'appel de la Cour suprême de l'Alberta sur une question de compétence ou de droit.

La Division d'appel de la Cour suprême de l'Alberta a infirmé l'ordonnance de la Commission rendue le 1er octobre 1975 et lui a renvoyé l'affaire [TRADUCTION] «pour nouvel examen et décision». On peut tout de suite trancher une question préliminaire: on a soutenu devant les tribunaux d'insas in this Court, that the interim order under appeal (dated October 1, 1975) was made pursuant to the 1974 rate application, either as a variance of the 1974 order pursuant to s. 56 of *The Public Utilities Board Act*, or as an interim order in respect of the 1974 application. That submission, whatever its effect, was rejected by the Court of Appeal and must be rejected here. On the face of the interim order is found a reference to "the application of N.U.L. dated the 20th day of August, 1975". That reference, when read with the transcript of the evidence at the hearing leaves no doubt that the interim order was made with respect to the 1975 application which clearly was an independent application to establish, pursuant to the aforementioned sections of *The Gas Utilities Act*, the statutory prerequisites to a new tariff of rates, and then a new tariff of rates.

I turn then to the first issue as to whether the Board by its interim order of October 1, 1975, has offended the provisions of s. 31 of *The Gas Utilities Act* by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975. It was not argued before this Court that the Board could not through s. 31 reach back to August 20, 1975, and grant a rate increase to recover costs thereafter incurred. The recitals to the order of October 1975 make it difficult to determine whether in fact the Board has invoked s. 31 in the interim rates established by the order or whether the Board has simply made an interim order under s. 51(2) of *The Public Utilities Board Act*. We need not determine the answer to that question in order to deal with this issue.

The issue is at this stage very narrow. No contest is raised as to the validity of the September 15, 1975, order nor the various interim rates authorized in the 1974 application. The issue is simply whether or not the Company by not applying in the 1974 application for a further interim order has caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the Company will have the effect of recovering from future gas consumers revenue losses incurred by the

tance inférieure et devant cette Cour que l'ordonnance provisoire (du 1er octobre 1975) contestée en appel faisait suite à la requête présentée en 1974 et constituait soit une modification de l'ordonnance rendue en 1974 en vertu de l'art. 56 de *The Public Utilities Board Act* soit une ordonnance provisoire se rapportant à la requête faite en 1974. Nous devons, comme la Cour d'appel, rejeter cet argument sans en examiner la portée. L'ordonnance provisoire mentionne «la requête de NUL en date du 20 août 1975». Cette mention, et la transcription de la preuve présentée à l'audition, indiquent clairement que l'ordonnance provisoire suit la requête présentée en 1975; cette dernière était totalement indépendante et visait à fixer, conformément aux articles susmentionnés de *The Gas Utilities Act*, les bases légales d'un nouveau tarif et ledit nouveau tarif.

J'en viens à la première question en litige: l'ordonnance provisoire rendue par la Commission le 1er octobre 1975 contrevient-elle à l'art. 31 de *The Gas Utilities Act* en permettant, selon la Ville, le recouvrement de pertes subies avant la présentation de la requête, le 20 août 1975? On n'a pas soutenu devant cette Cour que la Commission n'avait pas le pouvoir, en vertu de l'art. 31, de faire ses calculs à partir du 20 août 1975 et d'accorder une augmentation de tarifs pour couvrir les dépenses engagées après cette date. Les attendus de l'ordonnance d'octobre 1975 ne permettent pas d'établir si la Commission s'est fondée sur l'art. 31 pour fixer une augmentation provisoire ou a simplement rendu une ordonnance provisoire en vertu du par. 51(2) de *The Public Utilities Board Act*. Il n'est pas nécessaire de trancher cette question pour régler le point en litige.

La question soumise à cette Cour est très limitée. La validité de l'ordonnance rendue le 15 septembre 1975 et des nombreuses augmentations provisoires accordées à la suite de la requête présentée en 1974 n'est pas contestée. Il s'agit uniquement de déterminer si, en ne demandant pas d'ordonnance provisoire supplémentaire dans sa requête de 1974, la Compagnie a amené la Commission à répondre à la nouvelle requête de 1975 de manière à autoriser des tarifs qui auraient pour effet de faire supporter par les nouveaux consom-

Company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates but in a manner not authorized by s. 31.

The Appellate Division of the Supreme Court of Alberta in both the judgments of Clement J.A. and McDermid J. A., as well as counsel before this Court, devoted a considerable amount of attention to the accounting evidence filed by the Company with reference to the total revenue requirement of the Company in the years 1974 and 1975 and to the possibility that the inclusion in the rate base or the operating expenses established in Phase I of the 1975 application of the additional expenses which gave rise to the 1975 application, will have the effect of violating or going beyond s. 31 by authorizing rates which will have the effect of recovering past losses. We are here not concerned with capitalized losses because there is no suggestion that the rate base will be enlarged by the inclusion of any historical loss in the sense of an accounting deficit in prior fiscal intervals but rather with revenue losses other than those which may be recovered pursuant to s. 31 and which relate to the period from and after August 20, 1975. These losses of course have no relationship to a rate base computed and established pursuant to s. 28 of *The Gas Utilities Act*. We are concerned only with whether or not the Board in its processes has determined the total operating expenses for some period, as well as the fair return on the rate base, so as to enable the Board to calculate prospectively the anticipated total revenue requirement of the utility and thereby establish rates which prospectively will produce future revenues to match the estimated future total revenue requirement.

This procedure was the subject of comment by Porter J.A. in *Re Northwestern Utilities Ltd.*[6] at p. 290, and which comments I find apt in the circumstances now before us:

One effect of this ruling is that future consumers will have to pay for their gas a sum of money which equals that which consumers prior to August 31, 1959 ought to have paid but did not pay for gas they had used. In

[6] (1960), 25 D.L.R. (2d) 262.

mateurs de gaz les pertes de revenu sur le gaz livré avant la date de la requête (soit le 20 août 1975) ou avant la mise en vigueur des tarifs du 1[er] octobre 1975, mais d'une façon qui n'est pas autorisée par l'art. 31.

