July 28, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Re: EB-2008-0154 – Union Gas Limited Argument in Chief

Dear Ms. Walli:

Enclosed is Union's argument in chief concerning the Notice of Motion for a review of the Board's decisions in EB-2008-0034 (the 2007 Deferral Decision) and EB-2007-0598 (the 2006 Deferral Decision).

If you have any questions concerning this application and evidence please contact me at (519) 436-5476.

Yours truly,

[original signed by]

Mark Kitchen
Director Regulatory Affairs

cc G. Leslie (Blakes)
S. Wong (Blakes)
All Parties in EB-2007-0598
All Parties in EB-2008-0034
All Parties in EB-2005-0551

EB-2008-0154

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

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2008.

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2007.

AND IN THE MATTER OF Rules 7, 42, 44.01 and 45.01 of the Board's *Rules of Practice and Procedure*.

ARGUMENT IN CHIEF OF UNION GAS LIMITED

PART I: NATURE OF THE MOTION

1. In this motion, Union Gas Limited ("Union") is asking the Ontario Energy Board (the "Board") to exercise its jurisdiction under s. 21.2(1) of the *Statutory Powers Procedure Act* and Rule 42.01 the Board's *Rules of Practice and Procedure* to review and vary its decisions.

2. In particular, Union requests that the Board

i) review the Board's decision in EB-2008-0034 (the "2007 Deferral Decision"[1]) with respect to whether Union's 2007 Long-Term Peak Storage Services deferral account No. 179-72 ("Account 179-72") is to be used only to record differences in actual and forecast net revenues in respect of long-term storage contracts entered into before the

[1] Attached as Exhibit A hereto.

Board's decision in the Natural Gas Electricity Interface Review, EB-2005-0551, (the "NGEIR Decision"[2]) was issued on November 7, 2006, and

ii) if the Board concludes that the 2007 Deferral Decision was not correct, then Union requests an order varying the 2007 Deferral Decision to allow Union to calculate its net revenue from ex-franchise long-term storage services that is to be shared with ratepayers until the end of 2010 pursuant to the NGEIR Decision based solely on the difference between actual and forecast net revenues in respect of long-term storage contracts entered into before the NGEIR Decision ("Pre-NGEIR LSS Contracts").

3. In the alternative, if the Board concludes that the 2007 Deferral Decision was correct, then Union requests:

i) a review of the Board's decision in EB-2007-0598 (the "2006 Deferral Decision"[3]) with respect to whether Union ought to be allowed to record to Account 179-72 deferred income tax expenses of $10.524 million as a cost of providing long-term storage services in 2006, and

ii) an order varying the 2006 Deferral Decision to allow Union to deduct from Account 179-72 all costs of providing all long-term storage services to its ex-franchise customers, including the costs associated with long-term storage contracts entered into after the NGEIR Decision ("Post-NGEIR LSS Contracts") and in particular including Union's 2006 deferred income tax expenses of $10.524 million, for the purpose of calculating Union's balance for Account 179-72.

4. As required by Procedural Order No 1, this Argument will first address the threshold question of whether the substantive issues should be reviewed before dealing with the substantive issues.

[2] NGEIR Decision, attached as Exhibit B hereto
[3] Attached as Exhibit C hereto.

PART II: THE THRESHOLD QUESTION

5. Rule 45.01 provides:

> 45.01 In respect of a motion brought under Rule 42.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

6. In the Board's Decision with Reasons in EB-2006-0322, EB-2006-0338 and EB-2006-0340 (the "NGEIR Review Threshold Decision") the Board stated the following test for determining whether the Board should review one of its decisions:

> In determining the appropriate threshold test pursuant to Rule 45.01, it is useful to look at the wording of Rule 44. Rule 44.01(a) provides that:
>
> > Every notice of motion… shall set out the grounds for the motion that raise a question as to the correctness of the order or decision…
>
> Therefore, the grounds must "raise a question as to the correctness of the order or decision". In the panel's view, the purpose of the threshold test is to determine whether the grounds raise such a question. This panel must also decide whether there is enough substance to the issues raised such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended.
>
> With respect to the question of the correctness of the decision, the Board agrees with the parties who argued that there must be an identifiable error in the decision and that a review is not an opportunity for a party to reargue the case.
>
> In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, **that the panel made inconsistent findings**, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently.
>
> The applicant must also be able to demonstrate that the alleged error is material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.

> In the Board's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review.[4]
>
> (emphasis added)

7. The test articulated in the NGEIR Review Threshold Decision requires that the applicant seeking review satisfy the Board with respect to the following two points:

i) That there are grounds for questioning the correctness of the decision. In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature.

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

8. Union has met both of these tests.

9. In addition, there are good grounds for granting an extension of time, if necessary, for the bringing of the motion for review of the 2006 Deferral Decision.

i) There are grounds for questioning the correctness of the 2007 and the 2006 Deferral Decisions

10. In the NGEIR Review Threshold Decision, the Board specifically referred to inconsistent findings as being sufficient grounds for questioning the correctness of a decision.

11. In this case, the Board's rulings in the 2007 Deferral Decision and the 2006 Deferral Decision in respect of the issues raised in this motion are inconsistent with each other, and also with the intent of the NGEIR Decision.

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[4] EB-2006-0322, EB-2006-0338 and EB-2006-0340, Decision with Reasons, at pp. 17-18, attached as Exhibit D hereto.

Background

12. The market prices that Union realizes on sales of storage services to ex-franchise customers generally have been higher than the cost-based rates charged to Union's in-franchise customers. Prior to the NGEIR Decision, the Board directed that most of this net revenue over cost be credited against Union's distribution rates or otherwise credited to ratepayers. Union forecasted the amount of its expected net revenue (also known as margins) from its ex-franchise storage contracts for the rate year in question as part of its rates case. Of the Board approved forecast amount, 90% was included as a credit against distribution rates for the year. To the extent that actual margins varied from the forecast built into rates, Union booked the difference in deferral accounts: account 179-70 for short-term transactions and account 179-72 for long-term transactions. Prior to the NGEIR Decision, these deferral account balances were shared 75:25 in favour of distribution ratepayers.

13. In the NGEIR Decision the Board decided to refrain from regulating rates for existing storage services to customers outside Union's franchise area and from regulating rates for new storage services to all customers, including those within the franchise.[5] The Board also determined that there should be a phase-out of sharing of margins on Union's long-term storage transactions over four years. The Board stated:

> For 2007, forecast margins (on long-term and short term transactions) ***now included in the determination of Union's rates*** will remain unchanged. After 2007, Union's share of long-term margins will be as follows: 2008 – 25%, 2009 – 50%, 2010 – 75%, 2011 and thereafter – 100%.
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> (NGEIR Decision, p. 107, emphasis added)

14. In Union's application in EB-2008-0034 for disposition of its 2007 deferral accounts, Union calculated Account 179-72 based solely on the difference between the actual margins earned from Pre-NGEIR LSS Contracts and the forecasted margins arising from the Pre-NGEIR LSS Contracts that were included in the determination of Union's 2007 rates, and without

[5] NGEIR Decision, at p. 70-71.

taking into account the margins that Union earned from Post-NGEIR LSS Contracts that were not included in the determination of 2007 rates.

15. The issue which fell for determination in the 2007 Deferral Case (EB-2008-0034) was whether the NGEIR Decision limited the sharing during the phase-out period from 2007 to 2010 to solely the sharing of the long-term margins arising from the Pre-NGEIR LSS Contracts as those were the only margins included in the determination of Union's 2007 rates. The panel in that case disagreed with that view of the NGEIR Decision, and it found that during the phase-out period Union is required to continue sharing with the ratepayers its net revenues from all long-term, unregulated, storage transactions, both Pre-NGEIR and Post-NGEIR. That finding requires Union to include in deferral Account 179-72 net revenues from deregulated transactions that were not included in the determination of Union's 2007 rates.

16. In the 2006 Deferral proceeding (EB-2007-0598), Union asked the Board to approve a debit (i.e. a charge against the ratepayers' share of Union's net revenue) to Account 179-72. Union incurred a deferred tax expense as a result of the deregulation of a part of Union's storage business in the NGEIR decision. The proposed debit to Account 179-72 was caused by the requirement under Canadian Generally Accepted Accounting Principles ("GAAP") to record that deferred tax expense.

17. In the 2006 Deferral Decision, the Board ruled that Union was not entitled to debit Account 179-72 by the amount of the deferred tax expense because it found "*that the deregulation of Union's storage assets is notionally equivalent to a divestiture, and that any liabilities associated with these assets should properly be associated with Union's newly formed ex-franchise storage service business.*" (at p. 9)

18. The Board's ruling in the 2006 Deferral Decision prohibits Union from deducting all costs associated with providing deregulated storage services after the NGEIR Decision when calculating the margin that Union is required to share with ratepayers during the phase-out period mandated in the NGEIR Decision. This ruling was based on the finding that the NGEIR Decision mandated the formation by Union of a new deregulated storage business that is separate

from Union's regulated business and that the assets and liabilities of the regulated business should be accounted for separately from the assets and liabilities of the unregulated business.

19. Union is asking the Board to review the 2007 Deferral Decision, and if it finds that the 2007 Deferral Decision was correct then Union is asking that the Board review the 2006 Deferral Decision, because the two decisions are based on inconsistent and contrary interpretations of the NGEIR Decision.

The Inconsistency between the Deferral Decisions

20. The 2006 Deferral Decision was based on the principle that the assets and liabilities of the regulated business should be accounted for separately from the assets and liabilities of the unregulated business, whereas the 2007 Deferral Decision was based on the opposite and inconsistent view that the earnings from the new unregulated business should be used to subsidize rates paid by customers of Union's regulated business.

21. As more fully discussed in Part III of this Argument, the deferred income tax expense which Union sought to debit against Account 179-72 is a cost resulting from the deregulation of Union's storage assets. The accounting rules for rate regulated entities allowed Union to defer certain current period tax costs, where such deferral benefited customers in the past. When Union's ex-franchise storage service was deregulated, Union was no longer able to defer recording that portion of future tax liabilities that related to the deregulated services. This had the result that, rather than recognizing the cost of those tax liabilities in the future, those formerly deferred liabilities had to be recognized in 2006 at the time of the release of the NGEIR Decision as a cost of providing long-term storage services.

22. In the 2006 Deferral Decision, the panel ruled that Union was not entitled to debit Account 179-72 by the amount of the deferred tax expense because the deferred tax expense was a cost associated with Union's deregulated storage assets:

> The Board finds that the deregulation of Union's storage assets is notionally equivalent to a divestiture, and that any liabilities associated with these assets

> should properly be associated with Union's newly formed ex-franchise storage service business.
>
> The taxes associated with this line of business, including the deferred taxes residing in the account should form a part of this new undertaking. This is the same treatment afforded to like liabilities associated with the divestiture of the ancillary services, detailed in Undertaking J1.3.
>
> (2006 Deferral Decision, at p. 9)

23. Despite that earlier ruling, the panel in the 2007 Deferral Decision interpreted the NGEIR Decision in a wholly contrary manner when it ruled that the NGEIR Decision requires that the **net revenues** on all long-term storage transactions, including deregulated Post-NGEIR LSS Contracts, must be accounted for in Account 179-72:

> The Board finds that the NGEIR decision does not require or permit Union to modify the method of calculating the balance in account 179-72 for 2007. The balance should equal 75% of the excess of (i) actual net revenues (on <u>all</u> long-term storage transactions, that is, transactions that occurred both before and after the publication of the NGEIR decision) for 2007, less (ii) the Board-approved forecast net revenue $21.405 million.
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> (2007 Deferral Decision, p. 8, emphasis in original)

24. "Actual net revenues" from the Post-NGEIR LSS Contracts cannot be calculated and applied to Account 179-72, as required by the 2007 Deferral Decision, without taking into account the costs associated with operating the unregulated storage assets, but the 2006 Deferral Decision ruled that Union is not entitled to apply costs related to the unregulated storage assets when it calculates Account 179-72. This obvious inconsistency between the two deferral decisions leaves Union with contradictory directions from the Board as to how it is to calculate the margins that are to be shared with the ratepayers during the phase-out period.

25. In addition, it would be unfair to require Union to share with ratepayers the margins earned from its unregulated Post-NGEIR LSS Contracts (as required by the 2007 Deferral Decision) while at the same time prohibiting Union from deducting from Account 179-72 all the costs of providing that unregulated service, including Union's 2006 deferred income tax expenses. Under such a scenario, Union would be in a worse financial position than it would

have been under the regulatory environment prior to the NGEIR Decision because it would be required to continue to share revenue but not permitted to deduct associated costs.

26. Union submits that the inconsistency between the two deferral decisions is a good reason for questioning whether one of the two deferral decisions is incorrectly decided.

ii) The alleged error is material and relevant to the outcome of the decision

27. Union submits that the Board erred in the 2007 Deferral Decision in its interpretation of the NGEIR Decision. The alleged error is material and relevant to the outcome of the proceeding because the panel's interpretation of the NGEIR Decision was the very issue that determined the outcome.

28. Union submits that the intent of the NGEIR Decision was that Union would not be required to share the net revenues from its unregulated Post-NGEIR LSS Contracts. The panel that rendered the 2007 Deferral Decision came to the opposite conclusion with the direct result that Union was required to recalculate the 2007 balance in Account 179-72 in a manner that includes the net revenue from its Post-NGEIR LSS Contracts. In addition, the ruling in the 2007 Deferral Decision as to how the NGEIR Decision is to be interpreted also directly affects the manner in which Account 179-72 will be calculated for the remainder of the phase-out period that ends on December 31, 2010 as it requires Union to share net revenues from its unregulated Post-NGEIR LSS Contracts until that time, and that, in turn, significantly affects the economics and risk profile for any new investments by Union to increase storage capacity in Ontario.

29. With respect to the 2006 Deferral Decision, if the Board finds on review that the 2007 Deferral Decision is correct, then Union submits that the 2006 Deferral Decision is incorrectly decided because it is based on an interpretation of the NGEIR Decision that is opposite to and inconsistent with the interpretation that was the basis for the 2007 Deferral Decision. Net revenues from the unregulated Post-NGEIR LSS Contracts cannot be calculated and applied to Account 179-72, as required by the 2007 Deferral Decision, without taking into account the costs associated with operating the unregulated storage assets, but the 2006 Deferral

Decision ruled that Union is not entitled to apply costs related to the unregulated storage assets when it calculates Account 179-72.[6] If the panel in the 2006 Deferral Decision misinterpreted the NGEIR decision on this point, then that error was material and relevant because that misinterpretation was the very basis for the Board's finding that the deferred income tax expense should not be included in account 179-72.

iii) There are good grounds for an extension of time to seek review of the 2006 Deferral Decision

30. Pursuant to Rule 7.01 of the Board's *Rules of Practice and Procedure*, the Board may extend the time for bringing a motion to review on such conditions as the Board considers appropriate.

31. The inconsistency between the 2006 Deferral Decision and the 2007 Deferral Decision did not become apparent until the issuance of the 2007 Deferral Decision on June 3, 2008.

32. The requirement in the 2007 Deferral Decision that Union share with ratepayers the margins earned from all of its unregulated Post-NGEIR LSS contracts when calculating deferral Account 179-72 rendered unfair the ruling in the 2006 Deferral Decision that Union is not entitled to deduct the costs associated with its unregulated business from deferral Account 179-72. This element of unfairness in the 2006 Deferral Decision did not become evident until the 2007 Deferral Decision was issued.

33. Union moved promptly to seek a review of the 2006 Deferral Decision forthwith after issuance of the 2007 Deferral Decision when the inconsistency and unfairness in the conflicting results became apparent. Union served it's Notice of Motion seeking review of both deferral decisions 20 days later on June 23, 2008.

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[6] See page 9 of the 2006 Deferral Decision, which states "that the deregulation of Union's storage assets is notionally equivalent to a divestiture, and that any liabilities associated with these assets should properly be associated with Union's newly formed ex-franchise storage service business."

34. The ruling in the 2006 Deferral Decision concerns a substantial sum of money, $10.524 million, in respect of Union's 2006 costs, and also concerns the proper method that ought to be applied by Union when it calculates the amount that must be shared with the ratepayers pursuant to the NGEIR Decision each year until the end of 2010.

35. No party will be prejudiced by the requested extension of time.

36. For all of the above reasons, Union submits that it would be just and appropriate for the Board to review the 2007 Deferral Decision and the 2006 Deferral Decision as requested in Union's notice of motion.

PART III: SHOULD ALL LONG-TERM STORAGE TRANSACTIONS, PRE AND POST-NGEIR, BE RECORDED TO CALCULATE THE BALANCE IN ACCOUNT 179-72?

37. The balance in Account 179-72 should only contain net revenue earned from Pre-NGEIR transactions for the following reasons:

(1) the intent of the NGEIR Decision was to limit the revenues that Union is required to share during the phase-out period to solely the sharing of the long-term margins arising from the Pre-NGEIR LSS contracts. This intent is demonstrated by the following statements in the NGEIR Decision:

a. long-term transactions should accrue entirely to Union (p.104);

b. there is no basis for sharing of margins on long-term storage transactions executed after the Board's forbearance decision (p.106);

c. the return from the deregulated storage assets accrues entirely to Union, so the Supreme Court of Canada's *ATCO* decision does not apply (p.109);

d. the further development of storage would be a benefit to Ontario consumers, and that under forbearance the utilities would have an incentive to develop assets and services (p. 50);

e. the regulation of storage rates places constraints on the development of flexible and innovative services, and that forbearance can remove these constraints (p. 45);

f. storage investments are riskier than other regulated activities, and utility shareholders should bear the risk of any storage development for the competitive market (p.51);

g. the key consideration is to ensure that new innovative services are developed and offered into the market, and the best way to ensure this public interest is met is to refrain from regulating these services (at p. 69);

h. any new storage which is developed by the utilities will be included as part of the competitive market, and utilities will bear the risk of these investments, not ratepayers; similarly, the Board will not regulate the rates, nor approve the contracts, arising from these investments (at p. 70);

i. a smooth transition away from the status quo would be in the best interest of ratepayers (p. 106), and the effect of the transition would likely be about a 1% increase in the typical residential consumer's bill (p. 119 and Executive Summary p. 4).

(2) The 2006 Deferral Decision, which was issued nine months after the NGEIR Decision, is entirely consistent with the attribution of all Post-NGEIR long-term storage revenues and costs to Union's account.

(3) Union's shareholder has made new storage investments based on the full access to market prices by the utility.

These reasons are explained below.

38. Account 179-72 is used to record the difference between the forecasted margins and the actual margins earned on long-term storage transactions that are to be shared with ratepayers. Accordingly, the correct answer to the question of whether all long-term storage transactions, including Post-NGEIR Contracts, should be recorded to calculate the balance in Account 179-72 depends on what margins Union is required to share during the phase-out period. In the NGEIR Decision, the Board stated:

> For 2007, forecast margins (on long-term and short term transactions) ***now included in the determination of Union's rates*** will remain unchanged. After 2007, Union's share of long-term margins will be as follows: 2008 – 25%, 2009 – 50%, 2010 – 75%, 2011 and thereafter – 100%.
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> (NGEIR Decision, p. 107, emphasis added)

39. The following excerpts from the NGEIR Decision demonstrate that the intent of that Decision was to require sharing during the phase-out period of only the long-term margins arising from the Pre-NGEIR LSS Contracts that were included in Union's 2007 rates, and there was no intent to require Union to share the margins from its new unregulated Post-NGEIR LSS Contract that were not previously included in the determination of rates:

a) The Board has determined that storage space in excess of the amount made available at cost-based rates (which is to be capped at 100 PJ – see Chapter 6) can be considered a "non-utility" asset. This is the space that will support Union's long-term storage sales. **The Board finds that profits from new long-term transactions should accrue entirely to Union, not to ratepayers.** (p. 104)

b) **The Board finds, however, that there is no basis for retaining a requirement that Union share the margins on new long-term storage transactions, that is, long-term deals executed after the Board's forbearance decision.** To continue sharing those margins with ratepayers would conflict with the Board's decisions (a) to recognize that part of Union's storage capacity constitutes a non-utility asset, and (b) to forbear from regulating the prices of ex-franchise transactions. **Union should reap the benefits and bear the risks of those new transactions.** (p. 106)

c) At the same time, **this decision finds that there are certain storage assets that are not part of the utility rate base and finds that the return from those assets, in terms of profit on sales to ex-franchise customers, should accrue entirely to the utility** and its shareholders. Again, no claim arises under the ATCO principles. **There is no appropriation to the benefit of the ratepayer of any utility assets**

> **or for that matter any proceeds from that asset.** Accordingly, the Board finds that ATCO decision has no application to this decision. (p. 109)

40. It is clear from these passages, and from the other passages referred to in paragraph 37(1) above, that the intent of the NGEIR Decision is that all of the net revenue from Union's unregulated Post-NGEIR LSS Contracts is to accrue to Union's benefit, without any sharing, because Union is bearing all of the risks associated with the deregulated, non-utility assets that are used to service the unregulated storage business, and in order to comply with the principles set out by the Supreme Court of Canada in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*[7](the "*ATCO Decision*").

41. The finding in the 2007 Deferral Decision that Union is required to account for the net revenue from the Post-NGEIR LSS Contracts in Account 179-72 has the result of requiring Union to share with ratepayers the proceeds of deregulated transactions which were earned using non-utility assets. This result is completely contrary to the clear statement on page 109 of the NGEIR Decision that the return on the storage assets that are not part of the utility rate base "*should accrue entirely to the utility*".

42. In the *ATCO Decision*, the Supreme Court of Canada explained that under the regulatory compact "all customers have access to the utility at a fair price — nothing more".[8] Customers do not have any property right in the utility company's regulated assets, because rates paid by the customers in no way purchased the company's assets:

> 68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control

[7] *ATCO Decision*, [2006] 1 S.C.R. 140, attached hereto as Exhibit E
[8] ibid, at para. 63

> of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves.[9]

43. This is particularly true in this case, where the Board has found that the rates paid by in-franchise customers were not used by Union to "pay for" Union's long-term storage space:

> Further, the Board's decision in RP-1999-0017 to allow all then existing cost-based contracts with ex-franchise customers to be renewed at market rates has resulted in a substantial growth in long-term margins, margins that have been largely for the benefit of ratepayers. It is certainly not possible today to assert that ratepayers have "paid for" the space that underpins Union's long-term storage contracts.[10]

44. The requirement in the 2007 Deferral Decision that Union share the net revenue from its unregulated storage transactions results in an "appropriation to the benefit of the ratepayer" of proceeds of non-utility assets which is clearly contrary to the *ATCO* principles . In another recent case involving ATCO and the Alberta Energy and Utilities Board, 2008 ABCA 2008[11], (the "*Carbon Storage"* case), the Alberta Court of Appeal made it clear that under the *ATCO* principles ratepayers are not entitled to any interest in the cash flow generated by the unregulated businesses of a utility, just as they are not entitled to the ownership of the assets.

45. In the *Carbon Storage* case, ATCO owned a carbon storage facility that had been partly used for its regulated gas business to manage peak utility supply requirements, and revenue from the sale of excess space had been used to offset the overall revenue requirement of the regulated business. ATCO stopped using the facility for operational purposes, and in 2006, the AEUB determined that the facility was no longer required for any operational purpose as a part of the regulated utility business. The only remaining reason to keep the facility within rate base would be to generate revenue which would be used to reduce the rates that would otherwise be payable by regulated customers. The AEUB determined that the asset should remain in rate base, primarily because revenue from the facility had been used to offset the regulated revenue

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[9] ibid, at para. 68
[10] NGEIR Decision, p. 105
[11] *Carbon Storage* decision, 2008 ABCA 2008, attached as Exhibit F hereto

requirement and had been part of the AEUB's determination of just and reasonable rates to customers for an extensive period.[12]

46. The Alberta Court of Appeal overturned the AEUB's decision, finding *inter alia* that the AEUB erred in failing to recognize that there had been radical change in the regulatory regime which had fundamentally changed the status of the facility, and that it was unreasonable for the AEUB not to recognize that fundamental change once the facility lost all of its operational purposes:

> [27] Fifthly, **while the Board noted that "fundamental changes" in the regulatory regime might change the status of an asset, the Board failed to give effect to the fact that the present issue respecting the use of the Carbon storage facility came about largely because of just such a change.** The regulatory regime has changed radically and the operations of the traditional integrated utility have now been split among a number of players. For many years the Carbon storage facility played a dual role as an operational asset, as well as a generator of revenue from the leasing of surplus capacity. Under the present circumstances, the Carbon storage facility has no operational role at all. The Board found in Decision 2007-05 at pp. 26-7 that: "it is not material whether or not revenue generation was a stand-alone use or an ancillary use associated with a utility service or function whose purpose was to indirectly offset the costs of providing this utility functionality." **The failure to recognize the fundamental change in the role played by the Carbon storage facility once it lost all of its operational purposes was unreasonable**.[13]
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> (emphasis added)

47. The Alberta Court of appeal then went on to apply the principles from the Supreme Court's *ATCO* decision:

> Regulation of a gas utility does not give the end customers an ownership interest in the assets of the utility: [*ATCO decision*[14]] at paras. 63-68. The end customers are entitled to service, not assets. The service that they are entitled to is the delivery of gas on reasonable and just terms, not revenue generation. Just as the end customers have no ownership interest in the assets of the utility, they have no interest in the profits, unregulated

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[12] *Carbon Storage*, para. 12

[13] *Carbon Storage* at para. 27

[14] The Supreme Court of Canada's *ATCO Decision*, [2006] 1 S.C.R. 140, is referred to as the *Stores Block* decision in the *Carbon Storage* decision – see 2008 ABCA 200, at para. 16

> revenues, or unregulated businesses of the utility. **The value of economic assets is often largely determined by the revenues they can generate, and if the end customers are not entitled to any ownership interest in the assets, they are likewise not entitled to any interest in the cash flow generated by those assets:** [*ATCO decision*] at para. 78. The end customers are entitled to receive gas delivery services from the utility, not revenue-generating services or gas rate subsidization.
>
> (*Carbon Storage*, para. 30, emphasis added)

48. In the NGEIR Decision, the Board determined that the storage market was sufficiently competitive to protect the public interest of ex-franchise storage customers, that it would refrain from regulating long-term ex-franchise storage services, and that the storage assets not needed to serve in-franchise needs would thereafter constitute "non-utility" assets for which Union's shareholder would thereafter bear the risk.

49. The NGEIR Decision brought about a fundamental change in the regulatory status of the assets that Union uses to serve the unregulated Post-NGEIR transactions. Those assets are now non-utility assets, and, as such, Union's customers are not entitled to claim any part of the revenues generated by those assets. The Board already made that ruling in the NGEIR Decision (see p. 104 and 109), and that ruling is the only one that is consistent with the *ATCO* principles.

50. Another expressed objective in the NGEIR Decision was to avoid an abrupt change in regulated rates:

> The Board recognizes that, particularly in recent years, Union's ratepayers have had a significant benefit due to sharing the bulk of the margins on long-term deals. The Board would prefer to have a smooth transition away from the status quo rather than an abrupt change in rates. (p. 106)

51. This statement indicates that the Board intended to gradually reduce the amount of the subsidy to the ratepayers over the phase-out period. Requiring Union to share the proceeds of the Post-NGEIR LSS Contracts with the ratepayers does not accomplish the goal of having a smooth transition away from the Pre-NGEIR status quo. Sharing of the proceeds from the Post-NGEIR LSS Contracts will result in the ratepayers receiving during the initial years of

the phase-out period a much larger subsidy than they received before the NGEIR Decision, followed by a steep decline at the end of the phase-out period.

52. On the other hand, if Union is only required to share the margins from the Pre-NGEIR LSS Contracts during the phase-out period that would gradually reduce the subsidy ratepayers are receiving from the unregulated storage transactions, which would better achieve the goal of having a smooth transition away from Pre-NGEIR status quo. Specifically, a 25% annual reduction in the amount of the subsidy included in the determination of Union's 2007 rates would result in rate increases of less than 1% per year, meeting the Board's estimated impact on ratepayers from the NGEIR decision (NGEIR Decision, p. 119 and Executive Summary p. 4).

53. For the reasons stated above, Union believed that it was not required to share the margins on the Post-NGIER LSS Contracts. Union's belief was subsequently affirmed when it received the 2006 Deferral Decision 9 months later that stated that the deregulated storage assets should be treated as if they had been divested. Union would not have made the investments that it committed to in 2007 (to develop additional high deliverability capacity at Dawn) and 2008 (to invest in the development of the Tipperary Storage Pools) to develop additional storage capacity if it had known that it would be required to share the proceeds from those projects.

54. This is also an issue of fairness, where Union undertook new, unregulated storage investments on the basis of their economic attractiveness using market prices. These new investments were entirely consistent with Union's testimony during the NGEIR hearing. Union testified that it had no economic incentive to develop and commit capital to new storage or new storage deliverability under a regime where it is required to share the returns from new investments, and that it would only consider new storage investments if it could keep all of the return from market prices.[15] Union's evidence on this point was clear and unchallenged.

[15] See the evidence of (Steve Baker, Transcript Volume 2, p. 144 -147 and Volume 4, p. 147, attached as Exhibit G hereto.

55. There is no reasonable basis upon which ratepayers are entitled to a share of the proceeds from Union's Post-NGEIR unregulated storage business. Accordingly, it is submitted that Union should not be required to record unregulated Post-NGEIR long-term storage transactions to calculate the balance in Account 170-72.

PART IV SHOULD UNION BE ALLOWED TO CLAIM A DEBIT CHARGE TO ACCOUNT 179-72 REFLECTING DEFERRED INCOME TAXES RELATED TO STORAGE SERVICES IN THE EVENT THAT THE BOARD CONCLUDES THAT THE 2007 DEFERRAL ACCOUNT DECISION IS CORRECT?

56. In the alternative, if the Board concludes that the 2007 Deferral Decision is consistent with the NGEIR Decision and correct, and that Union must record unregulated Post-NGEIR long-term storage transactions to calculate the balance in Account 170-72, then Union submits that the 2006 Deferral Decision should be varied to allow Union to deduct from Account 179-72 all costs of providing all long-term storage services to its ex-franchise, including the deferred income tax expense of $10.524 million.

What is the Deferred Income Tax Expense?

57. The deregulation of a portion of Union's storage business required a change to the timing of the recognition of certain deferred tax liabilities associated with the past activity of the deregulated storage business. The background is as follows.

58. Effective January 1, 1997, the Board ordered a change in the accounting treatment of income taxes for Union from a normalized or deferred basis to a flow-through basis. Under both methods, approved rates were set to recover all of the taxes associated with Union's current and past economic activity. The only difference between the two methods is when those liabilities must be recognized as a current cost of providing service.

59. The normalized method of accounting for income tax is, for most businesses, the required approach under GAAP. Under the normalized method of accounting for taxes, the taxes

recorded in a year must reflect both the current taxes payable and any future income taxes which relate primarily to the difference between tax and accounting depreciation in the relevant period.

60. Under the flow-through method of accounting, only those taxes actually payable in the current year need to be recorded as current liabilities. Under the flow-through method, therefore, those future tax liabilities arising from current economic activity which relate to the difference between tax and accounting depreciation need not be recorded in the current year but are only recorded in the year in which they actually become payable.

61. The flow-through method of accounting for taxes is, however, only available to rate regulated entities which meet three specified criteria:

1. rates for service must be subject to approval by a regulator;
2. rates must be designed to recover the cost of providing service; and
3. it must be reasonable to assume that rates set to recover costs in future can be charged to and collected from customers.

62. Under the flow-through method, the future deferred tax expense resulting from the difference between tax and accounting depreciation does not need to be reflected as a current expense because the entity is rate regulated and, therefore, there is a high level of comfort that the deferred future taxes associated with current or past economic activity will nevertheless be recoverable at a later date from customers. Deferring the recognition of certain tax costs to later years benefited Union's ratepayers at that time as it reduced rates by reducing the cost of service. However, it was expected that future rates would be set to recover the deferred tax expense over time.

63. Following the release of the NGEIR Decision in November 2006, Union no longer met the conditions precedent for flow-through accounting for income taxes with respect to

revenues generated by its deregulated storage business. In particular, Union could not assume that future rates would be set to recover the deferred income tax costs, as those services would no longer be rate-regulated. When a portion of a business ceases to fulfill the preconditions for the flow-through method of accounting, that portion of the business must immediately stop using the flow-through method, revert to the normalized method of accounting and reflect the deferred portion of the business' tax liabilities in its current financial statements.

64. The difference, in this case, between the current taxes paid under the flow-through method and the actual, all in, tax liabilities associated with Union's economic activity between 1997 and 2006 for long-term peak storage services is $10.524 million. This is dealt with in Note 19 to Union's 2006 financial statements, which were audited and approved, without reservation, by Deloitte & Touche LLP on March 23, 2007.

65. Union also retained a second, independent audit firm, Ernst & Young, to opine on whether as a matter of accounting practice, Union was required to record immediately the formerly deferred tax liability associated with the portion of storage services that became deregulated as a result of the NGEIR Decision. Ernst & Young's opinion is that Union was required to record that deferred tax liability immediately.[16]

66. As a result, Union was no longer able to defer recording that portion of existing tax liabilities that related to its deregulated storage business, and it was required to recognize all of those formerly deferred liabilities in 2006 as a cost of providing long term peak storage services.

67. In the 2006 Deferral Decision, the panel prohibited Union from debiting the deferred tax expense to Account 179-72.

[16] See Exhibit A to Union's Pre-Filed Evidence for EB-2007-0598, at pp. 14-15, attached as Exhibit H hereto.

68. Based on the Board's ruling in the 2006 Deferral Decision, Union absorbed the impact of all costs associated with the newly-formed deregulated business against the revenues from the Post-NGEIR LSS Contracts. These costs included the 2006 deferred tax true up amount disallowed for deferral, the 2007 deferred tax expense, overhead costs that were previously capitalized and other expenses that are properly matched to the unregulated storage revenues. This approach formed the basis of Union's year-end, audited financial statements.

69. 2006 Deferral Decision was based on two grounds:

i) the panel found that the deregulation of Union's storage assets should be treated as equivalent to a divestiture of the assets by Union and that any liabilities associated with those assets should properly be associated with Union's newly formed ex-franchise storage service business; and

ii) the panel was also concerned that allowing the debit would result "in a significant cross-generational subsidy", and the panel found that it would be inequitable for today's ratepayers to pay costs that have accumulated since the deferral account was started in 1997. [17]

70. Union submits that neither of the grounds relied on by the panel in the 2006 Deferral Decision can be sustained if the 2007 Deferral Decision is correct. However, the 2006 Deferral Decision is entirely sustainable if all the Post-NGEIR long-term storage revenues and costs are attributed to Union's account without sharing.

[17] Deferral Decision, page 9

Should the deregulation of Union's storage assets be treated as if it were a divestiture of the assets?

71. If the Board affirms the ruling in the 2007 Deferral Decision that requires Union to share with ratepayers the net revenues from the Post-NGEIR LSS Contracts, then there is no justification for treating Union's deregulated storage assets as if they have been divested by the regulated business. If the ratepayers are sharing in the benefits earned from Union's deregulated storage business, they should also be required to share in the costs associated with the deregulated storage business.

72. As stated in Part I, it would be unfair to require Union to share with ratepayers the margins earned from its unregulated Post-NGEIR LSS Contracts (as required by the 2007 Deferral Decision) while at the same time prohibiting Union from deducting from Account 179-72 all the costs of providing that unregulated service, including Union's 2006 deferred income tax expenses. Under such a scenario, Union would be in a worse financial position than it would have been under the regulatory environment prior to the NGEIR Decision because it would be required to continue to share revenue but not permitted to deduct associated costs.

73. The 2007 Deferral Decision was premised on Union being required to share with ratepayers the net revenues from all its unregulated long-term storage assets during the four year phase-out period. If that premise is correct, then the deregulation of the long-term storage assets cannot be equivalent to a divestiture by Union's regulated business because Union's regulated ratepayers are still entitled to benefit from the proceeds earned from the deregulated assets.

74. If the regulated rates are subsidized by the net revenues from the deregulated business, then the deregulated business is not wholly separate or divested from the regulated business, and all the costs associated with deregulated business, including the deferred income tax expense, must be recorded in Account 179-72 for the purpose of calculating the ratepayers' subsidy.

Is it inequitable for today's ratepayers to pay the deferred tax expense?

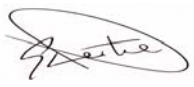
75. There is no inequity to today's ratepayers if Union is allowed to debit the cost of the deferred tax expense against the revenues that have been generated from the deregulated storage business. In fact, it would be inequitable not to allow Union to debit a legitimate expense resulting from the deregulation against revenues earned as a result of the deregulation.

76. It is important to note that all of the deferred tax expense was incurred in respect of Pre-NGEIR LSS Contracts, and prior to the NGEIR Decision it was expected that future rates would be set to recover the deferred tax expense over time.

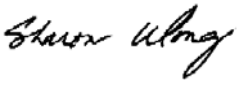
77. The effect of the 2006 Deferral Decision is that Union's shareholder is required to bear a cost associated with long-term ex-franchise storage contracts entered into before the NGEIR Decision, without recovery from rates, even though when Union entered into the contracts it was intended that the full income tax cost would be recoverable from future rates, and even though ratepayers benefited significantly from those Pre-NGEIR LSS Contracts since most of the net revenues from those contracts were used to subsidize rates in the past and will continue to be used to subsidize rates during the phase-out period. Union submits that this result would unfairly benefit ratepayers at the expense of the utility's investors.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

July 28, 2008



Glenn F. Leslie



Sharon S. Wong

Counsel for Union Gas Limited

LIST OF EXHIBITS TO THE ARGUMENT

(A) Board's decision in EB-2008-0034 (the “2007 Deferral Decision”)

(B) Board’s decision in the Natural Gas Electricity Interface Review, EB-2005-0551, (the “NGEIR Decision”

(C) the Board's decision in EB-2007-0598 (the “2006 Deferral Decision”)

(D) NGEIR Review Threshold Decision, EB-2006-0322, EB-2006-0338 and EB-2006-0340, Decision with Reasons

(E) *ATCO Decision*, [2006] 1 S.C.R. 140,

(F) *Carbon Storage* decision, 2008 ABCA 2008

(G) Evidence of Steve Baker, NGEIR Transcript Volume 2, p. 144 -147 and Volume 4, p. 147

(H) Exhibit A to Union’s Pre-Filed Evidence for the 2006 Deferral case, EB-2007-0598.

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0034

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

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2008.

BEFORE: Paul Vlahos
Presiding Member

Bill Rupert
Member

DECISION AND ORDER

The Proceeding

Union Gas Limited ("Union") filed an application on March 4, 2008 with the Ontario Energy Board (the "Board") seeking approval for final disposition and recovery of certain 2007 year-end deferral account balances including approval and disposition of the market transformation incentive and capital tax deferral amounts. The Board assigned docket number EB-2008-0034 to the application.

Union originally proposed that the resulting impacts from the disposition be implemented on April 1, 2008 to align with other rate changes expected to result from the Quarterly Rate Adjustment Mechanism ("QRAM") process. Union subsequently revised the proposed timing to align with the July 1, 2008 QRAM.

The Board issued a Notice of Written Hearing and Procedural Order No. 1, dated March 31, 2008, which was served on a list of intervenors involved in certain related hearings. The Procedural Order set the dates for filing interrogatories and submissions on Union's evidence and other procedural matters.

Interrogatories were submitted by the Industrial Gas Users Association ("IGUA"), London Property Management Association ("LPMA"), City of Timmins ("Timmins") and Board staff. Green Energy Coalition ("GEC") requested and was granted late intervenor status. IGUA, LPMA, Timmins and Board staff filed arguments and Union filed reply argument. The argument phase was completed on May 7, 2008.

The Board has summarized the record of the proceeding only to the extent necessary to provide context to its findings.

Deferral Accounts

Union has classified the deferral accounts into four groups:

a) Five Gas Supply accounts that are cleared through the QRAM process.
b) Two Gas Supply accounts that are not cleared quarterly in the QRAM process.
c) Five Storage and Transportation accounts.
d) Nine Other accounts.

The account balances, which are presented below, include interest at the applicable short-term interest rate approved by the Board in the EB-2006-0117 proceeding. The deferral accounts in category a) above are already being cleared through the QRAM process. The net balance of accounts in categories b), c), and d) above at December 31, 2007 is a $6.618 million credit payable to Union's ratepayers.

In addition to the above, Union sought to reflect in rates a Market Transformation allowance ($0.5 million debit) and the new capital tax rates ($1.813 million credit).

Therefore the total disposition amount is a $7.931 million credit. Union provided specifics regarding the disposition and allocation of this amount to its rate classes.

<u>Gas Supply Accounts – Cleared in the QRAM Process</u>
A credit balance (in parentheses) is money owed to ratepayers while a debit balance is money recoverable from ratepayers.

Under the Board-approved QRAM process, Union establishes reference prices for prospective recovery, or refund, of the projected balances (with interest) over the following 12-month period. Variances between the forecast and actual prospective

recovery amounts for these five accounts are tracked and included in the amounts prospectively recovered in future QRAM proceedings.

The net balance of the five accounts has been cleared through four QRAM decisions in 2007. In this proceeding, Union is seeking the Board's "final approval" with respect to these balances.

Account No.	Name	Balance (Dec 31, 2007, $ millions)
179-105	Northern and Eastern Purchased Gas Variance Account	$ (14.760)
179-100	TCPL Tolls and Fuel – Northern and Eastern Area	1.357
179-106	South Purchased Gas Variance Account	(98.140)
179-109	Inventory Revaluation Account	19.940
179-107	Spot Gas Variance Account	(1.716)
Total		**$ (93.319)**

Gas Supply Accounts – Not Cleared in the QRAM Process

The balances of the two accounts below are not cleared in the QRAM process. Union is requesting disposition of the total credit balance of $3.57 million.

Account No.	Name	Balance (Dec 31, 2007, $ millions)
179-89	Heating Value Deferral Account	$ (1.539)
179-108	Unabsorbed Demand Costs	(2.031)
Total		**$ (3.570)**

Storage and Transportation Accounts

Union defers the difference between actual net revenues from storage and transportation services and forecast revenues included in Union's rates. The differences are currently shared on a 75/25 basis between ratepayers and Union. The net credit balance of $7.482 million represents the ratepayer portion in these accounts.

Account No.	Name	Balance (Dec 31, 2007, $ millions)
179-69	Transportation and Exchange Services Deferral Account	$ (4.589)
179-70	Short Term Storage and Balancing Services	(1.351)
179-72	Long Term Peak Storage Services Deferral Account	(2.196)
179-73	Other S&T Services Deferral Account	(0.146)
179-74	Other Direct Purchase Services Deferral Account	0.799
Total		**$ (7.482)**

Other Accounts

The nine other accounts have a net balance recoverable from ratepayers of $4.434 million.

Account No.	Name	Balance (Dec 31, 2007, $ millions)
179-26	Deferred Customer Rebates/Charges Account	$ -
179-75	Lost Revenue Adjustment Mechanism Deferral Account	(0.268)
179-102	Intra-period WACOG Changes Deferral Account	(0.779)
179-103	Unbundled Services Unauthorized Storage Overrun	-
179-111	Demand Side Management Variance Account	(0.863)
179-112	Gas Distribution Access Rule Costs	(0.557)
179-113	Late Payment Litigation Deferral Account	0.147
179-115	Shared Savings Mechanism Variance Account	6.754
179-117	Carbon Dioxide Offset Credits	-
Total		**$ 4.434**

Other Adjustments

In addition to the above named deferral accounts, Union claimed amounts for Market Transformation and Capital Tax Deferral.

Union claimed a $500,000 incentive for a Market Transformation program (drain water heater recovery program). The amount was linked to Union meeting or exceeding the performance goals as outlined by the Market Transformation "scorecard" filed and approved by the Board in Union's 2007-2009 DSM Plan.

In accordance with the Board's EB-2005-0520 Decision, enacted tax legislation changes that would result in tax rates different than those used to establish 2007 rates were subject to deferral account treatment for 2007. In 2007, enacted legislation reduced the capital tax rate from 0.285% to 0.225%. Consequently, Union recorded a credit of $1.813 million which represents the cost difference between the two capital tax rates.

The Issues

Intervenors and Board staff addressed issues in the following areas:

- 2007 Capital Cost Allowance Amendments
- Commodity Costs – Northern and Eastern Customers
- Interest on Deferral Account Balances
- Long Term Peak Storage Services Margin
- Gas Supply Related Deferral Accounts

The specific matters raised and the Board's findings are set out below.

2007 Capital Cost Allowance Amendments

LPMA argued that the approximately $1 million credit impact resulting from a change in capital cost allowance (CCA) rates, although not yet enacted, should be disposed of now rather than waiting for 2009 as suggested by Union.

In its reply submission, Union confirmed that it is industry practice to include the CCA amendments in tax filings for 2007 and that the Canada Revenue Agency would be accepting the CCA amendments even though they have not been enacted. Accordingly, Union agreed to dispose of the additional credit to customers of $1 million associated with amendments to CCA rates for 2007.

The Board accepts Union's amended request to dispose of the additional $1.0 million.

Commodity Costs – Northern and Eastern Customers

Timmins asserted that residential customers in the Northern and Eastern areas pay $50 million more per year in gas supply commodity charges than do residential customers in the South.

Union refuted Timmins' claim citing the April 2008 QRAM data (EB-2008-0033). Using data from its EB-2008-0033 filing[1], Union calculated the annual commodity and fuel cost for typical residential customers consuming 2,600 m^3 per year to be identical for Rate 01 Eastern Zone and Rate M1 Southern customers.

The Board accepts Union's calculations that, indeed, Timmins' claims are not substantiated.

Interest on Deferral Account Balances

Timmins noted that while Union earned an overall rate of return that exceeded 8% on its rate base that included inventory, Union was paying 4.59% or 5.14% in connection with the same inventory.

Union argued that the two matters were not related, indicating that it accrues interest on Board-approved deferral account balances in accordance with Board-approved accounting orders.

The Board agrees with Union. The interest rate applicable to balances in deferral accounts has been viewed by the Board to be a different matter than the overall cost of capital authorized by the Board for setting rates. The interest rates applicable to both the gas and electricity sectors are prescribed by the Board quarterly, pursuant to the EB-2006-0117 proceeding, and are posted on the Board's website. The interest rates used by Union are those prescribed by the Board for the applicable period.

Long-Term Peak Storage Services Margin

In Union rates cases for 2007 and earlier periods, the Board has approved a forecast of net revenue (total revenue less allocated costs) from long-term storage transactions for the period in question and has required Union to credit 90% of that forecast amount to customers. The Long-Term Peak Storage Services deferral account (No. 179-72) is intended to capture 75% of the difference between (i) Union's actual net revenue from

[1] EB-2008-0033 Pre-filed Evidence Tab 2, Schedule 4, Page 2, Line 24, Column (k)

long-term peak storage services, and (ii) the forecast revenue approved by the Board in the Union rates case.

In its application in this proceeding, Union indicated that actual net revenues for 2007 were $18.934 million and forecast revenues were $16.006 million. The December 31, 2007 deferral account balance of $2.196 million credit is 75% of the difference in those amounts.

In response to an interrogatory from Board staff, Union noted that in the EB-2005-0520 rate order, the Board approved net long-term storage revenues for 2007 of $21.405 million, not $16.006 million as shown in Union's application.

In it reply submission, Union stated that it decided not to calculate the deferral account balance using the Board-approved forecast of 2007 net revenues and actual long-term net revenues for that year. Union stated that it departed from that approach based on it's interpretation of the Board's November 2006 decision on the Natural Gas Electricity Interface Review ("NGEIR").[2] As Union interprets the NGEIR decision, account 179-72 is to be used only to track differences in actual and forecast net revenues in respect of storage contracts entered into before November 7, 2006. In support of that interpretation, Union noted that page 106 of the NGEIR decision states: "The Board finds there is no basis for retaining a requirement that Union share the margins on new long-term storage transactions, that is, long-term deals executed after the Board's forbearance decision." The actual ($18.934 million) and forecast ($16.006 million) net revenues that Union used to calculate the balance in account 179-72 relate only to long-term storage contracts entered into prior to the NGEIR decision.

Union also indicated that, in future years, contracts executed prior to the NGEIR decision will form the basis for calculating the balance in account 179-72.

The Board does not agree with Union's interpretation of the NGEIR decision. The sentence on page 106 of that decision that is quoted by Union in its reply submission is not the conclusion reached by the Board on how the transition provisions of that decision should be applied. The Board did not find that Union should separately track its margins on pre- and post-NGEIR decision transactions. This is quite clear from the following sentences on page 107 of the NGEIR decision:

[2] EB-2005-0551 Decision with Reasons, November 7, 2006.

> The Board considered whether to require Union to record the margins on existing [pre-November 7, 2006] long-term contracts separately from the margins on new long-term contracts. Under this approach, ratepayers would be credited with 90% of the margins on existing contracts for the remaining term of those contracts. This approach conceptually has appeal but could give rise to ongoing implementation questions. For example, the Board might have to consider how contract re-negotiations or defaults by customers are to be treated. This level of complexity and potential ongoing review is unwarranted.
>
> The Board has concluded that it should adopt a simpler phase-out mechanism that is a rough sort of "proxy" for the conceptual approach described above. The phase-out of the sharing of margins on Union's long-term storage transactions will, take place over four years. The share accruing to Union will increase over that period to recognize that contracts will mature and a larger part of Union's total long-term margins will be generated by new transactions. For 2007, forecast margins (on long-term and short-term transactions) now included in the determination of rates will remain unchanged. After 2007, Union's share of long-term margins will be as follows: 2008 – 25%, 2009 – 50%, 2010 – 75%, 2011 and thereafter – 100%.

The Board finds that the NGEIR decision does not require or permit Union to modify the method of calculating the balance in account 179-72 for 2007. The balance should equal 75% of the excess of (i) actual net revenues (on all long-term storage transactions, that is, transactions that occurred both before and after the publication of the NGEIR decision) for 2007, less (ii) the Board-approved forecast net revenue $21.405 million.

In the interest of not delaying the July 1, 2008 date of implementing the disposition of other accounts, the Board will accept for now disposing of the $2.196 million included in Union's application. However, the Board directs Union to recalculate the 2007 balance in account 179-72 in accordance with the Board's finding. The difference shall be carried forward for disposition at a later time.

Gas Supply Related Deferral Accounts

Under the QRAM process, the Board approves a gas supply charge for Union for the next three-month period. That process also provides for recovery, or refund, of the projected balances in the five gas supply deferral accounts, including interest, over the following 12-month period.

In its application in this proceeding, Union states: “Under the QRAM process, the actual year-end deferral account balances are subject to the Board’s final approval.”

Timmins disputed Union’s position that the examination of its gas purchase and sale activities in each of the 2007 QRAMs was qualitative and involved an assessment of prudence of that activity. Timmins submitted that in order to conduct a prudence review, the Board would require detailed evidence of Union’s gas purchase activities and transportation alternatives. It claimed that whenever it or FONOM (Federation of Northern Ontario Municipalities) sought to question Union’s gas purchase activities in past QRAM proceedings, it has faced opposition from Union, which has contended that such matters could not be addressed since the format of the QRAM was determined in RP-2003-0063 and that examination of QRAMs simply involved compliance with that format. Timmins submitted that based on the above understanding, QRAMs were indeed formulistic and mechanical once the basic format had been investigated and set.

Timmins noted that the question before the Board was whether to approve the final disposition of Union’s 2007 purchase gas cost deferral accounts. Timmins posed the question whether the Board should look at how those balances came to exist. It submitted that if the balances were approved, Union would be able to argue that since the dollar amounts had been approved, all of its gas buying and selling activities for 2007 were prudent and in the public interest.

In reply argument, Union argued that it filed four QRAMs in 2007 and all applications included evidence related to Union’s actual and forecasted cost of gas and the actual and forecasted gas purchases for a 24-month period. Union stated that it did not receive any submissions with respect to its past or forecasted gas purchases for 2007. Accordingly, Union requested the Board to approve the final disposition of its 2007 gas supply related deferral accounts.

The Board concludes it is not necessary to provide the “final approval” sought by Union with respect to the balances in the five gas supply deferral accounts listed in the first table on page 3. The Board issues decisions and orders on Union’s QRAM filings each quarter. Those orders, which include approval of the prospective disposition of deferral account balances, are issued as final orders (unless an interim status is required to accommodate other rate setting processes that are running in a parallel time frame). For example, the decision and order with respect to the period beginning October 1, 2007 (EB-2007-0720) stated: “The Board has considered the evidence and finds that it is

appropriate to adjust Union's rates effective October 1, 2007 to reflect the projected changes in gas costs and the prospective recovery of the projected twelve-month balances of the gas supply deferral accounts for the period ending September 30, 2008."

Even if there were some purpose to be served by the Board granting the "final approval" that Union seeks, there has been no evidence filed in this proceeding that would permit this panel to reach any conclusion about the balances in those accounts.
The Board notes the concerns of Timmins. As Timmins indicates, the Board will undertake a review of the QRAM processes of both Union and Enbridge. However, the Notice of Proceeding issued on May 29, 2008 in this regard states that it is not intended that this proceeding will deal with transportation and gas supply contract issues. These issues, according to the Notice, are deferred to the establishment of guidelines through consultation at a later time and Timmins may wish to participate in that process.

Order and Cost Awards

The Board orders that the amounts Union seeks to dispose of in this proceeding, as adjusted or otherwise directed by the Board, shall be recovered from Union's ratepayers in accordance with the methodologies included in Union's application. The impacts which result from these adjustments shall be implemented on July 1, 2008 to align with other rate changes resulting from Union's QRAM application.

A decision regarding cost awards will be issued at a later date. Eligible parties shall submit theirs cost claims by June 18, 2008. Union may respond to such claims by June 25, 2008 and intervenors may respond to objections by July 4, 2008. The cost claims must be filed in accordance with the Board's *Practice Direction on Cost Awards*.

ISSUED at Toronto, June 3, 2008.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2005-0551

NATURAL GAS ELECTRICITY INTERFACE REVIEW

DECISION WITH REASONS

November 7, 2006

EB-2005-0551

IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

November 7, 2006

EXECUTIVE SUMMARY

INTRODUCTION

This proceeding was initiated by the Ontario Energy Board in late 2005 in response to issues first raised in the Board's *Natural Gas Forum Report* and more fully explored in the OEB staff report, *Natural Gas Electricity Interface Review*. The key issues addressed in this proceeding were:

- Rates and services for gas-fired generators
- Storage regulation.

The hearing participants, which included gas-fired generators and consumer groups, reached settlements with Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (Enbridge) on most of the issues related to services for gas-fired generators, and the Board has approved those settlements. The oral hearing and this Decision addressed the issues which were not settled and the issue of storage regulation.

SERVICES FOR GAS-FIRED GENERATORS

The need to examine new services for gas-fired generators arises because of the increasing number of so-called "dispatchable" gas-fired power generation plants that are planned or in operation. These plants operate in response to five-minute dispatch instructions from the Independent Electricity System Operator (IESO), and, as a result, their gas consumption profiles are more volatile and difficult to forecast than the relatively stable profiles of residential, commercial and industrial gas consumers. Flexible and responsive gas services, including high-deliverability gas storage, can ensure the reliable operation of these plants and allow the plant operators to manage the financial risk of the business.

Based on the settlements, the Board has approved a number of new services aimed at the needs of the gas-fired generators, including:

- new distribution rate structures for high-volume gas consumers
- more frequent nomination windows for the distribution, storage and transportation of gas
- the inter-franchise movement of gas
- redirection of gas to different delivery points on short notice
- simpler processes for title transfers of gas in storage
- high-deliverability storage services.

There was no agreement on the price at which high-deliverability storage services should be offered. The generators argued for a regulated framework, while the utilities argued for a competitive framework. The key consideration is to ensure that new innovative services are developed. The Board concludes that the public interest is best met by refraining from regulating these services. This will stimulate the development of these services, by utilities and other providers. The Board will accordingly refrain from regulating the rates for high-deliverability storage services.

The Board has a duty to protect the interests of consumers using these services with respect to price and reliability and quality of service. The crucial factor is the availability of the service itself – namely its reliability and quality. The Board expects Enbridge and Union to fulfill their commitments respecting the offering of these services. Pricing considerations are relevant, but competitive options will provide appropriate price protection. The Board will also be developing a reporting mechanism and complaint process to deal with any issues which arise.

NATURAL GAS STORAGE REGULATION

Union and Enbridge operate large underground gas storage facilities in southwestern Ontario. Those facilities, which are connected to multiple gas transmission pipelines,

are part of what is known as the Dawn Hub, one of the more important natural gas market centres in North America.

The issue in this hearing was whether the Board should refrain from regulating the prices charged for storage services. Section 29 (1) of the *Ontario Energy Board Act, 1998* states:

> On an application or in a proceeding, the Board shall make a determination to refrain, in whole or in part, from exercising any power or duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is, or will be, subject to competition sufficient to protect the public interest.

Competition in Storage

The Board has concluded that Ontario storage operators compete in a geographic market that includes Michigan and parts of Illinois, Indiana, New York and Pennsylvania. The Board finds that the market is competitive and that neither Union nor Enbridge have market power.

Price Regulation

The Board will cease regulating the prices charged for the following storage services:

- all storage services offered by Union and Enbridge to customers outside their franchise areas;
- new storage services offered by Union and Enbridge to their in-franchise customers; and,
- all storage services offered by other storage operators, including storage operators affiliated with Union and Enbridge.

Rates for storage services provided to Union’s and Enbridge’s distribution customers will continue to be regulated by the Board on a cost-of-service basis.

Union's existing storage capacity is well in excess of the current needs of its in-franchise customers and has been for many years. The Board has decided that Union will reserve approximately two-thirds of its existing capacity for in-franchise needs. At current rates of growth, that amount limit will satisfy in-franchise needs for several decades. Enbridge currently purchases storage from Union for a portion of its requirements. The Board has decided that Union will continue to provide these services at cost through a transition period ending in 2010.

Sharing the Premium on Ex-Franchise Sales

The sale of storage services by Union and Enbridge at market-based rates to ex-franchise customers has generated revenues well in excess of the cost of providing those services. Until now, the Board has required that most of the profits be used to reduce distribution rates. The Board has concluded that this sharing should continue for short-term storage deals. These are storage transactions that use storage space that is temporarily surplus to in-franchise needs. All of the profits on these transactions, less small incentive payments to the utilities, will be for the benefit of ratepayers.

The Board finds, however, that Union will not be required to share the profits on long-term storage transactions that use storage space not needed to serve in-franchise needs because that capacity now constitutes a "non-utility" asset for which the shareholders appropriately bear the risk. The sharing of these profits will remain unchanged for 2007 and then be phased out over the period to 2011.

Impact on Consumers

The Board's decisions are expected to have virtually no effect on consumers' bills in 2007. The impact after that cannot be precisely quantified because it will depend on future storage prices, the profit on ex-franchise storage sales, and the amount of gas consumed. While a precise forecast is not possible, bills are likely to increase by a small amount – perhaps around 1% for the typical residential consumer.

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1. THE PROCEEDING AND THE ISSUES

1.1 BACKGROUND

In the fall of 2003, the Ontario Energy Board began a comprehensive sector review – the Natural Gas Forum – to examine ways to further improve the efficiency and effectiveness of natural gas regulation in Ontario. The impetus for this review was recognition by the Board of the evolving natural gas market. In particular, the Board recognized that conventional gas supply sources are expected to experience flat to declining production. The anticipated increased reliance on non-conventional supply sources raised questions regarding the need for infrastructure within Ontario to meet changing natural gas flow patterns and about the adequacy of the current regulatory treatment of natural gas. On the demand-side, the anticipated expansion of gas-fired power generation was expected to affect the extent and type of investment required in gas infrastructure in Ontario and to drive the convergence of gas and electricity markets.

The outcome of the review was a Board report, released on March 30, 2005, entitled *Natural Gas Regulation in Ontario: A Renewed Policy Framework*[1] (the Natural Gas Forum Report). In this report the Board set as an "important and immediate priority" the need to ensure that Ontario's natural gas infrastructure could meet the demands created by new gas-fired generators. As a result, the Board initiated the Natural Gas Electricity Interface Review (NGEIR), to examine the regulatory treatment of natural gas infrastructure and services.[2]

NGEIR involved several months of research and meetings with stakeholders, which were led by Board Staff. The Board Staff NGEIR report was released for stakeholder

[1] Board File No. RP-2004-0213
[2] Board File No. EB-2005-0306

comment on November 21, 2005. The report's key recommendations were that the Board should initiate a generic hearing to review whether the Board should:

- require gas utilities to provide firm higher deliverability service from storage and greater nomination entitlements;
- require greater operational flexibility in the provision of distribution services;
- forbear from regulating rates for gas storage services.

After reviewing the stakeholder comments, the Board initiated this generic hearing, known as the Natural Gas Electricity Interface Review Proceeding (the NGEIR Proceeding), to determine whether it should order new rates for the provision of natural gas transmission, distribution and storage services to gas-fired generators (and other eligible customers). The Board indicated that it would also determine in the NGEIR Proceeding whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

In addition, the Board determined that the generic hearing would examine Union's Transmission Bidding Open Season process as it relates to the rates and contractual terms for allocating transportation capacity. In particular, the issues concerning the M12 rate premiums identified in the Board's decision regarding the Dawn-Trafalgar Pipeline Transmission Expansion (EB-2005-0201) were included.

1.2 THE PROCEEDING

The NGEIR Proceeding was commenced pursuant to sections 19, 29 and 36 of the *Ontario Energy Board Act, 1998*. On December 29, 2005, the Board issued a Notice of Proceeding on its own motion to determine:

- whether it should order new rates for the provision of natural gas transmission, distribution and storage services to gas-fired generators (and other qualified customers); and
- whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

The Notice of Proceeding directed Enbridge Gas Distribution Inc. (Enbridge) and Union Gas Limited (Union) to file evidence on potential rates for gas-fired generators.

Procedural Order No. 2, issued on February 28, 2006, set out the issues to be addressed in the proceeding. These are set out in full in Appendix A, but can be summarized as follows:

I. Rates for gas-fired generators (and other qualified customers), including more frequent nomination windows, firm high deliverability service, unbundled services, inter-franchise movement of gas, redirection of gas to a different delivery point on short notice, and title transfer of gas in storage

II. Storage regulation and whether the Board should refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario, including:
    - Is the market competitive?
    - Who should receive cost-based pricing?
    - Who should receive market-based pricing?
    - How should the amount of storage be allocated between the classes of customers?
    - Who should receive the premium?

III. Transportation capacity bidding process and allocation

IV. Enbridge rates for large volume customers (Rate 300 Series)

The Board also moved four issues from Union's 2007 rates proceeding (EB-2005-0520) to the NGEIR Proceeding. These issues, as set out in Procedural Order No. 3, were related to storage pricing and storage and transmission deferral accounts.

Further details of the process can be found in Appendix A. Lists of witnesses and participants are in Appendix B.

1.3 SETTLEMENT PROPOSALS

A settlement conference was held for Issues I (rates for gas-fired generators and other qualified customers), III (transportation capacity bidding process and allocation) and IV (Enbridge's Rate 300 series rates). The Board indicated that it would not receive a settlement proposal on Issue II (storage regulation), so a settlement conference was not held in relation to this issue.

Two separate Settlement Proposals were filed with the Board on June 13, 2006. Enbridge submitted a Settlement Proposal for Issues I and IV (the Enbridge Proposal) and Union submitted a Settlement Proposal for Issues I and III (the Union Proposal). A presentation of the Settlement Proposals was made to the Board on June 19, 2006. Details relating to the settlement process and the Board's treatment of the Settlement Proposals, including decisions on issues related to the Settlements and the Settlement Proposals themselves are provided at Appendix C and Appendix D for Enbridge and Appendix E and Appendix F for Union. The matters under Issues I, III and IV that were not resolved by way of settlement are discussed in Chapter 8.

1.4 MHP CANADA DECISION ON CORE POINTS

Market Hub Partners Canada (MHP Canada) is an affiliate of Union which proposes to develop third party storage in Ontario. As part of its evidence and submission to the Board in the context of the NGEIR Proceeding, MHP Canada made a request for an expedited decision on certain "core points", specifically that:

- MHP Canada cannot exercise market power;
- MHP Canada, similar to independent storage developers, will be granted authority to charge market-based rates for its services; and
- MHP Canada will be allowed flexibility to contract for services without requiring approval of individual contracts, provided that MHP Canada operates within a base set of service terms and conditions approved by the Board.