Les juges Clement et McDermid, qui ont rendu le jugement de la Division d'appel de la Cour suprême de l'Alberta, et les avocats devant cette Cour se sont longuement penchés sur la preuve comptable soumise par la Compagnie au sujet du revenu total nécessaire pour les années 1974 et 1975 et sur la possibilité que l'inclusion des dépenses supplémentaires à l'origine de la requête de 1975 dans la base de tarification ou dans les dépenses d'exploitation établies dans le cadre de la première étape de l'étude de la requête de 1975 contrevienne à l'art. 31 en autorisant des tarifs qui permettaient de compenser des pertes passées. Il ne s'agit pas de pertes capitalisées, car on n'a pas prétendu que la base de tarification avait été augmentée par l'inclusion d'une perte passée, au sens d'un déficit comptable d'années d'imposition précédentes; il s'agit plutôt de pertes de revenu autres que celles visées par l'art. 31 et qui auraient été subies après le 20 août 1975. Il est bien évident que ces pertes n'ont aucun lien avec la base de tarification calculée et établie en conformité de l'art. 28 de *The Gas Utilities Act*. La seule question à trancher à cet égard est de savoir si la Commission a établi les dépenses totales d'exploitation pour une période donnée et le rendement convenable sur la base de tarification afin d'être en mesure de calculer, pour l'avenir, le revenu total nécessaire à l'entreprise et donc fixer des tarifs pouvant produire suffisamment de revenus dans l'avenir pour correspondre au revenu total nécessaire ainsi déterminé.

Cette façon de procéder a fait faire au juge Porter, dans l'arrêt *Re Northwestern Utilities Ltd.*[6] à la p. 290, un commentaire qui me semble pertinent en l'espèce:

[TRADUCTION] Cette décision a notamment l'effet de faire payer aux nouveaux consommateurs de gaz une somme égale à ce que les consommateurs desservis avant le 31 août 1959 auraient dû payer, mais n'ont pas payé,

[6] (1960), 25 D.L.R. (2d) 262.

short, the undercharge to one group of consumers for gas used in the past is to become an overcharge to another group on gas it uses in the future. When the Board capitalized this sum, it made all the future consumers debtors to the company for the total amount of the deficiency, payable ratably with interest from their respective future gas consumption.

It is conceded of course that the Act does not prevent the Board from taking into account past experience in order to forecast more accurately future revenues and expenses of a utility. It is quite a different thing to design a future rate to recover for the utility a 'loss' incurred or a revenue deficiency suffered in a period preceding the date of a current application. A crystallized or capitalized loss is, in any case, to be excluded from inclusion in the rate base and therefore may not be reflected in rates to be established for future periods.

The evidence submitted by the Company on the hearing of the 1975 application centred largely upon the urgent need for interim refundable rates by which the Company;

> can recover its costs of service and earn an adequate return on its utility assets for the year 1975. If the interim rates requested are nor granted, the costs of providing natural gas service would not be fully recovered.

The evidence goes on to outline the utility income under existing rates for the years 1975 and 1976 and it is stated that these rates unless augmented by interim rates as proposed will produce a shortfall in revenue of approximately $700,000 per month. The accounts so filed reveal computations which show the need for an additional $2.785 million for the year 1975 of which operating expenses represent $2.105 million. Unhappily, the record does not reveal whether all the components of the additional $2.785 million are recurring expenses and costs, or legitimate demands for return on capital, which will run evenly into the future. It may be that in the quarterly period of 1975 remaining at the time of the order, these projections will exceed or be less than the actual expenses to be incurred in that very quarterly period. On this the evidence is strangely silent. The

pour le gaz qu'ils ont utilisé. Bref, une perception insuffisante dans le passé à l'égard d'un groupe de consommateurs de gaz entraîne une surcharge à l'égard d'un autre groupe de consommateurs pour le gaz qu'il utilisera à l'avenir. En capitalisant cette somme, la Commission a rendu tous les consommateurs éventuels de gaz débiteurs envers la Compagnie d'un montant correspondant au manque à gagner avec intérêts, à payer en proportion de leur consommation future.

Il est admis que la Loi n'empêche pas la Commission de tenir compte de l'expérience passée pour mieux évaluer les revenus et les dépenses à venir d'une entreprise de services publics. Mais ce n'est pas la même chose d'établir un tarif qui permette à l'entreprise de compenser une «perte» ou une insuffisance de revenus subie au cours d'une période antérieure à la date de la requête considérée. Une perte identifiée ou capitalisée doit, de toute façon, être exclue de la base de tarification et, en conséquence, elle ne peut se refléter dans les tarifs établis pour une période à venir.

La preuve fournie par la Compagnie à l'audition de la requête de 1975 a principalement porté sur le besoin urgent de tarifs remboursables pour lui permettre

> [TRADUCTION] de recouvrer ses frais d'exploitation et d'obtenir un rendement convenable sur son investissement pour l'année 1975. Si les tarifs provisoires demandés ne sont pas accordés, le prix du service de distribution de gaz naturel ne sera pas complètement couvert.

En ce qui concerne les revenus produits par les tarifs prévus pour les années 1975 et 1976, la preuve révèle qu'à moins d'être augmentés par les tarifs provisoires proposés, ils entraîneront un manque à gagner d'environ $700,000 par mois. La preuve comptable comprend en outre des calculs établissant le besoin de $2,785,000 supplémentaires pour l'année 1975, dont $2,105,000 pour les frais d'exploitation. Malheureusement, le dossier n'indique pas si la somme de $2,785,000 est entièrement composée de dépenses et de frais périodiques ou de réclamations légitimes relatives au rendement sur l'investissement, qui s'étaleraient régulièrement sur les périodes à venir. Il se peut qu'au cours du trimestre de 1975 restant à courir à l'époque de l'ordonnance, ces prévisions s'avèrent plus élevées ou plus faibles que les dépenses véritablement engagées au cours de ce trimestre. La evidence of the treasurer of the Company deals with the revenues for the year 1975 as follows:

A. The revenues from gas sales for the test year 1975 of $87,265,000 as shown on line 6 of Statement 2.01 (Forecast—Proposed Rates) constitutes $84,480,000 of revenues forecast under existing rates as shown on Line 6 of Statement 2.01 (Forecast—Existing Rates) and $2,785,000 of additional revenues to earn a utility rate of return of 9.93%. The increase is that estimated to be derived from introduction on October 1, 1975, of the requested interim rates, including an increase in franchise tax of $120,000.

Q. On what year are the interim rates designed?

A. 1975 was chosen as the test year and rates were designed to recover 1975 costs.

In its application for interim rates the Company reduces the effect of the anticipated loss of revenue to the conclusion:

The rate of return on the base rate drops from 9 percent in 1974 to 8.43 percent in 1975 and further declines to 6.77 percent in 1976. The requested rate of return on rate base for 1975 under the proposed rates is 9.93 percent. This difference of 1½ percent represents $1,600,000 in utility income.

This reference would appear to be to the difference between the prevailing rates in 1975 prior to October 1st and the rates which would prevail in 1975 under the proposal made for the rates effective October 1, 1975. The application for the interim rates goes on to state:

Without rate relief in the form of interim rates for the balance of 1975, the imputed return on common equity drops to 10.2 percent compared to the recommended equity return of 14⅝ percent to 15⅛ percent . . .

From this and like excerpts from evidence, testimentary and documentary, the City has taken the view that the augmentation to rates for the last quarter of 1975 sought by the Company and granted by the Board has in effect been a recognition of a deemed increase in the rate base or operating expenses by the inclusion therein of an

preuve n'éclaire absolument pas cette question. Le trésorier de la Compagnie a présenté le témoignage suivant au sujet des revenus de l'année 1975:

[TRADUCTION] R. Les revenus de $87,265,000 provenant de la vente de gaz pour l'année témoin 1975, inscrits à la sixième ligne du relevé 2.01 (Prévisions—tarifs suggérés) comprennent $84,480,000 de revenus prévus selon les tarifs actuellement en vigueur figurant à la sixième ligne du relevé 2.01 (Prévisions—Tarifs actuels) et $2,785,000 de revenus supplémentaires destinés à permettre un taux de rendement de 9.93%. L'augmentation correspond à l'estimation du montant résultant de la demande d'augmentation provisoire des tarifs présentée le 1^{er} octobre 1975 et à l'augmentation de $120,000 des droits sur la concession.

Q. Sur la base de quelle année les tarifs provisoires sont-ils établis?

R. L'année 1975 a été choisie comme l'année témoin et les tarifs ont été établis en fonction des coûts de cette année-là.

Dans sa demande de tarifs provisoires, la Compagnie ramène l'effet de la perte anticipée de revenus à la conclusion suivante:

[TRADUCTION] Le taux de rendement sur la base de tarification tombe de 9 pour cent en 1974 à 8.43 pour cent en 1975 et à 6.77 pour cent en 1976. Le taux de rendement pour 1975 compte tenu du tarif suggéré est de 9.93 pour cent. Cette différence de 1½ pour cent représente un revenu de $1,600,000 pour l'entreprise.

Il s'agit, semble-t-il, de la différence entre les tarifs en vigueur en 1975, jusqu'au 1er octobre, et les tarifs proposés à partir du 1er octobre 1975. La demande de tarifs provisoires dit en outre:

[TRADUCTION] Sans l'augmentation provisoire des tarifs pour le reste de l'année 1975, le rendement sur l'avoir des actionnaires ordinaires sera de 10.2 pour cent alors qu'il devrait être de 14⅝ à 15⅛ pour cent . . .

Se fondant sur cela, et sur d'autres preuves testimoniales et documentaires, la Ville prétend que l'augmentation des tarifs pour le dernier trimestre de 1975, demandée par la Compagnie et accordée par la Commission, revient à admettre une augmentation de la base de tarification ou des dépenses d'exploitation pour y inclure une perte qui ne otherwise unrecoverable loss in that part of the year 1975 preceding the 1975 application filed on August 20. Additionally, or perhaps more accurately, alternatively, the City has put the argument that the Company by its interim rate proposal has sought to recover in 1975 additional costs of $2.785 million without in any way establishing that the revenue so sought is required to match expenses to be incurred either during the effective period of the new interim rates, or is to recover lost revenue in the manner authorized by s. 31. In support of this argument, the City points out that the sum of $2.1 million, which is said to be required to meet increases in operating expenses, is not isolated and shown to be additional expenses to be incurred in the last quarter of 1975 but rather is the excess of 1975 expenses over and above those forecast in the earlier proceedings and which excess is forecast on the basis of actual expenditures in the first 6 months of 1975 together with anticipated expenditures in the last 6 months of 1975.

The Company meets this argument by the submission that losses contemplated by s. 31 cannot be discerned until the close of the fiscal period selected as the basis for the application for new rates and that this is peculiarly so in the case of a gas utility by reason of fluctuating conditions beyond the control of the utility. The Board in disposing of these opposing positions states simply:

AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975:

AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".

The terminology "past losses", employed perhaps by all parties before the Board and adopted by the Board in its order, makes it difficult in reviewing the record as well as the various orders of the Board to determine whether or not the

serait autrement pas remboursable pour la partie de l'année 1975 précédant le 20 août 1975, date de la présentation de la requête. En outre, ou, pour être plus précis, subsidiairement, la Ville a soutenu que l'augmentation provisoire réclamée par la Compagnie visait à compenser en 1975 un coût supplémentaire de $2,785,000 sans prouver soit que le revenu supplémentaire réclamé correspond aux dépenses engagées au cours de la période d'application des nouveaux tarifs provisoires soit qu'il vise à recouvrer une perte de revenu de la manière prévue à l'art. 31. A l'appui de cet argument, la Ville fait valoir que la somme de $2,100,-000 réclamée pour faire face à l'augmentation des dépenses d'exploitation n'a été ni isolée ni identifiée comme correspondant à des dépenses supplémentaires à engager au cours du dernier trimestre de 1975. Selon la Ville, cette somme représenterait au contraire l'excédent des dépenses engagées en 1975 sur celles prévues au départ, cet excédent étant lui-même calculé en fonction de dépenses engagées durant le premier semestre de 1975 et sur les prévisions de dépenses pour le dernier semestre de cette année-là.

La Compagnie répond à cet argument que les pertes visées à l'art. 31 ne peuvent être identifiées avant la fin de la période d'imposition choisie pour l'application des nouveaux tarifs et ajoute que c'est particulièrement vrai dans le cas d'une entreprise de distribution de gaz, en raison de fluctuations incontrôlables. Tranchant ces thèses contradictoires, la Commission a simplement déclaré:

[TRADUCTION] ET CONSIDÉRANT l'argumentation des avocats des intervenants en faveur du rejet, en totalité ou en partie, de la requête de NUL pour l'obtention de tarifs provisoires remboursables, au motif que l'augmentation provisoire et remboursable des tarifs vise à recouvrer des «pertes passées» subies par NUL depuis le 1er janvier 1975;

ET CONSIDÉRANT que le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées».

L'expression «pertes passées» employée par toutes les parties ou presque devant la Commission, et reprise par cette dernière dans son ordonnance, ne facilite pas l'examen du dossier et des diverses ordonnances de la Commission lorsqu'il