On September 7, 2006, the Board issued its oral decision on MHP Canada's request for an expedited decision on the core points. In its decision, the Board authorized MHP Canada to charge market-based rates and relieved MHP Canada of the requirement to have storage contracts approved by the Board. The transcript of the decision can be found in Appendix G.

1.5 ORGANIZATION OF THIS DECISION

This decision focuses principally on the second issue listed in the Board's Procedural Order No.2, that is, whether there is sufficient competition in natural gas storage for the Board to refrain in whole, or in part, from regulating rates.

Chapter 2 is a an overview of gas storage in Ontario today – the existing storage facilities, the use of storage by Union's and Enbridge's "in-franchise" customers, the "ex-franchise" market for storage, and the prices charged for storage services. This chapter does not contain any Board decisions. It provides background and context for the Board's decisions on the competition question and the implementation issues covered in later chapters.

Chapter 3 deals with the issue of competition in storage and whether Union and Enbridge have market power. The chapter addresses the framework for assessing market power, the definition of the product market, the scope of the geographical market, and quantification of market shares and concentration.

Section 29 of the *Ontario Energy Board Act, 1998* (the *OEB Act*) requires the Board to consider whether there is "competition sufficient to protect the public interest" before making a decision to refrain from regulation. **Chapter 4** sets out the Board's views on public interest issues relevant to gas storage.

Chapter 5 deals with the decision to refrain, or forbear, from regulating storage rates and approving storage contracts. It sets out the Board's basis for deciding to refrain in part from regulating rates, as well as the Board's decision that in-franchise customers will continue to receive regulated storage services at cost-based rates.

Having decided to retain regulated cost-based storage rates for in-franchise customers, it is necessary to determine how much of Union's existing storage space should be reserved for those customers. **Chapter 6** covers that issue together with the Board's decisions on how much cost-based space Union and Enbridge should allocate to individual unbundled and semi-unbundled in-franchise customers.

Chapter 7 sets out the Board's decisions on whether, and to what extent, Union's and Enbridge's in-franchise customers should continue to share in the margins over cost that the utilities earn on sales of storage services at market rates.

Issues I, III, and IV from Procedural Order No.2 were largely settled by the parties. **Chapter 8** covers the Board's decisions on a small number of Enbridge rate issues that were not settled.

Chapter 9 is a summary of the implementation and transition issues arising from the Board's decisions in Chapters 5, 6, 7 and 8.

2. ONTARIO GAS STORAGE - BACKGROUND

This chapter describes the development and current state of natural gas storage in Ontario, the pricing and allocation of storage, and the rate treatment for revenues earned from storage services sold at market-based rates.

2.1 ONTARIO GAS STORAGE FACILITIES

The existing and proposed underground natural gas storage facilities that were the subject of this hearing are all located in Southwestern Ontario, mostly in Lambton County. The storage pools now in operation are all depleted gas fields. With working gas capacity of over 240 Bcf, these Ontario facilities are among the largest gas storage pools in Canada.

The storage facilities are an integral part of what is commonly referred to as the Dawn Hub, which is widely recognized as one of the more important market centres in North America for the trading, transfer and storage of natural gas. In its Natural Gas Forum Report, the Board stated: "The large amount of nearby storage, combined with a convergence of pipelines linking the U.S. and Ontario gas markets, have made Dawn the most liquid trading location in Ontario."[3] The Federal Energy Regulatory Commission (the FERC), in its assessment of energy markets in the United States in 2004, made similar comments about the significance of Dawn:

> The Dawn Hub is an increasingly important link that integrates gas produced from multiple basins for delivery to customers in the Midwest and Northeast. … Dawn has many of the attributes that customers seek as they structure gas transactions at the Chicago Hub: access to diverse sources of gas

[3] *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, Report on the Ontario Energy Board Natural Gas Forum, March 30, 2005 at page 84.

> production; interconnection to multiple pipelines; proximity to market area storage; choice of seasonal and daily park and loan services; liquid trade markets; and opportunities to reduce long-haul pipeline capacity ownership by purchasing gas at downstream liquid hubs.[4]

The storage facilities currently in operation in Ontario are owned and operated by two entities, Union, which also owns and operates the gas transmission line between Dawn and Parkway, and Enbridge. The storage operations of these companies are described in the next sections of this chapter, followed by information on new storage operations proposed or under development by other parties.

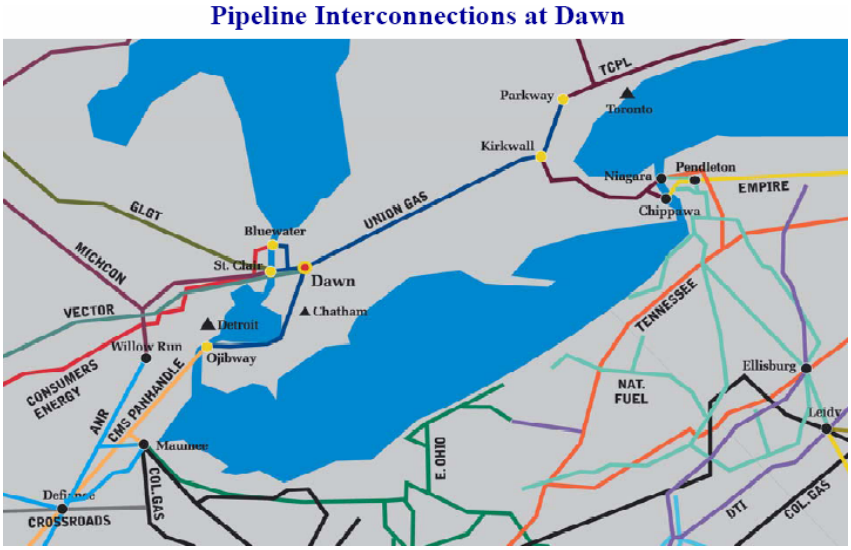
2.1.1 Union

Union is an indirect, wholly-owned subsidiary of Duke Energy Corporation, a U.S. company with large and diverse operations in North America's gas and electricity industries. Union owns and operates an integrated gas distribution, transmission and storage business in Ontario. On June 28, 2006, Duke Energy announced it would pursue a plan to create two separate publicly-traded companies by spinning off its natural gas businesses, including Union Gas, to shareholders.

Union's storage operations include 20 depleted gas fields with working gas capacity of approximately 152 Bcf and peak deliverability of 2.3 Bcf per day. Union's storage pools connect with the Vector, Great Lakes, CMS Panhandle, Michcon, and Bluewater transmission pipelines from Michigan in the west, and (via Union's Dawn-Parkway pipeline) the TransCanada pipeline and Enbridge's gas distribution system in the east. Figure 1 shows these pipeline interconnections.

[4] Federal Energy Regulatory Commission, *2004 State of the Markets Report*, June 2005, page 161.

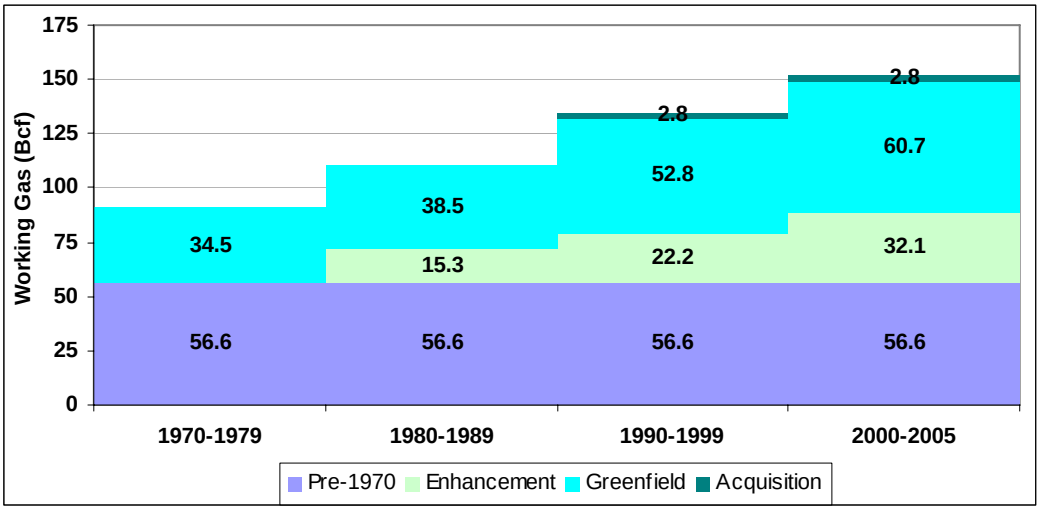
Figure 1: Pipeline Interconnections at Dawn



Source: Union Gas pre-filed evidence, Tab 2, page 10

Union has owned and operated storage facilities at Dawn since the 1940s. Since 1969, it has more than doubled the working gas capacity through enhancements, greenfield development, and acquisitions, as indicated in Figure 2.[5]

Figure 2: Union Working Gas Capacity Development



[5] Derived from information in Union Gas Undertaking K3.1, which was expressed in PJs. Table 1 was prepared using a conversion factor of 1Bcf = 1.055 PJ.

Union stated in the hearing that although there might be some potential to develop new storage capacity at its Dawn facilities, it has no current plans to do so.

For 2006, Union has allocated about 86 Bcf of its storage space to support the seasonal balancing needs of its in-franchise (distribution) customers. Gas for these customers is typically received from various connecting pipelines on a more or less constant basis during a year. Receipts in excess of demand during the spring, summer and early fall periods are stored and then withdrawn during the peak consumption period in the winter. The largest portion of storage space for in-franchise customers (approximately 61 Bcf) is allocated to customers that take bundled service (transmission, distribution, storage) and is managed by Union on an aggregate basis. Larger customers that take service under Rates T1 or T3 have one-year renewable contracts for fixed amounts of storage space. In aggregate, those contracts cover approximately 16 Bcf. Union also reserves 9 Bcf as "contingency" space related to its needs as system operator.[6]

Union earns revenue from selling long-term and short-term storage services to a variety of ex-franchise (non-distribution) customers.

- Long-term contracts – The working gas capacity of Union's pools far exceeds the amount required to support the seasonal balancing needs of Union's distribution customers. Union markets the excess space in multi-year contracts to "ex-franchise" customers, typically Canadian and U.S. gas distributors and marketers. Union's largest ex-franchise storage customer currently is Société en Commandite Gaz Métro (GMi), the largest gas distributor in Québec, which has four contracts covering over 22 Bcf of Union storage space.
- Short-term services – During the course of a year, the storage space required to meet the seasonal balancing requirements of distribution customers is frequently available to be used for short-term storage services for ex-franchise customers. These customers include the Canadian and U.S. marketers and retailers, the

[6] Space Allocation derived from Exhibit J5.02, converted to Bcf using a factor of 1Bcf=1.055 PJ.

trading units of financial institutions, U.S. power generators, and some industrial gas users.

2.1.2 Enbridge

Enbridge is a wholly-owned subsidiary of Enbridge Inc., a Calgary-based energy company. Enbridge is the largest gas distributor in Ontario ranked by customers and revenue.

Enbridge's Tecumseh storage facilities, which have been in operation since the 1960s, have a working gas capacity of 98 Bcf and peak deliverability of 1.8 Bcf per day.[7] The Tecumseh storage pools are connected to Union's gas transmission pipeline at Dawn. To reach Enbridge's distribution franchise areas in central and eastern Ontario, gas stored at Tecumseh flows over the Union pipeline and then through the TCPL transmission system.

Enbridge is at the early stages of assessing the potential for expanding the deliverability of some of its Tecumseh pools.

Tecumseh storage is not sufficient to cover the seasonal load balancing requirements of Enbridge's in-franchise customers. To meet those requirements, Enbridge has supplemented its Tecumseh space with three multi-year contracts with Union for a total of 19.9 Bcf of storage at Dawn.

Unlike Union, Enbridge does not have the ability to sell long-term storage services from its storage pools because the storage requirements of its in-franchise customers exceed the capacity of Tecumseh. But, similar to Union, Enbridge can utilize its storage assets to offer various short-term storage services to ex-franchise customers. The principal customers for these services are Canadian and U.S. marketers, retailers, and financial institutions.

[7] Union Gas has long-term contracts covering 6.7 Bcf of Tecumseh storage facilities, which reduce the space available to Enbridge to around 92 Bcf.

2.1.3 New Ontario Storage Proposed or Under Development

Tribute Resources Inc. and Tipperary Gas Corp. (Tribute)

Tribute, an independent storage company, received Board approval in 2005 to develop and operate a 3.2 Bcf gas storage pool located near Bayfield, Huron County (the Tipperary Storage Pool).[8] When operational, it will be connected to Union's transmission system.

The Tipperary Storage Pool has not yet been developed. The company is seeking additional approvals from the Board, including approval to drill a new horizontal and two lateral storage wells. Tribute plans to commence operation of this storage pool in June 2007. Tribute has received Board approval to charge market rates to its customers in accordance with Union's C1 range rate.

Market Hub Partners Canada L.P.

MHP Canada is a partnership that is wholly-owned by subsidiaries of Duke Energy and, as a result, is an affiliate of Union. MHP Canada plans to offer Dawn-based services to wholesale customers. It is currently developing its St. Clair Pool (1.1 Bcf) and, through a partnership, it intends to develop a further 5.3 Bcf at the Sarnia Airport Pool. Both projects are located in Lambton County and will be connected to Union's transmission system. MHP Canada has indicated it will seek development opportunities to increase its working gas capacity to 10 Bcf by 2010.

In a September 7, 2006 oral decision as part of this proceeding, the Board authorized MHP Canada to charge market-based rates for its storage services (in accordance with Union's C1 range rate) and allowed MHP Canada to enter into storage contracts without requiring Board approval of individual contracts.[9] MHP Canada expects its St. Clair Storage pool to be operational in June 2007.

[8] *RP-2003-0253 Decision with Reasons to Follow*, June 17, 2005
[9] The Board's decision on MHP Canada's core points is reproduced in Appendix G.

Enbridge Inc.

Enbridge Energy Distribution Inc. ("Enbridge Energy"), an unregulated subsidiary of Enbridge Inc, has carried out exploration and evaluation activities over the past several years to assess new storage potential in Ontario. The results indicate that undeveloped pinnacle reef storage in Ontario is smaller in size, of inferior quality, and located farther away from Dawn than the currently developed pools. Enbridge Inc. has concluded that the costs and risks associated with new storage development in Ontario are significantly higher than in the past.

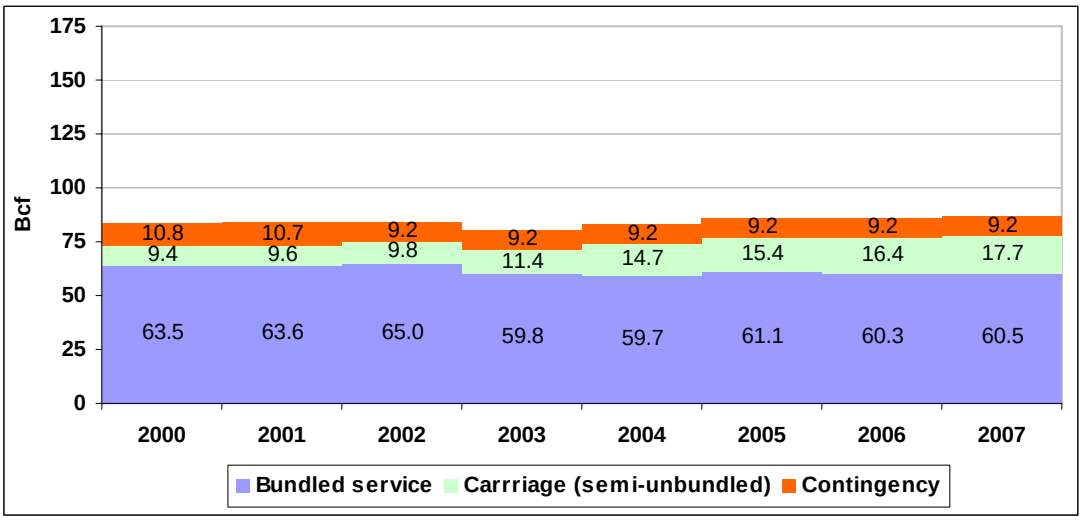
2.2 PRICING AND ALLOCATION OF ONTARIO STORAGE

The prices currently charged by Union and Enbridge for storage services depend on whether the buyer of the services is considered to be an "in-franchise" or an "ex-franchise" customer. As a generalization, in-franchise customers pay cost-based rates for the storage services they use and ex-franchise customers pay market-based prices. Prices for both groups of customers are regulated by the Board. However, the prices for ex-franchise customers are subject to Board approved maximum rates (so-called range rates) that are high enough that they have not yet constrained the pricing of services to ex-franchise customers.

Figure 3 shows Union's analysis of the actual and estimated space requirements for in-franchise customers.[10]

[10] Derived from Union Exhibit J5.02. Figure 3 was prepared using a conversion factor of 1 Bcf = 1.055 PJ.

Figure 3: Actual and Forecast Space Requirements Union In-franchise Customers (Bcf)



None of the participants in the hearing advocated that the Board refrain from regulating prices of storage services for in-franchise gas customers that require the traditional seasonal load balancing service. However, Union and Enbridge did propose changes to the allocation or pricing of storage services for in-franchise customers.

2.2.1 Definition of "In-Franchise Customer"

Although the term "in-franchise customer" was used repeatedly at the hearing and in most parties' evidence, there was no formal agreement on what the term means. In its evidence, Union provided the following definitions:

> In-franchise – Customers inside Union's franchise area. The in-franchise market consists predominantly of residential customers and has historically been considered to be the retail market.
>
> Ex-franchise – The ex-franchise market consists of storage services sold to those customers located outside Union's franchise area, including Ontario LDCs, marketers/brokers and end use consumers located outside of Ontario, primarily in eastern Canada and the Northeast United States. This market is considered to be the wholesale market, since the majority of these customers are not end use customers but intermediaries. [11]

[11] Union Gas prefiled evidence Exhibit A, Tab 1, footnotes 1 and 2.

Union's definition of in-franchise customer is a largely, but not completely, accurate description of the customers that currently receive cost-based storage from both Union and Enbridge. For example, there are the following exceptions:

- Three embedded gas distributors – the City of Kitchener's gas distribution utility (Kitchener), Natural Resource Gas Ltd. (NRG) and Six Nations Natural Gas Company Limited (Six Nations) – pay cost-based rates to Union for storage services. These distributors are physically connected to Union's distribution system but serve gas consumers outside Union's franchise area.
- Gazifère Inc., the gas distributor in the Outaouais region of Québec and a subsidiary of Enbridge Inc., is charged cost-based rates for storage services provided by Enbridge. Gazifère's system is connected to Enbridge's distribution system in Eastern Ontario but serves gas consumers outside Enbridge's franchise area.
- Greenfield Energy Centre Limited Partnership (GEC), owner of a gas-fired generation plant under construction in Union's franchise area in the Sarnia region, has received permission from the Board to construct a gas pipeline that will not connect to Union's system. If GEC were to purchase storage services from Union in the future, it would presumably be considered an ex-franchise customer, and would not be eligible for cost-based in-franchise rates.

Given these exceptions, it is probably more accurate to state that cost-based storage services are currently provided to the "distribution customers" of Union and Enbridge. When the term "in-franchise customers" is used in this decision, it is intended to refer to distribution customers of the utilities.

2.2.2 Allocation of Storage to In-Franchise "Bundled" Customers

Most of Union's and Enbridge's distribution customers receive a bundled service (distribution, transmission, and storage). The utilities are responsible for determining

how much storage is required in total for this customer group and for managing the aggregate allocation.

Even though individual bundled customers do not purchase or manage storage, the allocation of storage space is important to them for two reasons.

- It determines how much they are charged for storage. Union and Enbridge apply their cost-based storage rates to the storage allocations to determine the monthly charge to bundled customers. (Union's bills show storage charges as a separate line item. Enbridge includes its storage charges for bundled customers in distribution charges.).
- The allocation determines the amount of cost-based storage that commercial and industrial customers will be entitled to if they choose to take unbundled or semi-unbundled services from their utility. It also fixes the amount of storage that a natural gas retailer will receive at cost-based rates should the retailer choose to manage storage requirements for its customers rather than rely on the utility service.

Union currently uses the "aggregate excess" methodology to allocate storage to bundled customers in its Southern operations area. The aggregate excess is the difference between (a) the amount of gas a customer is expected to use in the 151-day winter period and (b) the amount that would be consumed in that period based on the customer's average daily consumption over the entire year.

Union totals the amounts calculated under the aggregate excess method and then reduces that total by 2.4%. This reduction is meant to reflect that less storage is needed to manage the balancing requirements of a large portfolio of customers with diverse consumption patterns.

The total amount of storage space allocated to Union's bundled customers has not been capped. As new bundled customers are added, the aggregate excess amount has grown.

Enbridge also uses a similar method to allocate storage to its bundled customers.

2.2.3 Allocation of Storage to In-Franchise "Unbundled" and "Semi-Unbundled" Customers

Union's and Enbridge's in-franchise customers can choose an unbundled delivery service under which they separately contract for storage service. Only one Enbridge customer has opted for that service to date, although the Board is reviewing redesigned unbundled Enbridge rates as part of this proceeding so there may be further migration. None of Union's customers have chosen unbundled service.

Union refers to its T1 and T3 services as "semi-unbundled" services. The commercial and industrial customers taking T1 service and Kitchener which takes service under the T3 rate have entered into renewable one-year contracts for storage space at cost-based rates. Three T1 customers are gas-fired generators that have multi-year storage contracts. If these T1 and T3 customers require storage space greater than their contracted amounts, they are required to purchase the extra space at market-based rates.

The allocation of space to most of these customers was determined in 2001 as part of RP-1999-0017, which dealt with Union's unbundling proposals.[12] Union proposed that the aggregate excess method be used to allocate cost-based storage to customers taking unbundled service, and that the same approach be used for the storage allocation to T-service customers. As part of a settlement agreement, Union agreed to

[12] *RP-1999-0017 Decision with Reasons*, July 21, 2001

grandfather the storage allocations to T-service customers.[13] This grandfathering has resulted in over 40 T1 customers having different (generally higher) storage space under contract than would be the case if the aggregate excess method were used. The three gas-fired generators taking T1 service also have storage space under contract that is well above the amount determined under the aggregate excess method.

2.2.4 Storage Prices for In-Franchise and Ex-Franchise Customers

As noted earlier, Enbridge has contracted with Union for additional space to supplement its Tecumseh storage. Thus, the current storage costs underpinning Enbridge's bundled customers are a blend of cost-based rates for Tecumseh and market-based prices under the Union contract. The Union contract has prices that are substantially higher than Union's cost of storage. Enbridge started to pay these higher prices on April 1, 2006 but has not yet received Board approval to include the full contract prices in its rates.

Cost-based rates

The current cost-based rates for in-franchise storage users are approximately $.30 per GJ for Union and $0.40 per GJ for Enbridge. These rates are derived from the net book value of the storage facilities (including base pressure gas at historical cost), variable operating and maintenance expenses, financing costs and a return on equity at the Board's approved rate. In Union's case, the rates reflect an allocation of the cost of its storage facilities between in-franchise and ex-franchise users.

Market-based rates

Union began selling short-term storage services (less than 2 years) at market-based rates to ex-franchise customers in 1989. In 1997, the Board approved long-term storage contracts (one five-year and three ten-year contracts) that Union had entered into at market-based rates pursuant to an open season process. Based on the Board's RP-

[13] Page 25 of the Settlement Agreement in RP-1999-0017 stated: "In order to facilitate the transition to the new allocation methodology [aggregate excess], Union agrees to grandfather existing T-service customers currently operating within there current deliverability level, whether those customers remain as t-service or select the new unbundled service."

1999-0017 Decision, Union began to transition all long-term ex-franchise customers to market-based rates.

Enbridge's Transactional Services function was established in 1997 to enable Enbridge to sell storage and transportation capacity that it considers surplus to what is needed to serve its in-franchise customers. All of Enbridge's Transactional Services are considered to be short-term (less than 2 years).

Sales of short-term and long-term storage services to ex-franchise customers are subject to maximum rates approved by the Board (so-called range rates). The actual prices realized by Union and Enbridge for sales of storage services to ex-franchise customers are determined by negotiation. Union's C1 rate schedule, which sets a maximum price of $3.00 per GJ, sets out the following factors that can affect the price of an individual transaction:

- The amount of storage service sought by the customer,
- Type of service (firm or interruptible; peak or off-peak),
- Utilization of facilities,
- Competition, and
- Term.

Market prices for storage used for seasonal load balancing tend to reflect seasonal differences in natural gas prices. Storage prices change constantly as the seasonal spread in gas prices changes. Over the past few years, the difference between the forward gas prices for the five-month winter withdrawal season (November through March), and the prices in injection periods has increased significantly. That has put upward pressure on market prices for storage.

Market prices for storage in recent years have been many times higher than the cost-based rates charged by Union and Enbridge. For example, the prices realized by Union

in the January and February 2006 open seasons for winter 2006/2007 storage are presented below in Table 1.

Table 1: Union Storage Prices
Open Seasons for Winter 2006/2007

	Volume	High Price	Low Price	Weighted Average
US$/MMBtu	7,800,000	US$2.90	US$1.55	US$2.09
CDN$/GJ	8,229,437	$3.43	$1.84	$2.48

2.3 RATE TREATMENT OF MARGINS ON STORAGE SERVICES

The market-based prices that are realized on sales of storage services to ex-franchise customers generally have been higher (sometimes, much higher) than the cost-based rates charged to in-franchise customers. In setting distribution rates for Union and Enbridge, the Board has directed that most of this premium over cost be credited against distribution rates.

This section reviews the amount of the margins realized by Union and Enbridge and the manner in which the margins are currently shared by distribution customers and the utilities.

2.3.1 Gross Margins

Figure 4 shows the actual margins on Union's ex-franchise storage sales for 1997-2005, estimates for 2006 and 2007.[14] The estimate for 2007 is included in the settlement

[14] Union information extracted from Exhibit K2.3, and the settlement agreement for Union's 2007 distribution rates.

agreement approved by the Board in its decision on Union's 2007 distribution rates.[15] The amounts are net of an allocation of some of Union's costs of its storage assets.

Figure 5 shows the actual margins on Enbridge's Transactional Storage Services for 1997-2005 and the estimate for 2006.[16] The amounts for Enbridge do not reflect any costs of its Tecumseh storage operations because all such costs are currently included in Enbridge's distribution rates.

Figure 4: Union Ex-Franchise Storage Margins

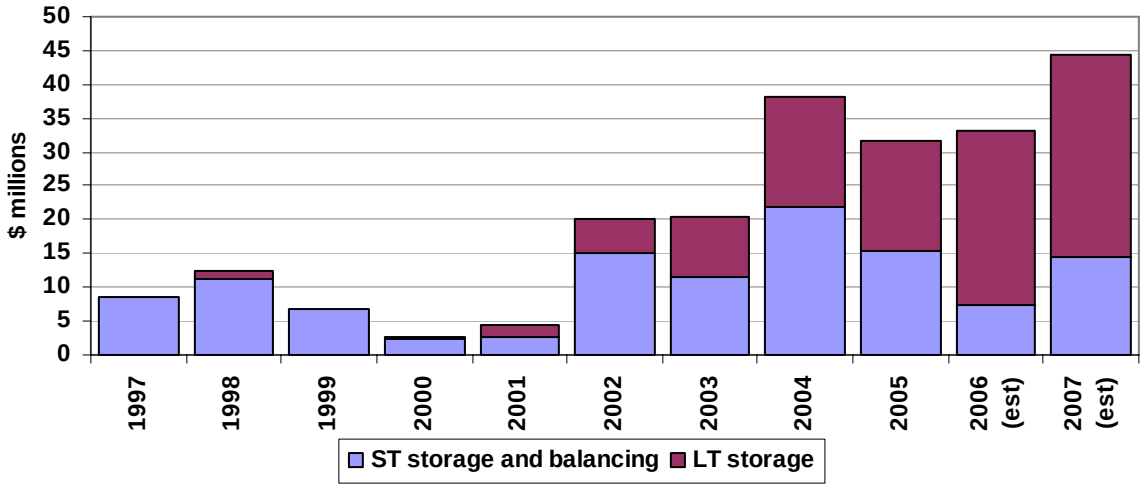
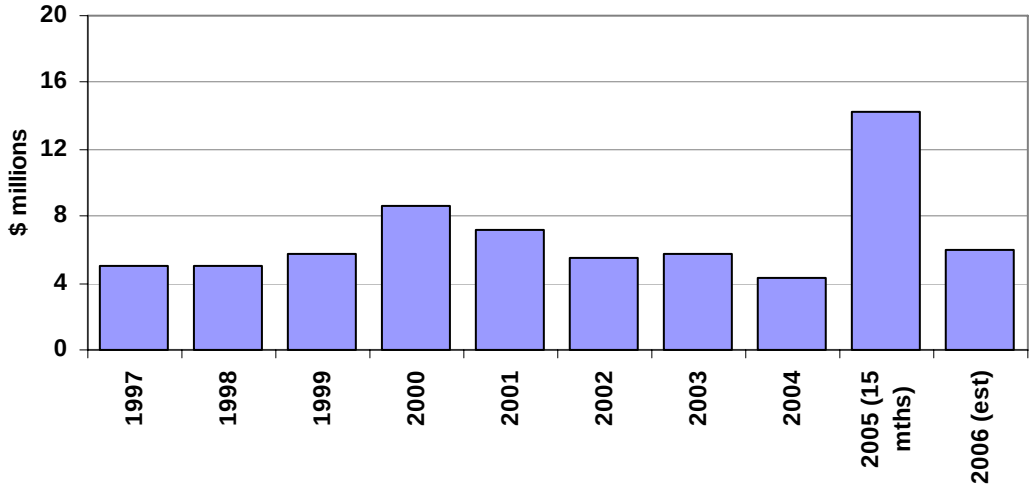


Figure 5: Enbridge Gas Short Term Storage Margins



[15] RP-2005-0520 dated June 29, 2006
[16] Enbridge information extracted from Exhibit K6.1 and, for the 2006 estimate, Transcript Day 7, page 20.

The growth in Union's margins on long-term storage business (long-term means contracts with terms of two years or longer) in recent years appears to have been caused primarily by two factors. First, starting in 2001, long-term contracts with ex-franchise customers that previously were at cost-based rates have been renegotiated at higher market-based rates as they come up for renewal. Second, the market value of storage for seasonal balancing – which is largely a function of the difference between forward gas prices for the injection and withdrawal seasons – has been increasing.

2.3.2 Sharing Mechanisms

The bulk of storage margins for Union and Enbridge have not accrued to those utilities. Instead, the Board has required that most of the margins be credited against distribution rates. The manner in which those margins are shared between in-franchise ratepayers and the utilities has varied to some extent in the past. The current approaches to sharing the margins are described below.

Union

Union forecasts the amount of short- and long-term storage margins for the rate year in question as part of the rates case. Of the Board approved forecast amount, 90% is included as a credit against distribution rates for the year. To the extent that actual margins vary from the forecast built into rates, Union books the difference in deferral accounts (account 179-70 for short-term transactions and account 179-72 for long-term transactions). When cleared, these deferral account balances are shared 75:25 in favour of distribution ratepayers.

Enbridge

In its decision on Enbridge's 2006 distribution rates, the Board determined that a forecast margin of $10.7 million for 2006 Transactional Services (storage and transmission) was appropriate.[17] The first $8 million of that amount, less $800,000 to cover Enbridge's incremental costs of providing Transactional Services, is for the

[17] *EB2005-0001/EB-2005-0437 Decision with Reasons*, February 9, 2006

account of ratepayers and is included as a reduction in 2006 distribution rates. To the extent that Enbridge is able to realize more than $10.7 million in margin in 2006, the excess will be booked to a deferral account and ultimately shared 75:25 in favour of distribution ratepayers.

3. THE ASSESSMENT OF STORAGE COMPETITION

This chapter outlines the statutory test under section 29 of the *OEB Act*, establishes the analytical framework to be used in assessing competition in the storage market, and applies the framework.

3.1 THE LEGAL TEST

This proceeding is brought pursuant to Section 29 (1) of the *OEB Act* which reads:

> On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest.

Section 29 was introduced in 1998 as part of the *Energy Competition Act*[18] and followed a similar provision that was introduced in the Federal telecommunications statute five years earlier.[19]

The concept of forbearance and light-handed regulation first surfaced in the late 1970s and early 1980s. In 1979, the Economic Council of Canada issued its interim report entitled *Responsible Regulation*[20] and a final report two years later, entitled *Reforming Regulation*[21] with specific recommendations. The McDonald Commission in 1985 concluded that it would be appropriate to adopt "selective deregulation" in Canada.[22]

[18] S.O. 1998, c.15
[19] Telecommunications Act S.C. 1993 c.38
[20] Economic Council of Canada , *Responsible Regulation – An Interim Report of the Economic Council of Canada (Ottawa, Supply and Services, 1979)*
[21] Economic Council of Canada , *Reforming Regulation* (Ottawa, Supply and Services, 1982)
[22] Royal Commission on the economic and development prospects for Canada, Volume 2, at 254 (1985)

Regulators in Canada and the United States offered two related grounds for forbearance. The first was that markets were being redefined by new technology and, therefore, competition rather than regulation could produce better outcomes in terms of the quantity and prices of goods and services, all of which would maximize social welfare. Much of the early work was done in the telecommunications industry. Not surprisingly, the absence of market power was held by both the U.S. Federal Communications Commission and the Canadian Radio-television and Telecommunications Commission (CRTC) to be sufficient grounds for the exercise of regulatory forbearance.[23]

The *Telecommunications Act*[24], which came into effect October 25, 1993, created the first statutory provision relating to forbearance in this country. Section 34 reads:

> Where the Commission finds as a question of fact that a telecommunications service or class of services provided by a Canadian carrier is or will be subject to competition sufficient to protect the interests of users, the Commission shall make a determination to refrain, to the extent that it considers appropriate, conditionally or unconditionally, from the exercise of any power or the performance of any duty under sections 24, 25, 27, 29, and 31 in relation to the service or class of services.

The CRTC between 1994 to 2007, pursuant to that section 34 decided to forbear from regulating telecommunications terminal equipment, cellular telephone and paging service, satellite services, data and private line services, internet services and ultimately long distance services.[25]

It is important to remember that the public policy rationale for forbearance is not limited to the belief that competition provided adequate safeguards in workably competitive markets. The second ground for forbearance is based on concerns related to regulatory costs. Those costs are not limited to the financial burden on utilities and ultimately

[23] Further Notice of Proposed Rulemaking, 84 F.C.C. 2d 445, at 472-74, 478 (1981). See, Enhanced services, Telecom Decision CRTC 84-18, at 6-17, 118 CAN GAZETTE PT I, 6117, at 6123-25 (12-July, 1984).
[24] Telecommunications Act S.C. 1993 c.38
[25] Exhibit E, Tab 2, Schedule 1, Attachment 2

consumers. As the Federal Communications Commission noted, the costs include reducing the firm's ability to react rapidly to the changing market conditions, dampening incentives to innovate and wasting resources through the regulation of firms that have no market power.[26]

There are degrees of competition in any market. They range from a monopoly, where there is a sole seller, to perfect competition, where there are many sellers and no one seller can influence price and quantity in the market. It is not necessary to find that there is perfect competition in a market to meet the statutory test of "competition sufficient to protect the public interest"; what economists refer to as a "workably competitive" market may well be sufficient.

It is also important to remember that competition is a dynamic concept. Accordingly, in section 29 the test is whether a class of products "is or will be" subject to sufficient competition. In this respect parties often rely on qualitative evidence to estimate the direction in which the market is moving.

3.2 ONUS

One of the issues raised was who has the onus in the NGEIR Proceeding. Generally, the onus is on the applicant. Most intervenors argued that the onus was on Union and Enbridge. The utilities and their affiliates disagreed. MHP, for example, countered that the onus was on any party seeking to change the status quo. In its view, Union has been selling storage at market-based rates for many years and that represents the status quo.

Some have argued that the ex-franchise prices are not competitive and that the framework should be revisited. Union itself is proposing to freeze the allocation of cost-based storage to in-franchise customers, and to acquire incremental volumes at market-

[26] Further Notice of proposed Rulemaking,84 FCC 2nd 445 at 472-74,478, (1981)

based prices. As pointed out by the Consumers Council of Canada (Consumers Council), that is certainly not the status quo.

In any event, there is no applicant in this proceeding, and the matter has been brought about on the Board's own motion. The Board therefore finds that it is not appropriate to assign onus to any particular party.

3.3 THE ANALYTICAL FRAMEWORK AND THE ASSESSMENT OF MARKET POWER

The Board must determine the appropriate analytical framework for assessing whether the market is competitive. In this section and in the balance of this chapter, we address the issues associated with the appropriate analytical framework and its application. Through this analysis, the Board can determine whether Union or Enbridge have market power and whether there is a workably competitive market for storage. The evidence and submissions identified three frameworks in which to consider the market power question: the Canadian Competition Bureau's Merger Enforcement Guidelines (MEGs), the CRTC approach to forbearance, and the U.S. Federal Energy Regulatory Commission (FERC) approach to addressing requests for market-based rate authority. The approaches followed by these three authorities are summarized below.

FERC

The FERC has applied a straightforward structural approach, derived from the U.S. Merger Enforcement Guidelines, to considering the market power implications of applications for new storage at market-based rates. Prior to FERC Order 678 (which has modified the FERC approach and which is described below), the product market was taken to be physical storage. The geographic market is based on an assessment of the extent of competition provided by neighbouring storage facilities. Once these

markets have been identified, a Herfindahl-Hirschmann Index (HHI)[27] calculation is performed to assess the potential for market power. The potential for entry is also assessed. An HHI threshold of 1800 is generally used as a screen: if the concentration in the market is below this value, the market is deemed to be competitive and a new storage supplier will be allowed to charge market-based rates. In several cases, even prior to Order 678, the FERC has allowed storage applications where the HHI was significantly above 1800, particularly if the new entrant had a small market share, because even if some incumbent firms possess market power, licensing a new entrant at market-based rates is unlikely to add to that market power and may well diminish it.

In 2005, the FERC initiated a Notice of Proposed Rulemaking culminating in Order 678, which relaxed this framework somewhat. Order 678 makes two significant changes to the framework for approving new storage applications. First, the product market has been broadened to potentially include pipeline capacity, local production and LNG peaking gas facilities. Second, even where the applicant cannot show that it does not have market power, it may be permitted to charge market-based rates, if such an outcome is determined to be in the public interest.

CRTC

The CRTC, relying on section 34 of the *Telecommunications Act*, is willing to forbear from regulation when "a service or class of services provided by a Canadian carrier is or will be subject to competition sufficient to protect the interests of users". The CRTC test thus resembles closely the language in section 29 of the *OEB Act*. Through application of these criteria, the CRTC has forborne from regulating the supply of long distance services, telephone equipment, customer inside wiring, business and residential local telephone services, high-speed Internet services, wireless telephone services and data services.

[27] The HHI is a measure of the competitive structure of an industry. It is equal to the sum of the squares of the market shares of all the companies in the industry (multiplied by 10,000). Thus an industry with ten equally sized firms would have an HHI of 1,000. An industry with five equally sized firms would have an HHI of 2,000.

Because of the original status of these industries as natural monopolies, the CRTC approach emphasizes the need to ensure that a dominant incumbent firm is not able to exercise substantial market power. Indeed, much of the CRTC's concern over forbearance has been a concern over prices that might be too low, rather than too high – in other words a concern about predatory behaviour exercised by the incumbent firms. In its 2006 decision[28] which establishes a framework for forbearance over competition in local telephone service, the CRTC required that the dominant firm's market share must have fallen below 75% before forbearance would proceed.

The CRTC follows a set of steps that mirror the methodology found in the Competition Bureau's Merger Enforcement Guidelines.

Competition Bureau's Merger Enforcement Guidelines

In their approaches to identifying market power both the FERC and CRTC follow a methodology derived from their respective national Merger Enforcement Guidelines or MEGs.[29] Although the methodology is intended for use in identifying the market power implications of mergers, it can be helpful when assessing whether the forbearance of regulation is likely to lead existing firms to exercise market power.

The MEGs approach is to identify the relevant market in terms both of products that are significant substitutes and the geographic area from which supplies of these products engage in competitive rivalry. Once this has been done, the degree of concentration in this market can be quantified by calculation of market shares to assess the degree of market power that is likely to be possessed by suppliers. In addition, an assessment is made of the conditions of entry because market power is unlikely to be possible in even a highly concentrated industry if price increases would encourage the swift entry of new and competitive suppliers.

[28] Telecommunications Decision CRTC 2006-15

[29] The Canadian and U.S. MEGs, while distinct, follow exactly the same methodology for the purposes of identifying market power.

Whereas the FERC focuses on the HHI, the Competition Bureau looks at market share to assess the potential for unilateral exercise of market power and generally will not challenge a merger if this indicator is below 35%. For assessing coordinated exercise of market power, the Bureau looks at the four-firm concentration ratio (the post-merger combined market share of the four largest firms) and generally will not challenge a merger when this indicator is below 65%.

Board Findings

The question before us in this proceeding is unlike that addressed by the Competition Bureau in a merger application or by the FERC in an individual application for market-based rates. The Board has entered into this broad-based inquiry to determine whether it will refrain from regulating storage rates in Ontario. However, the Board finds that there is much to be gained from considering the approaches of others in determining questions of market power – both the analytical tests used and the actual application in specific cases.

Enbridge argued that the Board can use the CRTC's approach to forbearance as a model for an appropriate analytical framework. Enbridge further argued that FERC's Order 678 amounts to a recognition by FERC that its assessment of market power should be less restrictive in order to encourage the development of storage and in order that customers get the benefits of reduced price volatility and greater assurance that peak demands will be met. Enbridge reasoned that the Board should not take guidance from FERC decisions which took a narrow approach to the assessment of market power because the FERC itself has moved away from this approach.

The Board notes that while the experts and intervenors differed as to how the test should be applied, there was little disagreement as to the key components of the analysis, namely those followed in the MEGs:

- Identification of the product market;

- Identification of the geographic market;
- Calculation of market share and market concentration measures;
- An assessment of the conditions for entry for new suppliers, together with any dynamic efficiency considerations (such as the climate for innovation and the likelihood of attracting new investment).

The Board finds that this approach is the appropriate means by which to determine whether Union or Enbridge have market power and whether the storage market is competitive. This approach encompasses the key components of the approaches used by the FERC and the Competition Bureau. Having determined the appropriate analytical framework, we turn now to the application of the framework to Ontario.

We will address each of the four components; we will also address the price impact issue raised by Mr. Stauft, an expert witness sponsored by a number of consumer intervenors. His analysis asserted that a comparison of the market price and the regulated price can be used to assess market power.

3.4 IDENTIFICATION OF THE PRODUCT MARKET

The product market identifies a set of products that are reasonably good substitutes for each other. In other words, where buyers will respond to a price increase by switching, in significant numbers, to a substitute product, the two products should be considered as belonging to the same product market. It should be noted that since storage has several distinct functions, including seasonal balancing and meeting short-term demand peaks, it is arguable that more than one product market may be identified for the different functions of storage.

Concentric Energy Advisors (CEA) provided expert evidence on behalf of MHP Canada. CEA suggested that the relevant product market would include physical storage, local production from the regions in the relevant geographic market, pipeline capacity in the relevant geographic market contracted by marketers either directly or as agents for

industrial customers, and utility peakshaving facilities. CEA's rationale for including marketer-contracted pipeline capacity is that this capacity could be reasonably expected to be active in the secondary market for transportation services, and thus provide readily available deliverability in direct competition to storage services. Local production and peakshaving would also provide deliverability in competition with storage.

Union offered expert evidence prepared by Energy and Environmental Analysis Inc and Professor Schwindt of Simon Fraser University (EEA/Schwindt report). The EEA/Schwindt report identified several products that can substitute for at least some storage uses. However, in the report, the boundaries of the geographic market were derived based on physical storage only, an approach the authors considered to be very conservative.

Mr. Stauft, the expert witness for a group of consumer intervenors[30], held that the relevant product market should be limited to storage only. While in Mr. Stauft's view LNG and uncontracted pipeline capacity could be substitutes for storage, in Ontario neither of these potential substitutes exist. Mr. Stauft did not agree that contracted pipeline capacity – even if held by active participants in the secondary market for pipeline services – could be correctly considered to be a close substitute for physical storage.

The Board Hearing Team[31] presented an expert witness, Ms. McConihe, and her evidence paralleled the evidence provided by Mr. Stauft, and she concluded that the relevant product market was storage only.

[30] Mr. Stauft's evidence was sponsored by IGUA, AMPCO, Consumers Council, Schools, Kitchener, and CME.
[31] In this proceeding there were two Board Staff teams. The Board Support Team took the traditional role of completing the public record and providing assistance to the Panel. The Board Hearing Team acted as a public interest intervenor, presented evidence, and made submissions.

Enbridge argued that the evidence shows that there are real substitutes for storage, including commodity sales, swaps, exchanges, displacement, delivery/redelivery and financial instruments.

The Association of Power Producers of Ontario (APPrO) argued that the product it is most interested in – high deliverability storage – is not currently available in Ontario. APPrO argued that competition cannot exist for a product that is not yet introduced and pointed out that when it is introduced it will be available only from Ontario utilities as ex-Ontario suppliers will be constrained by the nomination windows specified by the North American Energy Standards Board (NAESB).

Board Findings

The Board finds that the evidence supports the conclusion that there are non-storage products and services which provide reasonable substitutes for storage. These substitutes include commodity sales, swaps, exchanges, displacement, and delivery/redelivery services. The difficulty comes in trying to incorporate these into the quantitative analysis. The Board was not presented with data on these products which are comparable to the data available on physical storage. It should also be noted that these services (swaps, exchanges, displacement, etc.) do not increase the total availability of the underlying storage or commodity, but enhance the functioning of the market by increasing liquidity. Pipeline capacity contracted to marketers may well provide a proxy for the quantity of these services available; however, the Board finds that the evidence is not substantial enough to include this category in the analysis.

For these reasons, while the product market is broader than just physical storage, for purposes of the quantitative analysis we include physical storage only. The Board notes that this approach has the benefit of providing a conservative assessment of the level of competition. The real level of competition is undoubtedly higher than that shown by a quantitative analysis based only on physical storage.

With respect to APPrO's position, the Board is not convinced that high deliverability storage service is a different product. High deliverability storage may be a new service, but it is a particular way of using physical storage, which still depends upon the physical parameters of working capacity and deliverability. The Board provides a more detailed consideration of the pricing of high deliverability storage service later in this decision.

3.5 IDENTIFICATION OF THE GEOGRAPHIC MARKET

The geographic market is the area from which suppliers compete effectively for the business of a given group of customers. In the case of gas storage, this amounts to examining whether the market is restricted to Ontario or whether it should be more broadly drawn.

The utilities, their affiliates and Nexen argued for a larger geographic market, one which includes storage in Michigan and parts of Illinois, Indiana, New York and Pennsylvania. The consumer intervenors argued for a geographic market limited to Ontario. The issue centred on whether transportation constraints close off access to storage outside Ontario and included discussion of the secondary market.

Both Ms. McConihe and Mr. Stauft concluded that the storage market was limited to Ontario because there is limited firm uncontracted pipeline capacity joining Ontario to other markets and that, therefore, storage in other areas (such as Michigan) is not a substitute and not part of the same market.

EEA/Schwindt presented a seasonal price analysis and a price correlation analysis in support of a geographic market that includes Ontario, Michigan, northern Illinois, northern Indiana, and the Natural Fuel Gas territory in western New York and Pennsylvania. Energy Probe supported this analysis.

For the price correlation analysis, EEA/Schwindt presented correlation coefficients of daily gas commodity prices at nine North American trading hubs with the daily

commodity price at Dawn. Results were presented for several different time periods, and the full sample covers the period 1999 through August 2005. With two exceptions, the correlation coefficients are above 0.99.

For the seasonal price analysis, EEA/Schwindt examined differentials in the marginal value of storage approximated by the differential between the peak (winter) and off-peak (summer) prices. If storage providers at a particular market hub are exercising market power this differential should be greater than at other pricing hubs, but if there are no transportation constraints, then geographic arbitrage will make it impossible to exercise market power in this way. The EEA/Schwindt evidence on these seasonal differentials revealed little or no systematic variation between different pricing locations and in their view supported a conclusion of a broader geographic market.

The consumer intervenors acknowledged that the commodity market is highly integrated but argued that does not lead to the conclusion that the storage market is integrated. The Vulnerable Energy Consumers Coalition (VECC) and Canadian Manufacturers and Exporters (CME) argued that the price correlation analysis has never been accepted by the FERC. Union responded that the FERC rejected the use of the price correlation analysis as a means of demonstrating a lack of market power but that in this case it is being used as a means of defining the scope of the market.

Enbridge pointed out that it is clear that Dawn is physically connected to storage in Michigan and elsewhere through extensive pipeline interconnections. In the utilities' view, the secondary market provides adequate access to substitute storage facilities. They pointed to the evidence of GMi and BP Canada (BP) as being actual market participants who consider, and at times use, these alternative means.

The Board Hearing Team argued a similar position. In its view, the evidence – in particular that of GMi and BP – supports the conclusion that there are adequate substitutes for Ontario storage in the primary and secondary market. The Board

Hearing Team pointed to the MEGs standard and its reference to buyer behaviour and cited the evidence that marketers and utilities do purchase alternative services in Michigan and New York – and that these alternatives are not necessarily more expensive.

Board Findings

Ms. McConihe's conclusion that the market is restricted to Ontario was based on a survey of available firm primary pipeline capacity. This survey concluded that most of the pipeline capacity was under contract. Union and others argued that this is not surprising since pipelines are generally not built or expanded unless there are firm contracts to support the development. They argued that Ms. McConihe failed to understand the secondary market. As Mr. Reed on behalf MHP Canada stated, the existence of pipeline capacity is what is important in terms of integrating markets – not the availability of unsubscribed firm capacity.

There is no significant amount of uncontracted firm capacity to access other storage areas. However, there is strong evidence that the market does view Michigan and other areas as viable alternatives to storage provided by Union.

Ms. McConihe acknowledged the existence and likely significance of the secondary market, but expressed concern that it could not be quantified. While there may not be sufficient transaction level data about total secondary market activity, we certainly have evidence which supports the conclusion that the secondary market is relatively deep and liquid and that the market extends beyond just Ontario. Enbridge referred to this anecdotal evidence as "real-world examples of competitive alternatives". That evidence includes:

- GMi's evidence regarding its assessment of alternatives and the growth of the secondary market;

- the purchases of storage in Michigan and New York by Ontario utilities and marketers;
- the depth and liquidity of the Dawn Hub (as evidenced by the fact that traded volumes far surpass physical volumes);
- BP's evidence regarding its use of storage in Ontario, Michigan and the upper Midwest to offer services in Ontario and its evidence that at least one Union storage customer had switched to BP as a supplier for part of its storage needs;
- BP's evidence regarding its provision of services including swaps, exchanges, park and loans, delivery and re-delivery;
- Enbridge's RFP results included at least response from outside Ontario
- the evidence as to the significant holdings of storage and pipeline capacity by marketers generally;
- open seasons for new capacity on pipelines and for storage.

The Board concludes that the geographic market extends beyond Ontario, even though there is a lack of uncontracted firm pipeline capacity. The Board is satisfied that there are reasonable alternative means for storage customers in Ontario to access a broad market area. This can be done through the secondary markets or through participating in open seasons for new firm capacity. The Board is also satisfied that there is access to suitable substitutes for Ontario storage available in the broader market because there is direct evidence that the alternatives are considered and are being used.

The Board finds that the price correlation analysis, while not in and of itself determinative of this issue, supports this conclusion. The very high level of these correlations, combined with the other evidence about the advanced state of inter-hub trading and the absence of occurrences of "basis blow-outs"[32] at individual hubs, supports the conclusion that the market is highly integrated. The Board also finds that

[32] "Basis blowout" was described by Mr. Henning as "a description of the market conditions whereby the value, market value, of the pipeline services exceeds the maximum regulated costs". (Tr. 4, p. 27)

the seasonal price analysis supports the conclusion that storage facilities outside Ontario are part of the same market.

For these reasons, the Board agrees with EEA/Schwindt and concludes that the geographic market includes Ontario, Michigan, northern Illinois, northern Indiana, and the National Fuel Gas territory in western New York and Pennsylvania.

3.6 CALCULATION OF MARKET CONCENTRATION AND MARKET SHARE

The identification of geographic market and product market boundaries allows the calculation of measures of market concentration, both corresponding to individual firms (market share) and measures of concentration for the market as a whole, such as the HHI index. The former gives an indication of the potential for a single firm to exercise market power, whereas the latter is an overall indicator of how competitive the market is likely to be.

Board Findings

Before any calculations are made, an appropriate volumetric measure must first be selected to quantify the capacity of a storage facility. Subject to the availability of data, any of the following measures can be used: working gas capacity, injection capacity, deliverability, or capacity available to third parties. The last of these measures, capacity available to third parties, captures storage that is directly available to the competitive marketplace. However, there is clear evidence of market-based transactions taking place from what is otherwise considered dedicated storage capacity. Therefore, the Board concludes that it is reasonable to use the measures of working gas capacity and maximum daily deliverability. Market share data using these measures were provided by EEA/Schwindt.

The Board has found that the geographic market includes Ontario, Michigan, northern Illinois, northern Indiana, and National Fuel Gas in western New York and

Pennsylvania. The Board accepts the market share data provided by EEA/Schwindt which is summarized in Table 2.

Table 2: Market Shares and Market Concentration

	Working Gas Capacity	Max. Daily Deliverability
Union market share	13.1%	9.1%
Enbridge market share	7.9%	7.1%
4 Firm Concentration	61.7%	56.9%
HHI	1,270	1,220

The Board finds that these results support the conclusion that neither Union nor Enbridge have market power in the storage market. The Board finds that the storage market is workably competitive.

3.7 THE PRICE IMPACT ISSUE

Mr. Stauft testified that the regulated cost-based price for storage was a reasonable proxy for the competitive price of storage and that this approach was used by FERC. In his view, because the price for storage in the ex-franchise market is substantially higher than the cost-based rate, Union is exercising market power.

Board Findings

Most of the consumer intervenors, including the Industrial Gas Users Association (IGUA), the Association of Major Power Consumers of Ontario (AMPCO), Schools Energy Coalition (Schools), VECC, and the Consumers Council, supported Mr. Stauft's position. They took the position that the assessment of market power rests on a comparison of the price prevailing in the market with the current regulated price and

that, as a result, Union exercises market power. Union, Enbridge and their affiliates disagreed with the price analysis. Union argued that the price of cost-based storage was not a proxy for the competitive price of storage. In its view, market values for storage reflect seasonal commodity price differentials, which are unrelated to the cost of providing storage service.

The Board finds that the current cost-based regulated price is not a reasonable proxy for the competitive price. There is strong evidence that new storage is substantially more expensive due to higher costs for base pressure gas, reduced economies of scale, and smaller more remote pools. Enbridge Inc.'s oral testimony lays out these cost factors quite clearly, and the Low Income Energy Network (LIEN) has rightly observed that inflation is exerting upward pressure on these costs. Union pointed out that the FERC generally sets regulated storage rates on the basis of incremental costs.

Given the high cost of new storage and the high value for storage in terms of the commodity market, the Board does not agree that the market price being above historical cost-based rates is evidence of market power. In a competitive market, the costs of new capacity influence prices, and in the case of storage these costs are substantially higher than the historical cost-based rates.

The Board notes that the differential between current cost-based rates and the market value of storage, while not evidence of market power, would be a concern on distributional grounds if the Board were considering re-pricing cost-based storage to market-based levels. However, no party proposed such re-pricing. All parties, in one way or another, acknowledged that the in-franchise distribution customers do not have effective access to alternative storage providers, because they purchase a storage service which is bundled with distribution and transmission, and that therefore, these retail customers should remain subject to cost-based regulation. This distinction between in-franchise and ex-franchise customers is discussed further in Chapter 5.

3.8 BARRIERS TO ENTRY

Market power analysis typically includes an assessment of the conditions for entry for new suppliers, together with any dynamic efficiency considerations (such as the climate for innovation and the likelihood of attracting new investment). This analysis is particularly important in a market that is concentrated, or where the incumbent has a high market share, because if there is ease of entry then that market share can be quickly eroded if there is an attempt to raise prices. We do not have that concern here. The Board has found that neither Union nor Enbridge have market power in the storage market.

We did hear evidence regarding the high costs and high risks associated with developing new storage assets. In the view of most intervenors, there will be incentives for new investment if the Board refrains from regulating rates for third-party storage developments. This issue is discussed further in Chapter 4 and Chapter 5.

4. COMPETITION AND THE PUBLIC INTEREST

Although the Board has determined that the storage market in Ontario is subject to workable competition, the Board must also determine whether the level of competition is or will be "sufficient to protect the public interest". This is a key element of section 29. There has been considerable debate in this proceeding regarding the meaning of "public interest" in section 29. The public interest is multi-faceted and dynamic, but it is important to clearly identify how the Board will assess whether the public interest will be protected by competition if the Board refrains from regulating storage rates.

Board Findings

The public interest can incorporate many aspects including customers, investors, utilities, the market, and the environment. Union and Enbridge argued for a narrow definition of the public interest. In their view, competition itself protects the public interest, and once the Board has satisfied itself that the market is competitive, the public interest is protected by definition. The Board finds this to be an inappropriate narrowing of the concept. Competition is better characterized as a continuum, not a simple "yes" or "no". The Board would not be fulfilling its responsibilities if it limited the review in the way suggested without considering the full range of impacts and the potential need for transition mechanisms and other means by which to ensure forbearance proceeds smoothly.

Some of the intervenors took the position that the public interest review should be focussed on the financial impacts. For example, Schools argued that the Board should look at the benefits and costs of forbearance, and in its view, the costs include a possible transfer of between $50 million and $174 million from ratepayers to shareholders (arising from the proposed end to the margin-sharing mechanisms and the

potential re-pricing of cost-based storage to market prices). The Board agrees that the financial impacts are a relevant consideration, but does not agree that an assessment of the public interest should be limited to an assessment of the immediate rate impacts. The scope of appropriate considerations is broader and includes factors related to market signals, incentives and efficiency. These are discussed further below.

Some parties, including the Board Hearing Team and APPrO, argued that the Board's legislative objectives provide the best set of public interest considerations to apply in this case. Others took a similar approach, although expressed somewhat differently. For example:

- VECC submitted that the test is whether the market created by forbearance "will operate in a fashion that ensures that market discipline will be at least as effective as regulation in effecting fair and reasonable conditions in the customer relationship."
- Energy Probe argued that the Board should be guided by three public interest considerations: encouraging economically efficient pricing of gas storage services; protecting consumers of monopoly transmission and distribution services; and promoting the development of cost-effective storage opportunities in Ontario.

The Board finds that these broader approaches set out above represent a balanced and comprehensive approach to assessing the public interest. It is appropriate to consider the Board's legislative objectives in this case, because they are a clear expression of the factors the Board is to take into account. The Board's objectives which are most directly relevant in this case are as follows:

- to facilitate competition in the sale of gas to users;
- to protect the interests of consumers with respect to prices and the reliability and quality of gas service.

- to facilitate rational development and safe operation of gas storage

The Board notes that these may well be conflicting objectives. Put differently, there are public interest trade-offs. This is particularly relevant in light of another argument raised by the parties. Enbridge and MHP Canada argued that the forbearance contemplated in section 29, as a matter of statutory interpretation, is mandatory because of the use of the word "shall" in the statute. They argued that once the Board makes a factual finding that there is sufficient competition to protect the public interest, the *OEB Act* requires that the Board then refrain from setting prices through a cost of service regime.

The Board does not agree with Enbridge and MHP Canada's conclusion. Section 29 says that the Board shall make a determination to refrain "in whole or part" which the Board believes allows considerable flexibility in this regard. In addition, the Board concludes that it is required by the statute to address the public interest trade-offs, for example, between price impacts and the development of storage and the Ontario market generally.

We will now review each objective and discuss some of the public interest factors which the Board considers relevant to the assessment of whether the level of storage competition is sufficient to protect the public interest if the Board refrains from rate regulation and contract approval.

4.1 TO FACILITATE COMPETITION IN THE SALE OF GAS TO USERS

The Board has worked over time to ensure that Ontario consumers reap the benefits of commodity competition. The Board must continue to pursue this objective and can do so by facilitating the evolution of a robust market in Ontario. The development of the Dawn Hub has brought substantial benefits to consumers in Ontario and to other market participants.

The Board concludes that it is in the public interest to maintain and enhance the depth and liquidity of the market at the Dawn Hub as a means of facilitating competition. One way to do this is to encourage the development of innovative services and to ensure access to those services. Choice is the bedrock of competition. The evolution of the transactional services market is an example where innovative and flexible services have evolved within a market-based pricing structure.

Enbridge argued that forbearance will foster innovation by facilitating the provision of storage services in the competitive market. The Board agrees that regulating storage rates does place constraints on the development of flexible and innovative services; forbearance, within a framework of non-discriminatory access, can remove these constraints.

In the current industry structure, the gas utilities both acquire storage for their own customers and operate storage for their own needs and for other customers. The utilities also operate integrated storage and transportation systems. The Board considers later in this decision whether forbearance requires that there be greater separation between these operations or whether other procedures should be developed to ensure non-discriminatory access to storage and transportation.

4.2 TO PROTECT THE INTERESTS OF CONSUMERS WITH RESPECT TO PRICES AND THE RELIABILITY AND QUALITY OF GAS SERVICE

The interests of consumers were a primary focus for many intervenors. The submissions addressed issues related to the direct and indirect impacts of forbearance and competition. Interestingly, no ex-franchise customer opposed paying market-based rates; nor was there any evidence of a price impact on this market segment in the event of forbearance. This is consistent with the Board's finding that these customers have alternatives and that competition will provide adequate protection for these customers.

With respect to in-franchise customers, two rate impacts were discussed: the direct impact on storage rates and the indirect impact on the sharing of the storage premium. With respect to the direct impact, the utilities proposed to freeze the allocation of in-franchise storage and to acquire incremental storage at market-based prices. This would have the effect of increasing in-franchise storage rates (under current market conditions), albeit only marginally given the relatively slow growth of in-franchise storage demand. The utilities were of the view that this afforded in-franchise customers a significant level of protection. The other direct storage rate impact arises from the proposal that Enbridge be treated as an ex-franchise customer in respect of its contracts with Union. This would have the effect of raising Enbridge's storage rates.

However, attention of the parties was primarily focussed on the indirect impact arising from the premium which exists between the price of market-based storage and the underlying costs. Currently, that premium is shared between utility ratepayers and utility shareholders. Under the utilities' proposals for forbearance, the premium would be retained by the shareholders. This would result in significant transfer of funds in the case of Union (2007 estimate is $44.5 million); less so in the case of Enbridge (2007 estimate is $5 million to $6 million). The intervenors in general rejected these proposals and, as a result, opposed forbearance.

IGUA/AMPCO argued that there should be no forbearance if there will be any adverse impact on ratepayers. Similarly, they argued that the level of return under forbearance should be no greater than the regulated return; otherwise the level of competition is not sufficient, because the regulated return is a proxy for a competitive result. The Consumers Council argued that there should be no forbearance if a material increase in price is not offset by the prospect of decreasing prices.

Union argued that on IGUA/AMPCO's and the Consumers Council approach, the Board would never forbear, no matter how competitive the market. It argued that the financial impact is not a factor as to whether forbearance is warranted. Union argued that the

Board should consider that new storage development would attract additional volumes to Ontario, increasing market liquidity and enhancing security of supply for Ontario consumers.

The Board agrees that the distribution of the premium is a significant consideration. In many ways, it has been the underlying focus of the NGEIR Proceeding. However, the impact of removing the premium from rates is the result of removing a sharing of economic rents; it is not the result of competition bringing about a price increase. So while it is an important consideration which the Board must address (see Chapter 7), it is not a sufficient reason, in and of itself, to continue regulating storage prices.

Apart from the premium issue, the direct expected storage rate impacts under a forbearance scenario are modest for Union's in-franchise customers, under the utility proposal of fixing the in-franchise storage allocation. The impact for Enbridge customers is more pronounced given its lower level of storage assets. The Board must consider whether the allocation to Union's in-franchise customers should be fixed and whether Enbridge (and possibly other ex-franchise customers) should be entitled to cost-based storage from Union.

A key consideration with respect to this issue is the question of which consumers the Board is responsible for protecting. Some parties, such as Kitchener, have argued that our duty is to end-use consumers in Ontario – either to them directly or to them indirectly through their local distributor. These parties advocate cost-based storage pricing for Ontario end-users and market-based pricing for those outside Ontario.