Board was indeed attempting to isolate the elements to be taken into account by the Board in discharging its functions under ss. 27, 28 and 29 of *The Gas Utilities Act* with reference to specific parts of the calendar year 1975. If, for example, the Board had assumed that the additional revenue sought in the application of September 25, 1975, for an interim order pending the determination of the application of August 20, 1975, was to match expenses forecast to be incurred by the Company in the last quarter of 1975, then there would be no attempt by the Board to take into account revenue losses incurred prior to August 20, 1975, and thus no failure on the part of the Board to comply with the statute and with s. 31 in particular. The process of matching forecast revenues to be realized from the proposed interim rates against the forecast expenses comprising the total revenue requirements for the last quarterly period would be complete. It is impossible to discern whether or not that is the result which is sought to be reflected by the Board in its order of October 1, 1975. Such may well be the case, but on the other hand, it might be as submitted by the City that these additional expenses totalling $2.785 million are in whole or in part the result of annualizing expenses incurred before and/or after August 20, 1975, so that the total revenue requirement for the "test year" need be augmented by $2.785 million in order to meet the total revenue requirements for the year. It is in my view wholly unnecessary to enter the debate as to whether or not in making the estimates for future expenses a fiscal period of a year, two years, a half year, etc., need be selected. What is required by the statute is an estimate by the Board of the future needs of the utility which are recognized in the statute to be compensable by the operation in the future of the rates prescribed by the Board. Similarly the forecast of revenues to be recovered by the proposed rates need not be predicated necessarily upon a hypothetical or real fiscal year or a shorter period. Obviously in a seasonal enterprise such as the gas utility business a full calendar fiscal period represents the marketing picture throughout the four seasons of the year. Equally obviously, recurring cash outlays relevant to expenses unevenly incurred throughout the year can be annualized

s'agit de déterminer si cette dernière a effectivement tenté d'isoler les éléments dont elle devait tenir compte pour s'acquitter de ses fonctions en vertu des art. 27, 28 et 29 de *The Gas Utilities Act*, relativement à des périodes précises de l'année civile 1975. Si, par exemple, la Commission a présumé que le revenu supplémentaire réclamé dans la requête du 25 septembre 1975, visant une ordonnance provisoire applicable en attendant que soit tranchée la requête du 20 août 1975, correspondait aux dépenses que la Compagnie prévoyait effectuer au cours du dernier trimestre de 1975, alors on peut dire que la Commission n'a pas cherché à tenir compte des pertes de revenu subies avant le 20 août 1975 et qu'elle n'a en conséquence pas violé la Loi ni, plus précisément, l'art. 31. L'objectif, qui est de faire correspondre le montant des revenus projetés provenant des tarifs provisoires proposés au montant des dépenses projetées formant le revenu total nécessaire pour le dernier trimestre, serait donc atteint. Mais il est impossible de savoir si c'est effectivement le résultat recherché par la Commission dans son ordonnance du 1er octobre 1975. Il se peut fort bien que ce soit le cas; en revanche, il se peut aussi, comme le prétend la Ville, que ces dépenses supplémentaires de $2,785,000 soient fondées, en totalité ou en partie, sur des dépenses antérieures et/ou postérieures au 20 août 1975, de sorte que le revenu total nécessaire pour «l'année témoin» doit être augmenté de $2,785,000 pour correspondre au revenu total nécessaire pour l'année. Il est à mon avis inutile de débattre la question de savoir si les estimations des dépenses à venir doivent être fondées sur l'année d'imposition, sur deux ans ou sur un semestre. La Commission est tenue d'évaluer les besoins futurs de l'entreprise dont la Loi autorise la compensation par les tarifs prescrits par la Commission pour l'avenir. Les prévisions des revenus que devront produire les tarifs proposés ne doivent pas non plus nécessairement être fondées sur une année d'imposition hypothétique ou réelle ou sur une période plus courte. Il est bien évident lorsqu'il s'agit d'une entreprise saisonnière, comme un service de distribution de gaz, qu'une année complète d'imposition donne une image fidèle des ventes de l'entreprise au cours des quatre saisons de l'année. Il est également évident que les dépeneither by an accounting adjustment where the expense incurred relates to a longer period or extends beyond the fiscal year in question, or can be annualized where the expense incurred relates to a segment of the fiscal period. In any case the administrative mechanics to be adopted in the discharge of the function mandated by *The Gas Utilities Act* are exclusively within the power of the Board. We need not here deal with the question of arbitrariness in the discharge of administrative functions for there is no evidence on the record before this Court raising any such issue. This Court is concerned only with the issue as to whether the Board in the performance of its duties under the statute has exceeded the power and authority given to it by the Legislature. Clement J.A. has observed in his reasons:

[*P*]*rima facie* the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year.

I am not prepared to say that a *prima facie* case has been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. Indeed, in my respectful view, the test is not whether the "new tentative rate base includes an amount for revenue losses" but rather the question is whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The Company submitted to this Court that a determination of what is or is not a 'past loss' is a

ses de capital qui reviennent périodiquement et qui sont engagées à différentes époques de l'année peuvent être calculées sur une base annuelle avec les rectifications comptables appropriées lorsque la dépense est engagée pour une période plus longue, ou va au-delà de l'année d'imposition, ou même lorsqu'elle a trait à une partie seulement de l'année d'imposition. Quoi qu'il en soit, les techniques administratives auxquelles la Commission a recours pour s'acquitter du rôle que lui confère *The Gas Utilities Act* sont exclusivement de son ressort. Il ne saurait être question ici d'exécution arbitraire des fonctions administratives puisque le dossier soumis à cette Cour ne contient rien à cet égard. La seule question soumise à cette Cour consiste à déterminer si, dans l'exercice de ses fonctions, la Commission a excédé les pouvoirs que lui a conférés la Législature. Le juge Clement fait la remarque suivante dans ses motifs:

[TRADUCTION] *Prima facie*, la nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu subies depuis le début de 1975 jusqu'à la date de la présentation de la requête, en août, car les calculs ne répartissent pas la perte entre les deux périodes de l'année.

Je ne suis pas prêt à dire qu'il est établi *prima facie* que l'imposition des tarifs provisoires à compter du 1er octobre 1975 permettait le recouvrement dans l'avenir de pertes de revenu subies avant le 20 août 1975. Avec égards, je suis d'avis qu'au lieu de se demander si la «nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu», il faut se demander si l'imposition dans l'avenir des tarifs provisoires procurera un revenu excédant le revenu total requis selon les calculs pour la même période, suite à l'inclusion dans le calcul d'un montant destiné à couvrir les manques à gagner subis avant la date de la présentation de la requête, que ces derniers aient ou non été inclus, de quelque façon que ce soit, dans la base de tarification ou aient été inclus dans les dépenses d'exploitation prévues pour la période durant laquelle les nouveaux tarifs provisoires seront imposés, sous réserve évidemment du pouvoir limité de la Commission en vertu de l'art. 31.

La Compagnie a plaidé devant cette Cour que la détermination de ce qui constitue une «perte pure question of fact and as such is not subject to appeal by reason of s. 62 of *The Public Utilities Board Act, supra*, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involves a determination of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to the characterization of "the forecast revenue deficiency in the 1975 future test year" of the Company involves a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which, as I have said, involved the Board in construing ss. 28 and 31 of *The Gas Utilities Act*, raises a question of law and may well go to the jurisdiction of the Board.

However, it is not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order are so narrow in scope and of such extraordinary brevity that one is left without guidance as to the basis upon which the rates have been established for the period October 1, 1975, onwards. Hence this further submission of the Company must fail.

I turn now to the second issue, namely the application of s. 8 of *The Administrative Procedures Act* of Alberta, *supra*, to these proceedings. This provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it. Section 8 states:

Where an authority exercises a statutory power so as to adversely affect the rights of a party, the authority shall furnish to each party a written statement of its decision setting out

(*a*) the findings of fact upon which it based its decision, and

passée» est une question de fait, non susceptible d'appel en vertu de l'art. 62 de *The Public Utilities Board Act*, précité; cet article limite l'appel des décisions de la Commission aux seules questions de «droit ou de compétence». Le présent pourvoi implique l'analyse de l'intention du législateur relativement au pouvoir de la Commission de tenir compte des manques à gagner ou des dépenses excédentaires engagées avant la présentation d'une demande de nouveaux tarifs en vertu de la Loi. La décision de la Commission au sujet du «manque à gagner prévu pour 1975, l'année témoin», comporte la détermination de questions dont la Commission prend connaissance pour fixer les tarifs en vertu de la Loi. C'est là une question de droit susceptible d'appel en vertu de l'art. 62. Une décision relative à une requête qui, comme je l'ai dit, oblige la Commission à interpréter les art. 28 et 31 de *The Gas Utilities Act*, soulève une question de droit pouvant mettre en cause la compétence de la Commission.

Cependant, les circonstances de la présente affaire ne permettent pas au tribunal qui examine l'ordonnance de la Commission d'établir si cette dernière a excédé ou non sa compétence. Le libellé et le contenu de l'ordonnance de la Commission sont en effet d'une portée si limitée et d'une telle brièveté qu'il est impossible d'établir si les tarifs ont été fixés pour la période commençant le 1er octobre 1975. Cet argument de la Compagnie ne peut donc être retenu.

J'en viens maintenant à la deuxième question en litige; elle porte sur l'application de l'art. 8 de *The Administrative Procedures Act* de l'Alberta, précitée, aux présentes procédures. Cette disposition oblige certains tribunaux administratifs à communiquer aux parties une décision écrite, exposant les conclusions de fait et les motifs sur lesquels elle est fondée. Cet article prévoit:

[TRADUCTION] Lorsque, dans l'exercice de pouvoirs conférés par la loi, un organisme porte atteinte aux droits d'une partie, il doit communiquer à chaque partie un exposé écrit de sa décision et y préciser

a) les conclusions de fait sur lesquelles sa décision est fondée, et (*b*) the reasons for the decision.

The "reasons" handed down by the Board consist of the following:

INTERIM ORDER

UPON THE APPLICATION of Northwestern Utilities Limited, (hereinafter referred to as "N.U.L.") to the Public Utilities Board for an Order or Orders approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers;

AND UPON READING the application of N.U.L. dated the 20th day of August, 1975 and the Affidavit of Dorothea E. Blackwood concerning service by mail and by newspaper publication of a Notice of the matter as directed by the Board and written evidence of witnesses of N.U.L. and other material filed in support of the application;

AND UPON HEARING an application made by N.U.L. on September 25, 1975, for an Interim Order approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers pending final determination of the matter;

AND UPON HEARING the application, testimony and submission of witnesses and counsel for N.U.L.;

AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975;

AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".

AND THE BOARD considering that delay in granting an interim increase in rates may adversely affect N.U.L.'s financial integrity and customer service;

AND N.U.L. having undertaken to refund to its customers such amounts as the Board may direct if any of the said interim rates are changed after further hearing.

IT IS ORDERED as follows: . . . .

The law reports are replete with cases affirming the desirability if not the legal obligation at common law of giving reasons for decisions (*vide Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of Ameri-*

b) les motifs de sa décision.

Voici les «motifs» exposés par la Commission:

[TRADUCTION] ORDONNANCE PROVISOIRE

THE PUBLIC UTILITIES BOARD, SUR REQUÊTE de Northwestern Utilities Limited (ci-après appelée «NUL») en vue d'obtenir une ordonnance ou des ordonnances approuvant les modifications aux tarifs, taxes ou droits actuellement perçus par NUL pour le gaz fourni et les services rendus à ses clients;

ET APRÈS LECTURE de la requête de NUL en date du 20 août 1975, de l'affidavit de Dorothea E. Blackwood relatif à la signification par courrier et la publication dans un journal d'un avis de requête, conformément aux directives de la Commission, et de la preuve écrite des témoins de NUL et autres documents produits à l'appui de la requête;

ET APRÈS AUDITION d'une requête présentée par NUL le 25 septembre 1975 en vue d'obtenir une ordonnance provisoire approuvant les modifications aux tarifs, taxes ou droits actuellement perçus par NUL pour le gaz fourni et les services rendus à ses clients, en attendant une décision définitive;

ET APRÈS AUDITION de la requête, des témoins et des avocats de NUL;

ET CONSIDÉRANT l'argumentation des avocats des intervenants en faveur du rejet, en totalité ou en partie, de la requête de NUL pour l'obtention de tarifs provisoires remboursables, au motif que l'augmentation provisoire et remboursable des tarifs vise à recouvrer des «pertes passées» subies par NUL depuis le 1er janvier 1975;

ET CONSIDÉRANT que le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées»;

ET CONSIDÉRANT qu'un retard à accorder une augmentation provisoire des tarifs pourrait nuire à la stabilité financière de NUL et aux services fournis aux clients;

ET CONSIDÉRANT l'engagement de NUL de rembourser à ses clients les montants prescrits par la Commission si, après audition, cette dernière décidait de modifier lesdits tarifs provisoires;

STATUE que . . .

Les recueils judiciaires regorgent de jugements affirmant qu'il est souhaitable sinon obligatoire en *common law*, de rendre des décisions motivées (voir *Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of Ameri-*

ca Local 2142[7], *per* Hughes C.J.N.B. at p. 47; *MacDonald v. The Queen*[8], *per* Laskin C.J.C. at p. 262). This obligation is a salutary one. It reduces to a considerable degree the chances of arbitrary or capricious decisions, reinforces public confidence in the judgment and fairness of administrative tribunals, and affords parties to administrative proceedings an opportunity to assess the question of appeal and if taken, the opportunity in the reviewing or appellate tribunal of a full hearing which may well be denied where the basis of the decision has not been disclosed. This is not to say, however, that absent a requirement by statute or regulation a disposition by an administrative tribunal would be reviewable solely by reason of a failure to disclose its reasons for such disposition.