While the Board concurs that a key objective (and therefore a key public interest consideration) is the protection of consumers in Ontario, the Board concludes that this approach of separate treatment depending upon location is problematic. This is discussed further later in Chapter 5.

The Board concludes that long-term consumer protection in terms of price, reliability and quality of service is best achieved through thriving competition for the competitive elements of the storage market and effective regulation of the non-competitive elements of the market. The Board is of the view that refraining from rate regulation and contract approval in the ex-franchise market has the potential to foster more competition in the storage market, to the benefit of all customers, provided there are clear rules and non-discriminatory access by all market participants. In a competitive market, customers have choices, resources are distributed efficiently, and there are incentives to innovate and respond to customer needs.

4.3 TO FACILITATE RATIONAL DEVELOPMENT AND SAFE OPERATION OF GAS STORAGE

Discussion in this area focussed on the impact of forbearance on the development of new storage in Ontario, through the utilities directly, through their affiliates, or through independent storage developers. The estimates of new storage potential ranged from 50 Bcf to around 120 Bcf.

The Board has as an explicit objective to facilitate the rational development of gas storage. The Board therefore must look for means by which to achieve this objective. A number of authorities have identified the need to develop additional storage. For example, FERC has acknowledged that additional storage development will mitigate commodity price volatility and improve winter peak availability. The utilities and their affiliates took the position that this should be a key consideration for the Board and argued that new storage development will not take place in Ontario under the current regulatory regime. In their view, forbearance from setting rates and approving contracts would encourage storage development and the development of storage services. Nexen agreed with the utilities that forbearance will allow needed new services to develop.

Energy Probe also agreed and argued that there has been limited recent storage development despite the appearance of significant opportunities and that this can be contrasted with the level of development elsewhere. In Energy Probe's view, Ontario storage development has been artificially constrained due to unfavourable regulatory conditions. Energy Probe argued that forbearance will drive enhancements to meet the needs of gas-fired generators and that the public interest will benefit from having storage developers manage the risks and rewards of development.

Others, primarily consumer groups, took the view that new storage, to the extent that it is needed, can be stimulated by allowing market-based rates for new storage developers only. The position of these groups, including the London Property Management Association (LPMA), the Wholesale Gas Service Purchasers Group (WGSPG), VECC, and Consumers Council, can be summarized as follows:

- The existing facilities are more than sufficient to meet Ontario's needs.
- The utilities could further develop existing facilities under the current regulatory framework if additional capacity is needed. There is evidence that they have done so in the past.
- Forbearing from setting storage rates and transferring the rents to the shareholders will not provide an incentive to non-utility developers, and continued regulation of the utilities will not provide a disincentive to third-party storage development. The way to stimulate new storage development by third parties is by forbearing or regulating at market rates, which is consistent with FERC Order 678.
- There is no evidence that forbearing from regulating the utilities will cause them to increase capacity. The Enbridge evidence is that even with forbearance it might not invest in storage enhancements.

The evidence suggests that there is no need for significant new storage within Ontario to serve the traditional requirements of Ontario consumers. However, there is a

demonstrated desire for more specialized services to meet the load characteristics of power generators. The Board also agrees that further development of storage in Ontario would be of benefit to Ontario consumers in terms of reduced price volatility, enhanced security of supply and an overall enhanced competitive market at Dawn. There is also evidence that new services, once they are generally available, can enhance the service offerings of other parties, such as marketers, thereby increasing the liquidity of the market.

The Board concludes that it is appropriate to facilitate the development of storage to offer these services without undue risk for ratepayers. The issue is how this objective is best achieved. At a minimum, for third-party storage development, whether independent or affiliated, the Board agrees that it should refrain from setting storage rates and approving storage contracts. There was no significant opposition to this approach.

The more contentious issue concerns the utilities and whether forbearance on price setting is necessary to stimulate their investment in storage. The utilities claimed they would only develop storage under a forbearance scenario but would not commit to doing so. On the other hand, the evidence shows the utilities have been willing to invest in the past under regulation, and indeed, the Board has the authority to order the utilities to provide storage services. The Board concludes that while there is no guarantee that the utilities will develop storage under forbearance, it is apparent they will not develop it under a regulatory framework unless ordered to do so. The Board does not believe that the best way to stimulate development of storage assets and services is to order utilities to develop these resources. The Board's preferred approach is to use market mechanisms where possible, and under forbearance, the Board concludes, the utilities will have an incentive to develop assets and services.

A related question is whether it continues to be appropriate for storage to be developed as part of the regulated utility business or whether it should in the future be developed

separately. The Board accepts the evidence of Enbridge Inc. that storage development is more akin to exploration and development and is riskier than other distribution activities. Some parties disagreed that enhancements to existing storage facilities were as risky as new storage development. However, the Board is convinced by the evidence that storage investments are generally riskier than other regulated activities, such as distribution or transmission expansions, given the difficulty, for example, in accurately predicting the achievable operating parameters related to storage projects. This evidence was not significantly challenged. The Board therefore agrees with Energy Probe's view, namely that the risks associated with new storage development are best borne by storage developers. This approach is consistent with a rational development of storage in the Board's view. Under forbearance, the utility shareholders would be expected to bear the risk of any storage development for the competitive market.

5. FORBEARANCE

The Board has determined that the storage market is workably competitive. We have also considered some of the key elements of the public interest. The issue we address in this chapter is whether the Board should refrain from setting storage prices and approving storage contracts. The Board has the discretion under section 29 to refrain from regulating "in whole or part". The Board interprets this to mean that it has substantial flexibility to establish a framework which recognizes the circumstances of various segments of the market.

At its simplest, the issue is who is entitled to cost-based rates and who will pay market-based rates. The Board will consider this issue in the context of the public interest factors described in Chapter 4. First, the Board will address the issue of third-party storage, and then the Board will address utility storage. The chapter concludes with a consideration of reporting requirements.

5.1 THIRD-PARTY STORAGE

Third-party storage is not yet available in Ontario. Currently, Union and Enbridge own and operate all of the storage facilities. The Board has heard an application by Tribute, and approvals required to develop the Tipperary Storage Pool have been issued. However, the development of the project has been delayed and some of the Board approvals granted in 2005 have expired; Tribute is in the process of seeking renewals. Until renewals are granted, the Tipperary Storage Pool cannot be developed and made operational. The current development schedule proposes that operation of the pool will begin by June 2007.

MHP Canada has recently filed a series of applications in relation to its proposed St. Clair storage facility and has indicated that it intends to pursue its Sarnia Airport Pool project at some time in the future. The Board also heard testimony from Enbridge Inc. regarding its work in this area.

In its Natural Gas Forum Report, the Board indicated that it did not intend to regulate the rates of new independent storage operators. In our earlier partial decision on MHP Canada's core points, the Board determined that MHP Canada would be authorized to charge market-based rates within the Board approved range.[33] The issue before the Board now is whether it should refrain from setting the rates of all third-party storage (both independent and affiliated) and refrain from approving storage contracts entered into by these companies.

MHP Canada and Enbridge Inc. argued that the Board should refrain from regulating the rates of third-party storage. MHP argued that cost-based rates do not compensate for the risk of developing storage. It also took the position that the *Affiliate Relationships Code for Gas Utilities* (ARC) is sufficient to govern the relationship between Union and MHP Canada, but it sought confirmation on two points:

- that under a market-based rate framework the Board would not require disclosure of MHP Canada's costs and revenues where the services to Union arise from a fair and open competitive bidding process, and
- that section 2.3.10 of the ARC (which relates to services provided in a market which is not competitive) would not apply because the Board has found the market to be competitive.

Tribute was also of the view that the ARC requirements are sufficient to protect the competitive interests of affiliate and unaffiliated market players without placing undue additional conditions on utilities and their affiliates.

[33] The Board's decision regarding MHP Canada's core points appears at Appendix G.

There was no substantial opposition to the proposal that the Board should refrain from setting the rates and approving the contracts of new storage operators. Most intervenors recognized that doing so would stimulate storage investment in Ontario. For example, LPMA/WGSPG argued that without market-based pricing, little or no additional capacity or deliverability would likely be developed in Ontario and it therefore supported full market-based rates for third-party developers or utility affiliates (provided there is compliance with ARC). IGUA/AMPCO also agreed that market-based pricing for new storage developers would stimulate development of new storage although they argued that the Board should not refrain from regulating these rates.

Board Findings

The Board will refrain from setting the rates and approving the contracts related to third-party storage, both utility-affiliated storage and independent storage. These storage developers will be operating in the competitive storage market, and the Board agrees that they should have the ability to offset the substantial risks of these developments with the flexibility to price storage in a way which captures the market value of those storage services.

The ability to charge market prices in the absence of price regulation will provide a positive investment incentive and, to the extent new third-party storage is developed, this will enhance competition in storage – as well as competition in the market generally. This is in the public interest. If the new storage is used by Ontario consumers they may well face higher prices for this storage than they would for cost-based utility storage. However, these storage providers will have no captive customers, and Ontario consumers will not bear the risks associated with these new developments. The Board also finds this to be in the public interest. In conclusion, the Board finds that these storage operators will be subject to competition sufficient to protect the public interest.

MHP Canada requested that the Board confirm MHP Canada's interpretation of two aspect of the ARC. The ARC provides that if an open and fair tender is held, the prices in that tender will establish the market price for the service. Under those circumstances, the ARC would not require that a contracting party disclose its cost and revenue data.

5.2 UTILITY STORAGE

The Board must address a number of issues with respect to storage services offered by Union and Enbridge:

- Which storage services should the Board continue to regulate at cost-based rates?
- Should the Board set cost-based rates for the storage services Union provides to other Ontario LDCs?
- Should the rates for new storage services, such as high deliverability storage, be regulated at cost-based rates?
- Having determined which services will continue to be regulated at cost-based rates, should the Board refrain from regulating the prices of other services?
- Should the Board require separation of the competitive storage operations from other parts of the business, or is a cost allocation study sufficient to distinguish between regulated and unregulated storage?

The Board will address these issues in the following sections, 5.2.1 through 5.2.5.

5.2.1 Regulated Storage Services

In the current framework, the demarcation between cost-based and market-based rates is commonly expressed in terms of "in-franchise" and "ex-franchise": "in-franchise" customers pay cost-based rates and "ex-franchise" customers pay market-based rates. However, as pointed out in Chapter 2, this nomenclature is not entirely accurate. Kitchener, for example, is not in Union's franchise territory but does receive cost-based storage; similarly Gazifère is outside Enbridge's franchise territory (and outside the

Province) but also receives cost-based storage. Until recently, Enbridge's contract with Union was at cost-based rates, and Enbridge's rates continue to include Union storage costs at cost-based rates even though the contracts entered into as of April 1, 2006 are at market-based rates. However, the term "in-franchise" is commonly used to refer to all customers that take bundled, unbundled or semi-unbundled distribution, storage and contract carriage transportation services, and the term "ex-franchise" is commonly used to refer to customers that take cross-franchise storage and transportation services.

Virtually all parties agreed that the Board should continue to regulate storage rates for "in-franchise" customers and that these customers should pay cost-based storage rates. One exception was MHP Canada, which argued that conditions exist for the Board to forbear in relation to the market as a whole. While MHP advocated full forbearance, it recognized that the elimination of the bifurcated market may require a transition. MHP Canada proposed that the Board adopt a policy direction to move to full forbearance in the storage services market.

Board Findings

In terms of a section 29 analysis, the goal would be to continue to regulate (and set cost-based rates) for those customers who do not have competitive storage alternatives and to refrain from regulating (allow market-based prices) for those who do have competitive alternatives. The Board concludes that it should continue to regulate and set cost-based rates for existing storage services provided to in-franchise customers up to their allocated amounts. This approach was supported by all the intervenors, except by MHP Canada, as noted above.

The parties recognized that bundled customers, in particular, do not acquire storage services separately from distribution services, do not control their use of storage, and do not have effective access to alternatives in either the primary or secondary markets. Competition has not extended to the retail end of the market, and therefore is not sufficient to protect the public interest. However, the Board finds that customers taking

unbundled or semi-unbundled service should have equivalent access to regulated cost-based storage for their reasonable needs. The Board finds that it would not further the development of the competitive market, or facilitate the development of unbundled and semi-unbundled services, if these unbundled and semi-unbundled services were to include current storage services at unregulated rates. The Board also agrees with the parties that noted that re-pricing existing storage will not provide an incentive for investment in new storage and therefore cannot be said to provide that public interest benefit.

However, customers taking unbundled and semi-unbundled services do have greater control over their acquisition and use of storage than do bundled customers. It is also the Board's expectation that these customers will have access to and use services from the secondary market. Therefore, the Board concludes it is particularly important to ensure that the allocation of cost-based regulated storage to these customers is appropriate. This issue is addressed in Chapter 6.

MHP Canada has suggested that the Board adopt full forbearance in storage pricing as a policy direction. Similarly, Union has characterized its allocation proposal and Enbridge has characterized its "exemption" approach for in-franchise customers as being "transitions" to full competition. The Board has found that the current level of competition is not sufficient to refrain from regulating all storage prices; nor do we see evidence that it would be appropriate to refrain from regulating all storage prices in the future. The current structure (for example, the full integration of Union's storage and transportation businesses and the full integration of Union as a provider of storage services and as a user of storage services) is not conducive to full forbearance from storage rate setting. In addition, there would be significant direct and indirect rate impacts associated with full forbearance from rate setting, and there is little evidence of significant attendant public interest benefits. The current situation is that these customers are not subject to competition sufficient to protect the public interest; nor is there a reasonable prospect that they will be at some future time.

Although there was general support for the continued regulation of storage rates for the bundled, unbundled and semi-unbundled customers, three aspects of its application were disputed:

- The amount of storage which should be allocated to these customers, both in aggregate and individually;
- Whether Ontario utilities should receive access to cost-based storage from Union;
- Whether the rates for new storage services from utilities should be regulated.

The first issue, the allocation of storage to customers both individually and in total, is addressed in Chapter 6. We address the other two issues next.

5.2.2 Union's Storage Services for Other Utilities

Union currently provides storage service to a number of other utilities. It provides storage at cost-based rates to Kitchener, NRG and Six Nations. These customers, while not in Union's franchise territory, take "in-franchise" services. As such, the Board's finding regarding the continuation of regulated cost-based rates applies to these utilities as well.

Union also provides storage services to Kingston, Enbridge and GMi. These are cross-franchise storage and transportation services, and while they were originally provided at cost-based rates, Union received authority to charge market-based rates (within the C1 range) to these customers in the Board's RP-1999-0017 Decision. Due to differences in the terms of the contracts, Kingston and GMi have been paying market-based rates for some time, but Enbridge has only recently entered into a series of market-based contracts with Union.

Enbridge is one of Union's largest storage customers. Enbridge and Union entered into a long-term market-based contract for the period April 1, 2004 through March 31, 2014. Enbridge proposed to have its 2005 rates reflect the new storage costs. In the RP-

2003-0203 decision, the Board did not approve the flow through of market-based storage costs into Enbridge's rates on the basis that the claimed long-term benefits were speculative and that a reversion to cost-based rates until March 31, 2006 (which under the contract would be triggered by the Board's rejection of Enbridge's original proposal) would result in substantial cost savings. The Board did not question the Board's RP-1999-0017 decision to allow existing contracts to be renewed at market-based rates.

Upon the expiry of that cost-based arrangement on March 31, 2006, Union and Enbridge entered into three contracts with market-based prices with the following expiry dates and volumes:

2008 9.4 Bcf
2009 5.6 Bcf
2010 4.9 Bcf

Although these contracts began April 1, 2006, the costs associated with these services are not reflected in Enbridge's current distribution rates. At the time of Enbridge's 2006 rates case, it had not negotiated any agreement with Union, and therefore its rates proposal was based on the assumption that storage costs for Union services would continue at the same level.

Enbridge currently provides cost-based storage services to Gazifère, its affiliated Quebec distributor, under a bundled distribution service. Enbridge proposed to charge Gazifère market-based rates on the basis that it is an ex-franchise customer.

A number of parties argued that Union should provide regulated cost-based storage to all Ontario utilities. (No party argued that GMi should receive storage services at cost-based rates.) The Board Hearing Team grounded its argument on the basis of price

discrimination; other parties relied on the notion that storage is a Provincial asset (as articulated in the 1962 Langford Report[34]) as the basis for their argument.

The Board Hearing Team noted that the decision allowing Union to renew its cost-based storage contracts at market-based rates has resulted in the situation where customers in Union's franchise area pay cost-based rates, while customers in the Kingston area pay market-based rates. The Board Hearing Team noted that the Board in its Natural Gas Forum Report raised the issue of whether this pricing structure was inappropriately discriminatory.

In order to remedy this, the Board Hearing Team recommended that customers be split into two groups: "core" and "non-core". Under this proposal, the core customer category would include all Ontario end-use customers that take bundled and unbundled regulated services from the gas utilities. Core customers would receive regulated cost-based storage services from the total inventory of Union and Enbridge's storage assets. Retailers would also have access to cost-based storage. Non-core customers would include customers who have opted out of regulated rate protection and assume the total risk of their portfolio management, including storage. Non-core customers would also include marketers (excluding retailers serving the core market) and out-of-province utilities. These customers would pay market prices for storage.

The Board Hearing Team argued that this separation would ensure a consistent treatment of customers across all gas utility franchises in Ontario. Under this approach the current contracts between Union and Enbridge, and between Union and Kingston, would be revised to reflect cost-based rates. The Consumers Council suggested a similar approach. It argued that the definition ex-franchise should be refined and that it is more reasonable to distinguish between services which are provided using the integrated storage systems that have been developed by the utilities for the purpose of

[34] *Report of Committee on Oil and Gas Resources, Part II Underground Storage of Natural Gas*, June 1962 (commonly referred to as the "Langford Report")

providing a “core” or “utility related” delivery service, and discretionary services that are available because the utility storage infrastructure is not needed from time to time to perform the utility function.

Other parties took the view that storage is a Provincial asset and noted that the Langford Report recommended that distribution companies should have first call on Ontario gas storage. Those parties argued that Union’s storage should be provided at cost-based rates to consumers throughout Ontario, and specifically at cost-based rates to Enbridge and Kingston.

Board Findings

The Board finds that the core/non-core approach may be appropriate in some situations. It could serve, for example, as a means of determining which segment of the in-franchise customers should continue to have its storage rates regulated. However, the Board concludes, for reasons outlined below, that it is not necessary for Union to continue to provide cost-based storage to Enbridge, or to revert to cost-based storage for Kingston, in order to ensure that there is no undue price discrimination in the Province.

The Board agrees that effective competitive storage options do not exist for the in-franchise customers of Union and Enbridge. The Board has already determined that these customers will continue to receive regulated cost-based storage rates. However, Enbridge and Kingston, which are buying storage services on behalf of their customers because they do not have sufficient storage resources of their own, do have access to alternatives. This is as true for Enbridge as it is for GMi. Therefore, the question is whether Enbridge (for its storage needs beyond the capacity of Tecumseh) and Kingston (for all of its storage needs) should be entitled to cost-based storage rates from Union.

The Board Hearing Team cited the principle that customer rates for storage should not vary on the basis of where they are located in Ontario but should be based on the customer load profile and the costs to provide service. The Board notes that distribution rates for similar customers do vary across the Province, and even within Union's territory, to reflect the different underlying costs of serving customers. Union has developed sufficient storage to serve the needs of its distribution customers, while Enbridge has not. As Enbridge's storage requirements have increased, it has had to decide whether to contract for its requirements or develop additional assets itself. It is not surprising that Enbridge has continued to acquire services from Union, when it had access to cost-based rates, given that the costs of developing new storage have undoubtedly grown. This does not mean that if Union charges market-based rates the result is price discrimination. The Board Hearing Team appeared to recognize this when it stated that price differentiation should also be driven by the specific costs of a utility.

Other parties advocating regulated cost-based storage for all Ontario utility customers drew upon the Langford Report for support for their position, arguing that Ontario has historically recognized gas storage as a Provincial asset for the benefit of all Ontarians. The Board disagrees with this application of Langford's conclusions for two primary reasons. First, the Langford Report was prepared within a very different market context. The North American natural gas market was in its infancy. In the intervening period there has been extensive infrastructure development from wellhead to burner tip, market integration across North America, and the deregulation of the commodity. Utilities are no longer the only suppliers of gas to customers. We must determine the appropriate regulatory tools for Ontario storage within the current market context – one which is very different from the time of the Langford Report.

The Langford Report is relevant, however, in that it articulates the historic perspective on storage and its appropriate development, without being prescriptive on financial matters. The Langford Report, for example, does not express any explicit view in

respect of pricing, and this relates to the Board's second reason for disagreeing with those relying on the Langford Report as a reason for requiring Union to provide storage at cost-based rates to all Ontario customers. Advocates of cost-based pricing assume an automatic link between the concept of a Provincial asset and cost-based prices, but the Board finds that this approach is flawed. The public interest in Ontario is best served if Ontario storage assets are used efficiently. The Langford Report in fact recognizes this, when it states at page 56: "The role of the Provincial Government with respect to storage should be that of controlling and regulating it *only so far as is necessary to ensure efficient and economical development of the industry*" (emphasis added). It is in the Ontario public interest for storage and storage services to be further developed, and it is in the public interest for those customers who have access to alternatives to pay prices set in the competitive market.

There are also two other drawbacks to continuing to regulate cost-based rates for Union's service to Kingston and Enbridge. First, an "Ontario-utilities first" policy would send a negative market signal about what is otherwise a deep liquid trading point within the integrated North American market. Second, this approach could tip the playing field in favour of utilities over marketers, who may well serve Ontario customers but which under the various proposals would pay market-based rates. Neither of these market signals is consistent with the Board's objective of ensuring the continued strength and development of the Dawn Hub.

The issue is whether Enbridge and Kingston, as purchasers of storage for bundled customers, should receive regulated cost-based storage services from Union. The Board concludes that they should not, because the storage services they acquire are subject to competition sufficient to protect the public interest, but that in the case of Enbridge, a transition framework is required. The Board must also consider the application of its conclusions to the case of Gazifère. We will now address each of these utilities in turn.

Kingston

Kingston, which is connected to the TCPL system, not the Union system, has been operating at market-based rates for its cross-franchise service for some time and took no active part in the NGEIR Proceeding. The Board therefore concludes that Kingston is not opposed to paying market-based rates. The Board notes that because it does not set rates for Kingston's customers, the Board has no authority or control over how Kingston charges its own customers for storage. The Board is satisfied that Kingston has effective access to competitive alternatives and therefore does not require the protection of regulation for its acquisition of storage from Union. Because Kingston already receives market-based storage services, no transition framework is necessary.

Enbridge

The Board finds that a transition framework is warranted in the case of Enbridge. Enbridge does have access to storage alternatives and does operate within the competitive storage market. However, the quantity of storage it acquires from Union is a substantial portion of its total requirement, and, given the uncertainty around storage price regulation at the time Enbridge entered into its current contracts, it may have had limited effective access to alternatives at that time.

Given the current substantial difference between cost-based and market-based storage prices, if the prices of the new contracts were included in Enbridge's rates, there would be an increase in Enbridge's total storage costs (although the majority of Enbridge's storage costs would still be based on the costs of Tecumseh). The Board must be concerned about the impact on consumers from refraining from rate regulation and balance that consideration with the objectives of facilitating storage development and the competitive market. With respect to storage development, in section 5.2.1 we concluded that re-pricing existing storage does not provide an incentive to develop new storage; the Board is similarly satisfied that retaining cost-based rates for existing storage for a transition period will not create an adverse impact on new storage development.

With respect to protecting consumers, the Board finds that it is in the public interest to provide Enbridge and its customers with a transition to market-based pricing for its storage needs (in excess of its Tecumseh capacity), rather than requiring it to access the competitive market for its full requirement all at one time. This will have the effect of phasing-in the rate impact on Enbridge's customers, and facilitating the development of competitive alternatives – to the benefit of Enbridge's customers and competitive storage providers. The Board finds that this transition should begin in 2008 and be completed in 2010. This timing will allow Enbridge to tender for services during 2007. Enbridge's rates in 2007 will continue to reflect cost-based storage rates for the services it acquires from Union.

The way to achieve this transition is for Union and Enbridge to amend the current contracts (which under section 4.04 would expire as of March 31, 2007 as a result of the Board's NGEIR decision) to maintain the current volumes and expiration dates but to replace the market-based rates with cost-based rates. The result of this approach would be that in 2008 Enbridge would need to acquire 9.4 Bcf (less than 10% of its storage requirement) from the competitive market. Smaller incremental amounts would be sourced from the competitive market in 2009 and 2010. The Board concludes that the phased approach, and the relatively small amounts of competitively sourced storage added each year, will result in a small net impact on Enbridge customer rates. In this way, the interests of consumers will be sufficiently protected.

The Board's decision to refrain from regulating the prices of Union's ex-franchise storage services will be conditional on the amendment of the Union/Enbridge contracts as described above in order that these services will be subject to competition sufficient to protect the public interest.

Gazifère

The Board must also consider the application of its findings to Gazifère. Gazifère is a small Quebec distributor, serving 30,000 customers, which is connected to the Enbridge system and is an affiliate of Enbridge. Enbridge proposed to charge market based rates to Gazifère on the basis that it is an ex-franchise customer. Others argued that all customers outside Ontario should pay market-based rates.

As outlined earlier in this section, the Board has found that a decision to refrain from regulating storage rates should not be based on an in-Ontario, ex-Ontario approach, but rather on the competitive position of the customer. The appropriate consideration is whether Gazifère has access to alternatives. The evidence is that it does not; it is connected to the Enbridge system and takes a bundled distribution service. In all respects, Gazifère is similarly situated to the distributors attached to Union's system (namely, Kitchener, NRG, and Six Nations) which each take bundled or semi-unbundled service. The Board finds that it is appropriate for Gazifère to receive regulated cost-based service, just as Kitchener, NRG and Six Nations do, because the service they receive is not subject to competition sufficient to protect the public interest.

5.2.3 New Storage Services, including High Deliverability Storage

This issue concerns a set of new storage services and, in particular, high deliverability storage services. The services include Enbridge's proposed Rate 316 and services related to the Tecumseh storage enhancement project and Union's proposed high deliverability storage services and three ex-franchise services: F24-S, Upstream Pipeline Balancing Service (UPBS) and Downstream Pipeline Balancing Service (DPBS). These services are of particular interest to dispatchable gas-fired power generators, and indeed were developed in response to generator requests, because they provide the means by which these customers can conduct intra-day balancing.

The storage requirements for dispatchable gas-fired power generators are very different from existing customers. Whereas existing customers use storage for seasonal or daily

balancing, dispatchable generators want to use storage for intra-day balancing. And whereas existing customers can meet their needs with the standard deliverability service (daily delivery of 1.2% of storage space allocation), dispatchable generators want daily deliverability as high as 10% of their storage space allocation.

Many of the issues which existed between Union and Enbridge and their generator customers were resolved in the Settlement Proposals which were filed and accepted by the Board. These settlements, which can be found at Appendices D and F, set out the parameters for multiple nomination windows, the inter-franchise movement of gas, the redirection of gas, title transfers for gas in storage, and the allocation methodology for 1.2% deliverability storage. What remained unresolved was the pricing for the new high deliverability storage services.

The utilities proposed to offer these services at market-based rates and proposed that the Board refrain from regulating the rates for these services. The power generators took the position that storage services provided to them should be regulated at incremental cost-based rates.

APPrO argued that the utilities have an obligation to provide these services and, because allocations of 1.2% standard deliverability space have been agreed, power generators have no options (other than through the utilities) for acquiring the necessary deliverability services to make use of these storage allocations. In APPrO's view, storage in other geographic areas is not an option because all other transmission systems are limited to the four NAESB nomination windows. APPrO submitted that the utilities may have options as to how to meet the requirements – in particular storage enhancements and/or additional transportation capacity. Sithe Global Power Goreway ULC, Sithe Global Power Southdown ULC, TransCanada Energy Ltd., Portlands Energy Centre (collectively, the GTA Generators) agreed with APPrO's position.

The consumer representatives also generally agreed that services for power generators should be considered part of the in-franchise market and regulated accordingly.

Union argued that it would not develop assets to provide these services unless the rates are deregulated. If the rates remain regulated, then Union would plan to acquire the services in the market. Enbridge explained that if the Board refrains from regulating the prices for new storage developments, it will plan to offer capacity related to the Tecumseh storage enhancement project through an open season. This project might or might not proceed depending upon the economics at the time. Regardless of whether the Board refrains from regulating in this area, Enbridge will acquire services to underpin its unbundled high deliverability storage service (Rate 316) through an open tender, and it proposed to pass through those market-based costs to customers taking the service.

Enbridge maintained that the evidence supported a conclusion that the generators themselves acknowledge that they expect to have access to competitive alternatives. Union pointed out that the generators could acquire additional space in order to achieve a higher deliverability and if the additional space is not required, it could be resold in the market.

The marketers expressed some concern with the possibility that these services would be provided at cost exclusively to generators. Nexen argued that there should be no discrimination in favour of power generators and that on the Union system the playing field should be level between marketers and other ex-franchise customers such as Enbridge and generators outside Union's franchise area. BP cautioned that the Board should not confer a competitive advantage to some players to the detriment of others as a result of forbearance or through the development of new services and identified its objective as being a level playing field with equal treatment or access.

The issue of automatic renewal rights was also raised. Enbridge indicated that it is not considering automatic renewal rights for storage contracts under its Rate 316 proposal, since that service will be acquired by Enbridge through a tender. APPrO maintained that Rate 316 is a companion service to Rate 125 and that if a customer renews its Rate 125 service, that customer should have the right to renew its Rate 316 service as well.

Board Findings

There was no disagreement that these services are needed and should be developed. The generators have convincingly expressed the importance of these types of service to the effective functioning of their operations – both physically and financially. The issue for the Board, within a section 29 context, is how best to achieve this objective. APPrO and the GTA Generators (supported by the consumer intervenors) advocated a regulated framework; the utilities argued for a competitive framework.

These services are not currently offered, indeed they need to be developed, and investments must be made in order to offer them. Union has been conducting open seasons for its new offerings and is committed to providing these services if the Board refrains from regulating them. The Board concludes that these services are substantially different from the bundled, unbundled and semi-unbundled distribution services offered by Enbridge and Union. There is demand for these services from marketers (for example, BP and Nexen) and likely others. In addition, when the capacity generators hold is excess to their needs, they expect to be able to offer this excess into the competitive market. It follows that they expect to be able to acquire these services through the competitive market as well as sell them.

The Board could order the utilities to provide these services on a regulated basis. However, the Board concludes that this would not be the best approach to ensuring the development of these services. The key consideration is to ensure that new innovative services are developed and offered into the market. The Board concludes that the best way to ensure this public interest is met is to refrain from regulating these services. This

will stimulate the development of these services, by the utilities and by other providers. The Board finds that competition in these services will be sufficient to protect the public interest.

The Board does have a duty to protect the interests of consumers using these services with respect to price and reliability and quality of service. In this context we find that the crucial factor is the availability of the service itself – namely its reliability and quality. The Board notes that Enbridge committed to offer Rate 316, whether or not the Tecumseh enhancement project goes ahead, and to price it on a cost pass-through basis. The Board expects Enbridge to fulfill this commitment. Union has proceeded with its open season, and the Board expects Union to offer these services on an open season basis, without withholding capacity. These commitments will ensure a level of consumer protection.

Pricing considerations are relevant, but the Board finds that the development of competitive options will provide appropriate price protection for these consumers. The Board will also be developing a reporting mechanism and complaint process, discussed at the end of this chapter, and we expect that parties will bring any issues of market failure to the Board's attention.

The Board will refrain from regulating the rates for new storage services, including Enbridge's high deliverability service from the Tecumseh storage enhancement project and Rate 316, and Union's high deliverability storage, F24-S, UPBS and DPBS services.

Although this issue was discussed in the context of high deliverability services, the Board finds that its conclusions have general application, namely that any new storage which is developed by the utilities will be included as part of the competitive market. The utilities will bear the risk of these investments, not ratepayers. Similarly, the Board will not regulate the rates, nor approve the contracts, arising from these investments. If

the utilities provide storage to their regulated business through these investments, the ratemaking implications of that approach will be considered in the context of a rates proceeding.

5.2.4 Forbearance in the Ex-Franchise Market

Most parties argued that ex-franchise customers should pay market-based rates. Some parties took the position that the Board could refrain from regulating the prices in this market (if the Board determined the market was competitive), and others were of the view that the Board should continue to approve market-based range rates.

For example, the Consumers Council argued that the Board should not refrain from regulating storage but that it is appropriate for the utilities to charge market rates for Transactional Services and long-term storage services to maximize revenue from the assets for the benefit of ratepayers.

Board Findings

The evidence shows that other than for in-franchise customers, the storage market is competitive. With the exception of Enbridge, the customers in this competitive part of the market (commonly referred to as ex-franchise) have been acquiring storage at market-based rates for some time. The Board sees no benefit from continuing to regulate the prices of these services; on the contrary, competition in this area is sufficient to protect the public interest. The Board will therefore refrain from regulating rates or approving contracts for Union's short- or long-term ex-franchise storage services and will refrain from regulated the rates or approving the contracts for Enbridge's Transactional Storage Services.

5.2.5 Separation of Unregulated Storage Costs and Revenues

Both Union and Enbridge proposed to separate the unregulated costs and revenues from the regulated costs and revenues using a cost allocation study. The issue is whether a cost allocation approach is sufficient, or if a greater degree of separation is

required. Further, if a cost allocation approach is sufficient, there is an issue as to whether Union's current cost allocation study is adequate.

During the oral hearing, Union's witnesses indicated that Union would be preparing a new cost allocation study as the basis for revising the allocation of the costs of its storage assets between in-franchise (regulated) and ex-franchise (unregulated). In its final argument, however, Union submitted that the cost allocation necessary to split the costs of its storage assets between in-franchise and ex-franchise has already been completed in its 2007 rates case. According to Union, that allocation would result in the total storage rate base being split as follows ($ million):

Included in regulated rate base	$380.703 (79%)
Allocated to ex-franchise activities	$102.916 (21%)
Total	$483.619 (100%)

Enbridge proposed to separate the costs and revenues associated with its Transactional Storage Services at the next rates proceeding. It was Enbridge's position that no adjustment to rate base would be required if the Board were to forbear from price regulation.

Some parties argued that a greater degree of separation was required; others argued that Union's cost allocation study was inadequate.

Energy Probe argued that accounting separation is not sufficient because the historic cost allocation work could not have anticipated the dramatic change of storage forbearance. It took the position that the Board should encourage full structural separation at least, and that ratepayers should be held harmless for any associated costs.

The Board Hearing Team also recommended that Union's transmission and storage operations should be functionally separated, and that both Union and Enbridge's regulated and non-regulated storage should be functionally separated. The Board Hearing Team was of the view that this separation is necessary to ensure the development of the competitive storage market and to encourage new entrants. However, if no separation were required, the Board Hearing Team suggested that there should be a generic cost allocation review to examine the cost allocation thoroughly and to ensure no cross-subsidization.

LIEN argued that it would be difficult to separate costs for Union's integrated storage business. In LIEN's view, the current cost allocation study may be adequate to set rates, but it is not sufficient to separate price-regulated storage from non-price-regulated storage. LIEN proposed that an alternative would be to transfer assets which are surplus to distribution needs to a separate entity at fair market value which, in LIEN's view, would put Union on an equal footing with other storage providers.

Similarly, LPMA/WPSPG argued that Union's current cost allocation is not necessarily appropriate; there may be fundamental methodology issues to be addressed and there are storage-related costs that are included in distribution costs that should be considered for allocation to Union.

Board Findings

The Board finds that functional separation is not necessary. The evidence before the Board is that it would be costly and difficult to establish a functional separation of utility and non-utility storage, and there was no evidence to suggest that there would be significant benefits from such a separation. To the extent there may be concerns regarding the integrated operations, these will be addressed through the reporting requirements set out in section 5.4.

We also conclude that Union's current cost allocation study is adequate for the purposes of separating the regulated and unregulated costs and revenues for ratemaking purposes. The Board agrees with the Board Hearing Team that it is important to ensure that there is no cross-subsidization between regulated and unregulated storage. However, the Board is content that with its findings on the treatment of the premium on short-term storage services (Chapter 7) Union will have little incentive to use the cost allocation for purposes of cross-subsidy.

The issue of Enbridge's cost allocation is addressed in Chapter 7.

5.3 CONCLUSIONS ON FORBEARANCE

In the previous sections, the Board has found that it will refrain, in part, from regulating storage rates under section 36 (as that section relates to storage) of the *OEB Act* and refrain from approving certain storage contracts under section 39(2) of the *OEB Act*. Specifically:

- The Board will refrain from regulating the storage rates or approving the contracts of new storage providers.
- The Board will continue to regulate storage rates for bundled, unbundled and semi-unbundled customers of Union and Enbridge (up to the allocated amount).
- The Board will refrain from regulating the storage rates or approving the contracts of cross-franchise, or ex-franchise, storage customers of Union and Enbridge.
- The Board will refrain from regulating the rates or approving the contracts for new storage services offered by Union and Enbridge.

5.4 REPORTING

A number of parties made recommendations regarding ongoing reporting by utilities and other storage operators. The utilities and their affiliates generally agreed to provide the type of reporting required by FERC for interstate pipelines (FERC Regulations, §284.13)

although to some extent they challenged whether it was necessary. FERC Regulation §284.13 contains requirements for regular reporting on customer and system information.

Kitchener suggested that the Board develop a Storage and Transportation Access Rule or "STAR" to ensure non-discriminatory access to storage and transportation services, following on from the Gas Distribution Access Rule.

The Board Hearing Team identified four principles in this area:

- Create a level playing field for market participants,
- Adopt rules and practices to govern affiliate behaviour that protect the public interest,
- Support open and non-discriminatory access to transmission, and
- Establish a transparent storage/transmission market so market participants can make informed decisions.

The Board Hearing Team supported the development of a STAR. It also proposed that the ARC be amended to control the interaction between the utilities and their storage affiliates and that reporting requirements be put in place for all storage providers in order to enhance transparency in the market.

Board Findings

The Board agrees with the Board Hearing Team's principles and shares the concerns related to forbearance raised by a number of parties. Specifically, in refraining from regulating storage rates or approving storage contracts, the Board must:

- Ensure consumer protection within the competitive market for storage in Ontario.
- Ensure access to Union's transportation system on a non-discriminatory basis to new and existing storage operators.

The Board concludes that it is necessary to develop appropriate operating and reporting procedures to ensure these objectives are addressed. The Board finds that Kitchener's proposal for the development of a STAR (Storage and Transportation Access Rule) has merit.

The Board will initiate a process to develop rules of conduct and reporting related to storage. The Board will ensure that the process addresses the following:

- Requirements to ensure that Union cannot discriminate in favour of its own storage operations or those of its affiliates and cannot discriminate to the detriment of third-party storage providers;
- Reporting requirements for all storage providers, although the requirements may vary as between utility and non-utility storage providers, and which may include: terms and conditions, system operating data, and customer information;
- A complaint mechanism for customers (or other market participants).

6. ALLOCATION OF STORAGE AVAILABLE AT COST-BASED RATES

Having decided that Union and Enbridge should retain regulated, cost-based rates for storage used by in-franchise customers, the question becomes how much of the existing storage space should be reserved for those customers. There are two issues arising from this allocation matter.

First, should the amount of storage available to Union's in-franchise customers at cost-based rates be fixed at an amount less than the total working gas capacity of Union's storage pools, currently 152 Bcf? Union proposed to fix the amount of existing storage allocated to in-franchise customers at the amount Union estimates those customers will use in 2007.

Second, what method should Union and Enbridge use to allocate the amount of storage available at cost-based rates to individual unbundled and semi-unbundled customers? The evidence shows that, for various reasons, many of Union's T-service (semi-unbundled) customers have been allocated amounts of storage that are inconsistent with amounts determined under Union's standard "aggregate excess" method. In addition, Kitchener argued that as a gas distributor embedded in Union's distribution system, it requires more storage space at cost-based rates than the amount calculated under the aggregate excess method.

6.1 UNION'S TOTAL COST-BASED STORAGE ALLOCATION

Union proposed to freeze, on January 1, 2007, the amount of its storage capacity available to in-franchise customers at cost-based rates. The frozen amount would be 92.1 PJ (approximately 87 Bcf), Union's estimate of in-franchise requirements for 2007.

Incremental in-franchise storage requirements due to load growth would be met by Union purchasing the required additional amounts in the market and passing through the contract costs to its in-franchise customers.

Union noted that the in-franchise storage requirement has been very stable over the past seven years, increasing from 88.2 PJ in 2000 to 90.6 PJ in 2006, an annual growth rate of just 0.45%.

In its evidence, Union explained the rationale for its proposal as follows:

> Under the current regulatory framework, any future increase to in-franchise storage requirements would be provided through a reallocation of the portfolio of storage capacity owned and managed by Union.
>
> This current practice is not appropriate as it does not reflect the fact that the storage market is competitive, nor does it encourage or support the development of new storage capacity. Specifically, Union would not be incented to assume the risk and commit the capital and resources to develop new storage capacity with economics premised on competitive market pricing, when there is a risk of this storage being reallocated in the future to meet in-franchise requirements at a cost of service rate.[35]

In argument, Union summarized the reasons for its proposal as follows:

- "Claw-back" of assets etc. allocated to ex-franchise sales would undermine development of new storage capacity premised on market pricing.
- "Claw-back" would also make cost allocation issues more complex.
- Meeting incremental demand with services sourced from competitive markets is consistent with a transition to competition and a step toward sending better "price signals" to in-franchise customers.
- This proposal will not result in "rate shock" of any kind.[36]

Kitchener, LPMA/WGSPG, Consumers Council, VECC, and IGUA/AMPCO argued that there should be no freeze on the amount of Union's storage available at cost-based

[35] Union Pre-filed evidence, Exhibit C, Tab 1, page 15.
[36] Exhibit Y2.1, outline of Union reply argument, page 4.

rates to in-franchise customers. GMi and the Board Hearing Team supported Union's proposal.

Board Findings

Under the existing regulatory framework, Union's in-franchise customers have had first call, at cost-based rates, on Union's storage capacity. Said differently, Union has sold storage services to ex-franchise customers only when it can demonstrate that the storage being sold is surplus to in-franchise needs.

From an operational perspective, it is not necessary (nor would it appear to be feasible) for Union to physically split its storage facilities between "in-franchise" and "ex-franchise" uses. And until now, Union has been able to offer storage services in the ex-franchise market without capping or freezing the amount of capacity that is available for in-franchise uses.

Giving in-franchise customers a priority call at cost-based rates on all of Union's storage may be supportable if one takes the view that every Bcf of Union's storage capacity is a "utility asset" and is required to provide "utility services." But that view needs to be re-examined in light of the evidence presented at this hearing about the development and use of Union storage in recent years, and the Board's determination that the storage market is competitive.

Amount of Union's "surplus" capacity

There is no doubt that Union's existing storage capacity far exceeds the current requirements of its in-franchise customers. Some 40% of the current capacity has been sold in the ex-franchise market. And the requirements of in-franchise customers have grown slowly (less than 0.5% per year over the past six years according to Union's evidence). The excess is so large that it would take several decades for all of the current capacity of 152 Bcf to be required for in-franchise customer needs if those needs grow at 1% per annum, and more than 100 years at the current rate of growth.

In past decisions on storage, the Board has required Union to file forecasts of storage capacity and in-franchise needs to demonstrate that space being sold to ex-franchise customers is surplus to in-franchise needs. For example, in the EBRO 494-03 decision, the Board approved four long-term ex-franchise storage contracts based on Union's 10-year forecast of capacity and in-franchise needs. The Board considered, but did not require, Union to insert a clause into the contracts that would allow Union the right of recall because the Board "found…that the Company's forecast of its in-franchise storage needs is reasonable."[37]

Union's storage development

During the hearing, a common argument from many parties on several different issues (particularly on the issue of sharing the premium on ex-franchise sales) was that in-franchise customers have "paid for" or "substantiated" the storage assets of the utilities. If true, is this a basis for continuing to grant in-franchise customers a perpetual call on all of Union's storage capacity at cost-based rates?

This argument breaks down on two fronts. First, Union's rate base excludes capital costs of storage that underpins long-term ex-franchise sales. Second, the sheer magnitude of the current surplus makes it unlikely that Union's expansion of its storage facilities in the recent past has been driven primarily, or perhaps even to any significant extent, by the anticipated needs of in-franchise customters. For example, since 1999 Union has added almost 18 Bcf of capacity through greenfield developments and enhancements to existing pools, capacity that was not necessary to cover in-franchise needs. This additional capacity has been directed to, and taken up by, the "ex-franchise" market, not distribution customers of Union.

Ex-franchise customers have contracted for Union's long-term surplus space and have paid market-based rates, rates that have been much higher than cost-based rates. Rather than bearing the costs of surplus Union storage space that is offered long-term

[37] EBRO 494-03 Decision with Reasons, September 26, 1997, paragraph 2.2.29.

to the ex-franchise market, Union's in-franchise customers have in fact benefited through receiving most of the premium on long-term sales.

Union's rationale

Union claims that development of new storage capacity would be undermined unless the amount of storage allocated to in-franchise customers is capped. This claim appears to have little merit. First, no party to this proceeding has opposed market rates for new storage capacity by third parties. Second, a freeze on space for in-franchise customers would have a neutral effect on the development of the competitive market. This was illustrated by LPMA/WGSPG, which put forward the following scenario in its argument: Assume the incremental storage requirement for the in-franchise customers is, say, 2 Bcf in a particular year. Under Union's proposal, Union would purchase that 2 Bcf from third-party providers. Under the existing framework, that 2 Bcf would be supplied by Union, leaving it with 2 Bcf less for ex-franchise sales. That 2 Bcf shortfall could be provided by third-party providers. The net impact on third-party providers is 2 Bcf of additional storage in either case.

Union also claims that meeting incremental in-franchise demand at market prices is consistent with a "transition to competition" and would send "better price signals to in-franchise consumers." No one in this proceeding, however, has advocated that any in-franchise customers, except for some of the largest gas customers, should be obligated to take a service that might require them to participate directly in the competitive storage market.

GMi, currently Union's largest ex-franchise customer, and Nexen expressed concerns about "claw-back" that the Board finds more compelling than Union's argument. GMi opposed any storage allocation rules that could result in "clawing back storage capacity held by ex-franchise customers for the benefit of in-franchise consumers." It said it would view any such measure as unfair discrimination. Nexen submitted that "claw-back" of storage services from ex-franchise customers would be "discriminatory and

detrimental to not only GMi but to the very existence of the secondary market that Ontario currently supports and benefits from."

Conclusion

The Board finds that there should be a cap on the amount of Union's existing storage space that is reserved for in-franchise customers at cost-based rates. In the Board's view, Union's existing storage assets are, in substance, a combination of "utility assets" required to serve Union's in-franchise distribution customers and "non-utility assets" that are not required for regulated utility operations and that are sold in the competitive storage market. This distinction is supported by the significant excess of total capacity over in-franchise needs for the foreseeable future and by the fact that development in recent years has been driven by the ex-franchise market, not in-franchise needs. The Board does not accept IGUA/AMPCO's submissions that the entire amount of Union's storage is a "utility asset" and that ex-franchise customers (such as gas marketers and utilities in the U.S. Northeast) are buying "utility services" when they purchase storage from Union. The Board has determined that the ex-franchise market is competitive and that it will refrain from rate regulation or contract approval; these will no longer be "utility" services.

The Board concludes that its determination that the storage market is competitive requires it to clearly delineate the portion of Union's storage business that will be exempt from rate regulation. Retaining a perpetual call on all of Union's current capacity for future in-franchise needs is not consistent with forbearance. As evidenced by the arguments from GMi and Nexen, two major participants in the ex-franchise market, retaining such a call is likely to create uncertainty in the ex-franchise market that is not conducive to the continued growth and development of Dawn as a major market centre.

The Board concludes that it would be inappropriate, however, to freeze the in-franchise allocation at the level proposed by Union. Union's proposal implies that a distributor with an obligation to serve would be prepared to own, or to have under contract, only the

amount of storage needed to serve in-franchise customers for just the next year. In the Board's view, it is appropriate to allow for some additional growth in in-franchise needs when determining the "utility asset" portion of Union's current capacity.

The Board acknowledges that there is no single, completely objective way to decide how much should be reserved for future in-franchise needs. The Board has determined that Union should be required to reserve 100 PJ (approximately 95 Bcf) of space at cost-based rates for in-franchise customers. This compares with Union's estimate of 2007 in-franchise needs of 92 PJ (87 Bcf). At an annual growth rate of 0.5% each year, which Union claims is the growth rate since 2000, in-franchise needs would not reach 100 PJ until 2024. The limit would be reached in 2016 if the annual growth is 1%; at a very annual high growth rate of 2% per annum, the 100 PJ limit would be reached in 2012.

The 100 PJ (95 Bcf) amount is the capacity that Union must ensure is available to in-franchise customers if they need it. Union should continue to charge in-franchise customers based on the amount of space required in any year. If Union's in-franchise customers require less than 95 Bcf in any year, as measured by Union's standard allocation methodology, the cost-based rates should be based on that amount, not on the full 95 Bcf reserved for their future use. Union will have the flexibility to market the difference between the total amount needed and the 95 Bcf reserve amount.

6.2 ALLOCATION OF COST-BASED STORAGE: METHODOLOGY AND APPLICATION

Union and Enbridge have developed methods of allocating cost-based storage space to their in-franchise customers – both bundled customers as a group, and individual unbundled and semi-unbundled (T1 and T3) customers. The amount allocated currently has two implications for customers:

- It is the basis for determining how much a customer will be charged at cost-based rates.
- For unbundled or semi-unbundled customers, the amount is the maximum amount of cost-based storage to which they are entitled. Any storage they demand above the allocated amount must be procured at market-based rates.

In Union's case, the allocation methodology will take on greater significance in the future because it will also be used to determine when in-franchise needs exceed the 100 PJ of Union storage reserved for in-franchise customers.

The issues addressed in this section are:

- Should Union and Enbridge continue to use their current methods to determine the amount of cost-based storage allocated in total to customers taking bundled service?
- What method should be used to allocate cost-based storage to unbundled and semi-unbundled customers? Should a single method be used consistently by both Union and Enbridge or should the Board permit variations or exceptions?

6.2.1 Aggregate Excess Method – Bundled Service

Union has used the "aggregate excess method" since 2000. This method, which was approved by the Board in RP-1999-0017, calculates a standard amount of storage space to meet seasonal load balancing needs. It involves a comparison of forecast gas consumption in the winter (the five months November through March) with gas consumption for an entire year. Total winter consumption is forecast assuming normal weather conditions. The formula can be expressed:

Aggregate excess = Total winter consumption – [(151/365)* (Total annual consumption)]

To simplify the computation of overall storage needs for bundled customers, Union has developed standard aggregate excess volumes for residential customers in each of its operations areas. The calculation of the space required to serve bundled commercial and industrial M2 customers is also simplified by applying a standard percentage to those customers' forecast annual consumption.

Union reduces the total aggregate excess amount for bundled customers by 2.4% to recognize that not all of the bundled customers have the load profiles assumed by the aggregate excess method. Some bundled customers consume more gas in the summer than the winter, which reduces the amount of storage space Union needs to manage seasonal load balancing for its portfolio of bundled customers.

Kitchener raised concerns with respect to the aggregate access method, particularly in respect of its own storage allocation, and VECC echoed Kitchener's concerns. This issue is dealt with separately later in this chapter. No other party objected to Union continuing to use its "aggregate excess method" to determine total storage requirements for bundled customers.

Enbridge indicated it uses the same methodology as Union except that it uses 121 days for "rate-making purposes." At the Technical Conference, Enbridge indicated that it is "open to using the actual withdrawal cycle period, which is 151 days."

Board Findings

The Board accepts the continued use of the aggregate excess method by Union to determine the total storage space it requires to manage the seasonal load balancing needs of bundled customers.

Based on the evidence in this proceeding, it not clear that there is a single "official" aggregate excess method policy document in which Union outlines the calculation, the source of the inputs, how the method is to be applied in each of its operations areas,

and how Union validates the appropriateness of its 2.4% reduction factor. Given the Board's decision to "freeze" total in-franchise cost-based storage, it will be increasingly important that all stakeholders have a common understanding of exactly how the method works in all circumstances. The Board directs Union to file such a policy document within 90 days of this decision. The policy should also cover the issues addressed in the next section of this decision, namely the application of the allocation method to individual customers.

Enbridge appears to use a generally similar method although there was no detailed evidence filed on Enbridge's calculation at this hearing. The Board therefore also directs Enbridge to file an aggregate excess policy document with the Board within 90 days of this decision. Enbridge should also address the application of the allocation method to individual customers.

In order to ensure consistency where it is warranted, the Board will consider whether to pursue these matters on a generic basis.

6.2.2 Storage Allocation – Unbundled and Semi-unbundled Customers

There was considerable debate in this proceeding about using the aggregate excess method for allocating cost-based storage to individual unbundled and semi-unbundled (Union T1 and T3) customers. We first address the issue generally. We then address the specific issues which arise for gas-fired generators and Kitchener. While this issue has immediate application for Union, because it has customers taking semi-unbundled service, it will also be relevant for Enbridge because the Board is approving new unbundled rates as part of this proceeding, and Enbridge expects that there will be migration to these new rates.

Union has not consistently applied a single method to allocate cost-based storage to in-franchise customers taking semi-unbundled and unbundled service. The official position seems to be that Union uses the aggregate excess method. It became clear during the

hearing, however, that many T1 and T3 customers have been allocated amounts of storage that are considerably different than amounts derived from an aggregate excess calculation.

Union produced a document showing that 44 T1 customers, over half of Union's T1 customers, and one T3 customer (Kitchener) have been permitted to contract for volumes of cost-based storage that differ from the amounts that would be allocated under the aggregate excess method. Nine of the 44 T1 customers listed have contracts for quantities less than the aggregate excess amount. The other 35 T1 customers and Kitchener have more (and in many cases, significantly more) cost-based storage space under contract than would be permitted if the aggregate excess method were followed. For example, one T1 customer has a storage contract for 1,434,120 GJ but its aggregate excess amount is only 139,902 GJ. Another has a contract for 1,100,000 GJ but an aggregate excess amount of zero.

Union indicated there are three reasons for the differences:

- The cost-based storage allocations of 21 customers that were on T1 service before June 7, 2000 were "grandfathered" by the settlement agreement approved by the Board in RP-1999-0017. The contract quantities were not required to be adjusted to the customer's aggregate excess amount.
- The amount of the cost-based storage under contract generally does not get changed at the time of the annual contract renewal even when the customer's updated consumption profile results in a higher or lower aggregate excess amount. The reason for this is that the only "trigger" for a revision to a storage quantity at the annual renewal date is a five percent increase or decrease in Contract Demand (maximum daily gas demand as agreed between the customer and Union). A change in consumption profile, by itself, has no effect on the amount of storage under contract. Union pointed out that using the

change in Contract Demand as the trigger to amend storage contract quantities was agreed to in the RP-1999-0017 settlement agreement.

- At least three of the T1 customers that have contract quantities above aggregate excess amounts are gas-fired generators that have multi-year storage contracts with firm space and deliverability amounts.

Union proposed no changes to the way in which storage is currently allocated to in-franchise customers at cost-based rates.

IGUA/AMPCO submitted that the guiding principle should be to allocate to customers a sufficient amount to meet "reasonable load balancing requirements." For large volume customers, they argued that the allocation methodology should be as flexible as it has been in the past and that the grandfathering under the RP-1999-0017 settlement agreement should be preserved on the grounds of estoppel. IGUA/AMPCO said no changes in allocations should be made without customer consent.

The Board Hearing Team supported using the aggregate excess method for allocating cost-based storage to individual unbundled and semi-unbundled customers. The Board Hearing Team advocated adjusting the contract quantities of all existing T-1 contracts to the aggregate excess amount at the next contract renewal date. It also proposed, however, that a T1 customer that requires more storage than calculated by the aggregate excess method should make a case to its utility. Under that approach, any departure from aggregate excess would have to be submitted to the Board for approval.

Board Findings

The Board concludes it is essential that there be clear, standardized, and consistently applied rules for allocating cost-based storage to unbundled and semi-unbundled in-franchise customers. These types of rules clearly are not in effect today. The current allocations to a large proportion of Union's T1 and T3 customers bear no resemblance to aggregate excess volumes due to: the "grandfathering" process endorsed in RP-

1999-0017; the lack of an effective mechanism to adjust contract volumes for changed customer circumstances; and, some “non-grandfathered” T1 storage contracts with volumes that may have been at odds with the aggregate excess method even at the time the contracts were first negotiated.

The Board supports the continued use of the aggregate excess method as the default method for allocating cost-based space. That method is clearly designed for customers with the traditional seasonal load balancing need and fits well with the storage needs of many unbundled or semi-unbundled customers. But it appears that the storage requirements of at least some of the larger industrial and commercial customers may have little or nothing to do with seasonal load balancing. Allocating cost-based storage using a method that is based on assumptions that are materially at odds with a customer’s circumstances, in the Board’s view, would be unfair and unsupportable. Therefore, the Board concludes it is necessary to consider whether one or more additional allocation methodologies should be developed for cases where the aggregate excess method is clearly inappropriate.

Board does not, however, support a unique allocation approach for each customer. In the Board’s view, the objective of allocation of cost-based storage space is to assign an amount that is reasonably in line with what a customer is likely to require. The objective is not to allocate precisely the amount a particular customer claims it might need. That would require in-depth knowledge of each customer’s expected consumption, its gas supply portfolio, and the non-storage options (such as spot gas purchases) the customer might use to manage its needs. That would be impractical for the utilities to implement, both administratively and because it would never be possible to determine that one, and only one, allocation of storage is the “right” amount for any particular customer. Unbundled or semi-unbundled in-franchise customers that desire more storage than allocated to them by the utilities under the standard method(s) have the ability, as they do today, to purchase additional storage services at market-based rates or alternative services in the market.

The Board is not ordering any change in the contract quantities of T1 customers at this time for the following reasons:

- First, although it appears likely that one (or more) additional allocation methods may be necessary, the Board does not have enough information to reach a firm conclusion. Further evidence is required.
- Second, the Board is conscious that many of the existing contracts with volumes above the aggregate excess amounts have been in effect for several years. The Board does not accept the estoppel argument advance by IGUA/AMPCO, but even if one or more appropriate additional allocation methodologies were already developed, any changes to contracts should be done in a controlled and deliberate manner.

The Board does want to have better allocation rules developed in the near future. To further that objective, the Board orders Union (a) to review the use of storage by existing T1 customers to determine the extent to which their storage needs are not driven by traditional seasonal load balancing, (b) to develop one or more storage allocation methods that would result in better estimates of certain customers' needs than the aggregate excess method, and (c) submit within 90 days a proposed storage allocation policy for Board review that details the aggregate excess method and the proposed new method(s), including the circumstances in which each allocation model would be applicable.

Enbridge currently has only one customer taking unbundled service but it is likely that more customers will opt for unbundled service in the future. The Board therefore directs Enbridge to file, within 90 days, the methodology or methodologies it proposes to use to allocate cost-based storage to unbundled customers.

In order to ensure consistency where it is warranted, the Board will consider whether to pursue these matters on a generic basis.

6.2.3 Storage Allocation – Gas-Fired Generators

All parties in this proceeding recognized that the operators of dispatchable gas-fired power plants have very different needs for gas storage than the typical gas user that has seasonal load balancing needs. Several aspects of enhanced services for gas-fired generators were settled by the parties before the oral hearing started. Rate issues related to high deliverability storage services were not settled; however, there was a settlement on how much 1.2% deliverability storage should be made available at cost-based rates.

The Enbridge and Union Settlement Proposals take different approaches to the allocation of standard storage space to gas-fired generators. The portions of the Settlement Proposals that describe the agreed allocations are set out below.

> **Enbridge Settlement Proposal**
> Currently, the Company's customers only receive an allocation of cost-based storage at standard deliverability that meets 57% of the gap between system peak demand and the amount of gas delivered through pipeline supplies. The remainder of this gap is met through other balancing means such as peaking supplies and curtailment. In order to achieve consistency, the Company will limit the storage allocation available to gas fired generators to the same level, such that the allocation of storage at standard deliverability to gas fired generators will be scaled to 57% of the amount of storage at standard deliverability required to meet the gap between demand and pipeline supply. (Page 23)
>
> The allocation for gas fired generators for cost-based storage at 1.2% deliverability is as follows:
>
> (g) A gas fired generator is assumed to provide gas supply equal to 17 times the maximum hourly demand of the facility. In the event that the plant is not dispatched, up to 17 hours of supply may need to be injected into storage, assuming that storage is the only means of balancing available.
> (h) Assuming that high deliverability storage at 10% is available to meet the gas fired generator's needs, this would result in a space demand of 17 times the maximum hourly demand, divided by 10%.

(i) The space demand is then multiplied by .57 to determine the amount of cost-based standard storage at 1.2% deliverability available to the gas fired generator. (Page 24)

Union Settlement Proposal

The parties agree that new T1 and U7 customers with non-obligated supply shall be entitled to contract for T1 and U7 storage service with firm storage deliverability up to 24 times the customer's peak hourly consumption and storage space up to 24 times the customer's peak hourly consumption multiplied by 4 days. Should a customer elect to contract for firm storage deliverability that is less than the maximum entitlement, the maximum storage space that a customer is entitled to at cost shall be ten times the firm storage deliverability contracted for. In no event, shall the storage space exceed the maximum storage space entitlement previously described. Storage space with 1.2 % deliverability will be available at cost-based rates. Storage deliverability above the base firm deliverability of 1.2% up to the customer's firm CD shall be made available by Union to in-franchise customers in a manner to be determined by the Board as part of Issue No.2 [to Procedural Order No.2] (Pages 14 and 15)

Board Findings

The Board approved the Settlement Proposals with the cost-based storage allocations described above. The Union and Enbridge approaches to this issue are obviously somewhat different. The Board considered whether to carry out a detailed comparison of the proposed allocation methods to determine if greater consistency between the Enbridge and Union methodologies could be achieved. The Board has decided that step is not necessary. The developers of all the proposed Ontario dispatchable gas-fired facilities participated in the settlement process and were parties to the Settlement Proposals (directly or through their trade association). The Board also recognizes that the allocation of 1.2% deliverability space at cost-based rates is tied to some extent to the individual proposals of each utility for high deliverability storage.

The Union approach to allocation of cost-based space is available only to new T1 and U7 customers with non-obligated supply. During the hearing, the Board became aware that three operating gas-fired generators in Union's territory have multi-year T1 contracts for amounts of cost-based storage significantly greater than the amounts

calculated by the aggregate excess method. The evidence in this hearing indicated that those contracts were not among the pre-June 7, 2000 contracts that were "grandfathered" by RP-1999-0017. The Board does not know the basis on which the storage allocations for these three customers were determined. We also do not know the extent to which the contracted storage amounts exceed the amounts that would be available were the generators to be subject to the new allocation rules contained in the Union Settlement Proposal.

The Board concludes that in the future, allocations of cost-based storage should be made using clear, standardized rules that are consistently applied. If there are to be non-standard allocations, it is important that the Board understand the circumstances and be satisfied that any such exceptions are justified. As indicated in section 6.2.2, the Board has ordered Union to analyze the use of storage by existing T1 customers to determine if one or more allocation methodologies should be developed to deal with cases where the aggregate excess method is clearly inappropriate. As part of that work, the Board directs Union to file with the Board, on a confidential basis if necessary, the terms and conditions of these three contracts, the basis for the storage allocations, and the terms and conditions of any other multi-year T1 storage contracts.

6.2.4 City of Kitchener

Kitchener intervened in these proceedings to question the appropriateness of the aggregate excess methodology as it applies to embedded utilities in general and Kitchener in particular.

Kitchener owns and operates a gas distribution utility connected to Union's system. The rates Kitchener charges its approximately 60,000 customers are not subject to regulation by the Board.

Until 1999, Kitchener was a Rate M9 system gas customer. In 1999, it switched from Rate M9 to Rate T3 and negotiated a cost-based storage allocation of 89.3 million m^3

(3.37 million GJ). That initial T3 storage contract expired in 2005. Since then, Kitchener has received two Board-approved one-year extensions at the same contract volume.

The current contract expires March 31, 2007 and Kitchener is seeking a long-term storage contract with Union effective April 1, 2007. It is concerned that its allocation of cost-based storage in a new contract will be restricted to the amount calculated under the aggregate excess method. Kitchener's current aggregate excess amount is 3.01 million GJ, 10.6% lower than the amount of cost-based storage in its current contract

In this proceeding, Kitchener claimed that the aggregate excess method does not provide sufficient cost-based storage space for a gas distributor like Kitchener. It argued for an allocation of cost-based storage space that:

- Provides Kitchener with full deliverability from storage on March 1, recognizing the contractual requirement of Kitchener to maintain a minimum storage balance of 20% for maximum firm deliverability, and
- Provides Kitchener with a reserve on March 31 to enable it to manage temperature risk for the first two weeks of April.[38]

In the alternative, Kitchener argued that if the Board continues to approve the grandfathering of storage volumes in certain T1 contracts, it should extend the grandfathering to the amount of storage space in Kitchener's current T3 contract.

Kitchener made a number of arguments about why it believes the aggregate excess method is the wrong way to calculate its allocation of cost-based storage space. Kitchener's main objection seems to be that the aggregate excess method assumes "normal" weather. Kitchener says the allocation of cost-based space for an embedded distributor must provide for the possibility of a colder than normal winter and provide

[38] In its pre-filed evidence and during the oral hearing, Kitchener also put forward the idea that it should receive a proportionate share of Union's system integrity space. In its final argument, however, Kitchener withdrew that proposal.

protection for a cold snap after March 31.[39] Kitchener also asserted that the aggregate excess method understates the amount of storage required by Union itself to serve its bundled customers and that Union rectifies that problem by purchasing winter gas. Kitchener charged that such a strategy results in significant additional costs for Union's system gas customers.

Union supported the continued use of the aggregate excess method and argued against Kitchener's proposals. Union stated that Kitchener is confusing the issue of managing gas supply inventory during the winter months to meet a design day with the issue of allocation of physical storage space based on a seasonal requirement for storage.

Union pointed out that Kitchener acknowledges there has been only one occasion in the past five years when Kitchener's storage allocation was insufficient. On that occasion, Kitchener avoided any overrun charges by purchasing incremental gas. Union also observed that Kitchener has the option to contract to have Union provide the March 1 deliverability inventory if it so chooses. If it chose this option, Kitchener would no longer have to maintain 20% inventory on March 1.

Board Findings

In section 6.2.2, the Board expressed its view that the objective of the allocation of cost-based storage to unbundled and semi-unbundled customers is to assign an amount that is reasonably in line with what a customer is likely to require; the objective is not to allocate precisely the amount that a particular customer claims it might need. The Board also acknowledged that the seasonal balancing assumption that underlies the aggregate excess method might be materially at odds with the way that some

[39] Kitchener also made submissions on some problems with the way cost-based storage has been allocated to Union's T1 customers, including the deviations from aggregate excess that were grandfathered by the Board. Some of Kitchener's general concerns about the aggregate excess methods are addressed in section 6.2.2 of this decision.

customers use storage. The Board has directed Union to develop one (or possibly more) allocation methods that can be used to allocate storage to those customers.

The issue is whether Kitchener has made a compelling case that its use of storage is so different from the assumed use underlying the aggregate excess method that Union should be required to develop an allocation method just for Kitchener. The Board finds Kitchener has not successfully made that argument.

Kitchener acknowledges that it requires storage for seasonal load balancing, which is consistent with the assumptions of the aggregate excess method. Kitchener's circumstances are vastly different from those of dispatchable gas-fired generators, for example, a class of customer that everyone acknowledges does not use storage for seasonal load balancing.

The Board does not agree that the allocation of cost-based storage should be determined assuming colder than normal weather or that it should be designed to provide protection against a cold snap in April. To do so would result in in-franchise customers as a group being allocated more cost-based storage than they are expected to use in most winters. As noted in section 6.2.2, the Board concludes that the objective of the allocation of cost-based storage space is to assign an amount that is reasonably in line with what a customer is likely to require. In the Board's view, that supports continuing the assumption of normal weather.

The Board does not see the relevance of Union's gas supply plan to an allocation formula used to assign cost-based space to unbundled or semi-unbundled customers. Kitchener argued that Union "makes no attempt to produce a least cost [gas] supply plan which optimizes the level of cost based storage for in-franchise customers." The argument seems to be that if Kitchener's "least cost supply plan" advice were followed, Union would allocate more cost-based space to its bundled in-franchise customers, which would then cause Union to realize that all in-franchise customers should also get

more cost-based storage. In the Board's view, the method of allocating cost-based storage should not be linked to any specific gas supply plan. The aggregate excess method is based on the simple – and for most customers, realistic – assumption that natural gas is delivered from the supply regions in equal amounts each day of the year. The cost-based storage allocation is then derived from a particular customer's usual winter consumption.

The Board is not going to order that the amount of storage under contract to T1 customers be revised until the Board receives and considers information from Union on its development of one or more additional allocation methodologies, as described in section 6.2.2. That is unlikely to be completed by April 1, 2007, the date Kitchener's current contract expires. The Board will direct Union to renew Kitchener's storage contract for an additional year at current volumes to ensure that Kitchener receives equitable treatment with the other T1 customers which may have their storage allocations adjusted. This extension should not be interpreted as an indication that the Board intends to revisit the storage allocation method for Kitchener.

7. TREATMENT OF THE PREMIUM ON MARKET-BASED STORAGE TRANSACTIONS

Union and Enbridge ratepayers have received a significant portion of the premium over cost-based rates that results from the sale of storage services to ex-franchise customers at market-based rates. Chapter 2 provided information on the magnitude of the margins in recent years and the basis on which these margins are shared between the utilities and ratepayers. Union's ratepayers have received 90% of the forecast margins related to both long-term ex-franchise sales (contract terms of two years or more) and short-term transactions (contract terms of less than two years). Ratepayers also receive 75% of any margins that are greater than forecast amounts. Enbridge ratepayers have received approximately 75% of Enbridge's Transactional Services margins.

Union proposed to end the sharing of long-term and short-term margins with ratepayers. Specifically, Union proposed that the Board adjust distribution rates effective January 1, 2007, to exclude all storage costs and revenues associated with ex-franchise sales from 2007 rates and to eliminate five existing storage and transportation deferral accounts that currently capture market-based margins in excess of amounts incorporated into rates. Union has forecast 2007 margins at $29.9 million (long-term) and $14.6 million (short-term).

Enbridge also proposed to end margin sharing with ratepayers. It is seeking approval to exclude revenues and expenses associated with Transactional Storage Services from its distribution rates commencing in 2007. All Transactional Storage Service revenues, forecast to be $5 to $6 million in 2007, would accrue to Enbridge. The costs to be excluded from distribution rates in 2007 would be some portion of the approximately

$800,000 of O&M costs of Enbridge's Transactional Services business. Enbridge proposed to continue to include the entire net book value of its storage facilities in rate base.

The Board Hearing Team and Energy Probe supported the Union and Enbridge proposals. LPMA/WPSPG, Consumers Council, LIEN, VECC, IGUA/AMPCO, and Schools generally objected to any change in how margins are shared.

7.1 MARGINS ON SHORT-TERM STORAGE TRANSACTIONS

During the hearing, most parties presented views on the rationale for requiring the utilities to credit most of their storage margins to ratepayers. Several parties opposing the Union and Enbridge proposal to cease margin sharing referred to earlier Board decisions that they believed supported margin sharing.

The Board first dealt with margin sharing in the context of Union's short-term storage services, which Union started to sell at market-based rates in 1989. In 1996, the Board considered essentially the same issue when Enbridge proposed to start marketing its Transactional Services more aggressively and retain some of the margin. The Board has expressed a consistent view that Union's short-term storage transactions and Enbridge's Transactional Services involve sales at market-based rates of services derived from utility assets that are temporarily surplus.

In its decision in EBRO 492, dated September 10, 1996, the Board stated:

> The Company [Enbridge] stated that the objective of offering transactional services is to make additional use in off-peak periods of the Company's physical and contractual storage and transportation assets acquired in the first place to serve the in-franchise customers. [Paragraph 3.3.2, emphasis added]
>
> The Board does not agree that an incentive to provide these services should be necessary, and notes that the Company has offered both peak and off-peak services, along with assignments and exchanges in prior years without

> the need for an incentive. However, the Board acknowledges that the Company does incur some risk associated with its participation in these activities, and finds that a 10 percent incentive will be adequate to address these modest risks. [Paragraph 3.3.30]

In 1997, the Board for the first time approved Union entering long-term storage contracts at market-based rates with ex-franchise customers. In its decision in EBRO 494-03 dated September 26, 1997, the Board described the basis for allowing Union's short-term transactions as follows:

> Short-term storage for ex-franchise customers has been marketed on the basis that it is space required to provide in-franchise service. Due to weather and other variables part of the space is temporarily surplus to in-franchise needs. Customers already pay the costs of this storage in rates. Any revenue from short-term sales of storage services that is beyond the direct marginal cost to provide the service is a benefit to in-franchise consumers. [Paragraph 2.3.19, emphasis added]

Board Findings

The Board concludes that its decision to refrain in part from regulating rates for storage services does not invalidate the basis for sharing margins with ratepayers on short-term deals. Union's short-term storage transactions and Enbridge's Transactional Services storage sales are sales of services derived from utility assets that are temporarily surplus to in-franchise needs. The Board concurs with VECC's final argument on this point:

> In Union's case, the assets underpinning the short-term storage and balancing services sold in the ex-franchise market are presently included in rate base. In the case of Enbridge, all of the assets underpinning their transactional services sold in the ex-franchise market are included in rate base. As stated earlier, VECC views it as highly inappropriate for the utilities to seek the entire margin associated with these assets given that they have been "substantiated" by captive ratepayers who have paid in rates for the full opportunity cost of the associated capital investment (including a fair return on equity) along with overhead costs and direct operational costs associated with providing the services. In VECC's view, the utilities should be required to provide a rationale for receiving any of the associated margins given their earlier mentioned obligation to optimize the use of utility assets. [Page 16]

Requiring the utilities to share these margins with ratepayers is not in any way inconsistent with a finding that the storage market is competitive. The basis for sharing these margins is the nature of the assets that underpin the transactions, not the prices at which the transactions occur.

The Board finds that the entire margin on storage transactions that are underpinned by "utility asset" storage space, less an appropriate incentive payment to the utilities, should accrue to ratepayers. Ratepayers bear the cost of that space through the regulated storage rates and should benefit from transactions that utilize temporarily surplus space. The Board finds that shareholders will retain all of the margin on short-term transactions arising from the "non-utility" storage space.

Short-term margins derived from "utility assets"

The decision to require Union to notionally divide its existing storage into two pieces – a "utility asset" (maximum of 100 PJ) and a "non-utility asset" (the balance of Union's capacity) is set out in Chapter 6. Union's storage facilities will not be physically split into two pieces and Union is likely to continue operating its storage assets in much the same way as it does today. Union presumably will determine its ability to execute short-term deals based on the amount of temporarily surplus space in the entire storage facility. As long as the utility and non-utility storage is operated as an integrated asset, it will not be possible to determine that any particular short-term transaction physically utilizes space from either the "utility asset" or the "non-utility asset."

Given the impossibility of physically linking a short-term transaction to a specific slice of storage space, the Board considered other methods of determining the amount of storage margins that should accrue to Union's ratepayers. The Board has decided that the calculation should be based on how the costs of the storage facilities are split between the utility and non-utility businesses. Specifically, Union's revenues in any year from short-term storage transactions, less any incremental costs incurred by Union to

earn those revenues, should be shared by Union and ratepayers in proportion to Union's allocation of rate base between utility and non-utility assets.

As indicated in Chapter 5, the allocation is currently 79/21 utility/non-utility. Union's existing policy on what constitutes a short-term storage transaction will continue to apply. As and when Union requires more capacity for in-franchise needs (up to the 100 PJ cap) or adds storage capacity or enhances deliverability of its storage facilities, the cost allocation will presumably change. Once a revised cost allocation has been approved in a Union rates case, the basis on which margins on short-term storage transactions are shared will also change.

All of Enbridge's current storage assets (storage facilities and contracts) are required to serve its in-franchise customers. Thus, all of Enbridge's storage-related transactional services revenues today are derived from "utility assets." If and when Enbridge increases the capacity of its Tecumseh storage facilities, it will be necessary for the company to adopt a method of allocating storage-related Transactional Services revenues between utility and non-utility assets.

Incentive payments to utilities for short-term transactions

The Board has considered whether to continue allocating a portion of the margins from short-term transactions to the utilities as an incentive to optimize the use of the "utility assets" of each company.

The Board has decided that Enbridge should continue to share in margins on Transactional Services storage deals. Eliminating any sharing would leave Enbridge with no financial incentive to market temporarily surplus storage space. An incentive mechanism aligns Enbridge's interest with the interest of ratepayers. The size of the incentive is a matter of judgement and that issue has been debated in several past rates cases. The Board finds that the current 25% incentive is excessive given that ratepayers bear all of the costs of the existing storage assets. The Board believes a

10% incentive is sufficient. In the future, 10% of the storage component of Enbridge's Transactional Services revenue, less any incremental costs incurred by Enbridge to earn those revenues, will be for the account of Enbridge. The remainder will be for the benefit of ratepayers. As a result, Enbridge will not be required to separate its revenues and costs for Transactional Storage Services.

With respect to Union, an argument might be made that an incentive is not necessary. Union will receive margins from short-term storage deals that are deemed to arise from the "non-utility" portion of its storage facilities. Thus, Union will already be motivated to maximize the revenues on all short-term transactions. The Board has decided, however, that it would be appropriate for Union and Enbridge to be treated consistently and to each receive 10% of the net revenues deemed to arise from the "utility asset" portion of storage.

The Board is currently undertaking a process to determine a multi-year incentive ratemaking framework for Union and Enbridge. That process will address how best to implement the Board's findings on the sharing of short-term storage transaction margins within an incentive ratemaking framework. Enbridge's 2007 rates case is in progress; the Board's finding with respect to short-term margin sharing will be implemented through that proceeding.

7.2 MARGINS ON UNION'S LONG-TERM TRANSACTIONS

Margins on both Union's short-term storage transactions and its long-term deals historically have been shared with ratepayers in essentially the same way. Although the Board has devoted considerable time to long-term contracting issues in past Union cases, it has not determined that margins on the two types of transactions should be shared on fundamentally different bases. In its decision on Union's 2000 rates (RP-1999-0017), the Board described the rationale for sharing the margins on all of Union's storage sales:

> The Board recognizes that the assets necessary to provide both transactional services and long-term storage services have been paid for by Union's customers. Providing that the Company has a financial incentive to maximize revenues for these services should increase the benefits to both the customer and the shareholder. Consequently the Board authorizes a sharing of net revenues for transactional services and market premium for a long-term storage services in the ratio of 75:25 between ratepayer and shareholder as an incentive to maximize the revenue associated with both these services. [Paragraph 2.505]

Union's rationale for the sharing of storage margins has changed over time. In 1996, when it was unsuccessful in obtaining Board approval for long-term storage sales at market-based rates, Union had submitted that all of the margins would be credited to ratepayers "since in-franchise customers had paid for the development of the storage." In Union's 2000 rates case (RP-1999-0017), the Board noted that "Union's position was that ratepayers have paid for the services from the assets, not for the assets themselves." This is the position that Union advanced in this proceeding.

IGUA/APMCO claimed Union is estopped from changing its position on margin sharing. The argument is that the Board was persuaded to allow market-based rates on the condition that the bulk of the proceeds would go to the ratepayer. Accordingly, IGUA/AMPCO argued that it is now improper for Union to change its mind and to argue that these proceeds now need to go to the shareholder in order to promote the development of new storage.

Board Findings

The Board has determined that storage space in excess of the amount made available at cost-based rates (which is to be capped at 100 PJ – see Chapter 6) can be considered a "non-utility" asset. This is the space that will support Union's long-term storage sales. The Board finds that profits from new long-term transactions should accrue entirely to Union, not to ratepayers.

In comparing this decision with the past Board decisions on the sharing of margins on long-term storage sales, it is important to remember the context in which the Board made its earlier decisions. Until this proceeding, the Board had never reviewed the state of competition in storage and had not considered whether to refrain, in whole or in part, from regulating storage prices. Thus, there was little basis for the Board to treat the margins on short-term and long-term sales differently. Further, the Board's decision in RP-1999-0017 to allow all then existing cost-based contracts with ex-franchise customers to be renewed at market rates has resulted in a substantial growth in long-term margins, margins that have been largely for the benefit of ratepayers. It is certainly not possible today to assert that ratepayers have "paid for" the space that underpins Union's long-term storage contracts.

The Board does not accept IGUA/AMPCO's estoppel argument. Estoppel as a principle of contract law is sometimes called "detrimental reliance". IGUA/AMPCO's theory seems to be that when the Board made its decision on the sharing of long-term margins it relied upon an undertaking by Union to continue the sharing. Perhaps that might have been part of the Board's rationale at the time but the Board itself has now questioned the continuing need for the practice and whether the rationale developed at that time continues to exist.

This after all, is the purpose of section 29. Section 29 requires the Board to re-examine the need for regulation or the degree of regulation where market structures have changed. This Board in the Natural Gas Forum Report recognized that market conditions in energy markets have in fact changed. When such changes occur, regulators, particularly those such as the Board and the CRTC with statutory forbearance mandates in their governing legislation, must re-examine the regulatory construct in light of the current market conditions. That is what this proceeding seeks to accomplish. The concept of estoppel has no meaning in such a framework.

7.3 TRANSITION RELATED TO LONG-TERM MARGINS

IGUA/AMPCO and LPMA/WGSPG argued that in the event the Board decides to eliminate the sharing of any margins with ratepayers there should be some mitigation. As a precedent, LPMA/WGSPG referred to the 2003 decision by the Board on the phase-out of the Delivery Commitment Credit (DCC). There the Board recommended a five-year period based on a cost increase of 11.3 cents per GJ on a specific class of customers. LPMA/WGSPG argued that the phase-in period in the current case should be eight years, because the cost impact is a greater impact of 17.5 cents per GJ across all customer classes.

Board Findings

The Board recognizes that, particularly in recent years, Union's ratepayers have had a significant benefit due to sharing the bulk of the margins on long-term deals. The Board would prefer to have a smooth transition away from the status quo rather than an abrupt change in rates.

The Board finds, however, that there is no basis for retaining a requirement that Union share the margins on new long-term storage transactions, that is, long-term deals executed after the Board's forbearance decision. To continue sharing those margins with ratepayers would conflict with the Board's decisions (a) to recognize that part of Union's storage capacity constitutes a non-utility asset, and (b) to forbear from regulating the prices of ex-franchise transactions. Union should reap the benefits and bear the risks of those new transactions.

The margins that will be recorded in future years in respect of existing long-term deals are different. Those margins flow from long-term contracts that were negotiated and priced prior to the Board's forbearance decision and prior to the Board's decision that there is a non-utility part of Union's storage facilities. When those contracts were signed, Union had no reason to expect that it would receive anything more than 10% of

the margin. The Board has concluded that ratepayers should continue to receive some of the margin on those existing contracts.

The Board considered whether to require Union to record the margins on existing long-term contracts separately from the margins on new long-term contracts. Under this approach, ratepayers would be credited with 90% of the margins on existing contracts for the remaining terms of those contracts. This approach conceptually has appeal but could give rise to ongoing implementation questions. For example, the Board might have to consider how contract re-negotiations or defaults by customers are to be treated. This level of complexity and potential ongoing review is unwarranted.

The Board has concluded that it should adopt a simpler phase-out mechanism that is a rough sort of "proxy" for the conceptual approach described above. The phase-out of the sharing of margins on Union's long-term storage transactions will take place over four years. The share accruing to Union will increase over that period to recognize that contracts will mature and a larger part of Union's total long-term margins will be generated by new transactions. For 2007, forecast margins (on long-term and short-term transactions) now included in the determination of Union's rates will remain unchanged. After 2007, Union's share of long-term margins will be as follows: 2008 – 25%, 2009 – 50%, 2010 – 75%, 2011 and thereafter – 100%.

The Board is currently undertaking a process to determine a multi-year incentive ratemaking framework for Union and Enbridge. That process will address how best to implement the Board's findings on the transition for long-term storage transaction margins within an incentive ratemaking framework.

7.4 ATCO DECISION

During the oral hearing and in final argument, several parties referred to the recent Supreme Court of Canada decision on the proceeds of an asset sale by ATCO Gas and Pipelines Ltd. Some parties claimed the case supported a cessation of margin sharing

by the utilities, while other parties questioned whether the facts of that case were relevant to the Ontario storage market.

ATCO, a public utility in Alberta, applied to the Alberta Energy and Utilities Board (AEUB) as required by the Alberta *Gas Utilities Act*[40], for the approval of the sale of buildings and land located in the City of Calgary. The utility argued that the property was no longer useful and the sale caused no harm to ratepayers. The AEUB agreed that the customers would not be harmed and approved the sale.

In a second decision, the AEUB determined that it would allocate the net profits from the proceeds of the sale between the utility and ratepayers. The AEUB held that it had jurisdiction to order this allocation because it had authority to attach conditions to the order approving the sale to protect the public interest.

The Alberta Court of Appeal set aside the AEUB's decision[41] referring the matter back to the AEUB to allocate the entire proceeds from the sale to ATCO. The City of Calgary, representing the customers' interest, appealed to the Supreme Court of Canada, which upheld the Court of Appeal finding that the AEUB did not have the requisite jurisdiction. On February 9, 2006 the Supreme Court of Canada released its decision in the ATCO case.[42]

Board Findings

The Supreme Court of Canada found as follows:

> The customers pay an amount for the regulated service that equals the cost of the service and the necessary resources…The payment does not incorporate acquiring ownership or control of the utility's assets.[43]

[40] R.S.A. 2000, c. G-5, s.26
[41] ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board), [2004] 24 Alta. L.R. (4th) 205 (C.A.)
[42] ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board), [2006] S.C.J. No. 4, 2006 SSC 4.
[43] Ibid, par. 68

There are differences between the ATCO case and the present case. The ATCO case involved the sale of a capital asset (land), while this case involves providing a service (storage).

The Alberta case related to section 26 of the *Gas Utilities Act* in Alberta, which required ATCO to apply to the AEUB for approval to sell any asset. The sharing of the premium from the sale of storage services to ex-franchise customers at market-based rates has been decided in the context of rates cases.

The findings of fact in this case indicate that there are certain storage assets in rate base that are used to provide storage service to in-franchise ratepayers. This decision also finds that those services should be provided at cost-based rates as they have been in the past.

The utility also uses these assets to generate profits from sales to ex-franchise customers. The bulk of the revenues have historically flowed to ratepayers and a small share has gone to the utility. That share represents a “fee” that provides an incentive to the utility to generate these sales and profits from what at certain times of the year is excess capacity. This does not give rise to any claim by the utility under the ATCO principles. The ratepayers are receiving service relating to assets in rate base. No sale of assets is involved. The utility is being compensated for certain services.

At the same time, this decision finds that there are certain storage assets that are not part of the utility rate base and finds that the return from those assets, in terms of profit on sales to ex-franchise customers, should accrue entirely to the utility and its shareholders. Again, no claim arises under the ATCO principles. There is no appropriation to the benefit of the ratepayer of any utility assets or for that matter any proceeds from that asset. Accordingly, the Board finds that ATCO decision has no application to this decision.

7.5 STORAGE AND TRANSPORTATION SERVICE DEFERRAL ACCOUNTS

The deferral accounts at issue in this proceeding are the following:

- Short-Term Storage and Other Balancing Services Account (179-70)
- Long-Term Peak Storage Services Account (179-72)
- Transportation Exchange Services Account (179-69)
- Other S&T Services Account (179-73)
- Other Direct Purchase Services Account (174-74)

On March 15, 2006, the Board notified Union and the intervenors that Union's proposal to eliminate the five deferral accounts, made as part of the rate application EB-2005-0520, had been moved to this proceeding. The relevant evidence from EB-2005-0520 was re-filed in this proceeding.

Union explained that of the five accounts in question, the storage accounts (179-70 and 179-72) are directly related to the storage forbearance issue, while the remaining three transmission accounts (179-69, 179-73 and 174-74) are not directly related to the storage forbearance issue.

Union proposed to eliminate the Short-Term Storage and Other Balancing Services Account (179-70) and Long-Term Peak Storage Services Account (179-72) on the basis that these accounts would no longer be necessary if the Board decides to forbear from regulating ex-franchise storage service sales.

Union also proposed to eliminate the other three transmission-related deferral accounts (179-69, 179-73 and 179-74). Union advanced two reasons for this proposal. First, Union stated that the forecast of S&T revenue should not be treated any differently than the forecast of any other source of revenue. Second, Union submitted that its proposal is consistent with the Board's policy direction, as outlined in its Natural Gas Forum Report, that in an incentive regulation framework there should be no earnings sharing

and transactional services revenues should not receive special treatment. Union also expressed concern that there may not be another opportunity or forum to deal with this issue prior to the beginning of the proposed incentive regulation framework.

Most intervenors took the position that the storage related accounts (179-70 and 179-72) should continue if the Board determines that it will not refrain from regulating the prices of ex-franchise storage sales services. However, intervenors also acknowledged that if the Board were to forbear from regulating the prices of ex-franchise storage services, then these accounts would no longer be needed and under those specific circumstances should be eliminated. For example, the Board Hearing Team argued that under forbearance, gas utilities' shareholders will be bearing the risk associated with storage transactions in the ex-franchise market and any premium or shortfalls should accrue to the shareholder.

With respect to the transmission-related deferral accounts (179-69, 179-73 and 179-74), most intervenors were of the view that these accounts should not be eliminated because transmission will remain a regulated service. LPMA/WGSPG supported the objective of reducing the number of variance and deferral accounts but took the position that a comprehensive review of all such accounts should be undertaken as part of the incentive regulation mechanism that is still to be determined. Many intervenors adopted the LPMA/WGSPG position.

The Board Hearing Team supported Union's proposal. It argued that because transactional transportation services are part of the gas utility's monopoly service, these revenues should be treated no differently than any other regulated revenue.

Board Findings

With respect to the storage related accounts (179-70 and 179-72), most intervenors were of the view that the resolution of this issue depends on whether the Board refrains from regulating ex-franchise storage. The Board has determined that it will refrain from

regulating rates in this area. However, we have also concluded that there should continue to be a sharing of the premium arising from short-term storage transactions, for both Union and Enbridge, and that there should be a phase-out of the sharing of the premium arising from Union's long-term storage transactions. Accordingly, the Board concludes that the accounts should be maintained for now. As outlined in sections 7.1 and 7.3, we have determined that the gas incentive ratemaking process is the best place in which to determine the precise implementation of these findings.

With respect to the transmission-related accounts, there was general acknowledgement that the issue related to the structure of the incentive regulation framework and not the issue of storage regulation. Union was concerned that this proceeding would be the only opportunity to deal with its proposal before the introduction of incentive regulation. The Board does not agree. On September 11, 2006, the Board issued a letter indicating its intent to establish a consultation process to use in relation to the development of the gas incentive regulation framework. This process is specifically designed to address issues about the framework prior to the commencement of incentive regulation for natural gas utilities. The Board finds that the proposed elimination of these three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism.

The Board therefore concludes that all of the accounts will be maintained and will be reviewed as part of the process for setting the incentive regulation mechanism for natural gas utilities.

8. OUTSTANDING ENBRIDGE RATES ISSUES (RATES 125 AND 300)

The unresolved issues arising from the Enbridge Settlement Proposal relate specifically to the allocation of implementation costs and migration revenue deficiencies attributable to changes in Rates 125 and 300, and the Rate 125 eligibility criteria.

Early in the proceedings, there were two threshold issues. The first issue was whether the allocation of implementation costs and migration revenue deficiencies should be addressed in this proceeding or Enbridge's next rates proceeding. The Board determined that the issue should be addressed in this proceeding, and that decision was rendered orally on June 27, 2006. The second issue was whether residential customers should be allocated any of the implementation costs or migration revenue deficiencies. The Board rendered its decision orally on July 14, 2006, in which it stated that both the implementation costs and the migration related revenue deficiencies should be recovered from large volume customers as they are the main beneficiaries of these services. (The transcript of the Board's oral decisions on these issues is included at Appendix C.)

The remaining issues before the Board are the following:

- Smoothing of Migration-Related Impacts:
- Rate 125 Eligibility Criteria

8.1 SMOOTHING OF RATE MIGRATION IMPACTS

Enbridge stated that the offering of new services, such as Rate 125 and Rate 300, typically leads to the migration of customers from the existing rates to the new rates, if there is an economic advantage or a reduction in rates, for these customers. This

migration typically leads to an increase in the existing rate because the customers who are less costly to serve are often the ones which migrate. Enbridge's initial estimate of the impact of migration related deficiencies was based on the assumption that customers with the largest benefit would migrate away from Rate 115. This would result in a 60% increase in the Rate 115 distribution charges, or a 14% bill impact excluding commodity charges and a 2% bill impact including commodity charges. Enbridge subsequently proposed an approach that aims to mimic the Settlement Proposal, which restricts the initial migration to Rate 300 to 20 customers. The impact of this proposal would be an increase in Rate 115 distribution charge of 38%, which results in a bill impact of 7% excluding commodity charges or 1% including commodity charges.

In order to further limit the impact on Rate 115 customers, Enbridge presented the Board with a rate smoothing proposal that limits the distribution rate impact on Rate 115 customers to 15%. This proposal reflects the migration of the largest customer (TransAlta) and some additional load from Rate 115. As a result of this smoothing, the distribution rate impact on Rates 100, 110 and 115 would be 3%, 2% and 15% respectively. The corresponding bill impacts, excluding commodity costs, are 1%, 0.5% and 2.7%.

IGUA supported Enbridge's rate smoothing proposal. Enbridge stated that it does not have a preference for whether smoothing is used or not, but noted that it is important for the Board to indicate if smoothing should be used, to enable customers to make a well informed decision about whether they want to move to unbundled rates.

Board Findings

The evidence indicates that the migration of customers from an existing rate to a new rate will have rate consequences for the remaining customers in the rate class from which the customer migrates. The Board agrees that from a cost allocation perspective it is appropriate that the remaining customers in the rate class pay the higher average cost resulting from the migration of customers which are less costly serve. However,

from a pricing perspective, the Board is mindful of the rate impacts on the remaining customers. The Board concludes that a smoothing of the distribution-related impacts, as proposed by Enbridge, is appropriate. While the precise details of the resulting rates will be determined in the fiscal 2007 rates case, the Board concludes it is appropriate to signal now to all parties that this smoothing will be incorporated.

The Board therefore approves Enbridge's rate smoothing proposal which would limit the distribution rate increase to 15% for Rate 115 and spread the remainder of the migration related deficiencies over Rate 100 and Rate 110 resulting in distribution rate increases for these rates of 3% and 2% respectively.

8.2 RATE 125 ELIGIBILITY CRITERIA

There is agreement amongst all parties that the dedicated service (or "contract demand billing") portion of Rate 125 is to be limited to new customers only, and this is reflected in the Settlement Proposal. This aspect of the service is designed to make utility service competitive against the bypass option for new customers. The parties disagreed on whether the non-dedicated provision of service under Rate 125 is to be limited to new customers.

Enbridge maintained that when the Board first approved Rate 125 there was no distinction between new and existing customers and it was always known that there was a large customer which was eligible to migrate to Rate 125. This customer was subsequently identified in this hearing as TransAlta.

IGUA's position, supported by AMPCO and CME, is that the re-design of Rate 125 should not be treated as an existing rate with a bypass clause. IGUA argued that since there are no existing customers taking service under Rate 125 the Board should treat this as a new rate. APPrO argued that throughout the re-design of Rate 125, the Board has been aware of the likelihood of TransAlta migrating to Rate 125 and the resultant impacts of that migration.

Board Findings

The Board notes that from the time Rate 125 was first developed, TransAlta has been eligible to migrate to this rate. The primary change in the rate in this proceeding was the introduction of a bypass competitive component. TransAlta is not eligible for this aspect of the rate; nor has it sought access to this aspect. The Board concludes that it would be unfair to now deny TransAlta access to Rate 125 service unless there were compelling reasons to do so.

IGUA seeks to limit access to Rate 125 to new customers only. It appears to the Board that this position is driven mostly by a concern for the rate impact on remaining customers resulting from TransAlta's migration. The Board notes that this potential impact has always existed, and we believe that this concern is adequately mitigated by Enbridge's proposed smoothing mechanism which the Board has approved.

Accordingly, the only aspect of Rate 125 that will be restricted to new customers is the billing contract demand feature.

9. CUSTOMER IMPACTS AND IMPLEMENTATION OF BOARD DECISIONS

9.1 CUSTOMER IMPACTS

The Board's decisions in this proceeding will affect the future gas bills of all distribution customers of Union and Enbridge in some fashion over the next few years.

9.1.1 Enbridge

Union storage contracts

Amending the existing storage contracts with Union to include cost-based pricing will have no effect on customers' bills. Enbridge has not yet started to pass through the current higher contract prices to customers so the Board's decision preserves the status quo. When those contracts mature over the period 2008 to 2010, Enbridge will likely procure the needed storage, which is about 18% of what Enbridge currently requires to serve its customers, at market prices. Those prices will depend on market conditions at the time and cannot be predicted. It is likely, however, they will be higher than the cost-based rates Enbridge charges for storage services from its own storage facilities.

Reducing Enbridge's share of the storage-related margins from its Transactional Services business

This reduction, from 25% to 10%, will reduce consumers' bills in the future compared to the status quo. The impact will depend on the amount of margins Enbridge is able to earn, which will depend on future market prices. Based on the level of margins earned by Enbridge in recent years, the impact of this change on a customer's bill is likely to be modest.

9.1.2 Union

Enbridge storage contracts

Amending these contracts to include cost-based pricing will reduce the amount of long-term storage margins Union will earn over the period until the contracts mature (2008 to 2010) and will therefore reduce the share of the margin flowing to ratepayers.

Changing the sharing of short-term storage revenues

The Board has decided that Union should be credited with the portion of short-term storage margins that are deemed to use the "non-utility" space at Union's storage facilities. Union's share of the margin will also include an incentive related to the utility portion of Union's storage assets. Based on the current level of short-term storage margins, this change will result in a small reduction in the margins that are for the benefit of ratepayers.

Phase-out of sharing long-term storage margins

This is the most significant change for Union ratepayers, who currently are credited with 90% of Union's long-term margins. Starting in 2008, the ratepayer share of these margins will decline each year and reach zero by 2011.

9.1.3 Overall Impact

The Board's decisions on the sharing of premiums on storage transactions will have virtually no effect on consumers' bills in 2007. The impact after that cannot be precisely quantified because it will depend on future market prices of storage and the level of margins earned by the utilities on ex-franchise storage sales. The impact on any individual consumer will also depend on the amount of gas they consume in the future.

The total annual gas bill for a typical residential consumer in Enbridge's territory (Rate 1) and in Union's Southwestern Ontario operations area (Rate M2) is in the range of $1,000 to $1,500 depending on the price of natural gas during the year. Assuming (a) that Union and Enbridge are able to earn the same amount on ex-franchise storage

sales in the period 2008 through 2010 that they are forecast to earn in 2007, and (b) that gas prices and other delivery charges remain the same, the Board's decisions in this proceeding are likely to increase rates by a small amount – perhaps around 1% on the typical residential consumer's bill by 2011.

9.2 COMPLETION OF THE PROCEEDINGS AND COST AWARDS

As part of this proceeding, new unbundled rates have been approved for Enbridge and they are to be implemented as soon as possible. The Board therefore directs Enbridge to file a draft Rate Order within 15 days of this decision. The draft Rate Order should reflect the findings in this decision.

The Board also directs Union to file a Draft Rate Order reflecting the findings in this decision within 90 days. This should be done in conjunction with Union's filing of amended contracts with Enbridge.

The Board will issue a cost awards decision separately.

9.3 IMPLEMENTATION

The following table summarizes the Board's decisions in this proceeding and outlines next steps. Each item is cross-referenced to the relevant section of this decision.

	Implementation Issue	Regulatory Process	Timing
1.	Continued cost-based rate regulation for most in-franchise storage service (section 5.2.1)	No additional process required	
2.	Amendments to Enbridge's storage contracts with Union (19.9 Bcf) to incorporate cost-based rates (section 5.2.2)	Union to file amended contracts for Board approval	Within 90 days of this decision
3.	Refrain from rate regulation for Union and Enbridge ex-franchise storage services (section 5.2.4) and new storage services (section 5.2.3)	Union and Enbridge to file Draft Rate Orders	Enbridge to file within 15 days. Union to file within 90 days.
4.	Refrain from rate regulation and contract approval for third-party storage operators (section 5.1)	The Board will rescind MHP Canada's and Tribute's Rate Orders	
5.	Refrain from requiring Board approval of storage contracts (section 5.1, 5.2.4)	The Board to rescind Blanket Storage Orders	
6.	Union and Enbridge policies on aggregate excess method and its application (section 6.2.1)	Union and Enbridge to file policies; Board will consider possible generic process.	Within 90 days of this decision
7.	Development of storage allocation methodology (or methodologies) for use in cases where aggregate excess method is inappropriate (section 6.2.2)	Union and Enbridge to file proposals; Union to file long-term T1 contracts; Board will consider possible generic process.	Within 90 days of this decision

	Implementation Issue	Regulatory Process	Timing
8.	Extension to City of Kitcheners' contract with Union (section 6.2.4)	Union to amend contract and file with the Board	Within 90 days of this decision
9.	Share of margin on short-term storage transactions for Union to be based on non-utility assets (21%) and incentive related to utility assets (7.9%, that is 10% of 79%) (section 7.1)	Implementation to be determined through gas incentive ratemaking process	Beginning 2008 Rates
10.	Share of margin on short-term storage transactions for Enbridge to based on incentive (10%) (section 7.1)	Implementation through 2007 rates, with follow on implementation through the gas incentive ratemaking process	2007 rates
11.	Phase-out of ratepayer share of margins on Union's long-term storage transactions (section 7.3)	Implementation to be determined through gas incentive ratemaking process	2008 through 2011
12.	Smoothing of rate impacts from migration to Enbridge Rate 125 and Rate 300 (Chapter 8)	Implementation through Enbridge's 2007 rates proceeding	2007 rates
13.	Implementation of Enbridge unbundled rates (section 5.2.3 and Chapter 8)	Enbridge to submit draft Rate Order	Within 15 days of this decision
14.	Development of rules of conduct and reporting related to storage (section 5.4)	Board to initiate process.	

DATED at Toronto November 7, 2006

ORIGINAL SIGNED BY

_____

Gordon Kaiser
Presiding Member and Vice Chair

ORIGINAL SIGNED BY

_____

Cynthia Chaplin
Member

ORIGINAL SIGNED BY

_____

Bill Rupert
Member

APPENDIX A

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

DETAILS OF PROCEEDING

NOVEMBER 7, 2006

APPENDIX A

Details of the Proceeding

The Issues

The Board, in Procedural Order No. 2, set out the following issues for the NGEIR Proceeding:

I. Rates for gas-fired generators (and other qualified customers):

Should the Board order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers)? If the Board does order new rates, should that order contain the following requirements:

1. More frequent nomination windows for distribution, storage and transportation that correspond with the nominations of upstream pipelines that connect to the Ontario gas system.
2. Firm high deliverability service from storage with customer options for 1.2%, 5% and 10% deliverability.
3. Gas storage and distribution offered as discrete services.
4. Inter-franchise movement of gas (i.e., the ability to access services across Ontario, whether to a customer's own account or as a sale to a third-party).
5. Redirection of gas to a different delivery point on short notice (i.e., the ability to redirect or acquire gas on short notice to a different delivery point).
6. The ability to transfer the title of gas in storage (i.e., the title transfer in gas storage is treated as an administrative matter instead of a physical withdrawal or injection of gas).

II. Storage regulation:

Should the Board refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario? In making this determination, the Board will have regard to a number of considerations, including:

1. Do gas utilities (and/or their affiliates) either collectively or individually have market power in the provision of storage services for all or some categories of customers in Ontario?
2. If gas utilities (and/or their affiliates) do have market power in storage, is it appropriate for them to charge “market rates” for transactional and long-term storage services?
3. If gas utilities (and/or their affiliates) do not have market power, is it in the public interest that all or some customers continue to pay storage rates at cost as opposed to market rates? How should the extra revenue from storage services at market rates be allocated?
4. If the Board determines, based on considerations of market power and the public interest more generally, that some customers should pay for storage services at cost and others should pay for storage services at market prices, how should the line be drawn between the two types of customers and, specifically, should there be a constraining allocation of physical storage facilities to some types of customers based on measures such as aggregate excess or whether customers are considered “in-franchise” or “ex-franchise”? How should the extra revenue from storage services at market rates be allocated?

III. Transportation capacity bidding process and allocation:

Should the Board allow a gas transmitter to charge a premium above costs for gas transmission services and, if so, how should that premium be allocated?

IV. Enbridge rates for large volume customers (Rate 300 Series):

Should the Board consider any other terms and conditions in addition to

those outlined in Appendix B [to Procedural Order No. 2 – "Mandatory Evidence to be filed by Enbridge with respect to Rate 300 Series Rates"]?

What should be the maximum waiting period for customers to make the transition to the new Rate 300 series rates?

The Board also moved four issues from Union's 2007 rates proceeding (EB-2005-0520) to the NGEIR Proceeding. These issues, as set out in Procedural Order No. 3, were:

1. Matters relating to market pricing of storage services;
2. Union's proposal to eliminate storage and transmission deferral accounts;
3. Union's proposal to change the blanket storage order; and
4. Power services – M12 service upgrades for power producers.

Technical Conferences

On April 5 and 6, 2006, the Board held a technical conference on the mandatory evidence filed by Enbridge and Union with respect to potential rates for gas-fired generators and other qualified customers (Issue I of this proceeding). At the April 6, 2006 technical conference, Enbridge presented revisions to Rate 125 – Extra Large Firm Transportation Service and proposed a new High Deliverability Storage Service (Rate 316). The proposed rates were presented on a conceptual basis only, and Enbridge took the position that the setting of rates associated with Rate 125 and Rate 316 should only be done in the context of Enbridge's 2007 rate hearing. The Board did not agree and directed Enbridge to file supplemental evidence to complete the mandatory evidence on the potential rates for gas-fired generators and other qualified customers (Issue I) and added a one-day technical conference on April 27, 2006 on Issues I and IV.

A further technical conference was held on May 16-19, 2006 to provide participants with the opportunity to present their evidence relating to Issues II, III and IV and to allow other participants to obtain further clarification of the evidence.

Settlement Conference

A settlement conference was held for Issues I (rates for gas-fired generators and other qualified customers), III (transportation capacity bidding process and allocation) and IV (Enbridge's Rate 300 series rates). The Board indicated that it would not receive a settlement proposal on Issue II (storage regulation), so a settlement conference was not held in relation to this issue.

Two separate Settlement Proposals were filed with the Board on June 13, 2006. Enbridge submitted a Settlement Proposal for Issues I and IV (the "Enbridge Proposal") and Union submitted a Settlement Proposal for Issues I and III (the "Union Proposal"). A presentation of the Settlement Proposals was made to the Board on June 19, 2006. On July 14, 2006, the Board approved the Enbridge Proposal.[1] On June 27, 2006,[2] the Board approved the Union Proposal.

Proceeding

The oral hearing commenced on June 19, 2006 and concluded on July 20, 2006. Arguments were delivered orally and in writing during August and final reply arguments were heard on September 7, 2006.

[1] Tr. 11, page 130, lines 6-7
[2] Tr. 4, pages 152-153

APPENDIX B

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

PARTICIPANTS AND WITNESSES

NOVEMBER 7, 2006

APPENDIX B

Participants and Witnesses

List of Participants

Board Hearing Team	Donna Campbell Pascale Duguay Laurie Klein
Board Support Team	Kristi Sebalj David Brown Zora Crnojacki Ronald Man Rudra Mukherji
Union Gas Limited	Glenn Leslie Michael Packer Connie Burns
Enbridge Gas Distribution	Fred Cass David Stevens
Aegent Energy Advisors	Valerie Young
Association of Major Power Consumers of Ontario	Mark Rodger Adam White
Association of Power Producers of Ontario	Patrick Moran Richard King David Butters
BP Canada	David Brett Cheryl Worthy
Canadian Association of Petroleum Producers	Nick Schultz
Canadian Manufacturers & Exporters	Brian Dingwall
City of Kitchener	Alick Ryder James Gruenbauer
Competition Bureau	Mark Ronayne

Consumers Council of Canada	Robert Warren Julie Girvan
Coral Energy Canada Inc.	Paul Kerr
Direct Energy Marketing Inc.	Dave Matthews
Enbridge Inc.	Robert J. Howe Bob Craig
Energy Probe Research Foundation	David S. MacIntosh Thomas Adams
EPCOR Utilities Inc.	Elisabeth (Lisa) De Marco Leigh-Anne Palter
Greenfield Energy Centre LP	Patrick Moran John Rosenkranz
Hydro One Networks Inc.	Glen MacDonald
IESO	John M. Rattray George Katsuras
Inco Limited	John LeMay John Butler
Industrial Gas Users Association	Peter Thompson Peter Fournier
London Property Management Association	Randy Aiken
Low Income Energy Network	Malcolm Jackson
Natural Gas Consultant	Jason Stacey
Nexen Marketing Inc.	Debbie White Shannon Young
Market Hub Partners Canada	Laurie Smith Karen Illsey Toby Bishop Jim Redford

Ontario Energy Savings L.P.	Nola L. Ruzycki
Ontario Power Authority	Miriam Heinz Gia DeJulio
Ontario Power Generation Inc.	Barry Green Greg Olsen
Portlands Energy Centre	David Brown Nicolle Butcher John Wolnik
Pristine Power Inc.	Michael Peterson Kevin Gilchrist
School Energy Coalition	John DeVellis Jay Shepherd Brian Cain
Sithe Global Power Goreway ULC Sithe Global Power Southdown ULC	David Brown Duane E. Cramer
Société en Commandite Gaz Métro	Louis-André Leclerc Louis-Charles Ratelle Frederic Morel
TransAlta Cogeneration L.P. and TransAlta Energy Corp.	Sandy O'Connor
TransCanada Energy Ltd.	David Brown Margaret Duzy Jennifer Nichols John Wolnik
TransCanada PipeLines Limited	Bernard Pelletier Patrick Keys Murray Ross
Tribute Resources Inc.	Peter Budd Robert Lockhart
Vulnerable Energy Consumers Coalition	Michael Janigan Roger Higgin James Wightman

Wholesale Gas Service Purchasers Group	William Blake Nick Petruzzella Randy Aiken

Expert Witnesses

The Board Hearing Team presented the following expert witness:

Bruce McConihe	LECG, LLC

Union Gas Limited presented the following expert witnesses:

Bruce Henning	Energy and Environmental Analysis
Michael Sloan	Energy and Environmental Analysis
Richard Schwindt	Simon Fraser University

Enbridge Gas Distribution presented the following expert witnesses:

David McKeon	View Communications Inc.
Richard Smead	Navigant Consulting Ltd.

Market Hub Partners Canada L.P. presented the following expert witness:

John Reed	Concentric Energy Advisors

The Industrial Gas Users Association, Association of Major Power Consumers of Ontario, Consumers Council of Canada, Vulnerable Energy Consumers Coalition, School Energy Coalition, City of Kitchener, Canadian Manufacturers & Exporters, Inc. jointly sponsored the following expert witness:

Mark Stauft	Consultant

The Association of Power Producers of Ontario presented the following expert witnesses:

Robert Cary	Rob Cary & Associates
Michael Nolan	Ontario Power Generation
John Rosenkranz	Consultant
John Wolnik	Elenchus Research Associates

Witnesses by Party

Enbridge Gas Distribution	Jody Sarnovsky Malini Giridhar David Charleson James Grant Anton Kacicnik
Union Gas Limited	Mark Isherwood Mark Kitchen Chris Shorts Steven Poredos Steven Baker Mike Sloan Drew Quigley Mike Broeders
Market Hub Partners Canada	Jim Redford
Board Hearing Team	Ajit Ratra
Société en Commandite Gaz Métro	Jean-Pierre Bélisle Sophie Brochu Frédéric Morel
Association of Power Producers of Ontario	Duane Cramer Brian Kelly
Enbridge Inc.	Robert Craig
City of Kitchener	Dwayne Quinn James Gruenbauer
BP Canada	Cheryl Worthy Stephen Acker
Industrial Gas Users Association Association of Major Power Consumers of Ontario	Peter Fournier Adam White Darren MacDonald John Butler

APPENDIX C

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

DECISION ON ENBRIDGE SETTLEMENT PROPOSAL

NOVEMBER 7, 2006

APPENDIX C
Decision on Enbridge Settlement Proposal

A "threshold issue" was identified in the Enbridge Settlement Proposal. This threshold issue was described by various consumer related intervenors as pertaining to the allocation of the revenue deficiencies and implementation costs associated with Rates 125 and 300 as proposed by Enbridge. Specifically, Consumers Council took the position that any revenue deficiencies and costs associated with these rates should be allocated principally or solely to the large customers who, in Consumer Council's view, were the drivers behind the changes and the beneficiaries of the changes. Consumer Council also took the position that the question of the allocation of revenue deficiencies and costs associated with the new rates should be addressed within the NGEIR Proceeding. Consumer Council took no position, however, on the substance of the changes to Rates 125 and 300 and agreed that the settlement could proceed as set out in the Settlement Proposal.

IGUA/AMPCO took the position that some portion of the revenue deficiencies and costs should be borne by residential customers, but that the question of the allocation of these should be addressed in the fiscal 2007 Enbridge rates case.

The Board heard oral submissions on the procedural question of where this issue should be addressed: the current proceeding or the 2007 Enbridge rates case. The Board decided that it would hear the issue of the allocation of revenue deficiencies and costs associated with the new Rates 125 and 300 within the NGEIR Proceeding. The relevant excerpt of the NGEIR Proceeding transcript, which contains the Board's decision on this issue, is provided below for reference.

Decision on Preliminary Threshold Issue
Excerpt from the oral hearing transcript EB-2005-0551,
Volume 4, June 27, 2006, pages 153 line 12 to page 154 line 26.

> The second matter relates to the Enbridge settlement agreement, which we propose to reserve on at this time. The outstanding issue has to do with the

costs of unbundling. This was raised initially by Mr. Warren and Mr. Thompson on June 20th. Mr. Warren's submissions are at page 17 of that transcript to page 22. Mr. Thompson's are at page 23 to 36.

Essentially, Mr. Warren, on behalf of the Consumers Council, argues that the matter should be decided in this case. Mr. Thompson on behalf of IGUA takes the view that the matter should be decided in the 2007 Enbridge rate case. This relates to how certain costs and revenue deficiencies should be allocated between customer classes resulting from the proposed changes to rate 125, 300 and 115 categories.

Mr. Warren essentially argues that it would be very hard for us to make a decision on the settlement agreement without resolving this issue within the context of this case. The Board agrees with that proposition.

Mr. Thompson's argument was somewhat different. He was concerned that the initial data and information, which had been provided with respect to these rates late in the day, was altered in a significant fashion. He indicated in his submissions that the company was initially forecasting an impact on rate 100 of about 6.7 percent, rate 110 of 4.5 and rate 115 of zero. But through subsequent interrogatories, it turned out that the impact on rate 115 was about 60 percent. Accordingly, he felt that there hadn't been adequate notice to that class of customers.

He also believed that if the matter were deferred, the Board would have the advantage of further and better information.
This Panel has concluded we can hear the matter within this case. As indicated, there will be sufficient information. We will, however, direct Enbridge to file a notice to these customers. A draft notice has been prepared and that can be worked out in detail with Board counsel. Also, we are setting a date to hear this evidence. Correct me, is that July 14th?

MS. SEBALJ: Yes, it is. It's July 14th. It will be the first thing on the agenda.

MR. KAISER: All right. That completes the Board's ruling with respect to those two matters.

Upon delivering this preliminary decision on the “Threshold Issue”, The Board directed Enbridge to serve notice to Enbridge’s existing Rate 100, 110 and 115 customers given the potential magnitude of the impact on these customers.

On July 14, 2006, Enbridge put forward a witness panel to address the cost and revenue deficiency allocation issue. That witness panel was cross-examined by a

number of parties and oral submissions were made by several parties. The Board issued its decision orally and found that the evidence had established that the drivers for the Rates 125 and 300 service were the large volume customers and that the large volume customers are also the main beneficiaries of these services. The Board found that it would be inappropriate for the residential customers to bear any portion of the revenue deficiencies or costs associated with the implementation of the new Rates 125 and 300; rather all costs are to be borne by the large volume customers.

Although Enbridge had put forward a proposal with respect to smoothing that would mitigate the cost consequences or rate impacts on Rate 115 of the implementation of the new Rates 125 and 300, the Board found that it did not need to render a decision on that aspect of the issue at that time. Having decided the threshold issue, the Board at the same time approved the Enbridge Settlement Proposal. [1]

The relevant excerpt of the NGEIR Proceeding transcript, which contains the Board's decision on the substantive "Threshold Issue" of who would bear the revenue deficiencies or costs associated with the implementation of Enbridge's new proposed rates, is also provided below for reference.

Under the Settlement Proposal, IGUA and CME reserved their right to argue that the non-dedicated service portion of Rate 125 ought to be limited to new loads only, such that existing customers would not be able to switch to this rate. This issue was addressed by the parties by way of argument and as such, was not part of the Board approved Enbridge Settlement Proposal. The Board's findings on this issue can be found in Chapter 8.

Decision on Threshold Issue
Excerpt from the oral hearing transcript EB-2005-0551,
Volume 4, June 27, 2006, pages 152 line 1 to page 153 line 11.

> MR. KAISER: At the outset of this proceeding, a motion was brought jointly by the Consumers' Council and IGUA, raising a threshold issue that the parties wish

[1] Tr. 11, page 130, lines 6-7

to have decided before the Board dealt with the approval or non-approval of the settlement agreement with respect to Enbridge in this matter.

And that was set out at page 8 of 34 of the settlement agreement, which was filed on June 13th. And that's Exhibit S, tab 1, schedule 1, which stated:

> A threshold issue which the Board is asked to consider at the outset of the oral hearing is whether the changes to Rates 125 and 300 should be made only after the issue pertaining to the allocation of implementation costs and migration revenue deficiencies has been decided; or whether changes to Rates 125 and 300 can be made now, on an entirely without-prejudicial basis to all parties, including the establishment of the appropriate deferral accounts with the consideration and determination of all matters relevant to the recovery of the costs and revenue deficiencies in the Enbridge Gas Distribution 2007 rate case.

And as you're aware, we decided that this matter should not be deferred to the 2007 rate case, and we agreed to decide that threshold issue, which we're now prepared to deal with.

The issue in the simplest terms is whether these costs, as described, the implementation costs and the migration costs, should be borne entirely by the large volume customers or whether some portion of them should be borne by the residential customers. AMPCO, IGUA, and CME take the position that some portion should be borne by the residential customers.

Enbridge, supported by the Consumers' Council and APPrO, take the position that the costs should be borne entirely be to the large volume customers. Board Counsel takes no position on the matter.

With respect to the implementation costs, these are set out most recently in the letter of July 13th, which was filed with the Board today and was addressed in argument today. And those relate to the costs of a manual system, it being the wish of the parties that they wish to take up service earlier rather than later, and therefore, in order to accommodate that, it will be necessary to develop a manual system prior to ultimately implementing an automatic system.

And those costs, as I say, are laid out, including start-up one-time costs ranging from $600,000 to $875,000, and then ongoing operating costs, annual costs, ranging from $300,000 to $825,000.

With respect to the latter, we're now told that a significant portion of that relates to the cost of nomination windows, and those costs will be born specifically by those parties that take advantage of that service.

As a general proposition, the Board is of the view that the record has established that the drivers for this service, that is, the demanders of this service, are the

large volume customers. Mr. Warren has taken us through a litany of cases and arguments in previous proceedings where various parties were demanding of the utility to produce these unbundled services which are at issue in this proceeding, and complaining about the delay with respect to their lack of development.

And it is equally clear that those customers are the main beneficiaries of these services.

Accordingly the Board is of the view that it would be inappropriate for the residential customers to bear any portion of these costs.

Reference was made to a Union case which dealt with unbundled service. That is the decision of the Board of July 31st, 2002, which dealt with unbundling services and rates for small-volume customers. The Board would note that that did relate to small-volume customers. Those services had a particularly broad-based demand which is not the situation in this case. These are much narrower services, clearly designed to benefit the large volume customers, which was not the case with respect to the decision of July 31st, 2002.

That, then, brings us to the second aspect of the cost, which is the cost consequences of the movement of certain customers from Rate 115 to Rate 125 and Rate 300. We have a forecast of the number of customers who might move, and, in fact, the billing system is being designed to handle a maximum of 20. The proposal put forward by Enbridge is that ten of those would be the ten largest customers and the other ten would be chosen by lottery.

That yields certain cost consequences which are set out in the proposal that Enbridge has filed, which is that, assuming no smoothing, the distribution impacts on the Rate 100, 110, and 115 customers would be 2 percent, 1 percent, and 38 percent respectively. Those figures are somewhat modified from earlier figures presented in this proceeding.

There has been a proposal put forward by Enbridge with respect to smoothing that would cap, if you will, the cost consequences or rate increase impacts on Rate 115 and spread it over the other groups. That's dealt with in the Enbridge proposal.

The Board is of the view that we do not at this point need to consider whether the smoothing process is appropriate or not. We are of the view, however, that the cost consequences of these rates are relatively low, and I use the word "relatively" advisedly. The Enbridge proposal says the corresponding bill impacts, excluding commodity costs, on Rates 100, 110, and 115 would be .6 percent, .2 percent, and 7 percent respectively. That's without the smoothing. And with smoothing it becomes 1 percent, .5 percent, and 2.7 percent respectively. As stated, we are not making a decision with respect to the smoothing at this point. It's our understanding that there will be further

submissions made in this proceeding with respect to that aspect.
In any event, our position with respect to this category of the costs is the same as with the first, that is to say that none of the costs should be appropriately borne by the small residential customers. Instead, they should all be borne by the large volume customers. Those are the parties that requested this service. And those are the parties that will benefit from this service.

Subject to any questions, that completes the Board's ruling.

Ms. Chaplin corrects me. I think I used the term "large industrial." Substitute "large volume customers" because there are, obviously, customer categories within there that are not industrials, namely, the power generators and others.

APPENDIX D

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

ENBRIDGE SETTLEMENT PROPOSAL

NOVEMBER 7, 2006

SETTLEMENT PROPOSAL
FOR ISSUES RELATED TO
ENBRIDGE GAS DISTRIBUTION INC.
IN THE NGEIR PROCEEDING

ISSUES I and IV

June 13, 2006

TABLE OF CONTENTS

Issue	Description
	Introduction and Context
	Threshold issue
1	Rates for Gas Fired Generators
1.1	Rate 125 – extra large volume firm distribution service
1.2	Interfranchise movement of gas
1.3	Redirection of gas
1.4	Title transfer of gas in storage
1.5	Storage allocation methodology for gas fired generators (base level deliverability)
1.6	Rate 316
4	Rates 300 and 315

INTRODUCTION AND CONTEXT

This Settlement Proposal is filed with the Ontario Energy Board (the “Board") in connection with the Board’s proceeding, commenced on its own motion, regarding natural gas electricity interface and storage regulation issues. This Settlement Proposal addresses issues in the proceeding that relate to Enbridge Gas Distribution Inc. A separate Settlement Proposal is being filed in relation to Union Gas Limited.

A Settlement Conference for this proceeding was conducted May 29, 30 and 31 and June 1, 2, 5, 6, 12 and 13, 2006 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the “Rules”) and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). This Settlement Proposal arises from the Settlement Conference.

Enbridge Gas Distribution Inc. (“Enbridge Gas Distribution” or the “Company”), Union Gas Limited (“Union”) and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board hearing staff (“Board Staff”), participated in the Settlement Conference:

Aegent Energy Advisors Inc. (“Aegent”);
Association of Major Power Consumers in Ontario (“AMPCO”);
Association of Power Producers of Ontario (“APPrO”);
Canadian Manufacturers & Exporters ("CME");
City of Kitchener (“Kitchener”);
Consumers Council of Canada ("CCC");
Direct Energy Marketing Inc. (“Direct Energy”);
Energy Probe Research Foundation (“Energy Probe”);
Greenfield Energy Centre LP ("GEC");
Independent Electricity System Operator (“IESO”);
Industrial Gas Users Association ("IGUA");
Jason F. Stacey;
London Property Management Association (“LMPA”);
Low Income Energy Network (“LIEN”);
Ontario Power Authority (“OPA”);
Ontario Power Generation Inc. (“OPG”);
Portlands Energy Centre (“PEC”);
Sithe Global Power Goreway ULC (“Sithe”)
School Energy Coalition ("Schools");
Transalta Energy Corp. (“TransAlta”);
TransCanada Energy Ltd. (“TCE”);
TransCanada PipeLines Limited ("TCPL"); and,
Vulnerable Energy Consumers Coalition ("VECC").
Wholesale Gas Service Purchasers Group (“WPSPG”);

The Settlement Proposal deals with aspects of Issues I and IV listed at Appendix C to the Board's Procedural Order #2, dated February 28, 2006 (the "Issues List"). The Board has indicated that it does not expect any settlement proposal related to Issue II (storage regulation), and Issue III (transportation capacity) relates solely to Union. Accordingly, neither of those issues is addressed in this document.

In the Issues List, the Board set out the following in respect of Issue I:

I. Rates for gas-fired generators (and other qualified customers):

Should the Board order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers)? If the Board does order new rates, should that order contain the following requirements:

1. More frequent nomination windows for distribution, storage and transportation that correspond with the nominations of upstream pipelines that connect to the Ontario gas system.

2. Firm high deliverability service from storage with customer options for 1.2%, 5% and 10% deliverability.

3. Gas storage and distribution offered as discrete services.

4. Inter-franchise movement of gas (i.e., the ability to access services across Ontario, whether to a customer's own account or as a sale to a third party).

5. Redirection of gas to a different delivery point on short notice (i.e., the ability to redirect or acquire gas on short notice to a different delivery point).

6. The ability to transfer the title of gas in storage (i.e., the title transfer in gas storage is treated as an administrative matter instead of a physical withdrawal or injection of gas).

This Settlement Proposal addresses items 1, 2, 3, 4, 5 and 6 from the above list. Items 1 and 3 are addressed in a section titled "Rate 125 – extra large volume firm distribution service", which sets out the proposed agreement that has been reached between parties in respect of the Company's proposed delivery service. Items 4, 5 and 6 are addressed in separate sections related to each of these proposed services. A separate section, related to allocation of base level deliverability storage (1.2%) for gas fired generators and similar customers, is also attached at section 1.5. A final section, related to the Company's Rate 316 proposal is also attached. There is no settlement related to firm high deliverability storage at 5% or 10% deliverability.

In the Issues List, the Board set out the following in respect of Issue IV:

IV. Enbridge rates for large volume customers (Rate 300 Series):

Should the Board consider any other terms and conditions in addition to those outlined in Appendix B, namely:

1. combined multi-facility delivery, storage and load balancing options;

2. flexibility in delivery point, minimum annual volumes, daily delivery obligations, provision of fuel, and choice between bundled and unbundled services;

3. term differentiated rates.

What should be the maximum waiting period for customers to make the transition to the new Rate 300 series rates?

This Settlement Proposal addresses these matters in a section titled "Rate 300 Series", which relates to Enbridge Gas Distribution's proposed unbundled delivery and load balancing (Rate 300) and storage (Rate 315) offerings.

At the outset of this Settlement Proposal, a threshold issue about the allocation of costs and revenue deficiencies associated with the Company's proposals for the redesigned Rates 125 and 300 is set out. This threshold issue bears on the position that certain parties, CCC, VECC, SEC, LIEN, LMPA, WGSPG and Energy Probe, take on many of the otherwise settled issues in this Settlement Proposal.

Each matter described in this Settlement Proposal falls within one of the following three categories:

1. an issue for which there is complete settlement, because Enbridge Gas Distribution and all of the other parties who discussed the issue either agree with the settlement or take no position,

2. an issue for which there is partial settlement, agreed to by Enbridge Gas Distribution and a majority of parties but one or more parties do not agree with the settlement,

3. an issue for which there is no settlement.

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

It is acknowledged and agreed that none of the completely settled provisions of this Settlement Proposal is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2005-0551, accept the completely settled provisions of the Settlement Proposal in their entirety, there is no Settlement Proposal (unless the parties agree that any portion of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal).