The Board in its decision allowing the interim rate increase which is challenged by the City failed to meet the requirements of s. 8 of *The Administrative Procedures Act*. It is not enough to assert, or more accurately, to recite, the fact that evidence and arguments led by the parties have been considered. That much is expected in any event. If those recitals are eliminated from the 'reasons' of the Board all that is left is the conclusion of the Board "that the forecast revenue deficiency in the 1975 future test year requested by the Company cannot be properly characterized as "past losses" ". The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal are unable to determine whether or not, in discharging its functions, the Board has remained within or has transgressed the boundaries of its jurisdiction established by its parent statute. The obligation imposed under s. 8 of the Act is not met by the bald assertion that, as Keith J. succinctly put it in *Re Canada Metal Co. Ltd. et al. and MacFarlane*[9], at p. 587, when dealing with a similar statutory requirement, "my reasons are that I think so".

[7] (1973), 7 N.B.R. (2d) 41 (N.B.S.C.A.D.).
[8] (1976), 29 C.C.C. (2d) 257.
[9] (1973), 1 O.R. (2d) 577.

ca Local 2142[7], le juge en chef Hughes du Nouveau-Brunswick, à la p. 47; *MacDonald c. La Reine*[8], le juge en chef Laskin du Canada, à la p. 262). Cette obligation est salutaire: elle réduit considérablement les risques de décisions arbitraires, raffermit la confiance du public dans le jugement et l'équité des tribunaux administratifs et permet aux parties aux procédures d'évaluer la possibilité d'un appel et, le cas échéant, au tribunal siégeant en révision ou en appel d'accorder une audition complète, qui serait peut-être inaccessible si les motifs de la décision n'étaient pas révélés. Toutefois, cela ne signifie pas que la décision d'un tribunal administratif est susceptible de révision pour l'unique raison qu'elle n'est pas motivée, en l'absence d'obligation légale ou réglementaire en ce sens.

La décision de la Commission accordant l'augmentation provisoire de tarifs contestée par la Ville n'est pas conforme aux exigences de l'art. 8 de *The Administrative Procedures Act*. Il ne suffit pas d'affirmer ou, plus précisément, d'énoncer que la preuve et les moyens soumis par les parties ont été considérés. Cela va de soi. Si l'on soustrait ces attendus des «motifs» rendus par la Commission, il ne reste que la conclusion selon laquelle «le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées»». L'inobservation de l'art. 8 par la Commission comporte l'omission très grave d'exposer «les conclusions de fait sur lesquelles sa décision est fondée», de sorte qu'il est impossible pour les parties et pour le tribunal siégeant en révision de déterminer si, dans l'exercice de ses fonctions, la Commission a respecté ou excédé les limites de sa compétence qu'établit sa loi organique. L'exigence prévue à l'art. 8 de la Loi n'est pas respectée si l'on se contente de dire, comme le mentionne le juge Keith dans *Re Canada Metal Co. Ltd. et al. and MacFarlane*[9], à la p. 587, à propos d'un cas semblable, [TRADUCTION] «mes motifs sont que telle est ma conclusion».

[7] (1973), 7 N.B.R. (2d) 41 (N.B.S.C.A.D.)
[8] (1976), 29 C.C.C. (2d) 257.
[9] (1973), 1 O.R. (2d) 577.

The appellants are not assisted by the decision of the Appellate Division of the Supreme Court of Alberta in *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.*[10], affirmed by this Court at [1977] 2 S.C.R. 822 to the effect that under s. 8 of *The Administrative Procedures Act* the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor can the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. Brevity in this era of prolixity is commendable and might well be rewarded by a different result herein but for the fact that the order of the Board reveals only conclusions without any hint of the reasoning process which led thereto. For example, none of the factors which the Board took into account, in reaching its conclusion that the amounts contested were not "past losses" are revealed so that a reviewing tribunal cannot with any assurance determine that the statutory mandates bearing upon the Board's process have been heeded.

The Appellate Division of the Supreme Court of Alberta, after coming to the same result, vacated the Board's order and referred the matter to the Board for further consideration and determination pursuant to s. 64 of *The Public Utilities Board Act*. In doing so, it is evident from the reasons for judgment of the said Court that the Court properly viewed its appellate jurisdiction under s. 64 of *The Public Utilities Board Act* as a limited one. It is not for a court to usurp the statutory responsibilities entrusted to the Board, except in so far as judicial review is expressly allowed under the Act. It is, of course, otherwise where the administrative tribunal oversteps its statutory authority or fails to perform its functions as directed by the statute. Questions as to how and when operating expenses are to be measured and recovered through pre-

[10] (1976), 2 A.R. 453.

Les appelantes ne trouvent aucun appui dans l'arrêt de la Division d'appel de la Cour suprême de l'Alberta *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.*[10], confirmé par cette Cour à [1977] 2 R.C.S. 822, où il fut jugé que pour être conformes à l'art. 8 de *The Administrative Procedures Act*, les motifs doivent être appropriés, pertinents et intelligibles, et doivent permettre à la partie concernée d'évaluer les possibilités d'appel. La Commission ne peut pas invoquer non plus le caractère particulier de l'ordonnance en question, savoir une ordonnance provisoire dont les dispositions prévoient la possibilité d'un remboursement des montants perçus sous son autorité, pour se soustraire à son obligation de rendre une décision motivée. A une époque où le style est souvent verbeux, la brièveté est un atout et elle aurait pu donner lieu à un résultat différent en l'espèce si ce n'était que l'ordonnance de la Commission ne comporte que des conclusions et est muette quant au raisonnement suivi pour y arriver. Par exemple, la Commission ne révèle aucun des facteurs pris en considération pour parvenir à la conclusion que le montant contesté ne constitue pas des «pertes passées», de sorte que le tribunal siégeant en révision ne peut établir avec certitude si la Commission a observé les exigences légales dans l'élaboration de sa décision.

Parvenue à la même conclusion, la Division d'appel de la Cour suprême de l'Alberta a annulé la décision de la Commission et lui a renvoyé le dossier pour qu'elle l'examine à nouveau et rende une décision conformément à l'art. 64 de *The Public Utilities Board Act*. Il est évident, à la lecture des motifs de jugement de ladite cour, qu'elle a à juste titre considéré que sa compétence en appel aux termes de l'art. 64 de cette loi était limitée. Une cour ne doit pas s'approprier les responsabilités administratives conférées à la Commission, sauf dans la mesure où l'examen judiciaire est expressément prévu par la Loi. Bien sûr, il en va autrement lorsque le tribunal administratif excède ses pouvoirs ou n'exerce pas ses fonctions conformément à la Loi. Sous réserve des limites imposées par la Loi, il appartient à la Commission

[10] (1976), 2 A.R. 453.

scribed rates are, subject to the limits imposed by the Act itself, for the Board to decide, and the procedures for such decisions if made within the confines of the statute are administrative matters which are better left to the Board to determine (*vide City of Edmonton v. Northwestern Utilities Limited, supra, per* Locke J. at p. 406).

As for the participation of The Public Utilities Board in these proceedings, it was pointed out to the Court that s. 65 of *The Public Utilities Board Act* entitles the Board "to be heard ... upon the argument of any appeal". Under s. 66 of the Act the Board is shielded from any liability in respect of costs by reason or in respect of an appeal.

Section 65 no doubt confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given *locus standi* as a participant in the nature of an *amicus curiae* but not as a party. That this is so is made evident by s. 63(2) of *The Public Utilities Board Act* which reads as follows:

> The party appealing shall, within ten days after the appeal has been set down, give to the parties affected by the appeal or the respective solicitors by whom the parties were represented before the Board, and to the secretary of the Board, notice in writing that the case has been set down to be heard in appeal, and the appeal shall be heard by the court of appeal as speedily as practicable.

Under s. 63(2) a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself. The Board has a limited status before the Court, and may not be considered as a party, in the full sense of that term, to an appeal from its own decisions. In my view, this limitation is entirely proper. This limitation was no doubt consciously imposed by the Legislature in order to avoid placing an unfair burden on an appellant who, in the nature of things, must on another day and in another cause again submit itself to the rate fixing activities of the Board. It also recognizes the

de déterminer comment calculer les dépenses d'exploitation et leur recouvrement par l'imposition de tarifs appropriés et la procédure suivie pour parvenir à cette décision, si cette dernière est rendue dans le cadre de la Loi, constitue une question administrative dont la Commission est le meilleur juge (voir *Ville d'Edmonton c. Northwestern Utilities Limited*, précité, le juge Locke, à la p. 406).

En ce qui concerne la participation de The Public Utilities Board aux présentes procédures, on a cité à la Cour l'art. 65 de *The Public Utilities Board Act* selon lequel la Commission a le droit [TRADUCTION] «d'être entendue ... et de faire valoir ses arguments sur tout appel». L'article 66 de la Loi dégage la Commission de toute responsabilité quant aux dépens de l'appel.

Il est évident que l'art. 65 confère à la Commission le droit de participer à l'appel de ses décisions, mais en l'absence d'indication précise de l'intention du législateur, ce droit est limité. La Commission a un *locus standi* et son droit de participer aux procédures d'appel s'apparente à celui d'un *amicus curiae* et non à celui d'une partie. Cela ressort clairement du par. 63(2) de *The Public Utilities Board Act* que voici:

> [TRADUCTION] La partie qui interjette appel doit, dans les dix jours de l'inscription de l'appel, donner aux parties touchées par l'appel ou à leurs procureurs respectifs devant la Commission, et au secrétaire de la Commission, un avis écrit de l'inscription de l'appel pour audition et la cour d'appel doit entendre l'appel dans les plus brefs délais.

Le paragraphe 63(2) fait une distinction entre les «parties» qui interjettent appel de la décision de la Commission ou qui étaient représentées devant la Commission, et la Commission elle-même. La Commission a un rôle limité devant la Cour et elle ne peut pas être considérée comme une partie, au sens plein du terme, dans les procédures d'appel de ses propres décisions. J'estime cette restriction tout à fait justifiée. Le législateur l'a sans aucun doute consciemment imposée dans le but d'éviter de mettre un fardeau injuste sur les épaules d'un appelant qui, par la nature des choses, devra éventuellement retourner devant la Commission et se universal human frailties which are revealed when persons or organizations are placed in such adversarial positions.

This appeal involves an adjudication of the Board's decision on two grounds both of which involve the legality of administrative action. One of the two appellants is the Board itself, which through counsel presented detailed and elaborate arguments in support of its decision in favour of the Company. Such active and even aggressive participation can have no other effect than to discredit the impartiality of an administrative tribunal either in the case where the matter is referred back to it, or in future proceedings involving similar interests and issues or the same parties. The Board is given a clear opportunity to make its point in its reasons for its decision, and it abuses one's notion of propriety to countenance its participation as a full-fledged litigant in this Court, in complete adversarial confrontation with one of the principals in the contest before the Board itself in the first instance.

It has been the policy in this Court to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction. (*Vide The Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Limited et al.*[11]; *The Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Limited et al.*[12]) Where the right to appear and present arguments is granted, an administrative tribunal would be well advised to adhere to the principles enunciated by Aylesworth J.A. in *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board*[13], at pp. 589, 590:

[11] [1961] S.C.R. 72.
[12] [1947] S.C.R. 336.
[13] (1958), 18 D.L.R. (2d) 588.

soumettre de nouveau à ses procédures de détermination des tarifs. Cette restriction offre également une protection contre les défaillances humaines qui entrent en jeu lorsque des personnes ou des organismes se retrouvent ainsi en situation de conflit.

Aux fins de ce pourvoi, l'analyse de la décision de la Commission doit se fonder sur deux considérations concernant l'une et l'autre la légalité d'un acte administratif. L'une des deux appelantes est la Commission elle-même; son avocat a présenté une argumentation détaillée et approfondie à l'appui de la décision de la Commission en faveur de la Compagnie. Une participation aussi active ne peut que jeter le discrédit sur l'impartialité d'un tribunal administratif lorsque l'affaire lui est renvoyée ou lorsqu'il est saisi d'autres procédures concernant des intérêts et des questions semblables ou impliquant les mêmes parties. La Commission a tout le loisir de s'expliquer dans ses motifs de jugement et elle a enfreint de façon inacceptable la réserve dont elle aurait dû faire preuve lorsqu'elle a participé aux procédures comme partie à part entière, en opposition directe à une partie au litige dont elle avait eu à connaître en première instance.

Cette Cour, à cet égard, a toujours voulu limiter le rôle du tribunal administratif dont la décision est contestée à la présentation d'explications sur le dossier dont il était saisi et d'observations sur la question de sa compétence, même lorsque la loi lui confère le droit de comparaître. (Voir les arrêts *The Labour Relations Board of the Province of New Brunswick c. Eastern Bakeries Limited et autres*[11]; *The Labour Relations Board of Saskatchewan c. Dominion Fire Brick and Clay Products Limited et autres*[12].) Lorsque la loi donne à un tribunal administratif le droit de comparaître et de plaider, ce dernier aurait tout avantage à suivre les principes énoncés par le juge Aylesworth dans l'arrêt *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board*[13], aux pp. 589 et 590:

[11] [1961] R.C.S. 72.
[12] [1947] R.C.S. 336.
[13] (1958), 18 D.L.R. (2d) 588.

Clearly upon an appeal from the Board, counsel may appear on behalf of the Board and may present argument to the appellate tribunal. We think in all propriety, however, such argument should be addressed not to the merits of the case as between the parties appearing before the Board, but rather to the jurisdiction or lack of jurisdiction of the Board. If argument by counsel for the Board is directed to such matters as we have indicated, the impartiality of the Board will be the better emphasized and its dignity and authority the better preserved, while at the same time the appellate tribunal will have the advantage of any submissions as to jurisdiction which counsel for the Board may see fit to advance.