It is further acknowledged and agreed that parties will not withdraw from this Settlement Proposal under any circumstances except as provided under Rule 32.05 of the Rules.

For greater certainty, the parties further acknowledge and agree that these conditions apply to settled issues in respect of which they are shown as taking no position.

It is also acknowledged and agreed that this Settlement Proposal is without prejudice to parties re-examining these issues in any other proceeding, except where a party's rights to re-examine an issue have been specifically limited in this Agreement.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Proposal.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues; identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the settled issue; and provides a direct link between each settlement and the supporting evidence in the record to date. In accordance with paragraph 7 of Procedural Order No. 2, this Settlement Proposal also contains a discussion of the evidence supporting each aspect of the proposed settlement.

Best efforts have been made to identify all of the evidence that relates to each issue. The supporting evidence for each issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A, Tab 8, Schedule 1 is referred to as A-8-1. A concise description of the content of each exhibit is also provided. Additionally, references are included to the transcripts from the Technical Conferences held in this proceeding. Those Technical Conferences have afforded parties more than three full days of time to ask questions and have the Company clarify and explain its position and evidence. The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular issue.

THRESHOLD ISSUE

1. Enbridge Gas Distribution proposes to redesign Rates 125 and 300. The Company's proposals have been made at the request of the Board and certain parties. All parties agree that the Company should be entitled to recover all revenue deficiencies and reasonably incurred costs caused by the redesigned Rates 125 and 300.

2. Enbridge Gas Distribution proposes that the costs and revenue deficiencies attributable to the changes in Rates 125 and 300 should be recovered from large volume customers. The Company will continue to adhere to the principle that costs must be allocated fairly between customer classes, based on cost causality.

3. The costs and revenue deficiencies are in the following categories:

(i) The migration revenue deficiency associated with Rate 125;

(ii) The costs of the manual implementation of Rates 125 and 300;

(iii) The costs of implementing an automated solution for Rates 125 and 300;

(iv) The migration revenue deficiency for Rate 300.

4. CCC, VECC, SEC, LIEN, LMPA, WGSPG and Energy Probe believe that the implementation costs and revenue deficiencies should not be allocated to residential or general service customers because the costs were not incurred on their behalf and because they do not benefit from the proposed changes.

5. CCC, VECC, SEC, LIEN, LMPA, WGSPG and Energy Probe believe that the changes to Rates 125 and 300 must not be made, and costs or revenue deficiencies incurred must not be recorded, until the Board has determined how the costs and revenue deficiencies should be allocated to ratepayers. They believe that determination must be made in this proceeding.

6. IGUA, AMPCO and CME believe that a portion of the costs and revenue deficiencies, which they believe were incurred to make Enbridge Gas Distribution's system more robust against bypass, and some costs incurred to redesign the Company's rates, should be allocated to all customer classes.

7. IGUA, AMPCO and CME believe that the Board's determination of the extent to which customer classes, other than large volume customer classes, should be allocated any portion of the costs and revenue deficiencies should take place in Enbridge Gas Distribution's 2007 rates case when the forecasts of such costs and revenue deficiencies

and their impacts on customer classes will be more current and more appropriately scrutinized.

8. The threshold issue which the Board is asked to consider at the outset of the oral hearing is whether changes to Rates 125 and 300 should be made only after the issue pertaining to the allocation of implementation costs and migration revenue deficiencies has been decided, or whether changes to Rates 125 and 300 can be made now on an entirely without prejudice basis to all parties, including the establishment of the appropriate deferral accounts, with the consideration and determination of all matters relevant to the recovery of the costs and revenue deficiencies to be made in Enbridge Gas Distribution's 2007 rates case.

9. In the event that the Board indicates that it will decide allocation issues in this proceeding, then, on the Rates 125 and 300 issues, CCC, VECC, SEC, LIEN, LMPA, WGSPG and Energy Probe will pursue cross-examination of Company witnesses only on issues of costs and benefits related to the proposed Rates 125, 300 and 315.

1. RATES FOR GAS FIRED GENERATORS

Parties have considered Enbridge Gas Distribution's proposal for Rate 125, which is the distribution and limited balancing service to be offered to gas fired generators, and to other large volume customers. This redesigned rate offering was prepared by the Company in response to the perceived needs of gas fired generators, and is also intended to respond to the service attributes identified as being important by the Board in the Notice of Proceeding in this matter.

Parties have considered the Company's proposals for additional services that could be offered to customers, as set out at items 4, 5 and 6 of Issue I in this proceeding. These are addressed in separate subsections of this document.

Parties have also agreed upon a storage allocation methodology for base level deliverability storage for gas fired generators. This agreement is set out in subsection 1.5 below.

Finally, Rate 316, which is not a settled issue, is addressed below in subsection 1.6.

1.1 RATE 125 – EXTRA LARGE VOLUME FIRM DISTRIBUTION SERVICE

PARTIAL SETTLEMENT

Leading up to, and as part of this proceeding, Enbridge Gas Distribution has worked with gas fired generators and other customer groups to evaluate, understand and respond to the unique service needs anticipated by gas fired generators. As noted by the Board in its Notice of Proceeding (December 29, 2005), and as noted by APPrO in its prefiled evidence, gas fired generators require services that are flexible, responsive and cost-effective. (APPrO prefiled evidence, pp1-2) At the same time, Enbridge Gas Distribution has indicated that its aim in developing such services is to ensure existing customers are not unduly burdened or impacted by the introduction of new services for gas fired generators. (April 6, 2006, Tr. 193)

Through this proceeding, Enbridge Gas Distribution has developed proposed or modified rates for distribution service to power generators: Rate 125 - Extra Large Firm Transportation Service. As outlined in the Company's evidence, these service offerings are the outcome of extensive discussions with power generation customers, and are consistent with generally accepted rate principles, operational constraints, the Board's Procedural Orders in this proceeding, and the assumptions regarding services availability from upstream providers. (Enbridge Gas Distribution evidence: C-1-1, p. 1)

The Company has filed extensive written evidence about the proposed Rate 125, and has answered questions from all interested parties about this proposed Rate over the course of two days of Technical Conference (April 6 and 27, 2006). The Company's specific proposals for Rate 125, along with a discussion of the pricing for aspects of the proposed Rate, are set out in its prefiled evidence at C-1-1 (Overview), C-2-1 (Rate 125), C-2-3 (Rate 125 – Draft Rate Schedule) and C-2-4 (Rate 125 – Derivation of Charges). Certain of the undertaking responses filed by the Company also relate to the proposed Rate 125.

The Company has included in its evidence (C-2-3, p. 3) and Technical Conference testimony (April 16, 2006, Tr. 212-215), discussion about the termination rights that exist in the Rate 125 Rate Schedule to protect the reliability and safety of the gas system. This could include shut off of gas supply to the plant or flow control protections. (April 16, 2006, Tr. 212)

Evidence about the distribution and balancing service needs of gas fired generators, prepared by APPrO (APPrO evidence: pp. 1-44; 47-52; and 60-61), and about the new FT-SN and SNB transportation and balancing services proposed by TCPL for gas fired generators and others (TCPL Evidence, Section 2.2 and Appendix IB), has also been filed in this proceeding and addressed through Technical Conference on May 16 and 17, 2006.

Based upon the evidence in this proceeding, and discussions at the Settlement Conference, most parties have agreed to a resolution of most of the issues related to the Company's proposed Rate 125, as set out below.

Depending upon the determination of the Threshold Issue set out above, certain parties (CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe) do not support the settlement of issues related to the Company's proposed Rate 125. Specifically, if the Board determines, in response to the Threshold Issue, that any portion of the implementation costs and revenue deficiencies are to be allocated to residential or general service customers, then those parties (CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe) do not agree to any of the proposed changes to Rate 125.

Except as noted in the following paragraphs, which describe the consensus position of all other participating parties on matters discussed at the Settlement Conference, all other parties accept the Company's proposals for its redesigned Rate 125 and agree that the Company will develop for consideration and approval by all parties a Rate Schedule for Rate 125 which incorporates the Company's proposals, as modified by the items set out in the following subparagraphs.

It is the Company's expectation and belief that the Rate 125 proposals accepted in this proceeding will not have any adverse impact on the quality of or access to the utility's existing services. Based upon the current information available to the Company, and the

Company's best estimates, the only rate impacts of the Rate 125 proposals on other customers of the Company are described below at subparagraphs (n) to (r). The rates set out for Rate 125 are set on the basis of the Company's F2006 cost of service costs and, to the extent that relevant costs change in the Company's F2007 rate case, then the rates set out below and in the Company's draft Rate Schedule may also change.

a) At locations where Enbridge Gas Distribution interconnects with Union, Enbridge Gas Distribution will accept nomination changes at the thirteen nomination windows agreed upon between Union and APPrO, with changes becoming effective two hours later. At locations where Enbridge Gas Distribution interconnects with TCPL, and where TCPL has contracted with a shipper for FT-SN service, the Company will also accept and accommodate flow rate nominations at up to 96 nomination windows each day (as proposed by TCPL as part of its planned FT-SN service in TCPL's application to the National Energy Board ("NEB")), assuming that these nomination windows are approved by the NEB. All parties acknowledge and agree that Enbridge Gas Distribution's ability to implement these additional nomination windows is contingent on the customer's use of the nomination windows being offered by and available from upstream transporters (Union, TCPL etc.). To the extent that no hourly balancing requirements are imposed on the Company by upstream transporters, Enbridge Gas Distribution will not impose any hourly balancing requirements itself. The service will be available when additional nomination windows are made available by upstream transporters, but will not be made available until the earlier of the date that the Company's F2007 rates are approved and implemented or the first day of the month following the date that is 12 months after the Board issues its decision or issues approval of this Settlement Agreement, whichever occurs first, in this proceeding in respect of the distribution services described in this Section 1.1.

b) In order to allow customers to take advantage of the redesigned Rate 125, the Company will permit migrating customers to terminate their bundled rate contracts early, subject to the customers having to true up any imbalances in their existing contracts on termination.

c) Enbridge Gas Distribution's proposed redesigned Rate 125 distribution service, like the current Rate 125, will be available on a firm, all-day basis on the earlier of the date that the Company's F2007 rates are approved and implemented or the first day of the month following the date that is 12 months after the Board issues its decision or issues approval of this Settlement Agreement, whichever occurs first, in this proceeding in respect of the distribution services described in this Section 1.1.

d) In-franchise generators that subscribe for Rate 125 service will provide the utility with a day ahead non-binding hourly gas consumption forecast and will use

reasonable efforts to communicate changes from that forecast to assist the Company in managing its system.

e) Enbridge Gas Distribution will permit the pooling of Rate 125 contracts for legally related customers who meet the *Business Corporations Act* (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager will be jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers will remain severally liable for all of their obligations under their own contracts. Customers will not be permitted to change rate classes as a result of contract pooling.

f) Enbridge Gas Distribution will implement, at the same time as its new F2007 rates become effective, an informational posting on daily basis containing information about capacity constraints within the Company's distribution system.

g) The Company will change its cumulative imbalance fee charge from that set out in the draft Rate 125 Rate Schedule (1.895 cents/m^3) to a lower amount (1.004 cents/m^3). This fee is directed to ensuring that Enbridge Gas Distribution recovers its costs associated with the load balancing service component of Rate 125. The reduction in the fee is attributable to an increase in the annual load balancing volumes assumed in the derivation of the fee for incremental storage deliverability. (Exhibit C, Tab 2, Schedule 4, Appendix A, Line 7.0)

h) The Company will amend the description of "Operational Flow Order" found in the draft Rate 125 Rate Schedule (C-2-3, p. 5), so that the second sentence reads "Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:".

i) Enbridge Gas Distribution, in consultation with interested stakeholders, will review its Rate 125 Rate Schedule with a view to clarifying the meaning and application of the notion of "Billing Contract Demand". The updated Rate 125 Rate Schedule will be filed with the Board at the time of the presentation of the Settlement Proposal.

j) Enbridge Gas Distribution intends to make its appropriate distribution services available to any of its customers who subscribe for whatever form of TCPL's FT-SN and SNB service is approved by the NEB. In other words, the Company intends to permit customers taking those TCPL services to also take the Company's appropriate distribution service. The Company notes, however, that its rate schedules may have to be amended to ensure that system integrity and customer service are maintained. For example, as discussed in its Reply Evidence (F-1-1, pp. 3-6), the Company does not believe that it can offer Rate 125

load balancing service to direct connect FT-SN customers, given the way that the FT-SN service is currently proposed.

k) Enbridge Gas Distribution, Union and APPrO agree to convene an Industry Task Force, along with any other interested parties, and will invite all service providers interconnecting with Enbridge Gas Distribution and/or Union. The purpose of the Industry Task Force is to investigate and develop, where feasible, appropriate arrangements for services that would enable Enbridge Gas Distribution and Union to accept nomination changes each hour throughout the day (on a firm/reserved capacity basis) with changes becoming effective two hours later. The Industry Task Force will hold two meetings by September 30, 2006. Enbridge Gas Distribution, Union and APPrO agree to work co-operatively and diligently to investigate and develop, where feasible, appropriate arrangements.

l) Parties recognize that some operating experience with the new Rate 125 and the other rates and services being developed through this proceeding (Rates 300, 315 and 316) is needed before it can be determined whether further modifications to the services and associated rates schedules should be proposed. Parties agree that, once sufficient operating experience has been gained, and in any event no later than March 31, 2009, interested customer groups and Enbridge Gas Distribution will convene to evaluate and discuss the experience and success of the services offered as a result of this proceeding. At that time, any party may propose further modifications to the rate schedules.

m) The Company will incur administrative and staffing costs (estimated at between $250,000 and $750,000 per year, depending upon the number of customers) associated with offering the additional nomination windows described above in subparagraph (a). The Company intends to recover these costs from the parties using the additional nomination windows.

n) As set out at B-3-3, and C-2-4, page 1, the Company's proposed automated solution to support the offering and operation of unbundled rates and services will be used for all unbundled rates (Rates 125, 300, 315 and 316). The Company proposes to recover the costs of this automated solution from all large volume customers in the form of an increased customer charge. The question of when, and how, issues pertaining to the allocation of implementation costs and migration revenue deficiencies should be determined is the subject of the Threshold Issue set out above.

o) If Rate 125 is not confined to new loads only, parties agree that in Enbridge Gas Distribution's F2007 rate case, the Company will present a forecast of migration to the new Rate 125, with the impact of that migration on the Company's distribution

revenue and the rates of other applicable customer classes to be determined by the Board in that proceeding.

p) Parties agree that they will support the Company's request in its F2007 rate case for an Unbundled Rates Customer Migration Variance Account, which will capture the revenue consequences of actual customer migration being different from the revenue consequences of the forecast migration for the new unbundled rates (Rates 125, 300, 315 and 316). The pivot point for the variance account will be the revenue impact of the forecast of migration to new rates, such that if the actual revenue impact is smaller than forecast, there will be a refund to customers in applicable rate classes, and if the actual impact is larger than forecast, additional amounts will have to be collected from customers in applicable rate classes. Parties agree that they will support the clearing of this variance account in this manner at the appropriate time. The question of when, and how, the issues pertaining to the allocation of implementation costs and migration revenue deficiencies should be determined is the subject of the Threshold Issue set out above.

q) Under Enbridge Gas Distribution's proposal, Rate 125 applies to existing and new firm loads greater than of 600,000 m^3 per day. The forecast migration of one existing customer (who has qualified for the rate but has not chosen to migrate to Rate 125 over the past several years) would result in a distribution revenue shortfall to the Company of approximately $1 million. The forecast migration of up to an additional 20 customers to Rate 300 would result in a distribution revenue shortfall to the Company in the range of $400,000 - $700,000. If these migration revenue deficiencies are allocated to each of the large volume rate bundled rate classes under which the migrating customers were previously served, then the estimated distribution rate impacts on these rate classes are as follows:

(i) From the migration of the one customer to Rate 125

Rate 100 – 0%
Rate 110 – 0%
Rate 115 – 12%

(ii) From the migration of the 20 customers to Rate 300

Rate 100 – 3%
Rate 110 – 0%
Rate 115 – 48%

In order to keep all options open for mitigating the potentially adverse rate impacts for Rate 115, IGUA, AMPCO and CME reserve their right to request that the Board limit the availability of Rate 125 to new loads only.

r) All parties accept the proposed threshold for Rate 125 of 600,000 m^3 per day. IGUA, AMPCO and CME's acceptance is on condition that they can request the Board to limit the availability of Rate 125 service to new loads only.

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, Direct Energy, Jason Stacey, OPA, Aegent and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue, except for: (i) CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe, who do not accept the foregoing if any portion of the implementation costs and revenue deficiencies is to be allocated to residential or general service customers; and (ii) IGUA, AMPCO and CME, whose acceptance is on condition that they can request the Board to limit the availability of Rate 125 service to new loads only. =

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
B-1-1 Current Experience
B-2-1 Operational Characteristics and Needs of Power Generation Customers
B-3-1 Operational Characteristics and Issues: Load Balancing
B-3-3 Operational Characteristics, Issues and Proposed Solutions: Rate Implementation
B-4-1 Rate Design Principles and Approaches
C-1-1 Overview of Rate 125
C-2-1 Rate 125
C-2-2 Proposed Tariff for Rate 125
C-2-3 Rate 125 – Draft Rate Schedule
C-2-3 Rate 125 – Derivation of Charges
F-1-1 Reply Evidence – Load Balancing
F-2-1 Response to APPrO evidence (Rates 125 and 316)

APPrO Evidence

Prefiled Evidence of APPrO pp. 1-44; 47-52; and 60-61

TCPL Evidence

Section 2.2 Proposed New Services for Gas Fired Generators
Appendix 1B TransCanada's Application to the NEB for Approval of FT-SN and SNB

Technical Conference Evidence

April 6, 2006 Tr. 38-43, 46-48, 61-76, 91-98, 116-138, 142-153, 155-173, 199-203, 209-215, 218-224 and 240-244 (Enbridge Gas Distribution)

April 27, 2006 Tr. 19-41, 64-85, 93-95, 109-143 and 182-186 (Enbridge Gas Distribution)

May 16, 2006 Tr. 75-125; 161-175 (TCPL)
Tr. 191-195; 209-210 and 226-235 (APPrO)

May 17, 2006 Tr. 28-38, 56-65, 86-96 (APPrO)
Tr. 99-116 (IGUA)

Undertakings

Enbridge Gas Distribution Undertaking #s 1, 2, 6 -9, 11, 15-18, 24, 26-28, 30, 33-38, 44 and 45

1.2 INTERFRANCHISE MOVEMENT OF GAS

COMPLETE SETTLEMENT

Item 4 in the Board's Issues List relating to rates for gas fired generators and other qualified customers asked whether new rates for these customers should include inter-franchise movement of gas. Inter-franchise movement of gas is the ability for direct purchase customers to transfer gas that they have delivered to one utility to another utility in a seamless manner. (Enbridge Gas Distribution evidence: C-4-1, p. 1)

In response, the Company filed evidence proposing that an Enhanced Title Transfer ("ETT") service be introduced to the suite of balancing services made available by Enbridge Gas Distribution. The availability of this service would be dependent on a comparable service offering being made available by the utility whose franchise area the customer wants to transfer the gas into. (Enbridge Gas Distribution evidence: C-4-1, p. 1). The Company's evidence set out how the ETT service would function (C-4-1, pp. 1-6), how it would be costed (C-4-2, pp. 1-2) and included a draft Rate Rider (C-4-3). The Company also filed Reply Evidence explaining difficulties in having ETT transactions carried out at any locations except Dawn. (Enbridge Gas Distribution evidence: F-1-2, pp. 1-2)

It is the Company's expectation and belief that the ETT proposals accepted in this proceeding will not have any adverse impact on the quality of or access to the utility's existing services and will not have any rate impacts on existing customers.

Based upon this evidence, and discussions at the Settlement Conference, parties have agreed to a resolution of this issue, as set out below.

a) All parties accept and agree with Enbridge Gas Distribution's proposal for an Enhanced Title Transfer service to be introduced to the Company's suite of balancing services, as set out at C-4-1, pp. 1 to 6 and C-4-3. This service will not be made available until after the Company's F2007 rates are approved and implemented, but it will be available from and after that time, assuming that other utilities offer a compatible service.

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, TCPL, Direct Energy, Jason Stacey, OPA, Aegent and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
C-4-1 Additional Service Offerings
C-4-2 Additional Service Offerings – Derivation of Charges
C-4-3 Additional Service Offerings – Draft Rate Riders
F-1-2 Reply Evidence – Title Transfers

APPrO Evidence

Prefiled Evidence of APPrO p. 47

Technical Conference Evidence

April 6, 2006 Tr. 48-49 and 102-103 (Enbridge Gas Distribution)
May 17, 2006 Tr. 66 (APPrO)

1.3 REDIRECTION OF GAS

COMPLETE SETTLEMENT

Item 5 in the Board's Issues List relating to rates for gas fired generators and other qualified customers asked whether new rates for these customers should include redirection of gas to a different delivery point on short notice.

In response, the Company filed evidence explaining that "[t]here are currently upstream transportation services and market services that a direct purchase customer can use to effect a redirection of gas. These services are the same services that would be available to a utility. As such, Enbridge Gas Distribution does not see there being any benefit for the utility to establish a service that purely relies on services that participants in the marketplace can already avail themselves to. Any involvement by the utility would only add incremental administration costs to these services." (Enbridge Gas Distribution evidence: C-4-1, p. 6)

It is the Company's expectation and belief that its position on this issue, as accepted in this proceeding, will not have any adverse impact on the quality of or access to the utility's existing services and will not have any rate impacts on existing customers.

Based upon this evidence, and discussions at the Settlement Conference, parties have agreed to a resolution of this issue, as set out below.

a) All parties accept and agree with Enbridge Gas Distribution's evidence at as set out at C-4-1, pp. 6 to 7 which states, in effect, that redirection of gas is a matter for upstream transportation services and the Company is therefore unable to offer any useful or cost-effective redirection of gas service.

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, TCPL, Direct Energy, Jason Stacey, OPA, Aegent and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
C-4-1 Additional Service Offerings
C-4-2 Additional Service Offerings – Derivation of Charges
C-4-3 Additional Service Offerings – Draft Rate Riders

Technical Conference Evidence

April 6, 2006 Tr. 49 (Enbridge Gas Distribution)

1.4 TITLE TRANSFER OF GAS IN STORAGE

COMPLETE SETTLEMENT

Item 6 in the Board's Issues List relating to rates for gas fired generators and other qualified customers asked whether new rates for these customers should include the ability to transfer the title of gas in storage (i.e., the title transfer in gas storage is treated as an administrative matter instead of a physical withdrawal or injection of gas).

In response, the Company filed evidence filed evidence explaining the different considerations that apply for the title transfer of stored gas depending upon whether the contracts have identical or different contract service parameters. (Enbridge Gas Distribution evidence, C-4-1, pp. 7-11; Enbridge Gas Distribution Undertaking #3). The Company initially proposed a service where only an administrative fee would be charged for the title transfer of gas where the contract service parameters (which include withdrawal and injection amounts, ratchet provisions, firm vs. interruptible) are the same for both transacting parties.

It is the Company's expectation and belief that its title transfer of gas in storage proposal accepted in this proceeding will not have any adverse impact on the quality of or access to the utility's existing services and will not have any rate impacts on existing customers.

Based upon this evidence, and discussions at the Settlement Conference, parties have agreed to a resolution of this issue, as set out below.

a) All parties accept and agree with Enbridge Gas Distribution's proposal, as set out at C-4-1, pp. 7 to 11, C-4-2 and F-1-2, which, among other things, allows transacting customers with the same deliverability rights and contractual parameters to transfer title to gas volumes below ground, subject only to an administration fee and without injection or withdrawal charges. The contract parameters that must be the same include:

   - % Withdrawals
   - % Injections
   - Customer inventory within the same deliverability ratchets
   - Quality of service (firm versus interruptible)

   In addition, the Company will permit underground title transfers between in-franchise customers, at the Company's sole discretion based on operational conditions, subject to an administrative fee, without the application of withdrawal and injections charges when the transfer of gas in storage is from a customer with higher withdrawal entitlements to a customer with lower withdrawal entitlements.

Approval of all transactions would be limited to the lesser of the seller's withdrawal limit and the buyer's injection limit.

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, TCPL, Direct Energy, Jason Stacey, OPA and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
C-4-1 Additional Service Offerings
C-4-2 Additional Service Offerings – Derivation of Charges
C-4-3 Additional Service Offerings – Draft Rate Riders

APPrO Evidence

Prefiled Evidence of APPrO pp. 47 and 63

Technical Conference Evidence

April 6, 2006 Tr. 49, 103-104 and 138-140 (Enbridge Gas Distribution)

Undertakings

Enbridge Gas Distribution Undertaking # 3

1.5 STORAGE ALLOCATION METHODOLOGY FOR GAS FIRED GENERATORS (BASE LEVEL DELIVERABILITY)

COMPLETE SETTLEMENT

There is an agreement to settle this issue on the following basis:

Currently, Enbridge Gas Distribution's storage operations are directed at meeting winter demand. The existing Board approved methodology used by the Company for allocating cost based standard storage at 1.2% deliverability is called "excess over average". Under this methodology, storage space is allocated to customers based on the difference between the customer's average winter demand as compared to the customer's average annual demand.

Parties recognize that the current excess over average methodology would not be sufficient or appropriate to meet the profile and needs of gas fired generators. Gas fired generators, like other Enbridge Gas Distribution customers, are entitled to an allocation of cost based standard storage at 1.2% deliverability. A separate storage allocation methodology for cost based standard storage at 1.2% deliverability, subject to the same ratchets as the Company's other ratcheted storage contracts, is appropriate for gas fired generators.

Parties agree that it is appropriate to implement a storage allocation methodology for cost based standard storage at 1.2% ratcheted deliverability for gas fired generators that recognizes the very different characteristics of those customers but which, at the same time, is consistent with the level of storage allocated to existing customers. Currently, the Company's customers only receive an allocation of cost based storage at standard deliverability that meets 57% of the gap between system peak demand and the amount of gas delivered through pipeline supplies. The remainder of this gap is met through other balancing means such as peaking supplies and curtailment. In order to achieve consistency, the Company will limit the storage allocation available to gas fired generators to the same level, such that the allocation of storage at standard deliverability to gas fired generators will be scaled to 57% of the amount of storage at standard deliverability required to meet the gap between demand and pipeline supply.

The allocation methodology for gas fired generators' entitlement to cost based standard storage at 1.2% deliverability is also premised on the following:

a) The storage space requirement to meet gas fired generators' intra day balancing needs is based on the assumption that high deliverability storage is available to those customers in the market.

b) This agreement does not address the pricing or allocation of high deliverability storage, nor does it address whether or when the Company might offer that service using its own assets. In the event that the Company does not offer this service using its own assets, and customers request high deliverability storage from the Company, then the Company will use reasonable efforts to procure this service from third parties for its customers.

c) The storage allocated is offered at rolled-in cost based rates. This means that if the Company has to acquire additional storage capacity to meet the allocations requested by gas fired generators, then the cost of the acquired storage will be aggregated with the cost of the Company's existing storage and a new rolled in rate for all storage will be determined. The Company's best estimate of the impact of acquiring the standard storage at 1.2% deliverability that would be required under the new methodology for gas fired generators, assuming a total of 2000MW of generation capacity, is that the rolled-in cost based rates for storage would increase by approximately 1%.

d) The storage being allocated is subject to system ratchets, which are the standard ratchets applicable to the Company's storage contracts.

e) The storage allocated could be used for service under either Rate 315 or Rate 316 (at standard 1.2% deliverability).

f) Notwithstanding this specific allocation methodology for gas fired generators, a gas fired generator may still request that their base level storage entitlement be determined using the existing excess over average methodology.

The allocation for gas fired generators for cost based standard storage at 1.2% deliverability is as follows:

g) A gas fired generator is assumed to provide gas supply equal to 17 times the maximum hourly demand of the facility. In the event that the plant is not dispatched, up to 17 hours of supply may need to be injected into storage, assuming that storage is the only means of balancing available.

h) Assuming that high deliverability storage at 10% is available to meet the gas fired generator's needs, this would result in a space demand of 17 times the maximum hourly demand, divided by 10%.

i) The space demand that is determined is then multiplied by .57 to determine the amount of cost based standard storage at 1.2% deliverability available to the gas fired generator.

It is the Company's expectation and belief that the storage allocation proposal for gas fired generators accepted in this proceeding will not have any adverse impact on the quality of or access to the utility's existing services. Based upon the current information available to the Company, and the Company's best estimates, the only rate impacts of this proposal on other customers of the Company is described above at subparagraph (c).

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, TCPL, Direct Energy, Jason Stacey, OPA, Aegent and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

APPrO Evidence

PowerPoint Presentation at May 16, 2006 Technical Conference

Technical Conference Evidence

April 6, 2006 Tr. 107-111 and 178-181 (Enbridge Gas Distribution)

April 27, 2006 Tr. 62-64 (Enbridge Gas Distribution)

May 16, 2006 Tr. 198-201 (APPrO)

1.6 RATE 316

NO SETTLEMENT

The Company has filed extensive written evidence about its proposed Rate 316, and has answered questions from all interested parties about this proposed Rate over the course of two days of Technical Conference (April 6 and 27, 2006). The Company's specific proposals for Rate 316, along with a discussion of the pricing for aspects of the proposed Rate, are set out in its prefiled evidence at C-1-1 (Overview), C-3-1 (Rate 316), C-3-3 (Rate 316 – Draft Rate Schedule) and C-3-4 (Rate 316 – Derivation of Charges). Certain of the undertaking responses filed by the Company also relate to the proposed Rate 316.

Evidence about the storage needs of gas fired generators, prepared by APPrO (APPrO evidence: pp. 31-32 and 62; and PowerPoint Presentation at May 16 Technical Conference), has also been filed in this proceeding and addressed through Technical Conference on May 16 and 17, 2006.

While it appears that parties are supportive of many of the technical aspects of the proposed Rate 316, there is disagreement as to whether and how the service would be offered, and what pricing would apply.

In the event that the Company does offer Rate 316 storage service, it is prepared to offer the service using the same nomination windows as agreed to for Rate 125 (described at subsection 1.1(a) of this Settlement Proposal).

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
B-1-1 Current Experience
B-2-1 Operational Characteristics and Needs of Power Generation Customers
B-3-2 Operational Characteristics, Issues and Proposed Solutions: Storage
B-4-1 Rate Design Principles and Approaches
C-1-1 Overview
C-3-1 Rate 316
C-3-2 Proposed Tariff for Rate 316
C-3-3 Rate 316 – Draft Rate Schedule
C-3-4 Rate 316 – Derivation of Charges
F-2-1 Response to APPrO evidence (Rates 125 and 316)

APPrO Evidence

Prefiled Evidence of APPrO pp. 31-32 and 62

Technical Conference Evidence

April 6, 2006

April 27, 2006

May 16, 2006 Tr. 198-201 (APPrO)

Undertakings

Enbridge Gas Distribution Undertaking #s 10, 12, 19-23, 25-28, 39, 40 and 44

4. RATES 300 AND 315

PARTIAL SETTLEMENT

Since at least 2005, largely in response to interest expressed by some of its large volume customers, the Company has been working, in conjunction with stakeholders, on the redesign of its unbundled rates for those customers to make the rates more attractive. In the Company's F2006 rate case (EB-2005-0001), it explained the work that it had been doing, and the factors that were preventing the Company from presenting a proposal for redesigned rates in that case. In the decision in the F2006 rate case, the Board determined that the Company should prepare and present redesigned rates for conventional large volume customers as part of the NGEIR proceeding. (Enbridge Gas Distribution evidence, D-1-1, pp. 1-4)

The Company's proposal for redesigned rates for conventional large volume customers in this proceeding includes unbundled transportation and balancing services (Rate 300), as well as delivered storage service (Rate 315). As outlined in the Company's evidence, these service offerings are the outcome of extensive discussions with stakeholders and are responsive to the Board's Procedural Orders in this proceeding. (Enbridge Gas Distribution evidence: D-1-1, pp. 4-5)

The Company has filed written evidence about its proposed Rates 300 and 315, and answered questions from all interested parties about these proposed offerings at the April 27, 2006 Technical Conference. The Company's evidence about the activity and cost required to implement automated system changes to process unbundled customer transactions is set out at B-3-3. (Operational Characteristics, Issues and Proposed Solutions: Rate Implementation) The Company's specific proposals for Rate 300, along with a discussion of the pricing for aspects of the proposed Rate, are set out in its prefiled evidence at D-2-2 (Rate 300) and D-2-3 (Rate 300 – Draft Rate Schedule). The Company's proposal for Rate 315 is set out at D-3-1 (Rate 315) and D-3-2 (Rate 315 – Draft Rate Schedule). The Company's evidence and proposals addressing the issues inherent in approving and implementing new unbundled rates in the context of this proceeding, which is not a full rates case, is set out at C-1-1 (Proposed Tariffs for Power Generation Customers: Overview).

Based upon this evidence, and discussions at the Settlement Conference, most parties have agreed to a resolution of most of the issues related to the Company's proposed Rates 300 and 315, as set out below.

Depending upon the determination of the Threshold Issue set out above, certain parties (CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe) do not support the settlement of issues related to the Company's proposed Rates 300 and 315. Specifically, if the Board determines, in response to the Threshold Issue, that any portion of the

implementation costs and revenue deficiencies are to be allocated to residential or general service customers, then those parties (CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe) do not agree to any of the proposed changes to Rates 300 and 315.

Except as noted in the following paragraphs, which describe the consensus position of all other participating parties on matters discussed at the Settlement Conference, all other parties accept the Company's proposals for its redesigned Rate 300 and Rate 315 and agree that the Company will develop for consideration and approval by all parties Rate Schedules for Rates 300 and 315 which incorporate the Company's proposals, as modified by the items set out in the following subparagraphs.

It is the Company's expectation and belief that the Rate 300 and 315 proposals accepted in this proceeding will not have any adverse impact on the quality of or access to the utility's existing services. Based upon the current information available to the Company, and the Company's best estimates, the only rate impacts of the Rate 300 and 315 proposals on other customers of the Company are described below at subparagraphs (p) to (v). The rates set out for Rates 300 and 315 are set on the basis of the Company's F2006 cost of service costs and, to the extent that relevant costs change in the Company's F2007 rate case, then the rates set out below and in the Company's draft Rate Schedule may also change.

a) The new Rates 300 and 315 will be made available, on a limited basis at the customer's election on either January 1, 2007 or on April 1, 2007 (in the event that customers find that to be an easier date in terms of transitioning to unbundled storage service).

b) In order to allow customers to take advantage of the new Rates 300 and 315 on January 1 or April 1, 2007, the Company will permit migrating customers to terminate their bundled rate contracts early, subject to the customers having to true up any imbalances in their existing contracts on termination.

c) Initially, the new Rates 300 and 315 will only be available to a maximum of 20 customers. This is because the Company must implement a manual solution to process the activities and transactions involved with these unbundled services until such time as an automated solution is designed and implemented. The manual solution is not feasible for more than 20 customers.

d) As customers sign up for and begin to take service on the new Rates 300 and 315, the Company will evaluate the interest in, the technical, reporting and regulatory need for and the optimum timing for the implementation of an automated solution that will allow larger numbers of customers to take service under these rates (but that will cost in the range of $4 million). Once a decision has been taken to proceed with an automated solution, it will take a minimum of 43 weeks, and

perhaps longer (depending on CIS and GDAR implementation and other currently unknown technical issues) to implement.

e) The Company undertakes to report to customers every three months as to the level of take-up of the new unbundled Rates 300 and 315. As part of this process, within 6 months after the first customers take service under these Rates, the Company will provide customers with its view as to whether and when an automated solution should be developed and put in place.

f) By September 22, 2006, the Company, in consultation with customer representatives, will prepare written materials to support a presentation to customers detailing the nature and operational impact of unbundled services and describing how a customer would take advantage of these services, along with the positives and negatives as well as the changes inherent in unbundled services in comparison to bundled services. Included in these materials will be an explanation of how the "true-up" process will work for customers who terminate their bundled contracts early. The aim of the materials is to provide background for a presentation that will help customers to understand and evaluate the effects of deciding whether to become unbundled customers. The Company will make this presentation to interested customers on or before October 2, 2006. As part of this process, the Company will provide information to customers to allow them to better understand and evaluate the financial impact of making a decision to receive unbundled services.

g) Customers will indicate, on or after October 15, 2006, whether they would like to take the service. If more than 20 customers indicate on October 15, 2006 that they wish to subscribe to the service, then the Company will provide the service to the 10 interested customers who will benefit the most from the service, from a distribution rates perspective, and will use a lottery system to determine the remaining 10 interested customers who will be entitled to subscribe for the service. If fewer than 20 customers indicate on October 15, 2006 that they would like to subscribe for the service, then the Company will continue to accept customers who would like to subscribe for the service, on a first come, first served basis up to a maximum of 20 customers.

h) Parties agree that the levels of penalty provisions in the Company's proposed new Rates 300 and 315 are reasonable. To the extent that these penalty provisions are different from penalty provisions in bundled rates, there are valid reasons for this, relating to the increased risk to system operations from unbundled customers acting inappropriately as compared to bundled customers. These increased risks arise from, among other things, the fact that the Company has less system diversity in relation to unbundled customers on which the Company can rely to

counterbalance the activities of those customers who take service beyond the parameters set out in the applicable rate or contract.

i) The Company will amend the description of "Operational Flow Order" found in the draft Rate 300 Rate Schedule (D-2-2, p. 5), so that the second sentence reads "Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:".

j) The Company agrees to amend the wording in the Rate Schedule for Rate 315 to clarify that it is a firm service, and it is only in rare situations, such as major maintenance or construction projects, that the Company would limit injection and withdrawal rights based on system operating requirements (D-3-2, p. 2). The Company will also add a provision stating that "The Company will provide customers with one week's notice of its intent to limit injection or withdrawal rights and at the same time, shall provide its best estimate of the duration and extent of the limitations."

k) The Company confirms that it will treat bundled and unbundled customers equally in situations where there are operating conditions that impose storage constraints on its system. In such cases, the storage constraints will be applied pro rata against bundled and unbundled customers.

l) The Company agrees that in situations where injection and withdrawal rights are reduced because of system operating conditions, it will proportionately reduce the amount that affected Rate 315 customers will pay for injection and withdrawal. The Company will accomplish this in a manner similar to that employed by Union (demand charge relief) in its C1 Rate Schedule (Union evidence, Appendix L, Schedule A, p. 9, para. 8(b)). Specifically, Union's tariff provides:

> Demand Charge Relief for Storage Services: If on any day Union fails to deliver the quantity of gas nominated (up to the Withdrawal Demand) by reason of an event of force majeure on Union's system, then for that day Union shall credit to Shipper's bill an amount equal to the applicable Daily Demand Rate as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered to Shipper during such day and the quantity of gas which Shipper in good faith nominated on such day. The term "Daily Demand Rate" shall mean the monthly demand charge or equivalent (as stipulated in Article VIII of the Contract) divided by the number of days in the month for which such rate is being calculated.

All parties agree that this aspect of the agreement, and the associated rate impact, can be revisited in future years if the Company determines that it impairs full revenue recovery.

m) The Company agrees that for Rate 315, in circumstances where a customer nominates from storage and system conditions permit, the Company is prepared to permit a customer to nominate either to Dawn or to the customer's delivery area for purposes other than consumption at the customer's own meter.

n) For Rate 300 customers, at locations where Enbridge Gas Distribution interconnects with Union, Enbridge Gas Distribution will accept nomination changes at the thirteen nomination windows agreed upon between Union and APPrO, with changes becoming effective two hours later. At locations where Enbridge Gas Distribution interconnects with TCPL, and where TCPL has contracted with a shipper for FT-SN service, the Company will also accept and accommodate flow rate nominations at up to 96 nomination windows each day, assuming that these nomination windows are approved by the NEB. All parties acknowledge and agree that Enbridge Gas Distribution's ability to implement these additional nomination windows is contingent on the customer's use of the nomination windows being offered by and available from Union and TCPL.

o) All parties accept and agree that nominations under Rate 315 will only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows.

p) The Company agrees that Rate 315 will be made available to customers taking service on Rate 125. The storage allocation methodology for such service is as described above at section 1.5.

q) The Company will incur administrative and staffing costs (estimated at between $250,000 and $750,000 per year, depending upon the number of customers) associated with offering the additional nomination windows described above in subparagraph (a). The Company intends to recover these costs from the parties using the additional nomination windows.

r) Parties agree that a 2006 Unbundled Rate Implementation Cost Deferral Account should be established to collect the Company's costs associated with preparing to offer unbundled rates as of January 1, 2007. This Deferral Account will collect costs such as those related to the development of spreadsheets and procedures necessary to process transactions by unbundled customers, as well as staff hiring and training costs for the personnel who will actually run the manual solution. The Deferral Account will also include costs related to customer education (as described above) and limited EnTRAC changes required for even a manual solution, along with necessary implementation costs.

s) Parties agree to support recovery by the Company in future rate proceedings of all reasonably incurred costs that are placed in the 2006 Unbundled Rate Implementation Cost Deferral Account. When the recovery of costs in this Deferral Account is addressed by the Board, the Company will seek to have these costs recovered from large volume customers. The question of when, and how, the issues pertaining to the allocation of implementation costs and migration revenue

deficiencies should be determined is the subject of the Threshold Issue set out above.

t) If proceeding with an automated solution is required, parties agree that they will support the Company's request in future proceedings for the continuation of the Unbundled Rate Implementation Cost Deferral Account and the recovery by the Company of all reasonably incurred costs involved with this undertaking. The Company's current proposal to recover these costs is set out at C-1-1, page 9, and would involve an increased customer charge for large volume customers, estimated to be in the range of $50 per month. The question of when, and how, the issues pertaining to the allocation of implementation costs and migration revenue deficiencies should be determined is the subject of the Threshold Issue set out above.

u) Parties agree that in Enbridge Gas Distribution's F2007 rate case, the Company will present a forecast of migration to the new Rates 300 and 315, and the impact of that migration on the Company's distribution revenue. Until such time as the F2007 rate case is decided and implemented, the rates for Rate 300 and 315 will be set on the basis of the Company's F2006 cost of service costs. New rates will be set for Rates 300 and 315 in the Company's F2007 rate. The forecast of migration in 2007 will likely also impact on other rates. The Parties agree that they will support the Company's request in its F2007 rate case for an Unbundled Rates Customer Migration Variance Account, which will capture the revenue consequences of actual customer migration being different from revenue consequences of the forecast migration for the new unbundled rates (Rates 125, 300, 315 and 316). The pivot point for the variance account will be the revenue impact of the forecast of migration to new rates, such that if the actual revenue impact is smaller than forecast, there will be a refund to customers in applicable rate classes who have paid too much, and if the actual impact is larger than forecast, additional amounts will have to be collected from customers in applicable rate classes. Parties agree that they will support the clearing of this variance account in this manner at the appropriate time. The question of when, and how, the issues pertaining to the allocation of implementation costs and migration revenue deficiencies should be determined is the subject of the Threshold Issue set out above.

v) Parties agree that, regardless of the regulatory model in place, the Company may adjust the levels of its Rates 300 and 315, as well as the rate classes from which Rate 300 and 315 customers have migrated and any other applicable rate classes, in future years to reflect the impact of the actual levels of customer migration.

Participating Parties: All parties participated in the negotiation and settlement of this issue, except IESO, TCPL, Direct Energy, OPA, Sithe, PEC and Kitchener.

Approval: All participating parties accept and agree with the proposed settlement of this issue, except for CCC, VECC, LIEN, SEC, LMPA, WGSPG and Energy Probe, who do not accept the foregoing if any portion of the implementation costs and revenue deficiencies is to be allocated to residential or general service customers.

Evidence: The evidence in relation to this issue includes the following:

Enbridge Gas Distribution Evidence

A-1-1 Overview and Background
C-1-1 Overview
D-1-1 Overview – Proposed Tariffs for Rate 300 Customers
D-2-1 Rate 300 – Overview, Description and Derivation of Charges
D-2-2 Rate 300 – Draft Rate Schedule
D-3-1 Rate 315 – Overview, Description and Derivation of Charges
D-3-2 Rate 315 – Draft Rate Schedule

APPrO Evidence

Prefiled Evidence of APPrO pp. 1-44; 47-52; and 60-61

Technical Conference Evidence

April 6, 2006 Tr. 46-47, 64-72, 150-153 and 210-212 (Enbridge Gas Distribution)

April 27, 2006 Tr. 14-19, 55-62, 95-99, 154-163 and 173-180 (Enbridge Gas Distribution)

Undertakings

Enbridge Gas Distribution Undertaking #s 1, 2, 13, 14, 23, 27, 29-32 and 41-44

APPENDIX E

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

DECISION ON UNION SETTLEMENT PROPOSAL

NOVEMBER 7, 2006

APPENDIX E
Decision on Union Settlement Proposal

The Union Settlement Proposal described a nearly comprehensive settlement of Issue 1 (rates for gas-fired generators and other qualified customers), Issue III (transportation capacity bidding process and allocation) and one of the issues transferred from Union's fiscal 2006 rates case (power service – M12 service upgrades for power services).

There was one outstanding issue identified in the Union Settlement Proposal relating to priority access to Union's proposed F24-T service. The partial settlement provided for priority to parties who bid on transportation as part of Union's 2007 open season for the related Trafalgar expansion project. This in effect granted priority access to certain power generators. TCPL and Energy Probe opposed this method for priority access. All parties agreed that this issue was severable and that the Board could consider the Union Settlement Proposal separately from this discrete F24-T issue.

The Board heard testimony and submissions on this issue and rendered its decision on June 27, 2006. The Board ruled that Union's proposed allocation of F24-T capacity was not appropriate. The Board found that the ex-franchise Ontario power generator customers should receive priority access to F24-T service and provided its reasons for that determination. The Board at the same time approved the Union Settlement Proposal subject to this ruling with respect to Union's proposed allocation of F24-T capacity.

Union Settlement Proposal Decision
Excerpt from the oral hearing transcript EB-2005-0551,
Volume 11, June 27, 2006, pages 125 line 7 to page 129 line 21.

> MR. KAISER: The first matter relates to the Union settlement agreement, which is approved, subject to the following comments with respect to the F24-T matter. In that regard, the Board approves the rates, but has the following concerns with respect to the allocation that was proposed.

You will recall that Union felt there may be a requirement to ration the initial F24-T service - I think it was estimated at 500,000 gigaJoules a day - and proposed that that be allocated to those that had participated in the 2007 open season expansion.

The Board has concluded this is not the proper manner in which to allocate this capacity for a number of reasons. First, the Dawn-Trafalgar costs are rolled in; Secondly, the facilities are in place to serve all M12 customers; and, finally, the information on the open season with respect to this matter contained no indication of this additional service or that there would be a link between participation in the open season and eligibility for this new capacity.
Instead, the Board has concluded that the exfranchise Ontario Power Generator customers should receive priority. Again, there are three reasons we offer for that.

The first was, of course, that the service was designed primarily with their requirements in mind. The second is that the service is being offered on a pilot basis, and in those circumstances this Board doesn't believe that there is any unjust discrimination, or to use the words of one of the intervenors, the discrimination would be just and warranted.

A draft order has been prepared in this regard, which we would ask you, Mr. Leslie, and other interested parties to review. I don't need to read it at this point. You can review it at your leisure. It gives effect to, in greater detail, the principles that I have stated and exactly which customers will qualify, and further details. The Board can be spoken to if there are any concerns with respect to that, or you can settle it with Commission counsel.

APPENDIX F

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

UNION SETTLEMENT PROPOSAL

NOVEMBER 7, 2006

EB-2005-0551

UNION GAS LIMITED

SETTLEMENT AGREEMENT

June 13, 2006

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EB-2005-0551

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2005-0551, whether it should order Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge") to provide new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other eligible customers) and whether the Board should refrain from regulating the rates for storage of gas.

By its Notice of Proceeding dated December 29, 2005, the Board, on its own motion, commenced a proceeding pursuant to sections 19, 36 and 29 respectively of the *Ontario Energy Board Act, 1998* to determine (i) whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other eligible customers); and (ii) whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

By Procedural Order No. 1 dated January 24, 2006, the Board identified three issues for consideration in the proceeding: (1) Rates for gas-fired generators (and other qualified customers); (2) Storage regulation; and (3) Transportation capacity bidding process and

allocation. The Board indicated that it would receive a settlement agreement on Issues 1 and 3, but that it did not intend to receive a settlement proposal on Issue 2.

In Procedural Order No. 2, the Board noted that it had referred matters concerning Enbridge's 300 series rates to the NGEIR proceeding and added these matters as Issue 4. This issue was added to the matters to be resolved at the Settlement Conference.

In Procedural Order No. 3, the Board moved four issues from Union's 2007 rates proceeding to the NGEIR proceeding. These issues included i) matters relating to market pricing of storage services, ii) Union's proposal to eliminate S&T deferral accounts, iii) Union's proposal to change the blanket storage order, and iv) power services – M12 service upgrades for power services.

The Board scheduled the Settlement Conference to commence May 29, 2006. The Settlement Conference was duly convened with Mr. Chris Haussmann as facilitator. The Settlement Conference was scheduled to proceed until June 2, 2006. Agreement was not reached by June 2, 2006. Settlement discussions continued through to June 13, 2006.

Given that the Board did not intend that parties settle Issue No. 2 (storage regulation) and that Issue No. 4 (Enbridge series 300 rates) is a matter exclusive to Enbridge, this Agreement addresses only matters pertaining to Issue No. 1 (rates for gas-fired generators and other qualified

customers) and Issue No. 3 (Transportation capacity bidding process and allocation). The Agreement identifies the matters for which agreement has been reached. The Agreement is supported by the evidence filed in the EB-2005-0551 proceeding.

Each of the issues identified below falls within one of the following three categories:

1. an issue for which there is complete settlement, because Union and all of the other parties who discussed the issue either agree with the settlement or take no position,
2. an issue for which there is partial settlement, agreed to by Union and a majority of parties but one or more parties do not agree with the settlement,
3. an issue for which there is no settlement.

For the purposes of this Agreement, the term "no position" may include both parties who were involved in negotiations on an issue but who ultimately took no position on that issue and parties who were not involved in negotiations on that issue at all.

It is acknowledged and agreed that none of the completely settled provisions of this Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2005-0551, accept the completely settled provisions of the Agreement in their entirety, there is no Agreement (unless the parties agree that any portion of the Agreement that the Board does accept may continue as a valid Agreement).

Unless otherwise indicated in this Settlement Agreement the terms and conditions for Union's services are as set out in Union's evidence, as amended in these proceedings.

It is further acknowledged and agreed that parties will not withdraw from this Agreement under any circumstances except as provided under Rule 32.05 of the Ontario Energy Board's Rules of

Practice and Procedure.

For greater certainty, the parties further acknowledge and agree that these conditions apply to settled issues in respect of which they are shown as taking no position.

It is also acknowledged and agreed that this Agreement is without prejudice to parties re-examining these issues in any other proceeding, except where a party's rights to re-examine an issue have been specifically limited in this Agreement.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement.

The role adopted by Board Staff in Settlement Conferences is set out on page 5 of the Board's Settlement Conference Guidelines. Although Board Staff is not a party to this Agreement, as noted in the Guidelines, "Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding".

The evidence supporting the agreement on each issue is set out in each section of the Agreement. Abbreviations will be used when identifying exhibit references. For example, Exhibit B1, Tab 4, Page 1 will be referred to as B1/T4 p. 1. There are Appendices to the Agreement which provide

further evidentiary support. The structure and presentation of the settled issues is consistent with settlement agreements which have been accepted by the Board in prior cases. The parties agree that this Agreement and the Appendices form part of the record in the proceeding.

The following parties, as well as Ontario Energy Board hearing staff ("Board Staff") participated in the Settlement Conference:

Aegent Energy Advisors Inc. ("Aegent")

Association of Major Power Consumers in Ontario ("AMPCO")

Association of Power Producers of Ontario ("APPrO")

Canadian Manufacturers & Exporters ("CME")

Consumers Council of Canada ("CCC")

Direct Energy Marketing Inc. ("Direct Energy")

Enbridge Gas Distribution Inc. ("EGD")

Energy Probe Research Foundation ("Energy Probe")

Greenfield Energy Centre LP ("Greenfield")

Independent Electricity System Operator ("IESO")

Industrial Gas Users Association ("IGUA")

London Property Management Association ("LPMA")

Low-Income Energy Network ("LIEN")

Ontario Power Authority ("OPA")

Ontario Power Generation Inc. ("OPG")

Portland's Energy Centre ("Portland's")

School Energy Coalition (“SEC”)

Sithe Global Power Goreway ULC & Sithe Global Power Southdown ULC (“Sithe”)

The Corporation of the City of Kitchener (“CCK”)

TransAlta Cogeneration L.P. & TransAlta Energy Corp (“TransAlta”)

TransCanada Energy Ltd (“TransCanada Energy”)

TransCanada PipeLines Limited (“TCPL”)

Union Gas Limited (“Union”)

Vulnerable Energy Consumer's Coalition (“VECC”)

Wholesale Gas Service Purchasers Group (“WGSPG”)

OVERVIEW

Union Gas has worked with existing and prospective natural gas power generators and affected stakeholders on the development of new services or enhancement of existing services to meet the needs of power generators in a rapidly evolving natural gas power generation marketplace in Ontario. When proposing new services or modifications to existing services Union has adhered to the following guiding principles:

i) The introduction of new services or service enhancements should have no negative impact on the service to existing customers (either financial burden or reduction in service quality).

ii) Under all operating conditions, reliability and integrity of the gas system must be maintained.

iii) Customer requests for flexibility will be accommodated where possible.

iv) The principle of postage stamp rate-making will be adhered to.

v) Alignment with upstream and downstream services will be facilitated to the extent possible.

The new services and service enhancements that form the basis of this agreement are reasonably consistent with the above noted principles. These services contribute to economic efficiency and to the reliability of Ontario's power system.

The allocation of costs to rate classes will continue to be consistent with existing fully allocated cost allocation principles.

This agreement results in changes to the T1 and U7 rate schedules. Updated schedules will be circulated for review by all settlement conference participants and filed with the Board before the end of the evidentiary portion of the NGEIR proceeding.

1 RATES FOR GAS-FIRED GENERATORS (AND OTHER QUALIFIED CUSTOMERS)

Should the Board order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers)? If the Board does order new rates, should that order contain the following requirements:

1.1 MORE FREQUENT NOMINATION WINDOWS FOR DISTRIBUTION, STORAGE AND TRANSPORTATION THAT CORRESPOND WITH THE NOMINATIONS OF UPSTREAM PIPELINES THAT CONNECT TO THE ONTARIO GAS SYSTEM.

(Partial Settlement with the exception of Union's proposal that F24-S, UPBS and DPBS be priced at market based rates. The parties agree that the issue of market based storage pricing is within the ambit of Issue No. 2 (storage regulation) and accordingly beyond the scope of this settlement. TCPL and Energy Probe oppose Union offering new F24-T service first to 2007 transportation expansion shippers.)

The parties accept Union's proposal to develop four (4) new ex-franchise services (recognizing that it is Union's position that development of F24-S, UPBS and DPBS is contingent on the resolution of the storage pricing issue): F24T, F24S, UPBS and DPBS as described in its evidence subject to the following modifications:

- Three additional nomination windows will be provided. The additional nomination windows have nomination deadlines of 12:00, 18:00, and 07:00 with effective times of 14:00, 20:00, and 09:00 respectively. The complete nomination schedule has been attached as Appendix A. The additional nomination windows will provide more flexibility to customers such as power generators and can be provided without the implementation of hourly balancing agreements with upstream and downstream pipelines. The additional nomination windows apply to the receipt of gas from Enbridge, TCPL and Vector and to the delivery of gas to TCPL at Kirkwall and Parkway, all subject to their ability to confirm nominations.
- Union agrees to make the additional nomination windows available to U7 storage, U7 delivery services, and U7 receipts for new customers with loads greater than 1,200,000 m*3 per day.
- Union agrees to make the additional nomination windows available to T1 receipts for new customers with non obigated deliveries and loads greater than 1,200,000 m*3 per day.
- The U7 and T1 rate schedules will be modified to incorporate charges associated with making additional nomination windows available to those customers who elect to take the service. These charges will be cost-based, and will take into account the common IT capital costs and the costs associated with additional staffing associated with making additional nomination windows available for F24-T. The changes to the U7 and T1 rate schedules will be similar to the changes made to the M12 rate schedule to incorporate F24-T.

- Union agrees that it will evaluate the possibility of extending the additional nomination windows and reservation of capacity found in F24-T to the following transportation services:

  i) C1 between Ojibway and Dawn
  ii) C1 between Bluewater and Dawn
  iii) C1 between St. Clair and Dawn
  iv) C1 between Parkway and Kirkwall
  v) C1 transport within the Dawn yard (e.g. between Union Dawn and Vector Dawn)

  Union agrees to provide APPrO and other settlement conference participants with a summary of its findings no later than December 31, 2006.
- Customers may request that nomination changes become effective sooner and Union will use reasonable efforts to accommodate these requests, it being recognized that at the present time and for the foreseeable future Union does not expect to be able to make nomination changes effective sooner than two hours after the nomination.
- Union will also make reasonable efforts to allow large customers (with loads greater than 1,200,000 m3 per day) to take gas prior to a scheduled nomination. The customer will make a request for such service directly to Union's Gas Control Department, and Union will permit such early start-up provided it has no adverse impact on Union's system. Depending on the customer's location, the customer may need approval of Enbridge and TCPL's Gas Control Departments as well.
- The proposed UPBS will allow customers to deliver supply at even hourly flow rates to consume at accelerated flow rates over 4 to16 hours. The parties recognize that higher consumption flow rates will require higher levels of storage deliverability.

- Power generators that subscribe for U7 or T1 services and ex-franchise power generators that subscribe for F24-T, F24-S, UPBS, and DPBS services will provide the utility with a day ahead non-binding hourly gas consumption forecast and will use reasonable efforts to communicate changes from that forecast to assist Union in managing its system.
- Union, Enbridge and APPrO agree to convene an Industry Task Force and will invite all service providers interconnecting with Union and other parties that have expressed an interest. The purpose of the Industry Task Force is to investigate and develop, where feasible, appropriate arrangements for services that would enable Union to accept nomination changes each hour throughout the day (on a firm/reserved capacity basis) with changes becoming effective two hours later. The Industry Task Force will hold its first two meetings no later than September 30, 2006. Union, Enbridge and APPrO agree to work co-operatively and diligently to investigate and develop, where feasible, appropriate arrangements.
- Parties agree that once sufficient operating experience has been gained and in any event no later than March 31, 2009, interested customer groups and Union will convene to evaluate and discuss the experience and success of the services offered as a result of this proceeding. At that time, any party may propose further modifications to the rate schedules.

The parties accept Union's evidence that:

- To maximize the effectiveness of Union offering additional nomination windows, other pipeline operators, storage operators, marketers and producers will need to be able to manage and offer the same nomination windows and be able to confirm nominations on the same two hour schedule.

- F24-T will only be developed if there is 250,000 GJ/day or greater of customer demand (the level of demand used to determine the cost based F24-T rate). The parties are of the view that 250,000 GJ/day of demand is a realistic threshold. Union will offer the new F24-T service first to 2007 transportation expansion customers. Union will then hold an open season to determine if any other customers are interested in the service.
- The availability of F24-S, UPBS and DPBS is dependent upon Union's ability to develop assets to provide incremental storage deliverability.
- There will only be 500,000 GJ/day of F24-T available initially as a result of the 2006 and 2007 expansions of the Dawn-Trafalgar system. This capacity will not be available until the 2007 expansion of the Dawn-Trafalgar system is in service on November 1, 2007. Additional F24-T may become available as a result of future expansion of the Dawn-Trafalgar system and will be made available through an open season process.
- Union requires 12 months to develop the new IT systems required to implement F24-T, F24-S, UPBS and DPBS following a Board Decision and sufficient customer interest to develop the services. Upon the Board accepting this Settlement Agreement, Union will proceed immediately to contact 2007 expansion customers to ascertain their interest in subscribing to the F24-T service and if remaining capacity is available then hold an open season to determine if other existing M12 shippers are interested in the residual capacity. Union expects the open season process to be completed by 30 days after a Board Decision. Union will require approximately 24 months to build additional storage deliverability to provide new incremental high deliverability F24-S, UPBS and DPBS (recognizing that it is Union's position that development of F24-S, UPBS and DPBS are contingent on the resolution of the storage pricing issue).

- IT capital costs and the costs associated with additional staffing required to implement F24-T, F24-S, UPBS and DPBS will be recovered from the customers who elect the new services.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: APPrO, CCC, CME, IGUA, LMPA, LIEN, SEC, CCK, VECC, WPSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: Aegent

Evidence References:

1. Union Evidence - A/T4, D/T1 p.6-11 & p.15-18
2. Union Undertakings - UGL 12, UGL 28, UGL 23A, UGL 23B
3. Intervenor Evidence - APPrO May 1/06, TCPL Issue I (Section 2.2) & Appendix IB May 1/06, IGUA-AMPCO May 1/06
4. Intervenor Undertakings - APPrO 1, APPrO 2, APPrO 3, APPrO 7, TCPL 1, TCPL 2&3

1.2 FIRM HIGH DELIVERABILITY SERVICE FROM STORAGE WITH CUSTOMER OPTIONS FOR 1.2%, 5% AND 10% DELIVERABILITY.

(Complete Settlement with the exception of Union's proposal to price firm deliverability greater than 1.2% at market based rates. The parties agree that the issue of market based storage pricing is within the ambit of Issue No. 2 (storage regulation) and accordingly beyond the scope of this settlement.)

The parties agree that new T1 and U7 customers with non-obligated supply shall be entitled to contract for T1 and U7 storage service with firm storage deliverability up to 24 times the customer's peak hourly consumption and storage space up to 24 times the customer's peak

hourly consumption multiplied by 4 days. Should a customer elect to contract for firm storage deliverability that is less than the maximum entitlement, the maximum storage space that a customer is entitled to at cost shall be ten times the firm storage deliverability contracted for. In no event, shall the storage space exceed the maximum storage space entitlement previously described. Storage space with 1.2% firm deliverability will be available at cost based rates. Storage deliverability above base firm deliverability of 1.2% up to the customer's firm CD shall be made available by Union to in-franchise customers in a manner to be determined by the Board as part of Issue No. 2.

To the extent that a power generator does not contract for firm storage deliverability and chooses instead to rely on interruptible storage deliverability, there is no assurance that storage deliverability will be available on peak days.

An example of how these provisions may apply in specific circumstances is attached as Appendix B.

In the event of a conflict between the language of this section and the calculations shown on the attached examples, it is the parties' intention that the calculations shown in the examples shall govern the interpretation of this section.

The settlement of this issue has no identifiable adverse impacts on existing customers because the provision of storage services to these new T1 and U7 customers does not involve the "claw back"

of storage space or deliverability from existing customers and the costs associated with new high deliverability storage services will be recovered from the customers involved.

The following parties agree with the settlement of this issue: APPrO, CCC, CME, Energy Probe, IGUA, LMPA, LIEN, SEC, CCK, VECC, WGSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: Aegent, TCPL,

Evidence References:

1. Union Evidence - A/T3 p.30, A/T4 p.42, D/T1 p.2-5, D/T2 p.10, 18, 20, Appendix B
2. Union Undertakings - UGL 3, UGL 9, UGL 12, UGL 24, UGL 28
3. Intervenor Evidence - APPrO May 1/06

1.3 GAS STORAGE AND DISTRIBUTION OFFERED AS DISCRETE SERVICES.

(Complete Settlement)

The parties acknowledge that Union's current U7 service allows for storage and distribution services to be contracted for as discrete services, and that Union's T1 service allows for distribution services to be contracted with or without storage services.

New T1 (or U7) Firm Billing Contract Demand Levels

Parties agree that effective January 1, 2007, for new T1 and U7 customers with loads greater than 1,200,000 m*3 per day, that are directly connected to i) the Dawn-Trafalgar transmission system in close proximity to Parkway or ii) a third party pipeline, Union will allow the customer's firm Billing Contract Demand level to be set at a level that recognizes the economics of the facilities used to serve the customer over the contract term (i.e., annual revenues over the term of the contract that would enable Union to recover the invested capital, return on capital and O&M

costs of the dedicated service in accordance with its system expansion policies). Daily deliveries that exceed the firm Billing Contract Demand quantity will be subject to cost related authorized overrun charges as specified in the T1 and U7 rate schedule (where authorized overrun charges are set using the demand charge of the first block of T1 and U7 rate schedule and the applicable commodity charge unitized at 100% load factor). This approach to establishing the firm Billing Contract Demand level of a new T1 and U7 customer's contract is similar to a feature approved by the Board for Enbridge's Rate 125 service.