Where the parent or authorizing statute is silent as to the role or status of the tribunal in appeal or review proceedings, this Court has confined the tribunal strictly to the issue of its jurisdiction to make the order in question. (*Vide Central Broadcasting Company Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers, Local Union No. 529*[14].)

In the sense the term has been employed by me here, "jurisdiction" does not include the transgression of the authority of a tribunal by its failure to adhere to the rules of natural justice. In such an issue, when it is joined by a party to proceedings before that tribunal in a review process, it is the tribunal which finds itself under examination. To allow an administrative board the opportunity to justify its action and indeed to vindicate itself would produce a spectacle not ordinarily contemplated in our judicial traditions. In *Canada Labour Relations Board v. Transair Ltd. et al.*[15], Spence J. speaking on this point, stated at pp. 746-7:

It is true that the finding that an administrative tribunal has not acted in accord with the principles of natural justice has been used frequently to determine that the Board has declined to exercise its jurisdiction and therefore has had no jurisdiction to make the decision which it has purported to make. I am of the opinion, however, that this is a mere matter of technique in determining the jurisdiction of the Court to exercise the remedy of *certiorari* and is not a matter of the tribunal's defence of its jurisdiction. The issue of whether or not a board has

[14] [1977] 2 S.C.R. 112.
[15] [1977] 1 S.C.R. 722.

[TRADUCTION] Il ne fait aucun doute qu'en appel d'une décision du Conseil, celui-ci peut se faire représenter par un avocat qui plaidera sa cause devant le tribunal d'appel. Nous estimons toutefois approprié que la plaidoirie traite non du fond de l'affaire entre les parties qui ont comparu devant le Conseil, mais plutôt de la compétence ou du défaut de compétence de ce dernier. Si l'avocat du Conseil mène sa plaidoirie de la sorte, l'impartialité du Conseil sera d'autant mieux mise en valeur et sa dignité et son autorité en seront d'autant mieux garanties. En même temps, le tribunal d'appel bénéficiera de toutes les observations que l'avocat du Conseil jugera utiles de présenter sur la question de compétence.

Lorsque la loi constitutive ou organique ne dit rien du rôle ni du statut du tribunal dans les procédures d'appel ou d'examen judiciaire, cette Cour a limité ledit rôle à la seule question de la compétence pour rendre l'ordonnance contestée. (Voir *Central Broadcasting Company Ltd. c. Le Conseil canadien des relations du travail et la Fraternité internationale des ouvriers en électricité, Section locale n° 529*[14].)

Au sens où j'ai employé ce mot ici, la «compétence» n'inclut pas la transgression du pouvoir d'un tribunal par l'inobservation des règles de justice naturelle. Dans un tel cas, lorsqu'une partie aux procédures devant ce tribunal est également partie aux procédures de révision, c'est le tribunal lui-même qui fait l'objet de l'examen. Accorder au tribunal administratif la possibilité de défendre sa conduite et en fait de se justifier donnerait lieu à un spectacle auquel nos traditions judiciaires ne nous ont pas habitués. Dans l'arrêt *Re Conseil canadien des relations du travail c. Transair Ltd. et autres*[15], le juge Spence a écrit à ce sujet (pp. 746-7):

Il est exact qu'on a souvent utilisé la conclusion selon laquelle un tribunal administratif a manqué aux principes de justice naturelle pour décider qu'il a renoncé à l'exercice de sa compétence et par conséquent qu'il se trouvait dans l'impossibilité de statuer, comme il prétendait le faire. Cependant, j'estime que c'est là simplement une façon de permettre à la Cour d'avoir recours au *certiorari* et non une question qui touche à la compétence que le tribunal prétend avoir. Il est évident qu'il n'appartient pas au Conseil qui voit sa façon d'exercer

[14] [1977] 2 R.C.S. 112.
[15] [1977] 1 R.C.S. 722.

acted in accordance with the principles of natural justice is surely not a matter upon which the Board, whose exercise of its functions is under attack, should debate, in appeal, as a protagonist and that issue should be fought out before the appellate or reviewing Court by the parties and not by the tribunal whose actions are under review.

There are other issues subordinate to the two principal submissions which I have discussed above but which are inappropriate for comment at this stage by reason of the disposition which I propose in respect to this appeal. I would dismiss the appeal with costs to the respondent The City of Edmonton as against the appellant Northwestern Utilities Limited. In the result, therefore, the matter would revert to the Board for a continuation of the processing of the application by the Company of August 20, 1975, involving, as discussed above, the ascertainment by any means appropriate to the provisions of the statute, the expenses estimated to be incurred in the future and to be therefore properly recoverable by the application of the rates to be established by the Board; and in the event that s. 31 be invoked for the ascertainment of only those expenses which had been incurred after the application of August 20, 1975. Any further analysis of the factual background and subordinate issues would, in view of this disposition, be inappropriate.

Appeal dismissed with costs.

Solicitors for the appellant, The Public Utilities Board for the Province of Alberta: Major, Caron & Co., Calgary.

Solicitors for the appellant, Northwestern Utilities Ltd.: Milner & Steer, Edmonton.

Solicitor for the respondent, The City of Edmonton: M. H. Patterson, Calgary.

ses fonctions contestée, de plaider en appel, à titre d'intéressé, sur la question de savoir s'il a ou non agi conformément aux principes de justice naturelle; c'est là un point dont doivent débattre en appel les parties et non le tribunal dont les actions sont soumises à examen.

Il existe des questions sous-jacentes à ces deux points principaux mais, étant donné ma conclusion dans ce pourvoi, il est inutile d'en discuter ici. Je suis d'avis de rejeter le pourvoi, avec dépens en faveur de la ville d'Edmonton et à l'encontre de l'appelante Northwestern Utilities Limited. Je suis donc d'avis de renvoyer le dossier devant la Commission afin qu'elle poursuive l'étude de la requête présentée par la Compagnie le 20 août 1975 et qu'elle évalue, conformément à la Loi, les dépenses à venir et en ordonne le recouvrement par les tarifs qu'elle fixera; et, dans l'éventualité où l'on invoquerait l'art. 31, afin qu'elle évalue les seules dépenses engagées après la requête du 20 août 1975. Etant donné ma conclusion, une analyse plus poussée des faits et des autres questions sous-jacentes n'est pas pertinente.

Pourvoi rejeté avec dépens.

Procureurs de l'appelante, The Public Utilities Board de la Province de l'Alberta: Major, Caron & Co., Calgary.

Procureurs de l'appelante: Northwestern Utilities Ltd.: Milner & Steer, Edmonton.

Procureur de l'intimée, La ville d'Edmonton: M. H. Patterson, Calgary.