As a result of this agreement, the parties agree that Union's proposal to redesign the T1 firm transportation service by:

i. Replacing the current two block declining demand charge structure with a four step block demand rate structure, and

ii. Replacing the two block declining commodity charge with a single commodity charge applicable to all firm T1 transportation customers,

is no longer required and is withdrawn as part of this settlement. Union's proposed T1 redesign was a response to the Board's comments and findings in the RP-2005-0022/EB-2005-0411 GEC Decision.

Delivery Obligations

a) <u>West of Dawn:</u> For new T1 or U7 customers and for existing customers with new firm incremental loads greater than 1,200,000 m3 per day, at the customer's option there will be no obligated DCQ requirement, subject to the facilities required to support the incremental load being economic.

b) T1 Customers East of Dawn who have their Firm Billing Contract Demand set at a level that recognizes the economics of the facilities used to serve the customer as described above (New T1 (or U7) Firm Billing Contract Demand Levels): New T1 customers and existing customers with new firm incremetal loads greater than 1,200,000 m3 per day have the following options:

i) The customer could deliver a daily obligated supply at Parkway equal to 100% of their firm CD (i.e. 24 times their peak hour firm delivery entitlement).

ii) The customer could commit to M12 Dawn-Parkway transmission capacity sufficient to meet 100% of their firm CD (i.e. 24 times their peak hour firm delivery entitlement). The customer must assign the right to use the M12 Dawn-Parkway transmission capacity to Union to allow Union to manage the firm redeliveries to the plant on a no-notice basis. For greater clarity, this allows the customer to purchase all their gas supply at Dawn on a non-obligated basis, yet operate with the no-notice benefits of the T-1 service.

iii) Any combination of the above.

c) U7 Customers East of Dawn who have their Firm Billing Contract Demand set at a level that recognizes the economics of the facilities used to serve the customer as described above (New T1 (or U7) Firm Billing Contract Demand Levels): New U7 customers and existing customers with new firm incremetal loads greater than 1,200,000 m3 per day have the following options:

i) The customer could maintain arrangments sufficient to meet their Parkway call-back provision equivalent to 100% of their firm CD.

ii) The customer could elect to deliver their supply at Parkway in the same hourly pattern as their plant is consuming. This option requires modifications to the terms and conditions of the U7 service. This option is conditional on the Industry Task Force identified in Issue 1.1 developing appropriate arrangements that will permit Union to accept hourly nominations and possibly TCPL's proposed FT-SN being approved by the NEB.

iii) Any combination of the above.

d) T1 Customers East of Dawn who have not had their Firm Billing Contract Demand set at a level that recognizes the economics of the facilities used to serve the customer as described above (New T1 (or U7) Firm Billing Contract Demand Levels): New T1 customers and existing customers with new firm incremetal loads greater than 1,200,000 m3 per day have the following options:

i) The customer could deliver a daily obligated supply at Parkway equal to 80% of their firm CD (the current firm T1 rate class average load factor).

ii) The customer could commit to M12 Dawn-Parkway transmission capacity sufficient to meet 80% of their firm CD (i.e. 24 times their peak hour). The customer must assign the right to use the M12 Dawn-Parkway transmission capacity to Union to allow Union to manage the firm redeliveries to the plant on a no-notice basis. For greater clarity, this allows the customer to purchase all their

gas supply at Dawn on a non-obligated basis, yet operate with the no-notice benefits of the T-1 service.

iii) Any combination of the above.

e) U7 Customers East of Dawn who have not had their Firm Billing Contract Demand set at a level that recognizes the economics of the facilities used to serve the customer as described above (in the New T1 (or U7) Firm Billing Contract Demand Levels section): New U7 customers and existing customers with new firm incremetal loads greater than 1,200,000 m3 per day have the following options:

i) The customer could maintain arrangments sufficient to meet their Parkway call-back provision equivalent to 80% of their firm CD.

ii) The customer could elect to deliver their supply at Parkway in an amount equivalent to at least 80% of their hourly consumption. This option requires modifications to the terms and conditions of the U7 service. This option is conditional on the Industry Task Force identified in Issue 1.1 developing appropriate arrangements that will permit Union to accept hourly nominations and possibly TCPL's proposed FT-SN being approved by the NEB.

iii) Any combination of the above.

All of the foregoing delivery obligation options avoid costs that would otherwise be incurred and that would otherwise be borne by other ratepayers.

Multiple Redelivery Points

Union will permit multiple T1 (or U7) redelivery points not under common ownership provided the deliveries are managed by a common "fuel manager". Each redelivery point will need to individually meet the minimum qualifications for the T1 (or U7) rate schedule. Management by a common fuel manager will have no impact on the calculation of delivery charges applicable to each redelivery point. In addition, a fully binding agency agreement with the fuel manager will be required for each of the redelivery points. The fuel manager will be responsible for providing the necessary required credit to Union to cover the prudential requirements of all of the redelivery points. The fuel manager will be responsible for all of the redelivery points in aggregate. The fuel manager will receive the total monthly T1 invoice. The fuel manager will be jointly liable with each of the redelivery point contracting parties for all of their obligations under the contract while the individual redelivery point contracting parties will remain severally liable for their obligations related to their individual redelivery portion of the bill.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: Aegent, APPrO, CCC, CME, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: CCK, TCPL

Evidence References:

1. Union Evidence - A/T3 p.2-12, 31, Supplemental A/T3, A/T4 p.43, D/T1 p.11-15 & p.18-20
2. Union Undertakings - UGL 1, UGL 2, UGL 5, UGL 6, UGL 10, UGL 11, UGL 14, UGL 17, UGL 18, UGL 19, UGL 22, UGL 25, UGL 26, UGL 28, UGL 52D
3. Intervenor Evidence - APPrO May 1/06, APPrO May 26/06, IGUA-AMPCO May 1/06, TCPL Issue I (Section 2.2) & Appendix IB May 1/06
4. Intervenor Undertakings - APPrO 1, IGUA 1

1.4 INTER-FRANCHISE MOVEMENT OF GAS (I.E., THE ABILITY TO ACCESS SERVICES ACROSS ONTARIO, WHETHER TO A CUSTOMER'S OWN ACCOUNT OR AS A SALE TO A THIRD PARTY).

(Complete Settlement)

The parties accept Union's current range of services that permit the redirection or acquisition of gas on short notice subject to Authorization Notice. These services were described in Appendix B to Union's evidence and include in-franchise transfers, ex-franchise transfers, DCQ assignments, suspensions, diversions, incremental supplies, loans, short-term storage and the Discretionary Gas Supply Service (DGSS). Union believes that its services align with Enbridge's proposed Enhanced Title Transfer service if settlement occurs daily.

Provided that customers remain within firm contractual parameters, it is acknowledged that customer's rights to divert or redirect gas should not be constrained or impeded by Union unless there are physical constraints on Union's system.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: APPrO, CCC, CCK, CME, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: Aegent, TCPL

Evidence References:

1. Union Evidence - A/T3 p.31
2. Intervenor Evidence - APPrO May 1/06, CCK May 1/06, TCPL Issue I May 1/06

1.5 REDIRECTION OF GAS TO A DIFFERENT DELIVERY POINT ON SHORT NOTICE (I.E. THE ABILITY TO REDIRECT OR ACQUIRE GAS ON SHORT NOTICE TO A DIFFERENT DELIVERY POINT).

(Complete Settlement)

The parties accept Union's current range of services that permit the redirect or acquisition of gas on short notice subject to Authorization Notice. These services were described in Appendix B to Union's evidence and include in-franchise transfers, ex-franchise transfers, DCQ assignments, suspensions, diversions, incremental supplies, loans, short-term storage and the Discretionary Gas Supply Service (DGSS).

Provided that customers remain within firm contractual parameters, it is acknowledged that customer's rights to divert or redirect gas should not be constrained or impeded by Union unless there are physical constraints on Union's system.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: APPrO, CCC, CCK, CME, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: Aegent, TCPL,

Evidence References:

1. Union Evidence - A/T3 p.31
2. Intervenor Evidence - APPrO May 1/06
3. Intervenor Undertakings - APPrO 1

1.6 THE ABILITY TO TRANSFER THE TITLE OF GAS IN STORAGE (I.E. THE TITLE TRANSFER IN GAS STORAGE IS TREATED AS AN ADMINISTRATIVE MATTER INSTEAD OF A PHYSICAL WITHDRAWAL OR INJECTION OF GAS).

(Complete Settlement)

The parties agree that underground title transfers shall be permitted between in-franchise customers (T1, T3, U7 and U9) with like and similar storage services subject to an administrative fee, without the application of withdrawal and injections charges. The contract parameters that must be the same include:

- % Withdrawals
- % Injections
- Supplier of deliverability inventory (customer supplied vs. Union supplied)
- Customer inventory within the same deliverability ratchets
- Quality of service (firm versus interruptible)

In addition, Union will permit underground title transfers between in-franchise customers on a interruptible basis (T1, T3, U7 and U9) subject to an administrative fee, without the application of withdrawal and injections charges when the transfer of gas in storage is from a customer with higher withdrawal entitlements to a customer with lower withdrawal entitlements.

Title transfers will be contracted for through Authorization Notices. Approval of all transactions would be limited to the lessor of the seller's withdrawal limit and the buyer's injection limit.

The settlement of this issue has no identifiable adverse impacts on existing customers.

The following parties agree with the settlement of this issue: Aegent, APPrO, CCC, CCK, CME, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG, Sithe, TransCanada Energy, Portlands

The following parties take no position on this issue: TCPL,

Evidence References:

1. Union Evidence - A/T3 p.32-37
2. Union Undertakings - UGL 23B
3. Intervenor Evidence - APPrO May 1/06, TCPL Appendix IA May 1/06
4. Intervenor Undertakings - APPrO 1

3 TRANSPORTATION CAPACITY BIDDING PROCESS AND ALLOCATION

3.1 SHOULD THE BOARD ALLOW A GAS TRANSMITTER TO CHARGE A PREMIUM ABOVE COSTS FOR GAS TRANSMISSION SERVICES AND, IF SO, HOW SHOULD THAT PREMIUM BE ALLOCATED?

(Complete Settlement)

On May 15th, 2006 Union submitted for the Board's review and approval a comprehensive Settlement Agreement between Union Gas and various intervenors, as part of the EB-2005-0520 proceeding. This Settlement Agreement included complete settlement of Issue 6.10 "Are the terms and conditions of M12 and C1 services, including the proposed rate schedule changes, appropriate (excluding the consideration of potential new services for power producers)?".

As part of this Agreement, Union agreed to some future actions which were anticipated to result in settlement of NGEIR Issue III. Specifically, Union proposed and the stakeholders accepted the following:

"In the event the Board approves this Settlement Agreement, Union will send a letter to the Board panel presiding over the NGEIR proceeding (supported by TCPL) providing for the following:

1. Union agrees to amend the contracts of the Parties that bid a premium in the 2006 and 2007 open seasons to remove the premium. These customers would then pay the posted M12 toll only. This would reduce Union's revenue forecast for 2007 by $150,000.
2. Union agrees to develop, prior to its next open season, an allocation procedure which defines the criteria by which Union will allocate long term firm transportation capacity for expansion, promptly post it on its web site, and notify shippers of any changes six months in advance.
3. Union will include in its allocation procedure or otherwise, a requirement that Union identify in its open season documents any anticipated capacity constraints, if a constraint is expected, and
4. Union agrees to not use bid premium as a criterion for allocating long term firm transportation capacity in the future."

The following parties agreed with the settlement of this issue in the EB-2005-0520 proceeding: CME, FONOM & the Cities, CCK, CCC, EGD, Energy Probe, IGUA, LPMA, SEC, Sithe, TransAlta, TCPL, WGSPG

The following parties took no position on this issue in the EB-2005-0520 proceeding: Coral, LIEN, OAPPA, OESLP, SEM, VECC

The settlement of this issue has no identifiable adverse impacts on existing customers other than the reduction in the 2007 revenue forecast of $150,000.

The following additional parties in this proceeding agree with the settlement of this issue:

APPrO, Sithe, TransCanada Energy, Portlands

The following additional parties in this proceeding take no position on this issue:

Evidence References:

1. Union Evidence - A/T5 p.1-3, Letter filed with Board re Settlement of Issue III dated May 15, 2006
2. Union Undertakings - UGL 52a, UGL 52d, UGL 52e, UGL 52f, UGL 52g
3. Intervenor Evidence - APPrO May 1/06, TCPL Issue III & Appendix IIIA May 1/06, IGUA AMPCO May 1/06
4. Intervenor Undertakings - APPrO 1, TCPL 4

EB-2005-0551
Appendix A

Nomination Window Schedule

June 10th Gas Day Nom Cycles	Nom #	Nomination deadline	Effective Time	Elapsed Hours	Remaining Hours
Timely Nom*	1	12:45 June 9	10:00 June 10	0	24
Evening Nom*	2	19:00 June 9	10:00 June 10	0	24
STS 1**	3	10:00 June 10	12:00 June 10	2	22
Intraday 1*	4	11:00 June 10	18:00 June 10	8	16
12:00	5	12:00 June 10	14:00 June 10	4	20
14:00	6	14:00 June 10	16:00 June 10	6	18
STS 2**	7	16:00 June 10	18:00 June 10	8	16
18:00	8	18:00 June 10	20:00 June 10	10	14
Intraday 2*	9	18:00 June 10	22:00 June 10	12	12
STS 3**	10	0:00 June 11	02:00 June 11	16	8
STS 4**	11	04:00 June 11	06:00 June 11	20	4
6:00	12	06:00 June 11	08:00 June 11	22	2
7:00	13	07:00 June 11	09:00 June 11	23	1

***NAESB Windows**

****TCPL STS Windows**

*** and**:** **Future changes to these common industry windows will change Union's schedule of nomination windows.**

All windows are scheduled in Ontario Clock Time.

Storage Deliverability and Space Allocation Example

100 MW Combined-Cycle Generating Plant

Firm Max Hour (GJ)	791
Firm Peak Day (GJ)	18,984
Max Firm Space (GJ)	75,816

Contracted Firm Deliverability			Max Firm Space Entitlement	% Deliverability	Cost-Based Deliverability		Deliverability Days
% Peak Day	Hours of Use	GJ/day			GJ/Day	% of Total	
A	B	C	D (C x 4 days)	E (C/D)	F (D x 1.2%)	G (F/C)	H (D/C)
100%	24.0	18,984	75,936	25.0%	911	4.8%	4.0
90%	21.6	17,086	75,936	22.5%	911	5.3%	4.4
80%	19.2	15,187	75,936	20.0%	911	6.0%	5.0
70%	16.8	13,289	75,936	17.5%	911	6.9%	5.7
60%	14.4	11,390	75,936	15.0%	911	8.0%	6.7
50%	12.0	9,492	75,936	12.5%	911	9.6%	8.0
40%	9.6	7,594	75,936	10.0%	911	12.0%	10.0
30%	7.2	5,695	56,952	10.0%	683	12.0%	10.0
20%	4.8	3,797	37,968	10.0%	456	12.0%	10.0
10%	2.4	1,898	18,984	10.0%	228	12.0%	10.0

APPENDIX G

NATURAL GAS ELECTRICTY INTERFACE REVIEW
DECISION WITH REASONS
BOARD FILE NO. EB-2005-0551

DECISION ON MHP CANADA'S CORE POINTS

NOVEMBER 7, 2006

APPENDIX G
Decision on Market Hub Partners Canada's Core Points

As part of its evidence and submission to the Board in the context of the NGEIR Proceeding, Market Hub Partners Canada L.P. ("MHP Canada") made a request for an expedited decision on certain "Core Points".

The "Core Points" are described in MHP Canada's pre-filed evidence as follows:

(i) MHP Canada cannot exercise market power;

(ii) MHP Canada, similar to independent storage developers, will be granted authority to charge market-based rates for its services; and

(iii) MHP Canada will be allowed flexibility to contract for services without requiring approval of individual contracts, provided that MHP Canada operates within a base set of service terms and conditions approved by the Board.

The "Core Points" were addressed by the Board in the NGEIR Proceeding as a result of a reference from the St. Clair Pool Storage Project proceeding (EB-2006-0162 and EB-2006-0165).

On August 11, 2006, the Board issued a Notice of Reactivated Proceeding (Notice) in relation to the St. Clair Pool Storage Project. In the Notice, the Board stated that it did not intend, in the St. Clair Pool Storage Project proceeding, to consider evidence or issue a decision in relation to MHP Canada's request for a market-based rate pursuant to section 36 of the *Ontario Energy Board Act, 1998* (EB-2006-0162), nor to consider the evidence or issue a decision in relation to MHP Canada's request for approval to enter into agreements for storage services pursuant to section 39(2) of the *Ontario Energy Board Act, 1998* (EB-2006-0165). In the Notice, the Board stated that these two issues would be addressed in the NGEIR Proceeding.

On September 7, 2006, the Board issued its oral decision on MHP Canada's Core Points. In its decision, the Board addressed each of the "Core Points". The relevant transcript excerpt from the NGEIR Proceeding, which contains the Board's oral decision on the Core Points, can be found below. The Board also ordered MHP Canada to file with the Board and deliver to all registered intervenors in the St. Clair Pool Storage Project Proceeding (EB-2006-0165) as directed in the Board's oral decision dated September 7, 2006 (EB-2005-0551) copies of its proposed standard terms and conditions for storage contracts.

MHP Core Points Decision
Excerpt from the oral hearing transcript EB-2005-0551, Volume 17, September 7, 2006, page 166 line 5 to page 175 line 26.

> MR. KAISER: Thank you. There's one outstanding matter we'd like to deal with, that with your indulgence, will take a few moments. And that relates to the request by Market Hub Partners for a decision on certain core issues, which we'll deal with at this point.
>
> Market Hub Partners Canada has requested an expedited decision on three issues which relate to the Partnership's proposed St. Clair storage operations. These issues have arisen in this proceeding, the Natural Gas Electricity Interface Review, as a result of a reference from another proceeding.
>
> Market Hub filed an application before the Board some time ago for approval of market-based rates that will govern gas storage contracts to be entered into by the Partnership. That proceeding was adjourned, and then subsequently, on June 30th, the Partnership requested it be reactivated.
>
> The Board issued a notice of reactivated proceedings on August 11th, referring these three core issues to this proceeding. Market Hub, as we know, has participated and intervened in this proceeding, has filed evidence, and argument.
>
> By way of background, Market Hub Partners is a Partnership that is wholly owned by subsidiaries of Duke Energy Corporation. The Partnership was established to develop natural gas storage facilities in Southwestern Ontario near Dawn, where it intends to offer merchant storage service at market-determined prices directed to wholesale customers.
>
> The Partnership is currently developing its St. Clair Pool, which will provide 1.1 Bcf of working gas capacity.
>
> As indicated, Market Hub has reactivated its application to the Board for a

number of regulatory approvals related to that facility, including the determination regarding market-based pricing.

Market Hub also intends to develop, through a partnership, a further 5.3 Bcf of working gas capacity at the Sarnia Airport Pool and has also indicated it will seek development opportunities to increase its working gas capacity to 10 Bcf by 2010.

The request by Market Hub for an expedited decision on these three core points was set out in its July 20th letter to the Board, and it was also addressed in some detail in Market Hub's August 11th written argument.

Specifically, the three questions are as follows. Market Hub has asked the Board to find that Market Hub:
One, cannot exercise market power; two, be granted authority to charge market-based rates for its services; and three, be allowed flexibility to contract for services without requiring approval of individual contracts, provided that Market Hub operates within a base set of service terms and conditions approved by the Board.
So those are the three issues that are before us today.

It should be pointed out that Market Hub has indicated that the term "authority to charge market-based rates" means the authority to charge rates within the Union Gas C1 rate range, which would be in effect from time to time.

The Partnership had previously asked that a decision on these core points be reached by the end of August in order to commit to necessary contractors, to conduct its open season, and to continue the regulatory approval process.

It's important to note that Market Hub has not asked the Board to make an expedited decision about whether it will or will not forbear from regulating storage prices charged by Market Hub Partners or any other storage operator. This is set out in the August 11th written argument, which I will quote:

> To be clear, Market Hub Partners Canada's request for an expedited decision on the Core Points is intended only to provide Market Hub Partners Canada with the confidence to move the St. Clair project plans forward such that the incremental storage services can be offered to the market commencing in 2007. The request to an expedited decision does not substitute in any way for the forbearance decision ...

And that appears at page 29 of the Market Hub argument.
Before reaching the decision on this, it's useful to set out the position of the parties on this issue.

The final arguments of the parties on August 28th and 29th dealt with a number of issues in this proceeding. Although most of the intervenors did not deal in any detail with the Market Hub request, there were, however, four parties that did make some comments.

First, the Board hearing team took the position that because of MHP's status as an affiliate of Union, a decision on the core points was, in effect, a decision on the merits of Union's position. Accordingly, the Board hearing team concluded that an expedited decision would not be appropriate.

IGUA and AMPCO said that Market Hub Partners cannot exercise market power by itself and concurred with granting Market Hub Partners the authority to charge market-based rates.

With respect to the issue of contract approval, Mr. Thompson, the counsel for IGUA, raised the question as to whether waiving the Board's approval of storage contracts - which was the third point Market Hub asked the Board to address - would be consistent with the Board's treatment of contracts entered into by Tribute Resources, an independent Ontario storage developer that received approval to charge market-based rates. And that decision is the Board's decision of June 17th of this year, the reasons for which were issued on August 25th.

The final argument of the School Energy Coalition did not address Market Hub's core points directly but did state that, in its view, Market Hub, because they're affiliated with Union, would have market power.

And finally, London Property Management Association and the Wholesale Gas Services Purchasers Group argued that prices charged for utility affiliate storage should not be regulated.

I'd like to deal first with this question of market power. And that, as I have said, is one of the core points.

The gas storage capacity that Market Hub proposes to develop in Ontario is relatively small. The St. Clair Pool as proposed would have a capacity of 1.1 Bcf. The Sarnia Airport Pool as proposed, which may be in service in 2008, would have a capacity of 5.3 Bcf.

In the Board's view, even on the narrowest definition of a geographic market as advanced in this case, the total capacity of these two pools would be less than 3 percent of the market capacity. The Board believes it can easily conclude that Market Hub Partners, if considered separate from Union, cannot wield market power today or even when its proposed storage pools become operational.

The Board also notes that, with the exception of Schools, no party has explicitly asserted that Market Hub will have market power.

Market Hub and Union Gas are affiliates and are under common control. The Board in this hearing has heard considerable evidence that affiliate relations can affect market power and the determination of market power.

A number of parties have referred to the FERC regulations in this area, which have been recently reconfirmed by Order No. 678.

The relevant part of those regulations states as follows:

> Capacity (transportation, storage, LNG, or production) owned or controlled by the applicant and affiliates of the applicant in the relevant market shall be clearly and fully identified and may not be considered as alternatives competing with the applicant. Rather, the capacity of an applicant's affiliates is to be included in the market share calculated for the applicant.

That's a reference to the FERC regulation paragraph 284.503(b)(4).

If the Board were to follow FERC policy in this particular case, the Board would be first required to make a determination as to whether Union has market power, an assessment it has not yet made, before it could determine whether Market Hub had market power.

This is the concern that appears to be expressed by the Board hearing team and Schools in arguments that they have filed.

Given the specific circumstances of Market Hub as outlined above, the Board has concluded that it's not necessary to combine Market Hub's proposed storage capacity with Union's capacity to determine whether Market Hub lacks market power.

Market Hub Partners is proposing to develop only a small amount of new storage capacity. It has no existing customer base and, unlike Enbridge and Union, does not have any in-franchise or captive customers.

The Board will require Market Hub to offer its storage service to the market in a non-discriminatory fashion, to adhere to the Affiliate Relationships Code for gas utilities, and, as volunteered by Market Hub, to file confidentially with the Board information on all of its storage transactions.

The Board is of the view that these requirements will minimize any concerns that Market Hub and Union Gas will be acting in concert. Accordingly, the Board finds that Market Hub partners cannot exercise market power.

Turning next to the issue of market-based rates, the Board in its NGF report

stated - and this is at page 50 - that it will not fix cost-of-service rates for new storage developed by independent storage operators.

The Board has approved market-based rates for Tribute Resources, a new independent storage developer, and that's the decision I referred to earlier.

Given that the Board has determined that Market Hub cannot exercise market power, the Board finds it is appropriate to grant Market Hub the same treatment it has accorded Tribute.

The Board also notes that many of the parties argued that market-based rate authority would provide an appropriate stimulus for new storage development.

Accordingly, the Board will permit Market Hub Partners to charge market-based rates; that is, rates that are subject to the maximums set out in Union Gas' rate schedule C1.

The third issue relates to contract approvals and the request of Market Hub in that regard.

Section 39(2) of the OEB Act prohibits storage companies from entering into or renewing an agreement for gas storage unless the Board has approved the parties to the agreement, the period of the agreement, and the storage that is subject to the agreement.

Market Hub says that the process and time involved in obtaining these approvals is not consistent with the needs of a competitive market, particularly the short-term storage or transactional market. This is set out at page 27 of the Market Hub argument.

As a new market entrant with no existing customer base, Market Hub is understandably concerned about potential barriers to signing customers. Even if the time and cost of contract approval were minimal, the Board is not aware of any compelling public interest reason to pre-approve the storage contracts of Market Hub Partners.

In the past, the Board has given blanket storage orders that effectively exempt storage operators from seeking the Board's pre-approval of storage contracts that meet certain conditions. The Board considered that approach in this case with respect to Market Hub Partners; however, in light of the Board's determination that Market Hub cannot exercise market power, the Board has decided that it can forbear from requiring pre-approval of MHP's storage contracts.
Again, the Board notes that there was general support for this approach by all parties to this proceeding.

The Board wants to stress, however, that this forbearance is only with respect to Section 39(2) of the OEB Act and only in respect of MHP. The Board has not yet made any determination as to whether to forbear from regulating storage rates or approving storage contracts more generally.

MHP's request to the Board referred to a base set of terms and conditions approved by the Board. The Board will require MHP to file its proposed standard terms and conditions in EB-2006-165, a proceeding that's currently underway with respect to the St. Clair project.

With respect to any contracts between Union and MHP, the Board will be engaged in this matter through its regulation of Union. The Board's Affiliate Relationships Code for Gas Utilities applies to the terms and conditions of those contracts. The Board will also have the ability to carry out a prudence review of such contracts as part of its regulation of Union.

And the Board will be considering, as part of its deliberation on the issues in this case, whether to require pre-approval of storage contracts between regulated distributors and affiliates.

Now, I would add here that, in argument today, Mr. Smith has requested a clarification of the current ARC guidelines. This decision will not deal with that, but it will be dealt with in the main decision.

I trust that's satisfactory, Mr. Smith.

Finally, as to reporting requirements, as the Board considers the issues in this hearing, it will be considering reporting requirements for all storage operators. Several parties have advocated that the Board require storage operators to make public certain contract information and other data. Market Hub should be aware that this decision not to require Board approval of Market Hub contracts is not an indication that the Board has made any decision on the extent of reporting obligations of storage operators generally.

We would ask you, Mr. Smith, to prepare and file a draft Order in accordance with this decision, if possible, within 15 days.

MR. SMITH: Yes, sir.

MR. KAISER: Possibly earlier, and to distribute copies to your friends for comment.

That completes the Board's decision with respect to the Market Hub core issues.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0598

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

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

1. Introduction

1.1. The Application

Union Gas Limited ("Union" or the "Company") filed an application on April 27, 2007 with the Ontario Energy Board (the "Board") seeking approval for final disposition and recovery of certain 2006 year-end deferral account balances and the 2006 year-end earnings sharing amount. Union also proposed that the resulting impacts from the disposition be implemented on July 1, 2007 to align with other rate changes expected to result from the Quarterly Rate Adjustment Mechanism ("QRAM") proceeding. Union revised the proposed timing to align with the October QRAM.

1.2. The Proceeding

The Board issued a Notice of Written Hearing and Procedural Order No. 1, dated May 16, 2007, setting the dates for submissions on Union's evidence and other procedural matters. As part of the Order, any parties that objected to proceeding by way of written hearing were required to provide good reason why any issues should proceed by way of an oral hearing.

On May 24, 2007 the Industrial Gas Users Association ("IGUA") requested that a matter concerning the treatment of certain deferred taxes, totaling $10.524 million, proposed for recovery via the Earnings Sharing Mechanism ("ESM") be considered as part of an oral hearing (the "Deferred Taxes Issue"). The Deferred Taxes Issue is outlined in Account No. 179-72 Long-Term Peak Storage Services, Ex. A, Tab 1 of Union's evidence which states, "Included in the actual cost to provide storage services in 2006 is an increase in deferred income tax expense of $10.524 million resulting from the Board's decision in the Natural Gas Electricity Interface Review ("NGEIR")."

On June 22, 2007 the Board issued Procedural Order No. 2 involving a confidentiality request, to schedule an oral hearing, and to amend scheduling with regards to this proceeding. The oral hearing with respect to the Deferred Taxes Issue was set for July 9, 2007.[1] All other issues remained part of the written hearing.

On July 6, 2007 Union provided a list of witnesses to all parties and the Board also received a position paper from ratepayer representatives as guidance for the oral hearing. The paper was submitted by IGUA and written on behalf of the London Property Management Association ("LPMA"), the School Energy Coalition ("SEC"), the Vulnerable Energy Consumers Coalition ("VECC"), the Consumers Council of Canada ("CCC"), and IGUA.

On July 9, 2007 the Board held an oral hearing concerning the Deferred Taxes Issue. All other issues in this proceeding were dealt with by way of a written hearing. This decision deals with the matters heard both orally and in writing.

[1] As defined in Procedural Order No. 2

1.3. Structure of this Decision

A brief summary of the deferral accounts and amounts requested for disposition is presented in section 2. This is followed by discussion of the Deferred Taxes Issue and other Earnings Sharing amounts for 2006. A summary of these accounts is attached as Appendix ”A”. A list of witnesses and participants is attached as Appendix “B”.

2. The Deferral Accounts

Union applied for disposition of the deferral accounts as follows:

Gas Supply related (credit)	$	197.804
Storage and Transportation related (credit)	$	16.991
Other (debit)	$	(35.224)
Total (credit)	$	179.571 million

The individual components are as follows:

Gas Supply related deferral accounts:

The net balance in the 2006 Gas Supply related deferral accounts as of December 31, 2006 was a $197.804 million credit. The accounts are:

- North Purchased Gas Variance Account (179-105)
- TCPL Tolls and Fuel – Northern and Eastern Operations Area (179-100)
- South Purchased Gas Variance Account (179-106)
- Inventory Revaluation Account (179-109)
- Spot Gas Variance Account (179-107)
- Heating Value Deferral Account (179-89)
- Unabsorbed Demand Cost Deferral Account (179-108)

Storage and Transportation related deferral accounts:

At the end of December 2006, Union stated that the balance accumulated in the Storage and Transportation related deferral accounts was a credit of $16.991 million (ratepayer portion).

The accounts are:

- Transportation and Exchange Services Deferral Account (179-69)

- Short Term Storage and Other Balancing Services Deferral Account (179-70)
- Long Term Peak Storage Services Deferral Account (179-72)
- Other S&T Services Deferral Account (179-73)
- Other Direct Purchase Services Deferral Account (179-74)

Other deferral accounts

At the end of December 2006, the balance accumulated in the "Other" deferral accounts was a debit of $35.224 million. The "Other" deferral accounts are:

- Deferred Customer Rebates/Charges Account (179-26)
- Comprehensive Customer Information Program Account (179-56)
- Direct Purchase Revenue and Payments Deferral Account (179-60)
- Lost Revenue Adjustment Mechanism Deferral Account (179-75)
- Intra-period WACOG Deferral Account (179-102)
- Unbundled Services Unauthorized Storage Overrun Account (179-103)
- Storage Rights Compensation Costs Deferral Account (179-110)
- Demand Side Management Variance Account (179-111)
- Deferred Gas Distribution Access Rule Costs (179-112)
- Late Payment Litigation Deferral Account (179-113)
- Incremental OEB Cost Assessment Deferral Account (179-114)
- Shared Savings Mechanism Variance Account (179-115)
- Interest on the Gain on the 2004 Cushion Gas Disposition (179-116) (subject of proceeding EB-2005-0211)

The Company explained the basis for the balances in each account. Intervenors raised concerns about Union's treatment of the disposition of the Long-Term Peak Storage Services deferral account. The Company provided its rationale for a significant deferred tax charge to ratepayers based on the Board's NGEIR Decision (EB-2005-0551).

The Board accepts Union's evidence regarding the account balances and Union's proposal regarding the allocation and amounts of the balances and the proposed timing for disposition, with the exception of the Long-Term Peak Storage Services deferral account (Account No. 179-72) ("LSS account"), Lost Revenue Adjustment Mechanism Deferral Account (Account No. 179-75)

("LRAM account"), and the Demand Side Management Variance Account (Account No. 179-111) ("DSMVA account"). The discussion and treatment of these accounts are outlined later in this decision.

3. The Deferred Taxes Issue

Background

The Deferred Taxes Issue involves a claim by Union for certain amounts in the LSS account (Account No. 179-72).

Union claims that it is required to record a deferred income tax expense of $10.524 million related to storage service as a result of the change in the regulatory treatment of storage services provided to customers outside of Union's franchise area.

Union asserted that the change in accounting treatment results from the Board's decision in NGEIR to refrain from regulating rates for storage services to customers outside Union's franchise area and for new storage services to customers within the franchise area.

Union's contention is that the Canadian Generally Accepted Accounting Principles ("GAAP") require that once a segment of a utility's operation ceases to be rate regulated, as is the case with ex-franchise storage services, that portion of the company's operation ceases to qualify for deferred tax accounting treatment. Accordingly, the deferred tax deferral account which has been in place since 1997 cannot continue to capture amounts related to these operations.

The Oral Hearing

Union Gas Limited

In its oral argument Union asserted that the appropriate time to give effect to the change in accounting treatment arose as soon as the Board's Decision in NGEIR

had been made in November of 2006. Its view was rooted in the understanding that as soon as there is no expectation of regulated revenues to offset the future tax liability, the liability must be recorded as a deferred tax expense in the period when the change in status from regulated to non-regulated occurred.

It is Union's position that insofar as the ex-franchise storage service business can no longer use the "flow through" method of recording the tax liabilities associated with it, the entire amount of the tax liability must be recorded in the current period, and should also be applied to its revenue requirement for the regulated business and reflected in current rates.

Furthermore, Union contended that the use of the "flow through" method up to the point that the Board made its NGEIR Decision operated to the benefit of its customers and that accordingly they should now realize the offsetting debit of those associated liabilities. Union contended that the deferral of taxes for accounting purposes over the period from 1997 to 2006 has had the effect of reducing Union's revenue requirement to the extent that current tax liability was deferred. Union urged that the principle that "burdens follow benefits", should be applied by the Board to recover the accumulated tax liability reflected in the account from ratepayers now.

Position of the Parties

One position paper was submitted by all intervenors representing ratepayer interests that emphasized three points in their opposition to Union's treatment of the Deferred Taxes Issue. That paper considered whether there is:

(a) any basis for this charge to be reflected in 2006; and
(b) any basis that the Board could conclude that the recent characterization of Union's ex-franchise storage business as non-utility could give rise to a recovery of amounts recorded in the deferred tax account; and
(c) any rationale for the recovery of other amounts in the future.

IGUA articulated the opposition of a number of intervenors regarding the appropriateness of the time period for the claim. It argued that the change in accounting should be applied when the storage revenues were taken out of the utility's revenue stream. IGUA pointed out that while the Board's NGEIR Decision was issued on November 7, 2006, the rates reflecting the change in status were not effective until January 1, 2007. IGUA argued that there was no cash expense in 2006 associated with the deferred tax liability in question, and that the liability is an amount that Union is not required to address in full until 2018.

IGUA contended that Union's ex-franchise line of business would, by definition, be a non-utility line of business, and therefore purely a shareholder enterprise, denying Union any rationale for the collection of these amounts from ratepayers.

CCC stated that Union's failure to raise the potential impact of the Deferred Taxes Issue in a timely manner is sufficient reason to invalidate Union's claim. It asserts that Union had an obligation to stipulate the potential effect of the NGEIR Decision on the Deferred Taxes Issue earlier, when the NGEIR panel was considering the impact of deregulation of ex-franchise storage services. It suggests that, had the Board panel considering NGEIR known that such an effect had been argued for, it may have affected that Decision.

SEC suggested that the Ernst and Young letter ("E&Y"), dated April 27, 2007, and relied upon by Union in support of its contention, really provided no opinion on Union's decision to adopt the changes in accounting treatment. SEC argued that E&Y's only comment was to assume that Union's choice of year, 2006, was correct and that the accounting treatment was appropriate.

For its part, LPMA secured an undertaking from Union which confirmed that Union's sale of ancillary services on January 1, 1999 did not trigger a deferred tax liability in the 1998 calendar year. LPMA argued that Union should observe a consistent accounting approach to the two events. Further, LPMA argued that crossover on this deferred tax liability does not commence until 2009, and is only

approximately $150,000.[2] By 2010, the amount escalates to $1.0 million, still far less than the $10.524 million that Union seeks.

LPMA made further argument that 10% of Union's newly deregulated storage asset is composed of cushion gas. Since cushion gas is a non-depreciable asset, depreciation of this asset will never exceed the capital cost allowance, and the asset will never reverse. By definition, 10% of Union's claim can never have an associated deferred tax liability.

VECC followed the submissions of LPMA by commenting on the time value of money and its effect on the disposition of deferral accounts.

The City of Kitchener adopted the submissions of other intervenors and highlighted that they would face a significant charge as Union's sole T3 customer.

Board Findings

The Board notes that while accounting treatment can be an important consideration in the regulatory treatment of matters, it is not always predictive of the regulatory outcome. The fact that Union may have to change its accounting treatment of the deferred tax account as a result of the NGEIR decision, does not automatically lead to the conclusion that the accounting tax liability associated with it should come into rates now, or at all. In the absence of a near certain revenue stream that matches future costs, a company must book the future liability. Regulated entities have the assurance that prudently incurred costs will be offset by regulated revenues and therefore they need not book the future liability. In these circumstances, this rule has limited relevance for how the change may be reflected from a regulatory point of view.

The respective accounting treatments for regulated and non-regulated entities reflect the distinction of one entity having a predictable revenue stream where as the other does not. Furthermore, the CICA handbook does not consider the

[2] Crossover: For storage assets, the rate of tax depreciation of an asset exceeds the book depreciation in the early years of the asset. This results in a tax savings. The crossover point is when the book depreciation equals tax depreciation. From this point on there is a tax liability associated with asset.

disposition of the historic costs or who bears them in a regulatory context. This remains the purview of the regulator.

The Board finds that the deregulation of Union's storage assets is notionally equivalent to a divestiture, and that any liabilities associated with these assets should properly be associated with Union's newly formed ex-franchise storage service business.

The taxes associated with this line of business, including the deferred taxes residing in the account should form a part of this new undertaking. This is the same treatment afforded to like liabilities associated with the divestiture of the ancillary services, detailed in Undertaking J1.3.

The Board is also concerned that the treatment requested by Union would result in a significant cross-generational subsidy. The deferral account has been in operation since 1997. It is inequitable that today's ratepayers should be burdened with costs that have accumulated over that period.

The Board finds that Union must eliminate any and all deferred income tax expense from the LSS account. The balance in the LSS account shall be revised from of a debit of $9.341 million to a credit of $3.015 million to ratepayers.[3]

4. Earnings Sharing

Union proposed to clear the Demand Side Management Variance Account ("DSMVA") using 2004 allocation factors by rate class. Given the fact that Union has the 2006 actual allocation factors at its disposal, the Board finds that Union must update the DSMVA amounts to reflect 2006 actual allocation factors. This does not affect the balance for disposition.

Intervenors expressed concern that the Lost Revenue Adjustment Mechanism Account ("LRAM") reflects unaudited amounts, and argued that Union should wait until the final 2006 audited statements become available. In the previous disposition of deferral accounts (EB-2006-0057) the Board approved Union's

[3] As stated in Interrogatory Response to IGUA, Exhibit B3.3.

2005 unaudited LRAM amounts prior to final audited financial statements. The Board finds it appropriate that the 2006 LRAM forecast be used subject to true-up of the audited amount.

Union proposed a “non-utility adjustment” to corporate earnings to exclude $1.278 million from earnings subject to sharing. LPMA requested further details on the adjustment through interrogatories. In connection with Rules 10 and 29.02 of the OEB’s Rules of Practice and Procedure, Union requested that any interrogatories be held in confidence by the Board. The Board granted Union’s request.

Respecting the confidential nature of the claim, and the evidence and argument presented, the Board finds that the proposed adjustment is directly attributable to the utility’s regulated business, and would not possibly have been made otherwise. Union shall include $1.278 million associated with the “other non-utility adjustment” as part of the 2006 Earnings Sharing Calculation (Exhibit A, Tab 1, Schedule 4).

5. Costs

A decision regarding cost awards will be issued at a later date. The eligible parties shall submit their cost claims by August 30, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on Union. The cost claims must be done in accordance with the Board's Practice Direction on Cost Awards.

Union will have until September 14, 2007 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

The party whose cost claim was objected to, will have until September 21, 2007 to make a reply submission as to why their cost claim should be allowed. Again, a copy of the submission must be filed with the Board and one copy is to be served on Union.

THE BOARD ORDERS THAT:

1. The 2006 actual year end Gas Supply, Storage and Transportation and Other deferral account balances are approved, as listed in Appendix "A" with the exception of the balance in the Long-Term Peak Storage Services Account (Account No. 179-72). The balance in this account shall be revised to a credit of $3.015 million to ratepayers. Union shall revise Table 3 at Exhibit A, Tab 1, page 11 to agree with Union's interrogatory response at Exhibit B3.3. Union is directed to file this updated table with the Board by way of letter.

2. The balances in the deferral accounts shall be cleared as proposed by way of adjustments to customers' bills timed with the next QRAM cycle October 1st though December 31, 2007.

3. Earnings sharing disposal shall be timed with the next QRAM for M2, Rate 01 and Rate 10 customers and as a one time adjustment for in-franchise contract and ex-franchise rate classes. Earnings sharing interest shall accrue from January 1, 2007 at Union's approved short term borrowing rate. Union is directed to file an updated version of the Earnings Sharing Calculation table (Exhibit A, Tab 1, Schedule 4) to include the "non-utility adjustment" in earnings sharing, as well as any effects attributed to the revised balance of the Long-Term Peak Storage Services Account as set out in this order.

4. Union is directed to re-allocate the 2006 Demand Side Management Variance Account amounts on the basis of actual 2006 allocation factors.

DATED at Toronto, August 17, 2007

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

APPENDIX A

2006 Gas Supply Related Deferral Accounts

Account No	Account Description	
(179-105)	North Purchased Gas Variance Account	$54.735m credit
(179-100)	TCPL Tolls and Fuel – Northern and Eastern Operations Area	$0.522m credit
(179-106)	South Purchased Gas Variance Account	$145.719m credit
(179-109)	Inventory Revaluation Account	($12.769m) debit
(179-107)	Spot Gas Variance Account	$6.484m credit
(179-108)	Unabsorbed Demand Costs	$0.708m credit
(179-89)	Heating Value Deferral Account	$2.405m credit

Storage and Transportation Related Deferral Accounts

The storage and transportation related deferral accounts are:

Account No	Account Description	
(179-69)	Transportation and Exchange Services Deferral Account	$4.004m credit
(179-70)	Short Term Storage and Other Balancing Services Deferral Account	$21.565m credit
(179-72)	Long Term Peak Storage Services Deferral Account	$3.015m credit
(179-73)	Other S&T Services Deferral Account	$0.390m credit
(179-74)	Other Direct Purchase Services Deferral Account	$0.373m credit

Other Deferral Account

The other deferral accounts are:

Account No	Account Description	
(179-26)	Deferred Customer Rebates/Charges Account	$0
(179-56)	Comprehensive Customer Information Program Account	$0
(179-60)	Direct Purchase Revenue and Payments Deferral Account	$0.171m credit
(179-75)	Lost Revenue Adjustment Mechanism Deferral Account	($4.088) debit
(179-102)	Intra-period WACOG Deferral Account	($15.742m) debit
(179-103)	Unbundled Services Unauthorized Storage Overrun Account	$0
(179-110)	Storage Rights Compensation Costs Deferral Account	($0.511m) debit
(179-111)	Demand Side Management Variance Account	($7.213m) debit
(179-112)	Deferred Gas Distribution Access Rule Costs	Not available
(179-113)	Late Payment Litigation Deferral Account	($0.303m) debit
(179-114)	Incremental OEB Cost Assessment Deferral Account	($1.541m) debit
(179-115)	Shared Savings Mechanism Variance Account	($7.000m) debit
(179-116)	Interest on the Gain on the 2004 Cushion Gas Disposition	$0.896m credit

APPENDIX B

Participants and Witnesses

List of Participants

Board Counsel	Michael Millar
Board Staff	Vincent Cooney
Union Gas Limited	Michael Penny Michael Packer Chris Ripley Annabelle Anchetta
City of Kitchener	Jim Gruenbauer
Consumers Council of Canada	Robert Warren
Enbridge Gas Distribution	Barbara Bodnar
Industrial Gas Users Association	Peter Thompson
London Property Management Association	Randy Aiken
School Energy Coalition	John DeVellis
Vulnerable Energy Consumers Coalition	James Wightman

Witnesses

Union Gas Limited	Patricia Elliott

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2006-0322
EB-2006-0338
EB-2006-0340

MOTIONS TO REVIEW THE NATURAL GAS ELECTRICITY INTERFACE REVIEW DECISION

DECISION WITH REASONS

May 22, 2007

EB-2006-0322
EB-2006-0338
EB-2006-0340

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas;

AND IN THE MATTER OF Rules 42, 44.01 and 45.01 of the Board's *Rules of Practice and Procedur*e.

BEFORE: Pamela Nowina
Vice Chair, Presiding Member

Paul Vlahos
Member

Cathy Spoel
Member

DECISION WITH REASONS

May 22, 2007

EXECUTIVE SUMMARY

In November of 2006 the Board issued a Decision with Reasons in the Natural Gas Electricity Interface Review proceeding (the "NGEIR Decision"). This proceeding was initiated by the Ontario Energy Board in response to issues first raised in the Board's Natural Gas Forum Report issued in 2004. The NGEIR Decision addressed the key issues of natural gas storage rates and services for gas-fired generators, and storage regulation.

In the NGEIR Decision, the Board determined that it would cease regulating the prices charged for certain storage services but that the rates for storage services provided to Union and Enbridge distribution customers will continue to be regulated by the Board.

The Board received three Notices of Motion for review of certain parts of the NGEIR Decision. The Board held an oral hearing to consider the threshold questions that the Board should apply in determining whether the Board should review those parts of the NGEIR Decision and whether the moving parties met the test or tests.

The Board finds that the motions do not pass the threshold tests applied by the Board, except in two areas.

First, the Board finds that the decision to cap the storage available to Union Gas Limited's in-franchise customers at regulated rates to 100 PJ is reviewable.

Second, the Board finds that the decisions regarding additional storage requirements for Union Gas Limited's in-franchise gas-fired generator customers and Enbridge's Rate 316 are reviewable.

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Section A: Introduction

The Board received three Notices of Motion for review of its Decision in the Natural Gas Electricity Interface Review proceeding[1] ("NGEIR"). Motions were filed by the City of Kitchener ("Kitchener") and the Association of Power Producers of Ontario ("APPrO"). There was also a joint notice by the Industrial Gas Users' Association ("IGUA"), the Vulnerable Energy Consumers Coalition ("VECC") and the Consumers Council of Canada ("CCC")

On January 25, 2007, the Board issued a Notice of Hearing and Procedural Order which established a schedule for the filing of factums by the moving parties, any responding parties' factums, and an oral hearing date for hearing the threshold question. On February 8, 2007, factums were filed by Kitchener, APPrO, IGUA, and jointly by CCC and VECC.

Responding factums were filed on February 15, 2007 by Board Staff, Union Gas Limited, Enbridge Gas Distribution Inc., Market Hub Partners Canada Ltd., School Energy Coalition, The Independent Electricity System Operator and BP Canada Energy Company.

In its Procedural Order No.2, the Board indicated that, at the upcoming oral hearing, parties should confine their submissions to the material in their factums and to responding to the factums of other parties. The Board also stated that parties should address only the issues set out in the Board's Procedural Order No. 1, namely:

1) What are the threshold questions that the Board should apply in determining whether the Board should review the NGEIR Decision? and

2) Have the Moving Parties met the test or tests?

[1] EB-2008-0551 (November 7, 2006)

On March 5 and 6, 2007, the Board heard the oral submissions of all the parties with the exception of the Independent System Operator and BP Canada who had advised the Board that they would not be appearing at the oral hearing.

The NGEIR Decision

On November 7, 2006 the Board issued its Decision with Reasons in the Natural Gas Electricity Interface Review proceeding (the "NGEIR Decision"). This proceeding was initiated by the Ontario Energy Board in response to issues first raised in the Board's Natural Gas Forum Report issued in 2004. The 123-page NGEIR Decision addressed the key issues of:

1) Rates and services for gas-fired generators, and

2) Storage regulation.

The parties reached settlements with Enbridge and Union on most of the issues related to rates and services for gas-fired generators. These settlements were approved by the Board. The oral hearing and the NGEIR Decision addressed the broad issue of storage regulation and any issues that were not settled in the settlement negotiations.

The issue concerning storage regulation was whether the Board should refrain from regulating the prices charged for storage services under section 29 (1) of the Ontario Energy Board Act, 1998. The Board found that the storage market is workably competitive and that neither Union nor Enbridge have market power in the storage market. The Board determined that it would cease regulating the prices charged for certain storage services; however, the Board found that rates for storage services provided to Union and Enbridge distribution customers will continue to be regulated by the Board.

The motions requested the following decisions made in the NGEIR Decision be either reviewed and changed; cancelled, or clarified, in a new Board proceeding:

Kitchener

- The aggregate excess methodology for allocating storage space
- The 100 PJ cap on Union's regulated storage

APPrO

- Whether short notice balancing service should be included on the tariffs of Union and Enbridge

IGUA/CCC/VECC

- Parts of the NGEIR Decision pertaining to storage, storage regulation and storage allocation be cancelled
- Review to be heard by a different Board panel

The parties outlined the grounds for the motions which included allegations of errors of fact and in some cases, errors of law.

Organization of the Decision

In this Decision, the Board organized the issues raised by the parties into sections that cover the same or similar topics. In each section following the section on the threshold test, the Board identifies the issue or issues raised, and makes a finding whether the issues are reviewable by applying the threshold test.

The sections of this Decision are:

A. Introduction (this section)
B. Board Jurisdiction to Hear Motions
C. Threshold Test
D. Board Process

E. Board Jurisdiction under Section 29
F. Status Quo
G. Onus
H. Competition in the Secondary Market
I. Harm to Ratepayers
J. Union's 100 PJ Cap
K. Earnings Sharing
L. Additional Deliverability for Generators and Enbridge's Rate 316
M. Aggregate Excess Method of Allocating Storage
N. Orders
O. Cost Awards

The Board has reviewed the factums and arguments of all parties but has chosen to set out or summarize the factums or arguments by parties only to the extent necessary to provide context to its findings.

Section B: Board Jurisdiction to Hear the Motions

Under Rule 45.01, the Board may determine as a threshold question whether the matter should be reviewed before conducting any review on the merits.

In the case of IGUA's motion, which raises questions of law and jurisdiction, counsel for Board Staff argued that the Board should not, and indeed could not, review the NGEIR Decision as these grounds are not specifically enumerated in Rule 44.01 as possible grounds for review. Counsel for Board Staff argued that the Board has no inherent power to review its decisions and the manner in which it exercises such power must fall narrowly within the scope of the *Statutory Powers Procedure Act* (SPPA), which grants the Board this power.

The Board's power to review its decisions arises from Section 21.1(1) of the SPPA which provides that:

> A tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or any part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order.

Part VII (sections 42 to 45) of the Board's Rules of Practice and Procedure deal with the review of decisions of the Board. Rule 42.01 provides that "any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision". Rule 42.03 requires that the notice of motion for a motion under 42.01 shall include the information required under Rule 44. Rule 44.01 provides as follows:

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

(i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

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

(b) if required, and subject to Rule 42, request a stay of the implementation of the order or decision, or any part pending the determination of the motion.

Counsel for Board Staff argued that while the grounds for review do not have to be exactly as those described, they must be of the same nature, and that to the extent the grounds for review include other factors such as error of law, mixed error of fact and law, breach of natural justice, or lack of procedural fairness, they are not within the Board's jurisdiction. He argued that Rule 44 should be interpreted as an exhaustive list, and that as section 21.1(1) of the SPPA requires that the tribunal's rules deal with the matter of motions for review, the Board's jurisdiction is limited to the matters specifically set out in its Rules.

In support of this interpretation of the Rule 44.01, Counsel relied on the fact that an earlier version of the Board's rules specifically allowed grounds which no longer appear in Rule 44.01. Therefore, it must be assumed that the current Rules are not intended to allow motions for review based on those grounds. The relevant section of the earlier version of the Rules read as follows:

63.01 Every notice of motion made under Rule 62.01, in addition to the requirements of Rule 8.02, shall:

> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error of law or jurisdiction, including a breach of natural justice;
>
> (ii) error in fact;
>
> (iii) a change in circumstances;
>
> (iv) new facts that have arisen;
>
> (v) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time;
>
> (vi) an important matter of principle that has been raised by the order or decision;
>
> (b) request a delay in the implementation of the order or decision, or any part pending the determination of the motion, if required, …

Counsel for Board Staff argued that the "presumption of purposeful change" rule of statutory interpretation should be applied to the Board's Rules. This rule applies generally to legislative instruments and is based on the presumption that legislative bodies do not go to the bother and expense of making changes to legislative instruments unless there is a specific reason to do so. Applied to Rule 44, this means that the Board should be presumed to have intended to eliminate the possibility of motions for review based on grounds which are no longer enumerated. He further argued that because the SPPA requires the Board's Rules "to deal with the matter", the

Board can only deal with them in the manner allowed for by its Rules, and any deviation from the Rules will cause the Board to go beyond its power to review granted by Section 21.1(1) of the SPPA.

In general Union and Enbridge supported the argument made by counsel for Board Staff.

Other parties made several arguments to counter those put forward by counsel for Board Staff. These included:

- as the Board's rules are not statutes or regulations but deal with procedural matters the rules of statutory interpretation such as the presumption of purposeful change have little if any application

- to the extent rules of statutory interpretation apply, section 2 of the SPPA specifically requires that the Act and any rules made under it be liberally construed:

  > This Act, and any rule made by a tribunal under subsection 17.1(4) or section 25.1, shall be liberally construed to secure the just, most expeditious and cost-effective determination of every proceeding on its merits

- that the *Interpretation Act* requires that the word "may" be construed as permissive, whereas "shall" is imperative, so the list of grounds in Rule 44 should be considered as examples. In support of this argument, counsel for CCC referred to Sullivan and Dreiger on the Construction of Statutes, Fourth Edition, Butterworths, pp 175*ff* which cites the Supreme Court of Canada decision in *National Bank of Greece (Canada) v. Katsikonouris* (1990), 74 D.L.R. (4th) 197

- that the Ontario Court of Appeal decision in *Russell v. Toronto(City)* (2000), 52 O.R. (3d) 9 provides that a tribunal (in that case the Ontario Municipal Board) cannot use its own policy or practice to restrict the range of matters which it will consider on a motion to review

- that the *Russell* decision gives tribunals a broad jurisdiction to review in contradistinction to the narrow right of appeal to the Divisional Court.

Findings

In the Board's view, in addition to the specific sections of the SPPA and the Board's Rules dealing with motions to review, it is helpful to look at the overall scheme of the SPPA and the Rules to determine the scope of the Board's jurisdiction to review a decision.

Originally, the SPPA was enacted to ensure that decision making bodies such as the Board provided certain procedural rights to parties that were affected by those decisions. These basic requirements apply regardless of whether a tribunal has enacted rules of practice and procedure. They include such requirements as:

- Parties must be given reasonable notice of the hearing (s 6)

- Hearings must be open to the public, except where intimate personal or financial matters may be disclosed (s 9)

- The right to counsel (s 10)

- The right to call and examine witnesses and present evidence and submissions and to conduct cross-examinations of witnesses at the hearing reasonably required for a full and fair disclosure of all matters relevant to the issues in the proceeding (s 10.1)

- That decisions be given in writing with reasons if requested by a party (s 17 (1))

- That parties receive notice of the decision (s 18)

- That the tribunal compile a record of the proceeding (s 20).

In addition to these requirements there are several practices and procedures that tribunals are allowed to adopt, if provision is made for them in an individual tribunal's rules. These include:

- Alternative dispute resolution. Section 4.8 provides that a tribunal may direct parties to participate in ADR if "it has made rules under section 25.1 respecting the use of ADR mechanisms…"

- Prehearing conferences. Section 5.3 provides that "if the tribunal's rules under section 25.1 deal with prehearing conferences, the tribunal may direct parties to participate in a pre-hearing conference…"

- Disclosure of documents. Section 5.4 provides that "if the tribunal's rules made under section 25.1 deal with disclosure, the tribunal may,…, make orders for (a) the exchange of documents, …"

- Written hearings. Section 5.1 (1) provides that "a tribunal whose rules made under section 25.1 deal with written hearings may hold a written hearing in a proceeding."

- Electronic hearings. Section 5.2 provides that "a tribunal whose rules made under section 25.1 deal with electronic hearings may hold an electronic hearing in a proceeding."

- Motions to review. Section 21.1(1) provides that "a tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or any part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order."

Beyond stating that a tribunal's rules have to "deal with" each of these procedures in order for the tribunal to avail itself of them, there are no restrictions on the way in which they do so. In this regard nothing distinguishes motions to review from the other "optional" procedural matters listed above. A tribunal is free to create whatever procedures it thinks appropriate to handle them, provided they are consistent with the SPPA.

The Board notes that there are situations where the SPPA does not give tribunals full discretion in developing their rules to deal with "optional" procedural powers. For example, section 4.5(3) allows tribunals or their staff to make a decision not to process a document relating to the commencement of a proceeding. This section not only requires a tribunal to have "made rules under section 25.1 respecting the making of such decisions" but also requires that "those rules shall set out … any of the grounds referred to in subsection 1 upon which the tribunal or its administrative staff may decide not to process the documents relating to the commencement of the proceeding;…" While a tribunal can prescribe the grounds for such a decision in its rules, the grounds must come from a predetermined list found in the SPPA. In that case, it is clear that only certain grounds are permitted, and a tribunal must restrict itself to those grounds enumerated in its rules.

The SPPA could put similar restrictions on the development of a tribunal's rules dealing with motions to review, but it does not.

While the Court of Appeal's decision in *Russell v. Toronto* dealt with motions to review under the *Ontario Municipal Board Act* rather than under the SPPA, the power granted to review decisions is effectively the same, so the principles enunciated in the *Russell* decision are applicable to the Board. The Court of Appeal found that the OMB could not

use its own policies and guidelines to restrict the scope of the power to review which was granted to it by statute. The Board therefore finds that it cannot use its Rules to limit the scope of the authority given to it by the SPPA.

The SPPA allows each tribunal to make its own Rules, so as to allow it to deal more effectively with the specific needs of its proceedings. The SPPA does not give the Board the authority to limit the substantive matters within the Board's purview.

The provisions of the SPPA dealing with the making of rules, give tribunals a very wide latitude to meet their own needs, both in the context of creating rules and in each individual proceeding:

> 25.0.1 A tribunal has the power to determine its own procedure and practices and may for that purpose,
>
> (a) make orders with respect to the procedures and practices that apply in any particular proceeding; and
>
> (b) establish rules under section 25.1

> 25.1 (1) A tribunal may make rules governing the practice and procedure before it.
>
> (2) The rules may be of general or particular application.
>
> (3) The rules shall be consistent with this Act and with the other Acts to which they relate.
>
> (4) The tribunal shall make the rules available to the public in English and in French.
>
> (5) Rules adopted under this section are not regulations as defined in the *Regulations Act*.
>
> (6) The power conferred by this section is in addition to any other power to adopt rules that the tribunal may have under another Act.

In the Board's view these sections of the SPPA give the Board very broad latitude to determine the procedure best suited to it from time to time. While consistency with the Act is required, the Rules are not regulations, and can be amended from time to time by the Board to suit its evolving needs.

The Board finds that there is nothing in the SPPA to suggest that rules dealing with motions to review should be interpreted or applied any differently from other provisions of the Board's Rules.

The Board's Rules

In addition to Section 2 of the SPPA which provides for a liberal interpretation of the Act and the Rules, the Board's Rules include the following provisions as a guide to their interpretation.

> 1.03 The Board may dispense with, amend, vary or supplement, with or without a hearing, all or any part of any rule at any time, if it is satisfied that the circumstances of the proceeding so require, or it is in the public interest to do so.
>
> 2.01 These Rules shall be liberally construed in the public interest to secure the most just, expeditious and cost-effective determination of every proceeding before the Board.
>
> 2.02 Where procedures are not provided for in these Rules, the Board may do whatever is necessary and permitted by law to enable it to effectively and completely adjudicate on the matter before it.

As these provisions are of general application to all of the Board's Rules of Practice and Procedure, the Board finds that each of its individual rules should be read as if the above rules 1.03, 2.01 were part of them, except of course where restricted by the SPPA or another Act. Therefore, the Rules which "deal with the matter" of motions to

review, i.e. Rules 42 to 45, should be read in conjunction with Rules 1.03 and 2.01. Similarly, the rules dealing with alternative dispute resolution, written hearings and so on include Rules 1.03 and 2.01.

The Board finds that it should interpret the words “may include” in Rule 44.01 as giving a list of examples of grounds for review for the following reasons:

- It is the usual interpretation of the phrase;
- It is consistent with section 2 of the SPPA which requires a liberal interpretation of the Rules;
- It is consistent with Rule 1.03 of the Board’s rules which allows the Board to amend, vary or supplement the rules in an appropriate case; and
- If the SPPA had intended to require that the power to review be restricted to specific grounds it would have required the rules to include those grounds and would have required the use of the word “shall”.

With respect to the application of the principle of presumption of purposeful change urged by counsel for Board Staff, the Board notes that at the same time that its rules were amended to remove certain grounds of appeal from Rule 44.01, Rule 1.03 was also amended. The previous version of Rule 1.03 (then 4.04) read as follows:

> The Board may dispense with, amend, vary, or supplement, with or without a hearing, all or any part of any Rule, at any time by making a procedural order, if it is satisfied that the special circumstances of the proceeding so require, or it is in the public interest to do so.

When compared with the current Rule 1.03, it is apparent that the old rule was more restrictive – amendments had to be made by procedural order, and the circumstances of the proceeding had to be “special”. Given the need for a procedural order, it is reasonable to interpret the old rule as applying only to the sorts of matters dealt with in procedural orders, the conduct of the proceeding and not to other provisions of the rules. No such restriction applies in the current Rule 1.03.

The Board finds that to the extent the Rules were amended to remove specific grounds from the list for motions to review, the contemporaneous amendments to Rule 1.03 give the Board the necessary discretion to supplement this list in an appropriate case. The Board presumably was aware of that at the time of the amendments.

The Board therefore finds that it has the jurisdiction to consider the IGUA motion to review even though the grounds are errors of mixed fact and law which do not fall squarely within the list of enumerated grounds in Rule 44.01.

Even if this interpretation of Rule 44.01 is incorrect, the Board can apply Rule 1.03 to supplement Rule 44.01 to allow the grounds specified by IGUA. Given the number of motions for review, the timing involved, the nature of the hearing and the nature of the alleged errors, the Board concludes that it is in the public interest to avoid splitting this case into Motions reviewed by some parties and appealed by others.

This panel is also aware that Appeals to the Divisional Court can only be based on matters of law including jurisdiction. If the position advanced by counsel for the Board staff was accepted, errors of mixed fact and law could not be effectively reviewed or appealed by any body. This, the Board believes is not consistent with Section 2 of the SPPA.

Section C: Threshold Test

Section 45.01 of the Board's Rules provides that:

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

Parties were asked by the panel to provide submissions on the appropriate test for the Board to apply in making a determination under Rule 45.01.

Board Staff argued that the issue raised by a moving party had to raise a question as to the correctness of the decision and had to be sufficiently serious in nature that it is capable of affecting the outcome. Board Staff argued that to qualify, the error must be clearly extricable from the record, and cannot turn on an interpretation of conflicting evidence. They also argued that it's not sufficient for the applicants to say they disagree with the Board's decision and that, in their view, the Board got it wrong and that the applicants have an argument that should be reheard.

Enbridge submitted that the threshold test is not met when a party simply seeks to reargue the case that the already been determined by the Board. Enbridge argued that something new is required before the Board will exercise its discretion and allow a review motion to proceed.

Union agreed with Board Staff counsel's analysis of the scope and grounds for review.

IGUA argued that to succeed on the threshold issue, the moving parties must identify arguable errors in the decision which, if ultimately found to be errors at the hearing on the merits will affect the result of the decision. IGUA argued that the phrase "arguable errors" meant that the onus is on the moving parties to demonstrate that there is some reasonable prospect of success on the errors that are alleged.

CCC and VECC argued that the moving parties are required to demonstrate, first, that the issues are serious and go to the correctness of the NGEIR decision, and , second, that they have an arguable case on one or more of these issues. They argued that the moving parties are not required to demonstrate, at the threshold stage, that they will be successful in persuading the Board of the correctness of their position on all the issues.

MHP argued that the threshold question relates to whether there are identifiable errors of fact or law on the face of the decision, which give rise to a substantial doubt as to the correctness of the decision, and that the issue is not whether a different panel might arrive at a different decision, but whether the hearing panel itself committed serious errors that cast doubt on the correctness of the decision. MHP submitted that a review panel should be loathe to interfere with the hearing panel's findings of fact and the conclusions drawn there from except in the clearest possible circumstances.

Kitchener argued that jurisdictional or other threshold questions should be addressed on the assumption that the record in NGEIR establishes the facts asserted.

School Energy Coalition argued that an application for reconsideration should only be denied a hearing on the merits in circumstances where the appeal is an abuse of the Board's process, is vexatious or otherwise lacking objectively reasonable grounds.

Findings

It appears to the Board that all the grounds for review raised by the various applicants allege errors of fact or law in the decision, and that there are no issues relating to new evidence or changes in circumstances. The parties' submissions addressed the matter of alleged error.

In determining the appropriate threshold test pursuant to Rule 45.01, it is useful to look at the wording of Rule 44. Rule 44.01(a) provides that:

> Every notice of motion… shall set out the grounds for the motion that raise a question as to the correctness of the order or decision…

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

With respect to the question of the correctness of the decision, the Board agrees with the parties who argued that there must be an identifiable error in the decision and that a review is not an opportunity for a party to reargue the case.

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

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

In the Board's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review.

Section D: Board Process

IGUA's grounds for review included the following alleged errors in the process used by the panel:

1. The Board has no jurisdiction to conduct what amounts to its own public inquiry in the midst of a contested rates and pricing proceeding between utilities and their ratepayers,
2. In embarking on its own public inquiry with respect to matters in issue between the parties with respect to storage regulation, the Board erred in law in exceeding its adjudicative mandate and engaged in a process which disqualifies it as an adjudicator and invalidates its decision with respect to forbearance.

In particular, IGUA argued that the process adopted by the Board was flawed as it did not adhere to traditional notions of the adversarial process. IGUA's position was that a "contested rates and pricing proceeding between utilities and their ratepayers" is required to be conducted by the Board as if it were litigation between the parties as it is fundamentally an issue between them as to what the rates should be.

In IGUA's view, the Board departed from appropriate practice at the prehearing stage by

- Setting the agenda based on its priorities
- Defining the issues without input from the parties
- Directing the utilities to file evidence pertaining to some of the issues identified by the Board
- Directing that settlement discussions take place on all issues except storage regulation
- Directing all parties to file their evidence at the same time rather than dividing them by interest and having them file evidence in support of and then opposed to the issues identified by the Board

IGUA's largest area of concern however was that once evidence had been filed, "the Board did not confine its future participation in the process to the performance of the adjudicative functions of hearing and determining the matters of fact and law in dispute". IGUA's overriding complaint is that the Board was engaging in its own fact finding mission and was not confining itself to hearing and determining the disputed matters of fact and law which had been raised by parties opposite in interest to one another.

IGUA argued that once a dispute became clear as between the utilities and the ratepayers the Board had to "stay out of the arena" and allow these parties to determine how to present and argue the case, in effect constraining the Board to choose between the cases put forward by the various parties.

Examples of the alleged behaviour objected to by IGUA include:

- The Board advising the parties that it had retained its own expert, but then not filing a report from this expert nor having him made available for cross examination.
- Board members posing questions which indicated that they were searching for a forbearance solution to the Storage Regulation issues, but not asking questions about the ability of the existing regulatory regime to address the concerns which the Board raised.
- The Board advising BP Canada, a party to the hearing, that it wished to hear evidence from it on certain issues and providing a list of questions in advance – at the time counsel for ratepayer interests objected to the question as "rather leading".
- Counsel for the Board hearing team taking a position in argument adverse in interest to the evidence it had led.

Counsel for Board Staff argued that IGUA's complaints ignore critical differences between the Board and the courts and they confuse the role of the hearing panel with the roles of staff counsel in Board proceedings.

Counsel for Board Staff argued that the Board is not a court of record. It is a highly specialized tribunal that has a strong and important policy-making function. The Board is entitled to commence or initiate proceedings in its own right. It is not required to sit passively as an independent adjudicator and wait for parties to initiate proceedings before it, nor is the Board required to play a purely passive adjudicative role during the course of proceedings once they have been commenced, and particularly once they have been commenced at the instigation of the Board itself.

Counsel for Board Staff also argued that hearing panels of the Board are fully entitled to ask probing questions of witnesses who appear before them, and there is nothing whatsoever untoward about doing so.

The other parties largely supported the position of Board Staff.

Findings

At a minimum, the Board is required to comply with the provisions of the SPPA and the *Ontario Energy Board Act, 1998* ("OEB Act"). The SPPA provides parties with certain procedural rights, none of which IGUA has alleged has been disregarded by the Board in this case:

- Parties must be given reasonable notice of the hearing (s 6)
- Hearings must be open to the public, except where intimate personal or financial; may be disclosed (s 9)
- Parties have the right to counsel (s 10)
- Parties have the right to call and examine witnesses and present evidence and submissions and to conduct cross-examinations of witnesses at the hearing reasonably required for a full and fair disclosure of all matters relevant to the issues in the proceeding (s 10.1)

- Tribunals must give decisions in writing and must provide reasons if requested by a party (s 17 (1))

- Parties are entitled to notice of the decision (s 18)

- The tribunal must compile a record of the proceeding (s 20)

Beyond these basic requirements, the SPPA specifically allows tribunals to require parties to participate in various other procedures. With respect to prehearing conferences, section 5.3 of the SPPA provides that a tribunal may direct parties to participate in a prehearing conference to consider the settlement of any or all of the issues.

Section 19(4) of the OEB Act specifically allows the Board to determine matters on its own motion:

> The Board of its own motion may, and if so directed by the Minister under section 28 or otherwise, shall determine any matter that under this Act or the regulations it may upon an application determine, and in so doing the Board has and may exercise the same powers as upon an application.

Section 21 of the OEB Act provides that:

> The Board may at any time, on its own motion and without a hearing, give directions or require the preparation of evidence incidental to the exercise of the powers conferred upon the Board by this or any other Act.

Therefore as well as the power to initiate proceedings, the Board is also given the statutory right to require the preparation of evidence incidental to the exercise of its powers.

While the Board accepts IGUA's argument that in a hearing under Section 36 of the OEB Act it has the jurisdiction to hear and determine all questions of law and fact, it does not agree with IGUA's characterization of the limits on its exercise of this adjudicative function.

As the Board has an over-riding responsibility to make its decisions in the public interest the parties cannot have the final word in determining the nature of the dispute and the options open to the Board. The Board is not required to accept the position of any of the parties, provided that its process is transparent and open and the parties have a fair opportunity to exercise their rights under the SPPA.

IGUA cited several authorities in support of its argument. The Board found them of little assistance as they arose in quite different contexts, generally that of civil disputes between the parties. That is not the context within which the Board operates. We are not judges in civil disputes and the Board's mandate is much broader than determining rights between the parties.

With respect to the specific allegations made by IGUA, the Board's findings follow.

The Board was fully entitled to issue a notice of proceeding on its own motion in December of 2005 and to delineate the issues it expected the parties and the intervenors to address in the proceeding.

Pursuant to the Board's settlement guidelines and the SPPA, the Board is entitled to exclude from the ambit of a settlement conference particular issues that it believes should be heard in full in the hearing which is what the hearing panel did in this case. This is another example of an area where the Board's practice is fundamentally different from that of the courts.

The Board is fully entitled under its Rules to develop procedural orders to meet the needs of any particular proceeding and there is nothing in the Rules or the SPPA which would restrict it from directing all parties to file their evidence simultaneously. This does

not in any way impede the parties from exercising their statutory rights to have access to the evidence and to cross-examine witnesses.

In a proceeding initiated by the Board, as this one was, where there is no applicant, this procedure is an appropriate one.

With respect to the expert witness retained by Board Staff, Section 14 of the OEB Act expressly permits the Board "to appoint persons having technical or special knowledge to assist the Board." As there is no suggestion that the Board's expert played a role in the deliberations of the hearing panel or that the hearing panel relied in any way on the advice of the expert, there is nothing improper arising out of his retainer. Experts consulted by Board Staff are in the same position as staff and are not required to file evidence, or to submit to questioning by any of the parties.

The Board also finds that IGUA's complaints that the NGEIR panel members asked questions of witnesses, which IGUA complains indicated that they were searching for a forbearance solution to the storage regulation issue, are without merit. Adjudicators are entitled to ask probing questions of witnesses who testify before them, including leading questions. The fact that questions are asked or not asked does not mean that the panel has made up its mind one way or the other on an issue.

The Board also finds that the NGEIR panel was fully entitled as a result of the powers granted in section 21 of the OEB Act to act as it did in putting questions to a witness from BP Canada. It is also not an unusual occurrence for the Board to agree to hear evidence in camera, where there is confidential or sensitive commercial information involved.

The Board also finds no error in the fact that counsel for the Board hearing team made final argument in which she took a position adverse to the expert evidence that the Board hearing team led. The Board hearing team is entitled to take whatever position it chooses based on the evidence that was adduced during the hearing and nothing that Board hearing counsel did could possibly ground a complaint of breaches of the rules of

natural justice against the NGEIR hearing panel itself.

Section E: Board Jurisdiction under Section 29

The joint factum of CCC and VECC and the factum of the IGUA both allege that the original NGEIR panel erred in misinterpreting or overreaching in respect of its jurisdiction under section 29 of the OEB Act.

In particular, the CCC/VECC factum states as follows at paragraph 8:

> 8. The moving parties submit that the NGEIR Decision raises the following issues:
>
> (i) Whether the Board correctly interpreted Section 29 of the Ontario Energy Board Act (the "Act"). It is the position of the moving parties that the Board erred in its interpretation of Section 29 of the Act, thereby depriving itself of jurisdiction;
>
> (ii) Whether the Board gave effect to the legislative intent underlying Section 29 of the Act. It is the position of the moving parties that the Board failed to give effect to the intention of the Legislature in enacting Section 29 of the Act;

In its factum, IGUA alleged that the Board had no jurisdiction to conduct what IGUA characterized as the Board's "own public inquiry in the midst of a contested rates and pricing proceeding between utilities and their ratepayers". (IGUA factum par. 84(a))

IGUA also alleged that:

> …the Board erred in law in exceeding its adjudicative mandate and engaged in a process which disqualifies it as an adjudicator and invalidates its Decision with respect to forbearance. (IGUA factum par. 84(b))

In addition to these general submissions by CCC/VECC and IGUA about the NGEIR panel's interpretation of its jurisdiction under Section 29, these parties also argued specifically that the NGEIR panel exceeded its jurisdiction under Section 29 by restructuring the storage businesses of Union and Enbridge. They asserted that the power to restructure the storage business comes under section 36 of the legislation. (Tr. Vol. 1, pp. 28 and 56-57)

Findings

The NGEIR panel's interpretation and application of section 29 is central to the NGEIR Decision. The NGEIR Decision therefore deals extensively with the question of the legal test to be applied under section 29, the analytical framework for assessing whether the natural gas market is competitive and finally, the assessment of market power in the natural gas sector in Ontario.

The starting point for the NGEIR Decision is the Board's interpretation of section 29 which is set out in Chapter 3 of the Decision and reads as follows:

> On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest

In Chapter 3 of the NGEIR Decision, the NGEIR panel discussed the statutory test to be used in the assessment of competition in the storage market and applies the analytical framework mandated by that statutory test. In particular, the panel reviews the history of section 29 and of the concept of forbearance and light-handed regulation.

The NGEIR panel's review of Section 29 is described at two levels. The first is the assessment of competition, which is done by applying the market power tests, and the second is the relationship between competition and the public interest.

The NGEIR panel interprets "competition" within section 29 at page 24 of the NGEIR Decision as follows:

> There are degrees of competition in any market. They range from a monopoly, where there is a sole seller, to perfect competition, where there are many sellers and no one seller can influence price and quantity in the market. It is not necessary to find that there is perfect competition in a market to meet the statutory test of "competition sufficient to protect the public interest"; what economists refer to as a "workably competitive" market may well be sufficient.
>
> It is also important to remember that competition is a dynamic concept. Accordingly, in section 29 the test is whether a class of products "is or will be" subject to sufficient competition. In this respect parties often rely on qualitative evidence to estimate the direction in which the market is moving.

The NGEIR panel further interprets its mandate at page 44 as follows:

> …Section 29 says that the Board shall make a determination to refrain "in whole or part" which the Board believes allows considerable flexibility in this regard. In addition, the Board concludes that it is required by the statute to address the public interest trade-offs, for example, between price impacts and the development of storage and the Ontario market generally.

The NGEIR panel then proceeds to assess the "level of competition" using the market power tests and finds the storage market in Ontario is subject to "workable competition".

Following this, it then addresses the question of whether the level of competition is sufficient to protect the public interest. In so doing, the panel addresses what should be

encompassed in its consideration of the public interest in the context of the assessing competition as follows:

> The public interest can incorporate many aspects including customers, investors, utilities, the market, and the environment. Union and Enbridge argued for a narrow definition of the public interest. In their view, competition itself protects the public interest, and once the Board has satisfied itself that the market is competitive, the public interest is protected by definition. The Board finds this to be an inappropriate narrowing of the concept. Competition is better characterized as a continuum, not a simple "yes" or "no". The Board would not be fulfilling its responsibilities if it limited the review in the way suggested without considering the full range of impacts and the potential need for transition mechanisms and other means by which to ensure forbearance proceeds smoothly.
>
> Some of the intervenors took the position that the public interest review should be focussed on the financial impacts. For example, Schools argued that the Board should look at the benefits and costs of forbearance, and in its view, the costs include a possible transfer of between $50 million and $174 million from ratepayers to shareholders (arising from the proposed end to the margin-sharing mechanisms and the potential re-pricing of cost-based storage to market prices). The Board agrees that the financial impacts are a relevant consideration, but does not agree that an assessment of the public interest should be limited to an assessment of the immediate rate impacts. [Emphasis added] (pages 42 and 43)

The NGEIR panel then proceeds to balance the Board's public interest mandate against its legislative objectives and describes the trade-offs. It does this by reviewing each of the relevant objectives (i.e., to facilitate competition in the sale of gas to users, to protect the interests of consumers with respect to prices an the reliability and quality of gas service, to facilitate rational development and safe operation of gas storage) and

conducting an assessment of whether the level of storage competition is sufficient to protect the public interest in light of each of those objectives.

At page 56 of Chapter 5, having determined that part of the storage market is workably competitive and having considered some of the key elements of the public interest, the panel addresses whether and it what circumstances the Board should refrain from setting storage prices and approving storage contracts.

> In terms of a section 29 analysis, the goal would be to continue to regulate (and set cost-based rates) for those customers who do not have competitive storage alternatives and to refrain from regulating (allow market-based prices) for those who do have competitive alternatives.

The NGEIR panel then applies its interpretation of the legislative intent of section 29 to the facts before it. That panel's understanding of its mandate under section 29 and its careful application of that mandate are evidenced in its findings at pages 56 and 57 of the decision. The NGEIR panel's application of the requisite elements of section 29 is evident in the balancing between considerations of competition with aspects of public interest.

> The parties recognized that bundled customers, in particular, do not acquire storage services separately from distribution services, do not control their use of storage, and do not have effective access to alternatives in either the primary or secondary markets. Competition has not extended to the retail end of the market, and therefore is not sufficient to protect the public interest. However, the Board finds that customers taking unbundled or semi-unbundled service should have equivalent access to regulated cost-based storage for their reasonable needs. The Board finds that it would not further the development of the competitive market, or facilitate the development of unbundled and semi-unbundled services, if these unbundled and semi-unbundled services were to include current storage services at unregulated rates. The Board also agrees with

the parties that noted that re-pricing existing storage will not provide an incentive for investment in new storage and therefore cannot be said to provide that public interest benefit.

However, customers taking unbundled and semi-unbundled services do have greater control over their acquisition and use of storage than do bundled customers. It is also the Board's expectation that these customers will have access to and use services from the secondary market. Therefore, the Board concludes it is particularly important to ensure that the allocation of cost-based regulated storage to these customers is appropriate. This issue is addressed in Chapter 6.

MHP Canada has suggested that the Board adopt full forbearance in storage pricing as a policy direction. Similarly, Union has characterized its allocation proposal and Enbridge has characterized its "exemption" approach for in-franchise customers as being "transitions" to full competition. The Board has found that the current level of competition is not sufficient to refrain from regulating all storage prices; nor do we see evidence that it would be appropriate to refrain from regulating all storage prices in the future. The current structure (for example, the full integration of Union's storage and transportation businesses and the full integration of Union as a provider of storage services and as a user of storage services) is not conducive to full forbearance from storage rate setting. In addition, there would be significant direct and indirect rate impacts associated with full forbearance from rate setting, and there is little evidence of significant attendant public interest benefits. The current situation is that these customers are not subject to competition sufficient to protect the public interest; nor is there a reasonable prospect that they will be at some future time.

The submissions of both CCC/VECC and of IGUA are that the Board misinterpreted and misapplied section 29 of the OEB Act. This panel finds that there is no reviewable error

associated with the NGEIR panel's interpretation of section 29. The NGEIR Decision clearly evidences that the NGEIR panel knew and understood that section 29 was not a section that the Board had invoked in any previous decisions or analyses. For that reason, the Decision provides extensive background regarding the section and goes into significant detail regarding the appropriate framework and analysis required to be undertaken. The Decision shows that the NGEIR panel reviewed the elements of section 29 and considered each of those elements in considerable detail. Where moving parties raised specific questions regarding the application of Section 29, for example, with respect to whether the NGEIR panel had sufficient evidence upon which to make a finding that there was competition sufficient to protect the public interest and whether the NGEIR panel erred in setting a cap on the amount of natural gas storage available to in-franchise customers, the Board makes specific findings elsewhere in this Decision.

With respect to the allegation by CCC/VECC and IGUA that the NGEIR panel exceeded its jurisdiction by restructuring the storage businesses of Union and Enbridge, something which they assert should come under section 36 of the legislation, the Board also finds there is no reviewable error.

The NGEIR panel confined its considerations related to the application of the test under Section 29 in determining whether and to what extent there was competition in the natural gas storage market sufficient to protect the public interest. The portions of the decision that go on to discuss the impacts of the Section 29 decision on the structure of the natural gas storage market flow from the determination under Section 29, but the NGEIR panel does not, in its Decision, describe these as arising out of their Section 29 jurisdiction. The NGEIR proceeding was commenced pursuant to sections 19, 29 and 36 of the *Ontario Energy Board Act, 1998*. As such, the NGEIR panel acted under the authority of Section 29 and 36 in making the determinations in the NGEIR Decision. The decisions made by the NGEIR panel with respect to the allocation of storage available at cost-based rates and the treatment of the premium on market-based storage transactions were made based on evidence filed by the parties to the proceeding and the NGEIR panel considers this evidence as part of the NGEIR Decision.

The Board finds that the allegations of CCC/VECC and IGUA on this point do not raise a question as to the correctness of the decision. The NGEIR panel clearly confined itself to its legislative mandate as provided in Section 29 in determining whether the natural gas market was subject to competition sufficient to protect the public interest. The NGEIR's findings that flow from the Section 29 determination align with the evidence that was before it, did not fail to address any material issue and did not make any inconsistent findings with respect to the evidence before it, except as otherwise noted in this decision.

Section F: Status Quo

The factums and submission of both CCC/VECC and of IGUA allege that the NGEIR panel erred by failing to consider the option of retaining the current regulatory regime in respect of natural gas storage regulation. CCC/VECC and IGUA articulate this alleged error in a number of different ways in different parts of their factums and submissions.

For example, at paragraph 3 of their joint factum, CCC and VECC take the position that:

> "… the Board was obligated to consider whether a change in the status quo with respect to the regulation of storage was required and that it erred in failing to do so." IGUA's factum states that "…reasonable people, objectively examining the process which led to the Decision, will likely conclude that retaining the status quo was not a decision-making option which the Board considered, either fairly or at all, and that the Board itself was a proponent for forbearance relief."

Findings

The NGEIR Decision provides evidence in various places, of the NGEIR panel's recognition of both the current regulatory status with respect on natural gas storage in Ontario and the dynamic nature of competition generally.

In particular, Chapter 2 is described at page 5 of the decision as "…an overview of gas storage in Ontario today – the existing storage facilities, the use of storage by Union's and Enbridge's "in-franchise" customers, the "ex-franchise" market for storage, and the prices charged for storage services."

Later in the NGEIR Decision, as part of its findings on the assessment of assessment of storage competition, the Board expressly disagrees with Mr. Stauft's testimony that the regulated cost-base price for storage is a reasonable proxy for the competitive price of

storage. Implicit in this finding is the NGEIR panel's consideration of the current regulatory regime.

At page 46 of the Decision, the NGEIR Panel also considered the current regulatory regime in the context of question of the sharing of the premium which exists between the price of market-based storage and the underlying costs. The Board acknowledged the current state as follows:

> Currently, that premium is shared between utility ratepayers and utility shareholders. Under the utilities'' proposals for forbearance, the premium would be retained by the shareholders. This would result in significant transfer of funds in the case of Union (2007 estimate is $44.5 million); less so in the case of Enbridge (2007 estimate is $5 million to $6 million). The intervenors in general rejects these proposals and, as a result, opposed forbearance.

At page 47, the NGEIR panel specifically considered and expressly acknowledged the importance of the change from the status quo, but ultimately rejected these submissions as follows:

> The Board agrees that the distribution of the premium is a significant consideration. In many ways, it has been the underlying focus of the NGEIR Proceeding. However, the impact of removing the premium from rates is the result of removing a sharing of economic rents; it is not the result of competition bringing about a price increase. So while it is an important consideration which the Board must address (see Chapter 7), it is not a sufficient reason, in and of itself, to continue regulating storage prices.

There are a number of other examples throughout the NGEIR Decision that satisfy the Board that the NGEIR panel was conscious of the status quo regulatory regime and bore this in mind throughout its analysis on the narrow issue of competition and the s.

29 analysis as well as in considering the impacts upon both shareholders and ratepayers, of a completely or partial forbearance decision.

The Board also feels that the decision by the NGEIR panel to continue to regulate and set cost-based rates for existing storage services provided to in-franchise customers up to their allocated amounts evidences a clear understanding of the current regulatory framework and under what circumstances, based upon the evidentiary record before the NGEIR panel, it was appropriate to deviate from that current framework.

The Board is not convinced, however, that the analysis mandated by the legislative language of s. 29 requires the Board to consider the status quo in the way that has been suggested by some parties. Although it was important for the NGEIR panel to review the current regulatory framework to set the stage for the analysis, the Board is not convinced by the arguments of CCC/VECC, nor those of IGUA that consideration of the status quo is an integral, or even a necessary part of the s. 29 analysis. The purpose of s. 29 was clearly stated by the NGEIR panel and that is to determine whether there is or will be competition sufficient to protect the public interest. If there is a finding that competition does exist, nothing in the section requires the panel to then consider whether the current regulatory framework is sufficient to accommodate the competitive market. In fact, the section mandates that upon finding competition sufficient to protect the public interest, that "…the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act…" In this case, the Board determined that it would refrain, in part, from regulating the setting of rates and the review of contracts for natural gas storage.

The Board therefore concludes that CCC/VECC and IGUA have not demonstrated that their grounds for review based on the alleged failure of the NGEIR panel to consider retaining the status quo as a viable decision-making option raise an issue that is material and directly relevant to the findings made in the decision. This panel concludes that there is no reviewable error with respect to the NGEIR panel's alleged failure to fairly consider the status quo.

Section G: Onus

At paragraph 84(d) of its factum, IGUA alleges that the Board erred in concluding that there is no onus of proof to be assigned in the rates and pricing proceedings it initiated. IGUA alleges that the NGEIR panel erred in law in not assigning the onus of proof to the utilities.

Findings

Pages 26 to 27 of the NGEIR Decision deal explicitly with this issue. In that part of the Decision, the panel acknowledges that generally, the onus is on the applicant. The panel also, however, pointed out the unique nature of the NGEIR proceeding and the fact that the proceeding was brought on the Board's own motion.

The Board is satisfied that all parties to the NGEIR Proceeding were given a full and fair opportunity to provide submissions on the question of onus and that, based on the Decision, the NGEIR panel heard and understood those submissions. This panel is not satisfied that the question of onus is an issue that is material and directly relevant to the findings made in the Decision, nor that if a reviewing panel did decide the issue differently, that it would change the outcome of the Decision. For these reasons, the Board finds that there is no reviewable error relating to assignment of or the failure to assign onus in the NGEIR proceeding.

Section H: Competition in the Secondary Market

In the NGEIR Decision, the Board concluded that Ontario storage operators compete in a geographic market that includes Michigan and parts of Illinois, Indiana, New York and Pennsylvania, that the market is competitive and neither Union nor Enbridge have market power. This determination was made by employing the following four step process, based on the Competition Bureau's Merger Enforcement Guidelines (MEGs):

- Identification of the product market.
- Identification of the geographic market.
- Calculation of market share and market concentration measures.
- An assessment of the conditions for entry for new suppliers, together with any dynamic efficiency considerations (such as the climate for innovation and the likelihood of attracting new investment).

IGUA alleged that the NGEIR panel made numerous errors in assessing sufficiency of competition in the secondary market. IGUA's allegations of errors can be summarized as follows:

- The NGEIR panel erred in misapprehending and misapplying the analytical tests used for determining market power.
- The NGEIR panel did not recognize that the evidence pertaining to the operation of the secondary market did not quantitatively establish the extent to which storage services, excluding commodity, were available at Dawn, nor their prices, nor whether consumers regarded such services as substitutes for delivery services offered by Union.

- The NGEIR panel failed to recognize that the evidence of Gaz Métropolitain Inc. (GMi) did not establish that Union lacked market power in storage services transacted at Dawn, and indeed this evidence established the opposite.

Findings

IGUA alleges that the Board misapprehended and misapplied the market power analytical frameworks presented in documents from the Competition Bureau, the Federal Energy Regulatory Commission (FERC), and the Canadian Radio-Television and Telecommunications Commission (CRTC). According to IGUA, a 10 step procedure must be followed in order to correctly carry out a market power analysis instead of the four step process used by the NGEIR panel.

The Board notes that, in settling on the four step procedure that should apply to determine whether Union and Enbridge have market power and whether the storage market is competitive, the NGEIR Decision provided substantial review and analysis pertaining to Competition Bureau's Enforcement Guidelines (MEGs) and the FERC's 1996 Policy Statement on Market Power Analysis. It is evidenced in the Decision that this was the result of the review of substantial pre-filed evidence, cross examination and argument on this topic.

In the Board's view, the test to be applied is not whether a review panel of the Board would have adopted a different analytical framework. Rather, it is matter of whether in settling upon a certain analytical process, there was an error of fact or law. In view of the extensive record and the analysis and reasons provided in the NGEIR Decision, the Board finds that IGUA not raised an identifiable error in the NGEIR Decision. Rather the submissions of the moving parties are more in the nature of re-arguing the same points that were made in the original hearing. This evidence was presented and evaluated by the NGEIR panel. As the Board stated in enunciating the threshold test at Section C of this Decision, a motion for review cannot succeed if a party simply argues that the Board should have interpreted conflicting evidence differently. The Board has therefore

determined that there is not enough substance to the issues raised by IGUA such that a review of those issues could result in the Board determining that the NGEIR Decision or Order should be varied, cancelled or suspended. As such, the NGEIR panel's determination on the nature and application of market power analysis to the natural gas storage market in and around Ontario is not reviewable.

IGUA alleges that the NGEIR panel did not recognize that the evidence pertaining to the operation of the secondary market did not quantitatively establish the extent to which storage services were available at Dawn, nor their prices or whether consumers regarded such services as substitutes for delivery services offered by Union.

In the Board's view, this alleged error is essentially an application of the alleged market power analysis framework error discussed above. The NGEIR panel listed several forms of evidence in support of its conclusion that the secondary market in transportation services is unconstrained and therefore serves to enlarge the geographic market from what it would otherwise have been found to be.

The NGEIR panel treated evidence on the operation of primary and secondary markets in transportation as relevant to the determination of the geographic market in a manner consistent with the market power analysis methodology that the NGEIR panel had settled upon. For the reasons stated above, the Board finds that the original NGEIR panel's use of evidence relating to the secondary market in transportation services is not reviewable.

IGUA cites the NGEIR hearing transcript (volume 10, pages 56-120) in support of its allegation that the Board failed to recognize that GMi's evidence actually supported IGUA's view that Union has market power.

The Decision (at page 35, paragraphs 4-5) clearly reflects the statements of GMi witnesses that they regularly contact alternative suppliers for comparisons to Union's services. IGUA has not shown that the NGEIR panel's findings are contrary to the evidence that was before the panel, or that the panel failed to address GMi's evidence

or made inconsistent findings with respect to that evidence. The Board therefore finds that there is no reviewable error with respect to the NGEIR panel's use of the evidence provided by GMi.

Section I: Harm to Ratepayers

IGUA and CCC/VECC alleged that the Board erred when it bifurcated the natural gas storage market between those customers that continue to benefit from storage regulation and those customers who do not. They allege that as a result of this bifurcated market, the Board conferred a windfall benefit on the shareholders of the utilities with no corresponding benefit to ratepayers and that this is unfair.

The parties also alleged that the transitional measures the Board employed to implement the new regime merely serve to underscore the error in the finding that the market should be split. The parties alleged that the market, taken as a whole, was determined not to be workably competitive, and the transitional measures are evidence that a decision to forbear from the regulation of prices was not appropriate.

Finally, CCC and VECC alleged that the Board erred in its interpretation of section 29, and acted in excess of its jurisdiction, by moving assets out of rate base, with no credit to the ratepayer. They argued that the effect of the NGEIR Decision is to allocate the rate base storage assets of the utilities between in-franchise and ex-franchise customers, and to allow for a new shareholder business within each utility. They submitted that doing those things does not naturally follow from a finding that the rates charged by the utilities to ex-franchise customers do not need to be regulated.

Findings

The Board finds that the issues raised in this area have not met the threshold test for the matter to be forwarded to a reviewing panel of this Board. The NGEIR panel did not err in failing to consider the facts, the evidence, or in exercising its mandate. There were no facts omitted or misapprehended in the NGEIR panel's analysis nor are the moving parties raising any new facts.

It was entirely within the NGEIR panel's mandate and discretion how to assess the competitive position of segments of the market and how to address the regulatory treatment of customers within those segments. The NGEIR panel clearly decided that ex-franchise customers of both Union and Enbridge had access to a competitive natural gas storage market. Further, the decision goes on to make clear on page 61, that Enbridge as a utility is ex-franchise to Union and therefore should be subject to market prices. The NGEIR Decision differentiates between the competitive position of a utility (e.g. Enbridge) and the competitive position of that utility's in-franchise customers. For example, the Decision is clear that the in-franchise customers of Enbridge will pay cost-based rates which will continue to be regulated by the Board and are based on EGD's costs of storage service owned by the utility and the costs that EGD pays for procuring these services in the competitive market.

A key issue the parties raise is that the bifurcated market brings about unfair and inconsistent treatment, and therefore constitutes a misapplication of the Board's mandate to protect the public interest. However, on this point, the grounds that the moving parties raised to support a review are in fact the very points used by the NGEIR panel to protect consumers as a natural consequence of the decision to refrain from storage regulation of the ex-franchise market. It is clear that the NGEIR panel took into account the protection of the public interest in its decision to provide transition mechanisms to protect consumers.

With respect to the allegation of a windfall benefit for shareholders of the utilities with no corresponding benefit to ratepayers, the Board is of the view that this is related to the question of earnings sharing. This issue is more fully addressed in Section K of this Decision. It is important to note here, however, that the NGEIR panel's decisions with respect to the profit or earnings sharing mechanism were based on the evidence presented by all parties and flowed from the broader decisions with respect to the competitiveness of the gas storage market. Chapter 7 of the NGEIR Decision clearly described the NGEIR panel's considerations with respect to and its reasoning for changing the earnings sharing mechanism. In the Board's view, the changes related to the earnings sharing mechanism necessarily arise from a recognition by the Board of

the implications of its findings under Section 29 that there is a workably competitive market for storage in the ex-franchise market.

Section J: Union's 100 PJ Cap

In their factum, CCC and VECC allege that, on the one hand the Board in its NGEIR Decision said that a substantial portion of the storage market requires regulatory protection because there is insufficient competition to protect the public interest while on the other hand the Board exposed this same group to the effects of competition from the unregulated market.

Kitchener has also specifically sought the Board's review of an aspect of the NGEIR Decision related to the Board's placement of a "cap" on the amount of Union's storage space that is reserved for in-franchise customers at cost-based rates.

The Board determined at page 83 of the NGEIR Decision that Union should reserve 100 PJ of storage space at cost-based rates for its in-franchise customers. The Decision reads as follows (page 83):

> The Board acknowledges that there is no single, completely objective way to decide how much should be reserved for future in-franchise needs. The Board has determined that Union should be required to reserve 100 PJ (approximately 95 Bcf) of space at cost-based rates for in-franchise customers. This compares with Union's estimate of 2007 in-franchise needs of 92 PJ (87 Bcf). At an annual growth rate of 0.5% each year, which Union claims is the growth rate since 2000, in-franchise needs would not reach 100 PJ until 2024. The limit would be reached in 2016 if the annual growth is 1%; at a very annual high growth rate of 2% per annum, the 100 PJ limit would be reached in 2012.
>
> The 100 PJ (95 Bcf) amount is the capacity that Union must ensure is available to in-franchise customers if they need it. Union should continue to charge in-franchise customers based on the amount of space required in any year. If Union's in-franchise customers require less than 95 Bcf in any year, as measured by Union's standard allocation methodology, the

> cost-based rates should be based on that amount, not on the full 95 Bcf reserved for their future use. Union will have the flexibility to market the difference between the total amount needed and the 95 Bcf reserve amount.

The Board acknowledged that the cap might be reached at any time between 2012 and 2024, depending on what growth rate assumptions are used. At the current rate of growth (0.5% each year), the cap would not be met until 2024.

In Kitchener's oral submissions (page 187, Volume 1), Mr. Ryder on behalf of Kitchener makes the following comments:

> And while the cap of 100 pJs allows for some growth so it won't immediately affect the Ontario consumer, the cap will be reached between 2012 and 2024. That's between 5 and 17 years from now.
>
> Now, that's not far off, and if the public interest requires a margin for growth today in 2007, then the public interest will surely require it in five to 17 years from now when the cap is reached.
>
> And when it is reached, it is my submission that the Board will have wished it had reviewed the decision in 2007, because, when the cap is reached, this decision will be responsible for adding significantly to the costs of energy in Ontario, to the detriment of the Ontario consumer.

Page 7 of the CCC/VECC factum states:

> The Board made no finding, however, that at the end of the operation of those transitional measures, the public interest, as represented by in-franchise customers of Union and EGD, would be protected. The moving parties submit that Section 29 required the Board, before making an order to forbear from regulation under Section 29, to find on the evidence that,

> at the end of the transitional measures, there would be sufficient competition to protect the public interest. The moving parties submit that, in failing to make that finding, the Board erred.

Findings

On page 57 of the NGEIR decision, in reference to the in-franchise customers of Union the NGEIR panel makes the following statement:

> The current situation is that these customers are not subject to competition sufficient to protect the public interest; nor is there reasonable prospect that they will be at some future time.

Later in the decision at page 82, the decision states:

> The Board panel concludes that its determination that the storage market is competitive requires it to clearly delineate the portion of Union's storage business that will be exempt from rate regulation. Retaining a perpetual call on all of Union's current capacity for future in-franchise needs is not consistent with forbearance. As evidenced by the arguments from GMi and Nexen, two major participants in the ex-franchise market, retaining such a call is likely to create uncertainty in the ex-franchise market that is not conducive to the continued growth and development of Dawn as a major market centre.
>
> The Board concludes that it would be inappropriate, however, to freeze the in-franchise allocation at the level proposed by Union. Union's proposal implies that a distributor with an obligation to serve would be prepared to own, or to have under contract, only the amount of storage needed to serve in-franchise customers for just the next year. In the Board's view, it is appropriate to allow for some additional growth in in-

> franchise needs when determining the "utility asset" portion of Union's current capacity.
>
> The Board acknowledges that there is no single, completely objective way to decide how much should be reserved for future in-franchise needs."

The NGEIR panel then goes on to provide its decision on the methodology which was used to determine the cap and says at page 83 of the decision:

> The 100 PJ (95 BCF) amount is the capacity that Union must ensure is available to in-franchise customers if they need it.

The NGEIR panel then makes a finding with respect to how the excess capacity should be treated if the in-franchise customers require less than 100 PJ in a given year. The NGEIR panel is silent on the outcome if in-franchise customers require more than 100 PJ of storage per year. Although the NGEIR panel is clear that it does not expect this circumstance to occur for many years, the decision nevertheless appears to raise the possibility that in-franchise customers may, at some point, be subject to unregulated prices.

The Board finds that on this issue the moving parties have raised a question as to the correctness of the order or decision and that a review based on the issue could result in the Board deciding that the decision or order should be varied, cancelled or suspended.

In particular, in this instance, there are unanswered questions that are raised by the NGEIR Decision on the 100 PJ cap issue. Since the NGEIR Decision clearly stated that the in-franchise customers did not have and were not likely to have access to competition in the foreseeable future, a decision that forbears from the regulation of pricing for these customers at some time in the future does not appear to this panel to be consistent. The Board finds that the following questions should have been addressed by the NGEIR panel:

(a) If the cap of 100 PJ of storage for in-franchise Union customers remain in place in perpetuity, what is the basis for forbearance (under Section 29) of required storage above 100 PJ for in-franchise customers?

(b) If the cap of 100 PJ of storage for in-franchise Union customers does not remain in place in perpetuity, what mechanism should the Board use to monitor the likelihood of the cap being exceeded?

(c) If the cap of 100 PJ of storage for in-franchise Union customers is likely to be exceeded, what, if any, remedy is available to in-franchise customers?

The Board therefore finds that the NGEIR panel either failed to address a material issue or made inconsistent findings, that the alleged error is material and relevant to the outcome of the decision, and that if the error is substantiated by a reviewing panel and corrected, the reviewing panel could change the outcome of the decision.

The Board therefore finds that this is a reviewable matter.

Section K: Earnings Sharing

Certain parties, led by VECC, allege that the NGEIR panel erred because one of the effects of the NGEIR Decision on the in-franchise customers of Union is that these customers will lose the benefit of their share of the premium obtained by Union through the sale of storage to ex-franchise customers. The parties stated that the NGEIR Decision will result in a material increase in revenue to the shareholder of Union and, to a lesser extent, an increase in the revenue to EGD's shareholder. They also indicated that at the same time, there will be no corresponding benefit to the ratepayers of either Union or EGD. In fact the moving parties argued that the ratepayers of Union and EGD will suffer adverse impacts, in both the short and the long term. The moving parties maintained that the NGEIR Decision upsets the balance between the interests of ratepayers and shareholders which the regulatory system is supposed to maintain and that the NGEIR Decision is, therefore, contrary to public and regulatory policy.

It was also stated by the moving parties that section 29 of the OEB Act does not permit the Board to re-allocate rate-based storage assets. The effect of the NGEIR Decision was to allocate rate-based storage assets between in-franchise and ex-franchise customers and to allow for a new shareholder business within each utility. The moving parties stated that the Board exceeded its jurisdiction by moving assets out of rate base with no credit to the ratepayer.

It was further asserted that rather than requiring utility shareholders to share the premiums derived from the sale of storage to ex-franchise customers, there will now be a separation of utility and non-utility assets and revenues and costs associated therewith. The moving parties stated that this will raise cross-subsidization and other issues pertaining to the performance of utility and non-utility services; a result which they say contravenes the spirit and intent of the pure utility policy adopted by the Ontario government years ago.

Further, the parties allege that the Board erred in concluding that it has the power to forbear under Section 29 of the *OEB Act* when an exercise of the power results in a

windfall benefit to utility shareholders and consequential harm to ratepayers. The parties asserted that changes to the allocation between ratepayers and utility shareholders of financial benefits and burdens produced by a particular regulatory regime must take place under the auspices of regulation.

Findings

The Board notes that the NGEIR Decision deals extensively with the issue of the allocation/sharing of margins (also called premiums, revenues or earnings) associated with the sale of natural gas storage on both a short-term (transactional services) and long-term contractual basis. The Decision canvasses both the status quo (prior to the implementation of the changes required by the NGEIR Decision) and provides an explanation of the rationale for changing the earnings sharing structure, the new mechanisms for earnings sharing and the transitional implementation (where applicable) of those mechanisms.

In particular, chapter 2 of the NGEIR Decision provides, among other things, a description of the current types and volumes of sales of natural gas storage by Union to ex-franchise customers and canvasses the current regulatory treatment of ex-franchise sales, including the rate treatment of margins on storage sales. In Chapter 7, the NGEIR panel goes into greater detail regarding the extent of margin sharing and the regulatory history that underlines premium sharing for both short-term (for both Union and Enbridge) and long-term (for Union only) sales of storage.

Chapter 7 goes on to provide the Board's findings on for the sharing of margins for both short-term and long-term transactions and to describe a transition mechanism related to long-term margins.

The record that the NGEIR panel relied upon included extensive evidence and argument of many parties, including the moving parties to this proceeding and the utilities. The NGEIR Decision refers to various parties' submissions on the issue of premium sharing and the Board reiterated some of the historical evidence with respect

to the margin sharing in its Decision. The NGEIR Decision indicates that the NGEIR panel heard and considered the evidence and submissions before it in making its determinations with respect to this issue.

Importantly, the NGEIR panel's findings relate back to and to a certain extent flow from its broader decision to refrain, in part, from regulating rates for storage services. The Board does not accept the suggestion that the Board exceeded its jurisdiction by moving assets (in the case of Union) out of rate-base and by altering the status quo margin sharing mechanism. On the contrary, the NGEIR Decision clearly articulates that the changes to margin sharing flow necessarily and logically from the decision to refrain, in part, from regulated rates for storage services.

The determinations of the NGEIR panel are also consistent with its determination to distinguish between "utility assets" and "non-utility assets". The Decision clearly indicates that the NGEIR panel canvassed past decisions of the Board on this issue and considered the implications of its findings on both the utilities and ratepayers. Part of this consideration is evidenced in the development by the panel of a transition mechanism related to the implementation of the Board's finding that profits from new long-term transactions should accrue entirely to the utility (Union) as opposed to ratepayers. The threshold panel does not accept the argument that this transitional implementation is a form of implicit acknowledgement that the finding is inappropriate. The NGEIR panel exemplified Board precedent for the use of a phase-out mechanism and, in its finding, indicated that it had considered other options for a transitional mechanism.

The Board finds that the NGEIR panel's determinations on the treatment of the premium on market-based storage transactions are not reviewable. The record of the NGEIR proceeding clearly demonstrates that the NGEIR panel considered the evidence, the regulatory history with respect to the issue of premium sharing and parties' submissions and made its determination on the basis of that evidence and those submissions. There is nothing in the moving parties' evidence or arguments that demonstrate to the Board that the NGEIR panel made a reviewable error. For this

reason, the Board has determined that the threshold test has not been met and it will not order a review of the NGEIR Decision as it pertains to the issue of the division of the utilities assets or the sharing of the margin realized from the sale of natural gas storage to ex-franchise customers.

Section L: Additional Storage for Generators and Enbridge's Rate 316

Many of the issues which existed between Union and Enbridge and their generator customers were resolved in the Settlement Proposals which were filed and accepted by the Board in the NGEIR proceeding. These settlements deal with storage space parameters, increased deliverability for that space, and access to that enhanced space to balance on an intra-day basis. What remained unresolved was the pricing for the new high deliverability storage services for in-franchise generators.

The utilities had proposed in the NGEIR proceeding to offer these services at market-based rates and proposed that the Board refrain from regulating the rates for these services. The power generators took the position that storage services provided to them should be regulated at cost-based rates.

In the NGEIR Decision, APPrO's position was described as follows:

> The Association of Power Producers of Ontario (APPrO) argued that the product it is more interested in – high deliverability storage – is not currently available in Ontario. APPrO argued that competition cannot exist for a product that is not yet introduced and pointed out that when it is introduced it will be available only from Ontario utilities as ex-Ontario suppliers will be constrained by the nomination windows specified by the North American Energy Standards Board (NAESB).

The NGEIR Decision stated:

> With respect to APPrO's position, the Board is not convinced that high deliverability storage service is a different product. High deliverability storage may be a new service, but it is a particular way of using physical storage, which still depends upon the physical parameters of working capacity and deliverability.

In the Motions proceeding, APPrO stated that its position was and continues to be narrower than what was described by the NGEIR panel. APPrO was not seeking high deliverability storage. Rather, it was seeking services that would allow generators to manage their gas supply on an intra-day basis. It is not operationally possible for the generator to increase the rate at which gas can be delivered in and out of the storage space with deliverability from a supplier other than Union. Moreover, APPrO asserted that the frequent nominations windows required for such service are only available in Ontario from the utilities. Since this is a monopoly service, then it should be offered at cost.

Union argued that APPrO has not brought forward any new facts or changes in circumstance, nor has it demonstrated any error in the Board's original decision. It also stated that APPrO's assertion that high-deliverability storage is only available from the utility is demonstrably wrong and that there was sufficient evidence that high deliverability storage is available from others. Union disagreed with APPrO's position that deliverability could not be separated from storage space. Although this is correct in the physical context, Union submitted that there were substitutes for deliverability and storage space and gas-fired power generators could acquire their intra-day balancing needs from sources other than the utilities. This according to Union was clearly addressed in the original proceeding and considered by the Board in its decision and APPrO was simply seeking to re-argue its position that had already been fully canvassed.

Enbridge pointed out that any de-linking of storage and deliverability that occurred was as a result of the settlement agreed to by APPrO and the power generators with Enbridge. The settlement states that the allocation methodology for gas-fired generators' intra-day balancing needs is based on the assumption that high deliverability storage is available to those customers in the market.

APPrO has also raised an issue with some aspects of Rate 316 offered by Enbridge. Rate 316 was part of a proposal submitted by Enbridge during the NGEIR proceeding in response to generators' need for high deliverability storage service. As a result of the

Settlement Proposal, Enbridge's Rate 316 provides an allocation of base level deliverability storage at rolled in cost along with high deliverability storage at incremental cost to in-franchise gas fired generators. Section 1.5 of the Settlement Proposal indicates that generators are entitled to an allocation of 1.2% deliverability storage at rolled-in cost based rates.

Findings

In the Board's view, it is unclear from the NGEIR Decision whether the NGEIR panel took the implications of the Union settlement agreement into consideration. The NGEIR Decision does not provide sufficient clarity regarding the issues raised by APPrO. It appears that there are some practical limitations faced by gas-fired generators in that presently they can only access certain services from the utility. Although Union asserted that it is demonstrably wrong to suggest, as APPrO has, that "high-deliverability storage is only available from the utility" and that "there was sufficient evidence that high deliverability storage is available from others" this was not the finding expressed in the NGEIR Decision. In fact, at page 69 of the NGEIR Decision, the NGEIR Panel acknowledged this by stating that: "These services are not currently offered, indeed they need to be developed, and investments must be made in order to offer them." On the other hand, APPrO asserted that only TCPL offers some intra-day services but only in some parts of Ontario through a utility connection or a direct connection with TCPL. To the extent that APPrO's facts may be correct, there is sufficient question whether the NGEIR Decision erred by requiring that monopoly services be priced at market.

For these reasons, and given the potential material impact on power generators, the Board finds that the alleged errors raised by APPrO with respect to Union are material and relevant to the outcome of the decision, and that if the error is substantiated by a reviewing panel and corrected this could change the outcome of the decision. The Board will therefore pass this matter to a reviewing panel of the Board to investigate and make findings as it sees fit.

With respect to the Rate 316 issue, on page 70 of the NGEIR Decision, the Board stated:

> The Board notes that Enbridge committed to offer Rate 316, whether or not the Tecumseh enhancement project goes ahead, and to price it on cost pass-through basis. The Board expects Enbridge to fulfill this commitment.

The Board further noted:

> The Board will refrain from regulating the rates for new storage services, including Enbridge's high deliverability service from the Tecumseh storage enhancement and Rate 316, and Union's high deliverability storage, F24-S, UPBS and DPBS services.

At the motion hearing, APPrO indicated that it wanted the Board to issue an order requiring Enbridge to do what the Board has asked them to do, that is, to offer Rate 316 on a cost pass-through basis. Enbridge has already committed to offering this service in the Settlement Proposal and the Board has already noted this commitment in this decision. This panel does not see any further value to issuing an order stating the same.

However, there is some ambiguity with respect to Rate 316. The NGEIR decision seems to indicate that the Board will refrain from regulating Rate 316. Even so, the Enbridge NGEIR Rate Order has a tariff sheet for Rate 316 with storage rates for maximum deliverability of 1.2% of contracted storage space. This seems to indicate that Rate 316 is regulated for 1.2% deliverability storage and the Board has refrained from regulating rates for deliverability higher than 1.2%. It is difficult to recognize this distinction from the NGEIR Decision.

For these reasons, the Board finds that APPrO has raised a question as to the correctness of the order or decision in respect of the Rate 316 issue and that a review

panel of the Board could decide that the decision or order should be varied (by way of clarification or otherwise), cancelled or suspended.

Section M: Aggregate Excess Method of Allocating Storage

In the NGEIR proceeding, Union had proposed the "aggregate excess" method in allocating storage to its customers. The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer's average daily consumption over the entire year. Kitchener had proposed two alternative methodologies. The NGEIR Decision approved Union's proposal.

Kitchener argued that the NGEIR Decision failed to take into account that the aggregate excess methodology, because it uses normal weather to estimate a customer's storage allocation, unnecessarily increases utility rates and therefore offends the requirement of just and reasonable rates under sections 2 and 36 of the Act. Kitchener also argued that there is no evidence to support the Board's conclusion that aggregate excess meets the reasonable load balancing requirements of the Kitchener utility.

Union argued that these issues were fully considered by the Board in its NGEIR Decision and that Kitchener has not brought forward any new evidence or any new circumstances; it is simply attempting to reargue its case.

Findings

With respect to Kitchener's allegation that the NGEIR panel did not consider the impact on rates, the Board notes that the record in the NGEIR proceeding indicates that the impact on utility rates was examined extensively. The issue was raised in Kitchener's pre-filed evidence at page 5 and again at page 14. The transcript from the proceeding also indicates that there was extensive discussion on costs (Volume 12, pages 39-133) during cross examination and additional undertakings were filed on the topic. The record also indicates that the previous Panel questioned the witnesses specifically with respect to the costs and a utility's exposure to winter spot purchases (Volume 12, pages 183-184). The issue was again raised by Kitchener in argument (Volume 17, page 153)

and once again questions were posed to Kitchener's counsel by the NGEIR panel (Volume 17, pages 159-164).

The NGEIR Decision (pages 93 to 95) refers to Kitchener's alternatives and arguments and deals with that issue squarely when it finds that:

> The Board does not agree that the allocation of cost based storage should be determined assuming colder than normal weather or that it should be designed to provide protection against a cold snap in April. To do so would result in in-franchise customers as a group being allocated more cost-based storage than they are expected to use in most winters. As noted in 6.2.2, the Board concludes that the objective of the allocation of cost-based storage space is to assign an amount that is reasonably in line with what a customer is likely to require. In the Board's view, that supports continuing the assumption of normal weather.

In the Board's view, the record clearly indicates that this issue was thoroughly examined in the NGEIR proceeding. The Board believes that Kitchener's claim that the NGEIR panel failed to account for the fact the aggregate excess methodology increases utility rates is without merit. Kitchener presented no new evidence or new circumstances which would convince the Board that this issue is reviewable.

To support its second claim (i.e. the Board erred because there is no evidence to support the Board's conclusion that the aggregate excess method meets the reasonable load balancing requirements of the Kitchener utility), Kitchener argues that the Board ignored the evidence which suggests that the actual allocation to Kitchener over the past 6 years has been at a contractual level which is 10.6% higher than aggregate excess.

The Board disagrees. Contrary to Kitchener's assertions, the NGEIR Decision clearly considers the fact that Kitchener's aggregate excess amount is 10.6% lower than its current contracted amount. Specifically, the NGEIR Decision states:

> The current contract expires March 31, 2007 and Kitchener is seeking a long-term storage contract with Union effective April 1, 2007. It is concerned that its allocation of cost-based storage in a new contract will be restricted to the amount calculated under the aggregate excess method. Kitchener's current aggregate excess amount is 3.01 million GJ, 10.6% lower than the amount of cost-based storage in its current contract.

The NGEIR Decision also states:

> The issue is whether Kitchener has made a compelling case that its use of storage is so different from the assumed use underlying the aggregate excess method that Union should be required to develop an allocation method just for Kitchener. The Board finds Kitchener has not successfully made that argument.

In view of the above, the Board is convinced that the NGEIR panel considered the evidence before it. The claim by Kitchener that the Board ignored the evidence in question and based its decision only on the evidence provided by Union is demonstrably incorrect.

Kitchener also claims that the Board committed an error in fact by stating (at page 85 of the NGEIR Decision), that Enbridge uses a methodology similar to that of Union's. In the Boards' view, this reference is simply to provide context and is clearly referring to the mathematical formula used to calculate the storage allocation. It is certainly not a matter capable of altering the decision on this point.

In conclusion, the Board finds that the matters raised by Kitchener are not reviewable.

Section N: Orders

Having made its determinations on the Motions, the Board considers it appropriate to make the following Orders.

The Board Orders That:

The Motions for Review are hereby dismissed without further hearing, with the following exceptions. The Board's findings on Union's 100 PJ cap on cost-based storage for in-franchise customers and the additional storage requirements for in-franchise gas-fired generators are reviewable for the purposes set out in this Decision.

Section O: Cost Awards

The eligible parties shall submit their cost claims by June 5, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on both Union and Enbridge. The cost claims must be done in accordance with section 10 of the Board's Practice Direction on Cost Awards.

Union and Enbridge will have until June 19, 2007 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

The party whose cost claim was objected to will have until June 26, 2007 to make a reply submission as to why their cost claim should be allowed. Again, a copy of the submission must be filed with the Board and one copy is to be served on both Union and Enbridge.

DATED at Toronto, May 22, 2007

Original signed by

_____

Pamela Nowina
Presiding Member and Vice Chair

Original signed by

_____

Paul Vlahos
Member

Original signed by

_____

Cathy Spoel
Member

SUPREME COURT OF CANADA

CITATION: ATCO Gas & Pipelines Ltd. *v.* Alberta (Energy & Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4

DATE: 20060209
DOCKET: 30247

BETWEEN:

City of Calgary
Appellant/Respondent on cross-appeal
v.
ATCO Gas and Pipelines Ltd.
Respondent/Appellant on cross-appeal
- and -
Alberta Energy and Utilities Board, Ontario Energy Board, Enbridge Gas Distribution Inc. and Union Gas Limited
Interveners

CORAM: McLachlin C.J. and Bastarache, Binnie, LeBel, Deschamps, Fish and Charron JJ.

REASONS FOR JUDGMENT: (paras. 1 to 87) — Bastarache J. (LeBel, Deschamps and Charron JJ. concurring)

DISSENTING REASONS: (paras. 88 to 149) — Binnie J. (McLachlin C.J. and Fish J. concurring)

ATCO Gas and Pipelines Ltd. *v.* Alberta (Energy and Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4

City of Calgary *Appellant/Respondent on cross-appeal*

v.

ATCO Gas and Pipelines Ltd. *Respondent/Appellant on cross-appeal*

and

Alberta Energy and Utilities Board, Ontario Energy Board, Enbridge Gas Distribution Inc. and Union Gas Limited *Interveners*

Indexed as: ATCO Gas and Pipelines Ltd. *v.* Alberta (Energy and Utilities Board)

Neutral citation: 2006 SCC 4.

File No.: 30247.

2005: May 11; 2006: February 9.

Present: McLachlin C.J. and Bastarache, Binnie, LeBel, Deschamps, Fish and Charron JJ.

on appeal from the court of appeal for alberta

Administrative law — Boards and tribunals — Regulatory boards — Jurisdiction — Doctrine of jurisdiction by necessary implication — Natural gas public utility applying to Alberta Energy and Utilities Board to approve sale of buildings and land no longer required in supplying natural gas — Board approving sale subject to condition that portion of sale proceeds be allocated to ratepaying customers of utility — Whether Board had explicit or implicit jurisdiction to allocate proceeds of sale — If so, whether Board's decision to exercise discretion to protect public interest by allocating proceeds of utility asset sale to customers reasonable — Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) — Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 — Gas Utilities Act, R.S.A. 2000, c. G-5, s. 26(2).

Administrative law — Judicial review — Standard of review — Alberta Energy and Utilities Board — Standard of review applicable to Board's jurisdiction to allocate proceeds from sale of public utility assets to ratepayers — Standard of review applicable to Board's decision to exercise discretion to allocate proceeds of sale — Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) — Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 — Gas Utilities Act, R.S.A. 2000, c. G-5, s. 26(2).

ATCO is a public utility in Alberta which delivers natural gas. A division of ATCO filed an application with the Alberta Energy and Utilities Board for approval of the sale of buildings and land located in Calgary, as required by the *Gas Utilities Act* ("GUA"). According to ATCO, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to ratepaying customers. ATCO requested that the Board approve the sale transaction, as well as the proposed disposition of the sale proceeds: to retire the remaining book value of the sold assets, to recover the disposition costs, and to recognize that the balance of the profits

resulting from the sale should be paid to ATCO's shareholders. The customers' interests were represented by the City of Calgary, who opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

Persuaded that customers would not be harmed by the sale, the Board approved the sale transaction on the basis that customers would not "be exposed to the risk of financial harm as a result of the Sale that could not be examined in a future proceeding". In a second decision, the Board determined the allocation of net sale proceeds. The Board held that it had the jurisdiction to approve a proposed disposition of sale proceeds subject to appropriate conditions to protect the public interest, pursuant to the powers granted to it under s. 15(3) of the *Alberta Energy and Utilities Board Act* ("AEUBA"). The Board applied a formula which recognizes profits realized when proceeds of sale exceed the original cost can be shared between customers and shareholders, and allocated a portion of the net gain on the sale to the ratepaying customers. The Alberta Court of Appeal set aside the Board's decision, referring the matter back to the Board to allocate the entire remainder of the proceeds to ATCO.

Held (McLachlin C.J. and Binnie and Fish JJ. dissenting): The appeal is dismissed and the cross-appeal is allowed.

Per Bastarache, LeBel, Deschamps and Charron JJ.: When the relevant factors of the pragmatic and functional approach are properly considered, the standard of review applicable to the Board's decision on the issue of jurisdiction is correctness. Here, the Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset. The Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common

law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate any portion of the proceeds of sale of the property to ratepayers. [21-34]

The interpretation of the AEUBA, the *Public Utilities Board Act* ("PUBA") and the GUA can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. On their grammatical and ordinary meaning, s. 26(2) GUA, s. 15(3) AEUBA and s. 37 PUBA are silent as to the Board's power to deal with sale proceeds. Section 26(2) GUA conferred on the Board the power to approve a transaction without more. The intended meaning of the Board's power pursuant to s. 15(3) AEUBA to impose conditions on an order that the Board considers necessary in the public interest, as well as the general power in s. 37 PUBA, is lost when the provisions are read in isolation. They are, on their own, vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to any order it makes. While the concept of "public interest" is very wide and elastic, the Board cannot be given total discretion over its limitations. These seemingly broad powers must be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The context indicates that the limits of the Board's powers are grounded in its main function of fixing just and reasonable rates and in protecting the integrity and dependability of the supply system. [7] [41] [43] [46]

An examination of the historical background of public utilities regulation in Alberta generally, and the legislation in respect of the powers of the Alberta Energy and Utilities Board in particular, reveals that nowhere is there a mention of the authority for

the Board to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights. Moreover, although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities, is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates. The goals of sustainability, equity and efficiency, which underlie the reasoning as to how rates are fixed, have resulted in an economic and social arrangement which ensures that all customers have access to the utility at a fair price — nothing more. The rates paid by customers do not incorporate acquiring ownership or control of the utility's assets. The object of the statutes is to protect both the customer and the investor, and the Board's responsibility is to maintain a tariff that enhances the economic benefits to consumers and investors of the utility. This well-balanced regulatory arrangement does not, however, cancel the private nature of the utility. The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. [54-69]

Not only is the power to allocate the proceeds of the sale absent from the explicit language of the legislation, but it cannot be implied from the statutory regime as necessarily incidental to the explicit powers. For the doctrine of jurisdiction by necessary implication to apply, there must be evidence that the exercise of that power is a practical necessity for the Board to accomplish the objects prescribed by the

legislature, something which is absent in this case. Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that broadly drawn powers, such as those found in the AEUBA, the GUA and the PUBA, can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation. [39] [77-80]

Notwithstanding the conclusion that the Board lacked jurisdiction, its decision to exercise its discretion to protect the public interest by allocating the sale proceeds as it did to ratepaying customers did not meet a reasonable standard. When it explicitly concluded that no harm would ensue to customers from the sale of the asset, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Finally, it cannot be concluded that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process. [82-85]

Per McLachlin C.J. and Binnie and Fish JJ. (dissenting): The Board's decision should be restored. Section 15(3) AEUBA authorized the Board, in dealing with ATCO's application to approve the sale of the subject land and buildings, to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" pursuant to s. 22(1) GUA, the Board made an allocation of the net gain for public policy reasons. The Board's

discretion is not unlimited and must be exercised in good faith for its intended purpose. Here, in allocating one third of the net gain to ATCO and two thirds to the rate base, the Board explained that it was proper to balance the interests of both shareholders and ratepayers. In the Board's view to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs, but on the other hand to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business. Although it was open to the Board to allow ATCO's application for the entire profit, the solution it adopted in this case is well within the range of reasonable options. The "public interest" is largely and inherently a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, Alberta's grant of authority to its Board is more generous than most. The Court should not substitute its own view of what is "necessary in the public interest". The Board's decision made in the exercise of its jurisdiction was within the range of established regulatory opinion, whether the proper standard of review in that regard is patent unreasonableness or simple reasonableness. [91-92] [98-99] [110] [113] [122] [148]

ATCO's submission that an allocation of profit to the customers would amount to a confiscation of the corporation's property overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the ratepayers carry the costs and the regulator sets the return on investment, not the marketplace. The Board's response cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what is regarded in comparable jurisdictions as an appropriate regulatory allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. Similarly,

ATCO's argument that the Board engaged in impermissible retroactive rate making should not be accepted. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective not retroactive. Fixing the going-forward rate of return, as well as general supervision of "all gas utilities, and the owners of them", were matters squarely within the Board's statutory mandate. ATCO also submits in its cross-appeal that the Court of Appeal erred in drawing a distinction between gains on sale of land whose original cost is not depreciated and depreciated property, such as buildings. A review of regulatory practice shows that many, but not all, regulators reject the relevance of this distinction. The point is not that the regulator must reject any such distinction but, rather, that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. Finally, ATCO's contention that it alone is burdened with the risk on land that declines in value overlooks the fact that in a falling market the utility continues to be entitled to a rate of return on its original investment, even if the market value at the time is substantially less than its original investment. Further, it seems such losses are taken into account in the ongoing rate-setting process. [93] [123-147]

Cases Cited

By Bastarache J.

Referred to: *Re ATCO Gas-North*, Alta. E.U.B., Decision 2001-65, July 31, 2001; *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171; *Re TransAlta Utilities Corp.*, Alta. E.U.B., Decision 2000-41, July 5, 2000; *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R.

982; *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485, 2004 SCC 19; *Consumers' Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (QL); *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy Utilities Board)* (1996), 41 Alta. L.R. (3d) 374; *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557; *Dome Petroleum Ltd. v. Public Utilities Board (Alberta)* (1976), 2 A.R. 453, aff'd [1977] 2 S.C.R. 822; *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28; *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27; *Bell ExpressVu Limited Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42; *H.L. v. Canada (Attorney General)*, [2005] 1 S.C.R. 401, 2005 SCC 25; *Marche v. Halifax Insurance Co.*, [2005] 1 S.C.R. 47, 2005 SCC 6; *Contino v. Leonelli-Contino*, [2005] 3 S.C.R. 217, 2005 SCC 63; *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984; *TransAlta Utilities Corp. (Re)*, [2002] A.E.U.B.D. No. 30 (QL); *ATCO Electric Ltd. (Re)*, [2003] A.E.U.B.D. No. 92 (QL); *Canadian Pacific Air Lines Ltd. v. Canadian Air Line Pilots Assn.*, [1993] 3 S.C.R. 724; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26; *Chieu v. Canada (Minister of Citizenship and Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3; *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722; *R. v. McIntosh*, [1995] 1 S.C.R. 686; *Re Dow Chemical Canada Inc. and Union Gas Ltd.* (1982), 141 D.L.R. (3d) 641, aff'd (1983), 42 O.R. (2d) 731; *Interprovincial Pipe Line Ltd. v. National Energy Board*, [1978] 1 F.C. 601; *Canadian Broadcasting League v. Canadian Radio-television and Telecommunications Commission*, [1983] 1 F.C. 182, aff'd [1985] 1 S.C.R. 174; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186; *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984; *Re Union Gas Ltd. and*

Ontario Energy Board (1983), 1 D.L.R. (4th) 698; *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989); *Market St. Ry. Co. v. Railroad Commission of State of California*, 324 U.S. 548 (1945); *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Consumers' Gas Co.*, E.B.R.O. 410-II, 411-II, 412-II, March 23, 1987; *National Energy Board Act (Can.) (Re)*, [1986] 3 F.C. 275; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64; *Leiriao v. Val-Bélair (Town)*, [1991] 3 S.C.R. 349; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167.

By Binnie J. (dissenting)

Atco Ltd. v. Calgary Power Ltd., [1982] 2 S.C.R. 557; *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 S.C.R. 539, 2003 SCC 29; *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171; *Dr. Q v. College of Physicians and Surgeons of British Columbia*, [2003] 1 S.C.R. 226, 2003 SCC 19; *Calgary Power Ltd. v. Copithorne*, [1959] S.C.R. 24; *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316; *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557; *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353; *Union Gas Co. of Canada Ltd. v. Sydenham Gas and Petroleum Co.*, [1957] S.C.R. 185; *Re C.T.C. Dealer Holdings Ltd. and Ontario Securities Commission* (1987), 59 O.R. (2d) 79; *Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37; *Re Consumers' Gas Co.*, E.B.R.O. 341-I, June 30, 1976; *Re Boston Gas Co.*, 49 P.U.R. 4th 1 (1982); *Re Consumers' Gas Co.*, E.B.R.O. 465, March 1, 1991; *Re Natural Resource Gas Ltd.*, O.E.B., RP-2002-0147, EB-2002-0446, June 27, 2003; *Yukon Energy Corp. v. Utilities*

Board (1996), 74 B.C.A.C. 58; *Re Arizona Public Service Co.*, 91 P.U.R. 4th 337 (1988); *Re Southern California Water Co.*, 43 C.P.U.C. 2d 596 (1992); *Re Southern California Gas Co.*, 118 P.U.R. 4th 81 (1990); *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (1973); *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (1976); *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684; *New York Water Service Corp. v. Public Service Commission*, 208 N.Y.S.2d 857 (1960); *Re Compliance with the Energy Policy Act of 1992*, 62 C.P.U.C. 2d 517 (1995); *Re California Water Service Co.*, 66 C.P.U.C. 2d 100 (1996); *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984; *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84115, October 12, 1984; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984.

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APPEAL and CROSS-APPEAL from a judgment of the Alberta Court of Appeal (Wittmann J.A. and LoVecchio J. (*ad hoc*)) (2004), 24 Alta. L.R. (4th) 205, 339 A.R. 250, 312 W.A.C. 250, [2004] 4 W.W.R. 239, [2004] A.J. No. 45 (QL), 2004 ABCA 3, reversing a decision of the Alberta Energy and Utilities Board, [2002] A.E.U.B.D. No. 52 (QL). Appeal dismissed and cross-appeal allowed, McLachlin C.J. and Binnie and Fish JJ. dissenting.

Brian K. O'Ferrall and *Daron K. Naffin*, for the appellant/respondent on cross-appeal.

Clifton D. O'Brien, *Q.C.*, *Lawrence E. Smith*, *Q.C.*, *H. Martin Kay*, *Q.C.*, and *Laurie A. Goldbach*, for the respondent/appellant on cross-appeal.

J. Richard McKee and *Renée Marx*, for the intervener the Alberta Energy and Utilities Board.

Written submissions only by *George Vegh* and *Michael W. Lyle*, for the intervener the Ontario Energy Board.

Written submissions only by *J. L. McDougall*, *Q.C.*, and *Michael D. Schafler*, for the intervener Enbridge Gas Distribution Inc.

Written submissions only by *Michael A. Penny* and *Susan Kushneryk*, for the intervener Union Gas Limited.

The judgment of Bastarache, LeBel, Deschamps and Charron JJ. was delivered by

BASTARACHE J. —

1. Introduction

1 At the heart of this appeal is the issue of the jurisdiction of an administrative board. More specifically, the Court must consider whether, on the appropriate standard of review, this utility board appropriately set out the limits of its powers and discretion.

2 Few areas of our lives are now untouched by regulation. Telephone, rail, airline, trucking, foreign investment, insurance, capital markets, broadcasting licences and content, banking, food, drug and safety standards, are just a few of the objects of public regulations in Canada: M. J. Trebilcock, "The Consumer Interest and Regulatory Reform", in G. B. Doern, ed., *The Regulatory Process in Canada* (1978), 94. Discretion is central to the regulatory agency policy process, but this discretion will vary from one administrative body to another (see C. L. Brown-John, *Canadian Regulatory Agencies: Quis custodiet ipsos custodes?* (1981), at p. 29). More importantly, in exercising this discretion, statutory bodies must respect the confines of their jurisdiction: they cannot trespass in areas where the legislature has not assigned them authority (see D. J. Mullan, *Administrative Law* (2001), at pp. 9-10).

3 The business of energy and utilities is no exception to this regulatory framework. The respondent in this case is a public utility in Alberta which delivers natural gas. This public utility is nothing more than a private corporation subject to certain regulatory constraints. Fundamentally, it is like any other privately held company: it obtains the necessary funding from investors through public issues of shares in stock and bond markets; it is the sole owner of the resources, land and other assets; it constructs plants, purchases equipment, and contracts with employees to provide the services; it realizes profits resulting from the application of the rates approved by the Alberta Energy and Utilities Board ("Board") (see P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 *Energy L.J.* 233, at p. 234). That said, one cannot ignore the important feature which makes a public utility so distinct: it must answer to a regulator. Public utilities are typically natural monopolies: technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment (see A. E. Kahn, *The Economics of Regulation: Principles and Institutions* (1988), vol. 1, at p. 11; B. W. F. Depoorter, "Regulation of Natural Monopoly", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 498; J. S. Netz, "Price Regulation: A (Non-Technical) Overview", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 396, at p. 398; A. J. Black, "Responsible Regulation: Incentive Rates for Natural Gas Pipelines" (1992), 28 *Tulsa L.J.* 349, at p. 351). Efficiency of production is promoted under this model. However, governments have purported to move away from this theoretical concept and have adopted what can only be described as a "regulated monopoly". The utility regulations exist to protect the public

from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service (see Kahn, at p. 11).

4 As in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions. And more relevant to this case, the utility, outside the ordinary course of business, is limited in its right to sell assets it owns: it must obtain authorization from its regulator before selling an asset previously used to produce regulated services (see MacAvoy and Sidak, at p. 234).

5 Against this backdrop, the Court is being asked to determine whether the Board has jurisdiction pursuant to its enabling statutes to allocate a portion of the net gain on the sale of a now discarded utility asset to the rate-paying customers of the utility when approving the sale. Subsequently, if this first question is answered affirmatively, the Court must consider whether the Board's exercise of its jurisdiction was reasonable and within the limits of its jurisdiction: was it allowed, in the circumstances of this case, to allocate a portion of the net gain on the sale of the utility to the rate-paying customers?

6 The customers' interests are represented in this case by the City of Calgary ("City") which argues that the Board can determine how to allocate the proceeds pursuant to its power to approve the sale and protect the public interest. I find this position unconvincing.

7 The interpretation of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), the *Public Utilities Board Act*, R.S.A. 2000, c. P-45 ("PUBA"), and the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") (see Appendix for the relevant provisions of these three statutes), can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. The Board's seemingly broad powers to make any order and to impose any additional conditions that are necessary in the public interest has to be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The limits of the powers of the Board are grounded in its main function of fixing just and reasonable rates ("rate setting") and in protecting the integrity and dependability of the supply system.

1.1 *Overview of the Facts*

8 ATCO Gas - South ("AGS"), which is a division of ATCO Gas and Pipelines Ltd. ("ATCO"), filed an application by letter with the Board pursuant to s. 25.1(2) (now s. 26(2)) of the GUA, for approval of the sale of its properties located in Calgary known as Calgary Stores Block (the "property"). The property consisted of land and buildings; however, the main value was in the land, and the purchaser intended to and did eventually demolish the buildings and redevelop the land. According to AGS, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to customers. In fact, AGS suggested that the sale would result in cost savings to customers, by allowing the net book value of the property to be retired and withdrawn from the rate base, thereby reducing rates. ATCO requested that the Board approve the sale transaction and the disposition of the sale proceeds to retire

the remaining book value of the sold assets, to recover the disposition costs, and to recognize the balance of the profits resulting from the sale of the plant should be paid to shareholders. The Board dealt with the application in writing, without witnesses or an oral hearing. Other parties making written submissions to the Board were the City of Calgary, the Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and the Municipal Interveners, who all opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

1.2 *Judicial History*

1.2.1 Alberta Energy and Utilities Board

1.2.1.1 *Decision 2001-78*

9 In a first decision, which considered ATCO's application to approve the sale of the property, the Board employed a "no-harm" test, assessing the potential impact on both rates and the level of service to customers and the prudence of the sale transaction, taking into account the purchaser and tender or sale process followed. The Board was of the view that the test had been satisfied. It was persuaded that customers would not be harmed by the sale, given that a prudent lease arrangement to replace the sold facility had been concluded. The Board was satisfied that there would not be a negative impact on customers' rates, at least during the five-year initial term of the lease. In fact, the Board concluded that there would be cost savings to the customers and that there would be no impact on the level of service to customers as a result of the sale. It did not make a finding on the specific impact on future operating costs; for example, it did not consider the costs of the lease arrangement entered into by ATCO. The Board noted that

those costs could be reviewed by the Board in a future general rate application brought by interested parties.

1.2.1.2 *Decision 2002-037, [2002] A.E.U.B.D. No. 52 (QL)*

10 In a second decision, the Board determined the allocation of net sale proceeds. It reviewed the regulatory policy and general principles which affected the decision, although no specific matters are enumerated for consideration in the applicable legislative provisions. The Board had previously developed a "no-harm" test, and it reviewed the rationale for the test as summarized in its Decision 2001-65 (*Re ATCO Gas-North*): "The Board considers that its power to mitigate or offset potential harm to customers by allocating part or all of the sale proceeds to them, flows from its very broad mandate to protect consumers in the public interest" (p. 16).

11 The Board went on to discuss the implications of the Alberta Court of Appeal decision in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171, referring to various decisions it had rendered in the past. Quoting from its Decision 2000-41 (*Re TransAlta Utilities Corp.*), the Board summarized the "*TransAlta Formula*":

> In subsequent decisions, the Board has interpreted the Court of Appeal's conclusion to mean that where the sale price exceeds the original cost of the assets, shareholders are entitled to net book value (in historical dollars), customers are entitled to the difference between net book value and original cost, and any appreciation in the value of the assets (i.e. the difference between original cost and the sale price) is to be shared by shareholders and customers. The amount to be shared by each is determined by multiplying the ratio of sale price/original cost to the net book value (for shareholders) and the difference between original cost and net book value (for customers). However, where the sale price does not exceed original cost, customers are entitled to all of the gain on sale. [para. 27]

The Board also referred to Decision 2001-65, where it had clarified the following:

> In the Board's view, if the TransAlta Formula yields a result greater than the no-harm amount, customers are entitled to the greater amount. If the TransAlta Formula yields a result less than the no-harm amount, customers are entitled to the no-harm amount. In the Board's view, this approach is consistent with its historical application of the TransAlta Formula. [para. 28]

12 On the issue of its jurisdiction to allocate the net proceeds of a sale, the Board in the present case stated:

> The fact that a regulated utility must seek Board approval before disposing of its assets is sufficient indication of the limitations placed by the legislature on the property rights of a utility. In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.
>
> Regarding AGS's argument that allocating more than the no-harm amount to customers would amount to retrospective ratemaking, the Board again notes the decision in the TransAlta Appeal. The Court of Appeal accepted that the Board could include in the definition of "revenue" an amount payable to customers representing excess depreciation paid by them through past rates. In the Board's view, no question of retrospective ratemaking arises in cases where previously regulated rate base assets are being disposed of out of rate base and the Board applies the TransAlta Formula.
>
> The Board is not persuaded by the Company's argument that the Stores Block assets are now 'non-utility' by virtue of being 'no longer required for utility service'. The Board notes that the assets could still be providing service to regulated customers. In fact, the services formerly provided by the Stores Block assets continue to be required, but will be provided from existing and newly leased facilities. Furthermore, the Board notes that even when an asset and the associated service it was providing to customers is no longer required the Board has previously allocated more than the no-harm amount to customers where proceeds have exceeded the original cost of the asset. [paras. 47-49]

13 The Board went on to apply the no-harm test to the present facts. It noted that in its decision on the application for the approval of the sale, it had already

considered the no-harm test to be satisfied. However, in that first decision, it had not made a finding with respect to the specific impact on future operating costs, including the particular lease arrangement being entered into by ATCO.

14 The Board then reviewed the submissions with respect to the allocation of the net gain and rejected the submission that if the new owner had no use of the buildings on the land, this should affect the allocation of net proceeds. The Board held that the buildings did have some present value but did not find it necessary to fix a specific value. The Board recognized and confirmed that the *TransAlta Formula* was one whereby the "windfall" realized when the proceeds of sale exceed the original cost could be shared between customers and shareholders. It held that it should apply the formula in this case and that it would consider the gain on the transaction as a whole, not distinguishing between the proceeds allocated to land separately from the proceeds allocated to buildings.

15 With respect to allocation of the gain between customers and shareholders of ATCO, the Board tried to balance the interests of both the customers' desire for safe reliable service at a reasonable cost with the provision of a fair return on the investment made by the company:

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred. [paras. 112-13]

16 The Board went on to conclude that the sharing of the net gain on the sale of the land and buildings collectively, in accordance with the *TransAlta Formula*, was equitable in the circumstances of this application and was consistent with past Board decisions.

17 The Board determined that from the gross proceeds of $6,550,000, ATCO should receive $465,000 to cover the cost of disposition ($265,000) and the provision for environmental remediation ($200,000), the shareholders should receive $2,014,690, and $4,070,310 should go to the customers. Of the amount credited to shareholders, $225,245 was to be used to remove the remaining net book value of the property from ATCO's accounts. Of the amount allocated to customers, $3,045,813 was allocated to ATCO Gas - South customers and $1,024,497 to ATCO Pipelines - South customers.

1.2.2 Court of Appeal of Alberta ((2004), 24 Alta. L.R. (4th) 205, 2004 ABCA 3)

18 ATCO appealed the Board's decision. It argued that the Board did not have any jurisdiction to allocate the proceeds of sale and that the proceeds should have been allocated entirely to the shareholders. In its view, allowing customers to share in the proceeds of sale would result in them benefiting twice, since they had been spared the costs of renovating the sold assets and would enjoy cost savings from the lease arrangements. The Court of Appeal of Alberta agreed with ATCO, allowing the appeal and setting aside the Board's decision. The matter was referred back to the Board, and the Board was directed to allocate the entire amount appearing in Line 11 of the allocation of proceeds, entitled "Remainder to be Shared" to ATCO. For the reasons that follow, the Court of Appeal's decision should be upheld, in part; it did not err when it

held that the Board did not have the jurisdiction to allocate the proceeds of the sale to ratepayers.

2. Analysis

2.1 *Issues*

19 There is an appeal and a cross-appeal in this case: an appeal by the City in which it submits that, contrary to the Court of Appeal's decision, the Board had jurisdiction to allocate a portion of the net gain on the sale of a utility asset to the rate-paying customers, even where no harm to the public was found at the time the Board approved the sale, and a cross-appeal by ATCO in which it questions the Board's jurisdiction to allocate any of ATCO's proceeds from the sale to customers. In particular, ATCO contends that the Board has no jurisdiction to make an allocation to rate-paying customers, equivalent to the accumulated depreciation calculated for prior years. No matter how the issue is framed, it is evident that the crux of this appeal lies in whether the Board has the jurisdiction to distribute the gain on the sale of a utility company's asset.

20 Given my conclusion on this issue, it is not necessary for me to consider whether the Board's allocation of the proceeds in this case was reasonable. Nevertheless, as I note at para. 82, I will direct my attention briefly to the question of the exercise of discretion in view of my colleague's reasons.

2.2 *Standard of Review*

21 As this appeal stems from an administrative body's decision, it is necessary to determine the appropriate level of deference which must be shown to the body. Wittmann J.A., writing for the Court of Appeal, concluded that the issue of jurisdiction of the Board attracted a standard of correctness. ATCO concurs with this conclusion. I agree. No deference should be shown for the Board's decision with regard to its jurisdiction on the allocation of the net gain on sale of assets. An inquiry into the factors enunciated by this Court in *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, confirms this conclusion, as does the reasoning in *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485, 2004 SCC 19.

22 Although it is not necessary to conduct a full analysis of the standard of review in this case, I will address the issue briefly in light of the fact that Binnie J. deals with the exercise of discretion in his reasons for judgment. The four factors that need to be canvassed in order to determine the appropriate standard of review of an administrative tribunal decision are: (1) the existence of a privative clause; (2) the expertise of the tribunal/board; (3) the purpose of the governing legislation and the particular provisions; and (4) the nature of the problem (*Pushpanathan*, at paras. 29-38).

23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

24 First, s. 26(1) of the AEUBA grants a right of appeal, but in a limited way. Appeals are allowed on a question of jurisdiction or law and only after leave to appeal is obtained from a judge:

> **26(1)** Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.
>
> **(2)** Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made
>
> (a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or
>
> (b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

In addition, the AEUBA includes a privative clause which states that every action, order, ruling or decision of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court (s. 27).

25 The presence of a statutory right of appeal on questions of jurisdiction and law suggests a more searching standard of review and less deference to the Board on those questions (see *Pushpanathan*, at para. 30). However, the presence of the privative clause and right to appeal are not decisive, and one must proceed with the examination of the nature of the question to be determined and the relative expertise of the tribunal in those particular matters.

26 Second, as observed by the Court of Appeal, no one disputes the fact that the Board is a specialized body with a high level of expertise regarding Alberta's energy resources and utilities (see, e.g., *Consumers' Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (QL) (Div. Ct.), at para. 2; *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy Utilities Board)* (1996), 41 Alta. L.R. (3d) 374 (C.A.), at

para. 14. In fact, the Board is a permanent tribunal with a long-term regulatory relationship with the regulated utilities.

27 Nevertheless, the Court is concerned not with the general expertise of the administrative decision maker, but with its expertise in relation to the specific nature of the issue before it. Consequently, while normally one would have assumed that the Board's expertise is far greater than that of a court, the nature of the problem at bar, to adopt the language of the Court of Appeal (para. 35), "neutralizes" this deference. As I will elaborate below, the expertise of the Board is not engaged when deciding the scope of its powers.

28 Third, the present case is governed by three pieces of legislation: the PUBA, the GUA and the AEUBA. These statutes give the Board a mandate to safeguard the public interest in the nature and quality of the service provided to the community by public utilities: *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576; *Dome Petroleum Ltd. v. Public Utilities Board (Alberta)* (1976), 2 A.R. 453 (C.A.), at paras. 20-22, aff'd [1977] 2 S.C.R. 822. The legislative framework at hand has as its main purpose the proper regulation of a gas utility in the public interest, more specifically the regulation of a monopoly in the public interest with its primary tool being rate setting, as I will explain later.

29 The particular provision at issue, s. 26(2)(d)(i) of the GUA, which requires a utility to obtain the approval of the regulator before it sells an asset, serves to protect the customers from adverse results brought about by any of the utility's transactions by ensuring that the economic benefits to customers are enhanced (MacAvoy and Sidak, at pp. 234-36).

30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.

31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28, at para. 86. The interpretation of general concepts such as "public interest" and

"conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. The second question is whether the method and actual allocation in this case were reasonable. To resolve this issue, one must consider case law, policy justifications and the practice of other boards, as well as the details of the particular allocation in this case. The issue here is most likely characterized as one of mixed fact and law.

32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition will be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan*, at para. 38:

> . . . the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

33 The second question regarding the Board's actual method used for the allocation of proceeds likely attracts a more deferential standard. On the one hand, the Board's expertise, particularly in this area, its broad mandate, the technical nature of the question and the general purposes of the legislation, all suggest a relatively high level of deference to the Board's decision. On the other hand, the absence of a privative clause on questions of jurisdiction and the reference to law needed to answer this question all

suggest a less deferential standard of review which favours reasonableness. It is not necessary, however, for me to determine which specific standard would have applied here.

34 As will be shown in the analysis below, I am of the view that the Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate *any* portion of the proceeds of sale of the property to ratepayers.

2.3 *Was the Board's Decision as to Its Jurisdiction Correct?*

35 Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, *Administrative Law in Canada* (3rd ed. 2001), at pp. 183-84).

36 In order to determine whether the Board's decision that it had the jurisdiction to allocate proceeds from the sale of a utility's asset was correct, I am required to interpret the legislative framework by which the Board derives its powers and actions.

2.3.1 General Principles of Statutory Interpretation

37 For a number of years now, the Court has adopted E. A. Driedger's modern approach as the method to follow for statutory interpretation (*Construction of Statutes* (2nd ed. 1983), at p. 87):

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

(See, e.g., *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, at para. 21; *Bell ExpressVu Limited Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42, at para. 26; *H.L. v. Canada (Attorney General)*, [2005] 1 S.C.R. 401, 2005 SCC 25, at paras. 186-87; *Marche v. Halifax Insurance Co.*, [2005] 1 S.C.R. 47, 2005 SCC 6, at para. 54; *Barrie Public Utilities*, at paras. 20 and 86; *Contino v. Leonelli-Contino*, [2005] 3 S.C.R. 217, 2005 SCC 63, at para. 19.)

38 But more specifically in the area of administrative law, tribunals and boards obtain their jurisdiction over matters from two sources: (1) express grants of jurisdiction under various statutes (explicit powers); and (2) the common law, by application of the doctrine of jurisdiction by necessary implication (implicit powers) (see also D. M. Brown, *Energy Regulation in Ontario* (loose-leaf ed.), at p. 2-15).

39 The City submits that it is both implicit and explicit within the express jurisdiction that has been conferred upon the Board to approve or refuse to approve the sale of utility assets, that the Board can determine how to allocate the proceeds of the sale in this case. ATCO retorts that not only is such a power absent from the explicit language of the legislation, but it cannot be "implied" from the statutory regime as

necessarily incidental to the explicit powers. I agree with ATCO's submissions and will elaborate in this regard.

2.3.2 Explicit Powers: Grammatical and Ordinary Meaning

40 As a preliminary submission, the City argues that given that ATCO applied to the Board for approval of both the sale transaction *and* the disposition of the proceeds of sale, this suggests that ATCO recognized that the Board has authority to allocate the proceeds as a condition of a proposed sale. This argument does not hold any weight in my view. First, the application for approval cannot be considered on its own an admission by ATCO of the jurisdiction of the Board. In any event, an admission of this nature would not have any bearing on the applicable law. Moreover, knowing that in the past the Board had decided that it had jurisdiction to allocate the proceeds of a sale of assets and had acted on this power, one can assume that ATCO was asking for the approval of the disposition of the proceeds should the Board not accept their argument on jurisdiction. In fact, a review of past Board decisions on the approval of sales shows that utility companies have constantly challenged the Board's jurisdiction to allocate the net gain on the sale of assets (see, e.g., *Re TransAlta Utilities Corp.*, Alta. E.U.B., Decision 2000-41; *Re ATCO Gas-North*, Alta. E.U.B., Decision 2001-65; *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984; *TransAlta Utilities Corp. (Re)*, [2002] A.E.U.B.D. No. 30 (QL); *ATCO Electric Ltd. (Re)*, [2003] A.E.U.B.D. No. 92 (QL)).

41 The starting point of the analysis requires that the Court examine the ordinary meaning of the sections at the centre of the dispute, s. 26(2)(d)(i) of the GUA,

ss. 15(1) and 15(3)(d) of the AEUBA and s. 37 of the PUBA. For ease of reference, I reproduce these provisions:

GUA

26. . . .

(2) No owner of a gas utility designated under subsection (1) shall

. . .

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them

. . .

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

AEUBA

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB [Energy Resources Conservation Board] and the PUB [Public Utilities Board] that are granted or provided for by any enactment or by law.

. . .

(3) Without restricting subsection (1), the Board may do all or any of the following:

. . .

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

. . .

PUBA

> **37** In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

42 Some of the above provisions are duplicated in the other two statutes (see, e.g., PUBA, ss. 85(1) and 101(2)(d)(i); GUA, s. 22(1); see Appendix).

43 There is no dispute that s. 26(2) of the GUA contains a prohibition against, among other things, the owner of a utility selling, leasing, mortgaging or otherwise disposing of its property outside of the ordinary course of business without the approval of the Board. As submitted by ATCO, the power conferred is to approve without more. There is no mention in s. 26 of the grounds for granting or denying approval or of the ability to grant conditional approval, let alone the power of the Board to allocate the net profit of an asset sale. I would note in passing that this power is sufficient to alleviate the fear expressed by the Board that the utility might be tempted to sell assets on which it might realize a large profit to the detriment of ratepayers if it could reap the benefits of the sale.

44 It is interesting to note that s. 26(2) does not apply to all types of sales (and leases, mortgages, dispositions, encumbrances, mergers or consolidations). It excludes sales in the ordinary course of the owner's business. If the statutory scheme was such that the Board had the power to allocate the proceeds of the sale of utility assets, as argued here, s. 26(2) would naturally apply to all sales of assets or, at a minimum, exempt only those sales below a certain value. It is apparent that allocation of sale proceeds to customers is not one of its purposes. In fact, s. 26(2) can only have limited,

if any, application to non-utility assets not related to utility function (especially when the sale has passed the "no-harm" test). The provision can only be meant to ensure that the asset in question is indeed non-utility, so that its loss does not impair the utility function or quality.

45 Therefore, a simple reading of s. 26(2) of the GUA does permit one to conclude that the Board does not have the power to allocate the proceeds of an asset sale.

46 The City does not limit its arguments to s. 26(2); it also submits that the AEUBA, pursuant to s. 15(3), is an express grant of jurisdiction because it authorizes the Board to impose any condition to any order so long as the condition is necessary in the public interest. In addition, it relies on the general power in s. 37 of the PUBA for the proposition that the Board may, in any matter within its jurisdiction, make any order pertaining to that matter that is not inconsistent with any applicable statute. The intended meaning of these two provisions, however, is lost when the provisions are simply read in isolation as proposed by the City: R. Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed. 2002), at p. 21; *Canadian Pacific Air Lines Ltd. v. Canadian Air Line Pilots Assn.*, [1993] 3 S.C.R. 724, at p. 735; *Marche*, at paras. 59-60; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26, at para. 105. These provisions on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of "public interest" found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations.

47 While I would conclude that the legislation is silent as to the Board's power to deal with sale proceeds after the initial stage in the statutory interpretation analysis,

because the provisions can nevertheless be said to reveal some ambiguity and incoherence, I will pursue the inquiry further.

48 This Court has stated on numerous occasions that the grammatical and ordinary sense of a section is not determinative and does not constitute the end of the inquiry. The Court is obliged to consider the total context of the provisions to be interpreted, no matter how plain the disposition may seem upon initial reading (see *Chieu v. Canada (Minister of Citizenship and Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3, at para. 34; Sullivan, at pp. 20-21). I will therefore proceed to examine the purpose and scheme of the legislation, the legislative intent and the relevant legal norms.

2.3.3 Implicit Powers: Entire Context

49 The provisions at issue are found in statutes which are themselves components of a larger statutory scheme which cannot be ignored:

> As the product of a rational and logical legislature, the statute is considered to form a system. Every component contributes to the meaning as a whole, and the whole gives meaning to its parts: "each legal provision should be considered in relation to other provisions, as parts of a whole" . . . .
>
> (P.-A. Côté, *The Interpretation of Legislation in Canada* (3rd ed. 2000), at p. 308)

As in any statutory interpretation exercise, when determining the powers of an administrative body, courts need to examine the context that colours the words and the legislative scheme. The ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme (*Bell ExpressVu*, at para. 27; see also *Interpretation Act*, R.S.A.

2000, c. I-8, s. 10 (in Appendix)). "[S]tatutory interpretation is the art of finding the legislative spirit embodied in enactments": *Bristol-Myers Squibb Co.*, at para. 102.

50 Consequently, a grant of authority to exercise a discretion as found in s. 15(3) of the AEUBA and s. 37 of the PUBA does not confer unlimited discretion to the Board. As submitted by ATCO, the Board's discretion is to be exercised within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation (see Sullivan, at pp. 154-55). In the same vein, it is useful to refer to the following passage from *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722, at p. 1756:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

51 The mandate of this Court is to determine and apply the intention of the legislature (*Bell ExpressVu*, at para. 62) without crossing the line between judicial interpretation and legislative drafting (see *R. v. McIntosh*, [1995] 1 S.C.R. 686, at para. 26; *Bristol-Myers Squibb Co.*, at para. 174). That being said, this rule allows for the application of the "doctrine of jurisdiction by necessary implication"; the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature (see Brown, at p. 2-16.2; *Bell Canada*, at p. 1756). Canadian courts have

in the past applied the doctrine to ensure that administrative bodies have the necessary jurisdiction to accomplish their statutory mandate:

> When legislation attempts to create a comprehensive regulatory framework, the tribunal must have the powers which by practical necessity and necessary implication flow from the regulatory authority explicitly conferred upon it.

Re Dow Chemical Canada Inc. and Union Gas Ltd. (1982), 141 D.L.R. (3d) 641 (Ont. H.C.), at pp. 658-59, aff'd (1983), 42 O.R. (2d) 731 (C.A.) (see also *Interprovincial Pipe Line Ltd. v. National Energy Board*, [1978] 1 F.C. 601 (C.A.); *Canadian Broadcasting League v. Canadian Radio-television and Telecommunications Commission*, [1983] 1 F.C. 182 (C.A.), aff'd [1985] 1 S.C.R. 174).

52 I understand the City's arguments to be as follows: (1) the customers acquire a right to the property of the owner of the utility when they pay for the service and are therefore entitled to a return on the profits made at the time of the sale of the property; and (2) the Board has, by necessity, because of its jurisdiction to approve or refuse to approve the sale of utility assets, the power to allocate the proceeds of the sale as a condition of its order. The doctrine of jurisdiction by necessary implication is at the heart of the City's second argument. I cannot accept either of these arguments which are, in my view, diametrically contrary to the state of the law. This is revealed when we scrutinize the entire context which I will now endeavour to do.

53 After a brief review of a few historical facts, I will probe into the main function of the Board, rate setting, and I will then explore the incidental powers which can be derived from the context.

2.3.3.1 *Historical Background and Broader Context*

54 The history of public utilities regulation in Alberta originated with the creation in 1915 of the Board of Public Utility Commissioners by *The Public Utilities Act*, S.A. 1915, c. 6. This statute was based on similar American legislation: H. R. Milner, "Public Utility Rate Control in Alberta" (1930), 8 *Can. Bar Rev.* 101, at p. 101. While the American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes, they do shed some light on the issue.

55 Pursuant to *The Public Utilities Act*, the first public utility board was established as a three-member tribunal to provide general supervision of all public utilities (s. 21), to investigate rates (s. 23), to make orders regarding equipment (s. 24), and to require every public utility to file with it complete schedules of rates (s. 23). Of interest for our purposes, the 1915 statute also required public utilities to obtain the approval of the Board of Public Utility Commissioners before selling any property when outside the ordinary course of their business (s. 29(g)).

56 The Alberta Energy and Utilities Board was created in February 1995 by the amalgamation of the Energy Resources Conservation Board and the Public Utilities Board (see Canadian Institute of Resources Law, *Canada Energy Law Service: Alberta* (loose-leaf ed.), at p. 30-3101). Since then, all matters under the jurisdiction of the Energy Resources Conservation Board and the Public Utilities Board have been handled by the Alberta Energy and Utilities Board and are within its exclusive jurisdiction. The Board has all of the powers, rights and privileges of its two predecessor boards (AEUBA, ss. 13, 15(1); GUA, s. 59).

57 In addition to the powers found in the 1915 statute, which have remained virtually the same in the present PUBA, the Board now benefits from the following express powers to:

1. make an order respecting the improvement of the service or commodity (PUBA, s. 80(b));

2. approve the issue by the public utility of shares, stocks, bonds and other evidences of indebtedness (GUA, s. 26(2)(a); PUBA, s. 101(2)(a));

3. approve the lease, mortgage, disposition or encumbrance of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(i); PUBA, s. 101(2)(d)(i));

4. approve the merger or consolidation of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(ii); PUBA, s. 101(2)(d)(ii)); and

5. authorize the sale or permit to be made on the public utility's book a transfer of any share of its capital stock to a corporation that would result in the vesting in that corporation of more than 50 percent of the outstanding capital stock of the owner of the public utility (GUA, s. 27(1); PUBA, s. 102(1)).

58 It goes without saying that public utilities are very limited in the actions they can take, as evidenced from the above list. Nowhere is there a mention of the authority

to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights.

59 Even in 1995 when the legislature decided to form the Alberta Energy and Utilities Board, it did not see fit to modify the PUBA or the GUA to provide the new Board with the power to allocate the proceeds of a sale even though the controversy surrounding this issue was full-blown (see, e.g., *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116). It is a well-established principle that the legislature is presumed to have a mastery of existing law, both common law and statute law (see Sullivan, at pp. 154-55). It is also presumed to have known all of the circumstances surrounding the adoption of new legislation.

60 Although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates (see Milner, at p. 102; Brown, at p. 2-16.6). Estey J., speaking for the majority of this Court in *Atco Ltd.*, at p. 576, echoed this view when he said:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities. Such an extensive regulatory pattern must, for its effectiveness, include the right to control the combination or, as the legislature says, "the union" of existing systems and facilities. This no doubt has a direct relationship with the rate-fixing function which ranks high in the authority and functions assigned to the Board. [Emphasis added.]

In fact, even the Board itself, on its website (http://www.eub.gov.ab.ca/BBS/eubinfo/default.htm), describes its functions as follows:

> We regulate the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and electrical energy; and the pipelines and transmission lines to move the resources to market. On the utilities side, we regulate rates and terms of service of investor-owned natural gas, electric, and water utility services, as well as the major intra-Alberta gas transmission system, to ensure that customers receive safe and reliable service at just and reasonable rates. [Emphasis added.]

61 The process by which the Board sets the rates is therefore central and deserves some attention in order to ascertain the validity of the City's first argument.

2.3.3.2 *Rate Setting*

62 Rate regulation serves several aims — sustainability, equity and efficiency — which underlie the reasoning as to how rates are fixed:

> . . . the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future. . . . Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive "too low" a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be "too high".
>
> (R. Green and M. Rodriguez Pardina, *Resetting Price Controls for Privatized Utilities: A Manual for Regulators* (1999), at p. 5)

63 These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price — nothing more. As I will further explain, it does not transfer onto the customers

any property right. Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated (see Black, at pp. 356-57; Milner, at p. 101; *Atco Ltd.*, at p. 576; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186 ("*Northwestern 1929*"), at pp. 192-93).

64 Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer *and* the investor (Milner, at p. 101). The arrangement does not, however, cancel the private nature of the utility. In essence, the Board is responsible for maintaining a tariff that enhances the economic benefits to consumers and investors of the utility.

65 The Board derives its power to set rates from both the GUA (ss. 16, 17 and 36 to 45) and the PUBA (ss. 89 to 95). The Board is mandated to fix "just and reasonable . . . rates" (PUBA, s. 89(a); GUA, s. 36(a)). In the establishment of these rates, the Board is directed to "determine a rate base for the property of the owner" and "fix a fair return on the rate base" (GUA, s. 37(1)). This Court, in *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684 ("*Northwestern 1979*"), at p. 691, adopted the following description of the process:

> 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.

(See also *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984, at p. 23; *Re Union Gas Ltd. and Ontario Energy Board* (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.), at pp. 701-2.)

66 Consequently, when determining the rate base, the Board is to give due consideration (GUA, s. 37(2)):

> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> (b) to necessary working capital.

67 The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same. The equity investor expects to receive the net revenues after all costs are paid, equal to the present value of original investment at the time of that investment.

The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process: MacAvoy and Sidak, at p. 244. In fact, speculation would accrue even more often should the public utility, through its shareholders, not be the one to benefit from the possibility of a profit, as investors would expect to receive a larger premium for their funds through the only means left available, the return on their original investment. In addition, they would be less willing to accept any risk.

68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves: "A utility's customers are not its owners, for they are not residual claimants": MacAvoy and Sidak, at p. 245 (see also p. 237). Ratepayers have made no investment. Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only "the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator" (MacAvoy and Sidak, at p. 245).

69 In this regard, I agree with ATCO when it asserts in its factum, at para. 38:

> The property in question is as fully the private property of the owner of the utility as any other asset it owns. Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for

> ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory . . . .

Wittmann J.A., at the Court of Appeal, said it best when he stated:

> Consumers of utilities pay for a service, but by such payment, do not receive a proprietary right in the assets of the utility company. Where the calculated rates represent the fee for the service provided in the relevant period of time, ratepayers do not gain equitable or legal rights to non-depreciable assets when they have paid only for the use of those assets. [Emphasis added; para. 64.]

I fully adopt this conclusion. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. While the utility has been compensated for the services provided, the customers have provided no compensation for receiving the benefits of the subject property. The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. There can be a default risk affecting ratepayers, but this does not make ratepayers residual claimants. While I do not wish to unduly rely on American jurisprudence, I would note that the leading U.S. case on this point is *Duquesne Light Co. v. Barasch*, 488 U.S. 299

(1989), which relies on the same principle as was adopted in *Market St. Ry. Co. v. Railroad Commission of State of California*, 324 U.S. 548 (1945).

70 Furthermore, one has to recognize that utilities are not Crown entities, fraternal societies or cooperatives, or mutual companies, although they have a "public interest" aspect which is to supply the public with a necessary service (in the present case, the provision of natural gas). The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness, stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.

71 From my discussion above regarding the property interest, the Board was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. As such, the City's first argument must fail. The Board was seeking to rectify what it perceived as a historic over-compensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates (*Northwestern 1979*, at p. 691; *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705 (Alta. C.A.), at p. 715, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical Canada Inc.* (C.A.), at pp. 734-35). But more importantly, it cannot even be said that there was over-compensation: the rate-

setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility (see MacAvoy and Sidak, at pp. 238-39).

2.3.3.3 *The Power to Attach Conditions*

72 As its second argument, the City submits that the power to allocate the proceeds from the sale of the utility's assets is necessarily incidental to the express powers conferred on the Board by the AEUBA, the GUA and the PUBA. It argues that the Board must necessarily have the power to allocate sale proceeds as part of its discretionary power to approve or refuse to approve a sale of assets. It submits that this results from the fact that the Board is allowed to attach any condition to an order it makes approving such a sale. I disagree.

73 The City seems to assume that the doctrine of jurisdiction by necessary implication applies to "broadly drawn powers" as it does for "narrowly drawn powers"; this cannot be. The Ontario Energy Board in its decision in *Re Consumers' Gas Co.*, E.B.R.O. 410-II/411-II/412-II, March 23, 1987, at para. 4.73, enumerated the circumstances when the doctrine of jurisdiction by necessary implication may be applied:

> * [when] the jurisdiction sought is necessary to accomplish the objectives of the legislative scheme and is essential to the Board fulfilling its mandate;
>
> * [when] the enabling act fails to explicitly grant the power to accomplish the legislative objective;
>
> * [when] the mandate of the Board is sufficiently broad to suggest a legislative intention to implicitly confer jurisdiction;

> * [when] the jurisdiction sought must not be one which the Board has dealt with through use of expressly granted powers, thereby showing an absence of necessity; and
>
> * [when] the Legislature did not address its mind to the issue and decide against conferring the power upon the Board.

(See also Brown, at p. 2-16.3.)

74 In light of the above, it is clear that the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework. This is explained by Professor Sullivan, at p. 228:

> In practice, however, purposive analysis makes the powers conferred on administrative bodies almost infinitely elastic. Narrowly drawn powers can be understood to include "by necessary implication" all that is needed to enable the official or agency to achieve the purpose for which the power was granted. Conversely, broadly drawn powers are understood to include only what is rationally related to the purpose of the power. In this way the scope of the power expands or contracts as needed, in keeping with the purpose. [Emphasis added.]

75 In the case at bar, s. 15 of the AEUBA, which allows the Board to impose additional conditions when making an order, appears at first glance to be a power having infinitely elastic scope. However, in my opinion, the attempt by the City to use it to augment the powers of the Board in s. 26(2) of the GUA must fail. The Court must construe s. 15(3) of the AEUBA in accordance with the purpose of s. 26(2).

76 MacAvoy and Sidak, in their article, at pp. 234-36, suggest three broad reasons for the requirement that a sale must be approved by the Board:

1. It prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers;

2. It ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder; and

3. It specifically seeks to prevent favoritism toward investors.

77 Consequently, in order to impute jurisdiction to a regulatory body to allocate proceeds of a sale, there must be evidence that the exercise of that power is a practical necessity for the regulatory body to accomplish the objects prescribed by the legislature, something which is absent in this case (see *National Energy Board Act (Can.) (Re)*, [1986] 3 F.C. 275 (C.A.)). In order to meet these three goals, it is not necessary for the Board to have control over which party should benefit from the sale proceeds. The public interest component cannot be said to be sufficient to impute to the Board the power to allocate all the profits pursuant to the sale of assets. In fact, it is not necessary for the Board in carrying out its mandate to order the utility to surrender the bulk of the proceeds from a sale of its property in order for that utility to obtain approval for a sale. The Board has other options within its jurisdiction which do not involve the appropriation of the sale proceeds, the most obvious one being to refuse to approve a sale that will, in the Board's view, affect the quality and/or quantity of the service offered by the utility or create additional operating costs for the future. This is not to say that the Board can never attach a condition to the approval of sale. For example, the Board could approve the sale of the assets on the condition that the utility company gives undertakings regarding the replacement of the assets and their profitability. It could also

require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system.

78 In my view, allowing the Board to confiscate the net gain of the sale under the pretence of protecting rate-paying customers and acting in the "public interest" would be a serious misconception of the powers of the Board to approve a sale; to do so would completely disregard the economic rationale of rate setting, as I explained earlier in these reasons. Such an attempt by the Board to appropriate a utility's excess net revenues for ratepayers would be highly sophisticated opportunism and would, in the end, simply increase the utility's capital costs (MacAvoy and Sidak, at p. 246). At the risk of repeating myself, a public utility is first and foremost a private business venture which has as its goal the making of profits. This is not contrary to the legislative scheme, even though the regulatory compact modifies the normal principles of economics with various restrictions explicitly provided for in the various enabling statutes. None of the three statutes applicable here provides the Board with the power to allocate the proceeds of a sale and therefore affect the property interests of the public utility.

79 It is well established that potentially confiscatory legislative provision ought to be construed cautiously so as not to strip interested parties of their rights without the clear intention of the legislation (see Sullivan, at pp. 400-403; Côté, at pp. 482-86; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64, at para. 26; *Leiriao v. Val-Bélair (Town)*, [1991] 3 S.C.R. 349, at p. 357; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167, at p. 197). Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to

the conclusion that a broadly drawn power can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. This would go against the above principles of interpretation.

80 If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation, as was done by some states in the United States (e.g., Connecticut).

2.4 *Other Considerations*

81 Under the regulatory compact, customers are protected through the rate-setting process, under which the Board is required to make a well-balanced determination. The record shows that the City did not submit to the Board a general rate review application in response to ATCO's application requesting approval for the sale of the property at issue in this case. Nonetheless, if it chose to do so, this would not have stopped the Board, on its own initiative, from convening a hearing of the interested parties in order to modify and fix just and reasonable rates to give due consideration to any new economic data anticipated as a result of the sale (PUBA, s. 89(a); GUA, ss. 24, 36(a), 37(3), 40) (see Appendix).

2.5 *If Jurisdiction Had Been Found, Was the Board's Allocation Reasonable?*

82 In light of my conclusion with regard to jurisdiction, it is not necessary to determine whether the Board's exercise of discretion by allocating the sale proceeds as it did was reasonable. Nonetheless, given the reasons of my colleague Binnie J., I will address the issue very briefly. Had I not concluded that the Board lacked jurisdiction, my

disposition of this case would have been the same, as I do not believe the Board met a reasonable standard when it exercised its power.

83 I am not certain how one could conclude that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process, and, moreover, when it explicitly concluded that no harm would ensue to customers from the sale of the asset. In my opinion, when reviewing the substance of the Board's decision, a court must conduct a two-step analysis: first, it must determine whether the order was warranted given the role of the Board to *protect the customers* (i.e., was the order *necessary in the public interest*?); and second, if the first question is answered in the affirmative, a court must then examine the validity of the Board's application of the *TransAlta Formula* (see para. 12 of these reasons), which refers to the difference between net book value and original cost, on the one hand, and appreciation in the value of the asset on the other. For the purposes of this analysis, I view the second step as a mathematical calculation and nothing more. I do not believe it provides the criteria which guides the Board to determine *if it should allocate* part of the sale proceeds to ratepayers. Rather, it merely guides the Board on *what to allocate and how to allocate it* (if it should do so in the first place). It is also interesting to note that there is no discussion of the fact that the book value used in the calculation must be referable solely to the financial statements of the utility.

84 In my view, as I have already stated, the power of the Board to allocate proceeds does not even arise in this case. Even by the Board's own reasoning, it should only exercise its discretion to act in the public interest when customers would be harmed

or would face some risk of harm. But the Board was clear: there was no harm or risk of harm in the present situation:

> With the continuation of the same level of service at other locations and the acceptance by customers regarding the relocation, the Board is convinced there should be no impact on the level of service to customers as a result of the Sale. In any event, the Board considers that the service level to customers is a matter that can be addressed and remedied in a future proceeding if necessary.
>
> (Decision 2002-037, at para. 54)

After declaring that the customers would not, on balance, be harmed, the Board maintained that, on the basis of the evidence filed, there appeared to be a cost savings to the customers. There was no legitimate customer interest which could or needed to be protected by denying approval of the sale, or by making approval conditional on a particular allocation of the proceeds. Even if the Board had found a possible adverse effect arising from the sale, how could it allocate proceeds now based on an unquantified future potential loss? Moreover, in the absence of any factual basis to support it, I am also concerned with the presumption of bad faith on the part of ATCO that appears to underlie the Board's determination to protect the public from some possible future menace. In any case, as mentioned earlier in these reasons, this determination to protect the public interest is also difficult to reconcile with the actual power of the Board to prevent harm to ratepayers from occurring by simply refusing to approve the sale of a utility's asset. To that, I would add that the Board has considerable discretion in the setting of future rates in order to protect the public interest, as I have already stated.

85 In consequence, I am of the view that, in the present case, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Hence,

notwithstanding my conclusion on the first issue regarding the Board's jurisdiction, I would conclude that the Board's decision to exercise its discretion to protect the public interest did not meet a reasonable standard.

3. Conclusion

86 This Court's role in this case has been one of interpreting the enabling statutes using the appropriate interpretive tools, i.e., context, legislative intention and objective. Going further than required by reading in *unnecessary* powers of an administrative agency under the guise of statutory interpretation is not consistent with the rules of statutory interpretation. It is particularly dangerous to adopt such an approach when property rights are at stake.

87 The Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset; its decision did not meet the correctness standard. Thus, I would dismiss the City's appeal and allow ATCO's cross-appeal, both with costs. I would also set aside the Board's decision and refer the matter back to the Board to approve the sale of the property belonging to ATCO, recognizing that the proceeds of the sale belong to ATCO.

The reasons of McLachlin C.J. and Binnie and Fish JJ. were delivered by

88 BINNIE J. (dissenting) — The respondent ATCO Gas and Pipelines Ltd. ("ATCO") is part of a large entrepreneurial company that directly and through various subsidiaries operates both regulated businesses and unregulated businesses. The Alberta Energy and Utilities Board ("Board") believes it not to be in the public interest to

encourage utility companies to mix together the two types of undertakings. In particular, the Board has adopted policies to discourage utilities from using their regulated businesses as a platform to engage in land speculation to increase their return on investment outside the regulatory framework. By awarding part of the profit to the utility (and its shareholders), the Board rewards utilities for diligence in divesting themselves of assets that are no longer productive, or that could be more productively employed elsewhere. However, by crediting part of the profit on the sale of such property to the utility's rate base (i.e. as a set-off to other costs), the Board seeks to dampen any incentive for utilities to skew decisions in their regulated business to favour such profit taking unduly. Such a balance, in the Board's view, is necessary in the interest of the public which allows ATCO to operate its utility business as a monopoly. In pursuit of this balance, the Board approved ATCO's application to sell land and warehousing facilities in downtown Calgary, but denied ATCO's application to keep for its shareholders the entire profit resulting from appreciation in the value of the land, whose cost of acquisition had formed part of the rate base on which gas rates had been calculated since 1922. The Board ordered the profit on the sale to be allocated one third to ATCO and two thirds as a credit to its cost base, thereby helping keep utility rates down, and to that extent benefiting ratepayers.

89 I have read with interest the reasons of my colleague Bastarache J. but, with respect, I do not agree with his conclusion. As will be seen, the Board has authority under s. 15(3) of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), to impose on the sale "any additional conditions that the Board considers necessary in the public interest". Whether or not the conditions of approval imposed by the Board were necessary in the public interest was for the Board to decide. The Alberta Court of Appeal overruled the Board but, with respect, the Board is in a better position

to assess necessity in this field for the protection of the public interest than either that court or this Court. I would allow the appeal and restore the Board's decision.

I. Analysis

90 ATCO's argument boils down to the proposition announced at the outset of its factum:

> In the absence of any property right or interest and of any harm to the customers arising from the withdrawal from utility service, there was no proper ground for reaching into the pocket of the utility. In essence this case is about property rights.
>
> (Respondent's factum, at para. 2)

91 For the reasons which follow I do not believe the case is about property rights. ATCO chose to make its investment in a regulated industry. The return on investment in the regulated gas industry is fixed by the Board, not the free market. In my view, the essential issue is whether the Alberta Court of Appeal was justified in limiting what the Board is allowed to "conside[r] necessary in the public interest".

A. *The Board's Statutory Authority*

92 The first question is one of jurisdiction. What gives the Board the authority to make the order ATCO complains about? The Board's answer is threefold. Section 22(1) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA"), provides in part that "[t]he Board shall exercise a general supervision over all gas utilities, and the owners of them . . .". This, the Board says, gives it a broad jurisdiction to set policies that go beyond its specific powers in relation to specific applications, such as rate setting. Of more

immediate pertinence, s. 26(2)(d)(i) of the same Act prohibits the regulated utility from selling, leasing or otherwise encumbering any of its property without the Board's approval. (To the same effect, see s. 101(2)(d)(i) of the *Public Utilities Board Act*, R.S.A. 2000, c. P-45.) It is common ground that this restraint on alienation of property applies to the proposed sale of ATCO's land and warehouse facilities in downtown Calgary, and that the Board could, in appropriate circumstances, simply have denied ATCO's application for approval of the sale. However, the Board was of the view to allow the sale subject to conditions. The Board ruled that the greater power (i.e. to deny the sale) must include the lesser (i.e. to allow the sale, subject to conditions):

> In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.
>
> (Decision 2002-037, [2002] A.E.U.B.D. No. 52 (QL), at para. 47)

There is no need to rely on any such implicit power to impose conditions, however. As stated, the Board's explicit power to impose conditions is found in s. 15(3) of the AEUBA, which authorizes the Board to "make any further order and impose any additional conditions that the Board considers necessary in the public interest". In *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576, Estey J., for the majority, stated:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities. [Emphasis added.]

The legislature says in s. 15(3) that the conditions are to be what *the Board* considers necessary. Of course, the discretionary power to impose conditions thus granted is not unlimited. It must be exercised in good faith for its intended purpose: *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 S.C.R. 539, 2003 SCC 29. ATCO says the Board overstepped even these generous limits. In ATCO's submission:

> Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory . . . .
>
> (Respondent's factum, at para. 38)

In my view, however, the issue before the Board was how much profit ATCO was entitled to earn on its investment in a regulated utility.

93 ATCO argues in the alternative that the Board engaged in impermissible "retroactive rate making". But Alberta is an "original cost" jurisdiction, and no one suggests that the Board's original cost rate making during the 80-plus years this investment has been reflected in ATCO's ratebase was wrong. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective, not retroactive. Fixing the going-forward rate of return as well as general supervision of "all gas utilities, and the owners of them" were matters squarely within the Board's statutory mandate.

B. *The Board's Decision*

94 ATCO argues that the Board's decision should be seen as a stand-alone decision divorced from its rate-making responsibilities. However, I do not agree that the

hearing under s. 26 of the GUA can be isolated in this way from the Board's general regulatory responsibilities. ATCO argues in its factum that

> the subject application by [ATCO] to the Board did not concern or relate to a rate application, and the Board was not engaged in fixing rates (if that could provide any justification, which is denied).
>
> (Respondent's factum, at para. 98)

95 It seems the Board proceeded with the s. 26 approval hearing separately from a rate setting hearing firstly because ATCO framed the proceeding in that way and secondly because this is the procedure approved by the Alberta Court of Appeal in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171. That case (which I will refer to as *TransAlta (1986)*) is a leading Alberta authority dealing with the allocation of the gain on the disposal of utility assets and the source of what is called the *TransAlta Formula* applied by the Board in this case. Kerans J.A. had this to say, at p. 174:

> I observe parenthetically that I now appreciate that it suits the convenience of everybody involved to resolve issues of this sort, if possible, before a general rate hearing so as to lessen the burden on that already complex procedure.

96 Given this encouragement from the Alberta Court of Appeal, I would place little significance on ATCO's procedural point. As will be seen, the Board's ruling is directly tied into the setting of general rates because two thirds of the profit is taken into account as an offset to ATCO's costs from which its revenue requirement is ultimately derived. As stated, ATCO's profit on the sale of the Calgary property will be a current (not historical) receipt and, if the Board has its way, two thirds of it will be applied to future (not retroactive) rate making.

97 The s. 26 hearing proceeded in two phases. The Board first determined that it would not deny its approval to the proposed sale as it met a "no-harm test" devised over the years by Board practice (it is not to be found in the statutes) (Decision 2001-78). However, the Board linked its approval to subsequent consideration of the financial ramifications, as the Board itself noted:

> The Board approved the Sale in Decision 2001-78 based on evidence that customers did not object to the Sale [and] would not suffer a reduction in services nor would they be exposed to the risk of financial harm as a result of the Sale *that could not be examined in a future proceeding*. On that basis the Board determined that the no-harm test had been satisfied and that the Sale could proceed. [Underlining and italics added.]
>
> (Decision 2002-037, at para. 13)

98 In effect, ATCO ignores the italicized words. It argues that the Board was *functus* after the first phase of its hearing. However, ATCO itself had agreed to the two-phase procedure, and indeed the second phase was devoted to ATCO's own application for an allocation of the profits on the sale.

99 In the second phase of the s. 26 approval hearing, the Board allocated one third of the net gain to ATCO and two thirds to the rate base (which would benefit ratepayers). The Board spelled out why it considered these conditions to be necessary in the public interest. The Board explained that it was necessary to balance the interests of both shareholders and ratepayers within the framework of what it called "the regulatory compact" (Decision 2002-037, at para. 44). In the Board's view:

> (a) there ought to be a balancing of the interests of the ratepayers and the owners of the utility;

(b) decisions made about the utility should be driven by both parties' interests;

(c) to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs; and

(d) to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business.

100 For purposes of this appeal, it is important to set out the Board's policy reasons in its own words:

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.
>
> The Board believes that some method of balancing both parties' interests will result in optimization of business objectives for both the customer and the company. Therefore, the Board considers that sharing of the net gain on the sale of the land and buildings collectively in accordance with the TransAlta Formula is equitable in the circumstances of this application and is consistent with past Board decisions. [Emphasis added; paras. 112-14.]

101 The Court was advised that the two-third share allocated to ratepayers would be included in ATCO's rate calculation to set off against the costs included in the rate base and amortized over a number of years.

C. *Standard of Review*

102 The Court's modern approach to this vexed question was recently set out by McLachlin C.J. in *Dr. Q v. College of Physicians and Surgeons of British Columbia*, [2003] 1 S.C.R. 226, 2003 SCC 19, at para. 26:

> In the pragmatic and functional approach, the standard of review is determined by considering four contextual factors — the presence or absence of a privative clause or statutory right of appeal; the expertise of the tribunal relative to that of the reviewing court on the issue in question; the purposes of the legislation and the provision in particular; and, the nature of the question — law, fact, or mixed law and fact. The factors may overlap. The overall aim is to discern legislative intent, keeping in mind the constitutional role of the courts in maintaining the rule of law.

103 I do not propose to cover the ground already set out in the reasons of my colleague Bastarache J. We agree that the standard of review on matters of jurisdiction is correctness. We also agree that the Board's *exercise* of its jurisdiction calls for greater judicial deference. Appeals from the Board are limited to questions of law or jurisdiction. The Board knows a great deal more than the courts about gas utilities, and what limits it is necessary to impose "in the public interest" on their dealings with assets whose cost is included in the rate base. Moreover, it is difficult to think of a broader discretion than that conferred on the Board to "impose any additional conditions that the Board considers necessary in the public interest" (s. 15(3)(d) of the AEUBA). The identification of a subjective discretion in the decision maker ("the Board considers necessary"), the expertise of that decision maker and the nature of the decision to be

made ("in the public interest"), in my view, call for the most deferential standard, patent unreasonableness.

104 As to the phrase "the Board considers necessary", Martland J. stated in *Calgary Power Ltd. v. Copithorne*, [1959] S.C.R. 24, at p. 34:

> The question as to whether or not the respondent's lands were "necessary" is not one to be determined by the Courts in this case. The question is whether the Minister "deemed" them to be necessary.

See also D. J. M. Brown and J. M. Evans, *Judicial Review of Administrative Action in Canada* (loose-leaf ed.), vol. 1, at para. 14:2622: "*'Objective' and 'Subjective' Grants of Discretion*".

105 The expert qualifications of a regulatory Board are of "utmost importance in determining the intention of the legislator with respect to the degree of deference to be shown to a tribunal's decision in the absence of a full privative clause", as stated by Sopinka J. in *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316, at p. 335. He continued:

> Even where the tribunal's enabling statute provides explicitly for appellate review, as was the case in *Bell Canada* [*v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722], it has been stressed that deference should be shown by the appellate tribunal to the opinions of the specialized lower tribunal on matters squarely within its jurisdiction.

(This *dictum* was cited with approval in *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557, at p. 592.)

106 A regulatory power to be exercised "in the public interest" necessarily involves accommodation of conflicting economic interests. It has long been recognized that what is "in the public interest" is not really a question of law or fact but is an opinion. In *TransAlta (1986)*, the Alberta Court of Appeal (at para. 24) drew a parallel between the scope of the words "public interest" and the well-known phrase "public convenience and necessity" in its citation of *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353, where this Court stated, at p. 357:

> [T]he question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest . . . . [Emphasis added.]

107 This passage reiterated the *dictum* of Rand J. in *Union Gas Co. of Canada Ltd. v. Sydenham Gas and Petroleum Co.*, [1957] S.C.R. 185, at p. 190:

> It was argued, and it seems to have been the view of the Court, that the determination of public convenience and necessity was itself a question of fact, but with that I am unable to agree: it is not an objective existence to be ascertained; the determination is the formulation of an opinion, in this case, the opinion of the Board and of the Board only. [Emphasis added.]

108 Of course even such a broad power is not untrammelled. But to say that such a power is capable of abuse does not lead to the conclusion that it should be truncated. I agree on this point with Reid J. (co-author of R. F. Reid and H. David, *Administrative Law and Practice* (2nd ed. 1978), and co-editor of P. Anisman and R. F. Reid, *Administrative Law Issues and Practice* (1995)), who wrote in *Re C.T.C. Dealer*

Holdings Ltd. and Ontario Securities Commission (1987), 59 O.R. (2d) 79 (Div. Ct.), in relation to the powers of the Ontario Securities Commission, at p. 97:

> . . . when the Commission has acted *bona fide*, with an obvious and honest concern for the public interest, and with evidence to support its opinion, the prospect that the breadth of its discretion might someday tempt it to place itself above the law by misusing that discretion is not something that makes the existence of the discretion bad *per se*, and requires the decision to be struck down.

(The *C.T.C. Dealer Holdings* decision was referred to with apparent approval by this Court in *Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37, at para. 42.)

109 "Patent unreasonableness" is a highly deferential standard:

> A correctness approach means that there is only one proper answer. A patently unreasonable one means that there could have been many appropriate answers, but not the one reached by the decision maker.
>
> (*C.U.P.E.*, at para. 164)

110 Having said all that, in my view nothing much turns on the result on whether the proper standard in that regard is patent unreasonableness (as I view it) or simple reasonableness (as my colleague sees it). As will be seen, the Board's response is well within the range of established regulatory opinions. Hence, even if the Board's conditions were subject to the less deferential standard, I would find no cause for the Court to interfere.

D. *Did the Board Have Jurisdiction to Impose the Conditions It Did on the Approval Order "In the Public Interest"?*

111 ATCO says the Board had no jurisdiction to impose conditions that are "confiscatory". Framing the question in this way, however, assumes the point in issue. The correct point of departure is not to assume that ATCO is entitled to the net gain and then ask if the Board can confiscate it. ATCO's investment of $83,000 was added in increments to its regulatory cost base as the land was acquired from time to time between 1922 and 1965. It is in the nature of a regulated industry that the question of what is a just and equitable return is determined by a board and not by the vagaries of the speculative property market.

112 I do not think the legal debate is assisted by talk of "confiscation". ATCO is prohibited by statute from disposing of the asset without Board approval, and the Board has statutory authority to impose conditions on its approval. The issue thus necessarily turns not on the *existence* of the jurisdiction but on the *exercise* of the Board's jurisdiction to impose the conditions that it did, and in particular to impose a shared allocation of the net gain.

E. *Did the Board Improperly Exercise the Jurisdiction It Possessed to Impose Conditions the Board Considered "Necessary in the Public Interest"?*

113 There is no doubt that there are many approaches to "the public interest". Which approach the Board adopts is largely (and inherently) a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, and practice in the United States must be read in light of the constitutional protection of property rights in that country, nevertheless Alberta's grant of authority to its Board is more generous than most. ATCO concedes that its "property" claim would have to give way to a contrary legislative intent, but ATCO says such intent cannot be found in the statutes.

114 Most if not all regulators face the problem of how to allocate gains on property whose original cost is included in the rate base but is no longer required to provide the service. There is a wealth of regulatory experience in many jurisdictions that the Board is entitled to (and does) have regard to in formulating its policies. Striking the correct balance in the allocation of gains between ratepayers and investors is a common preoccupation of comparable boards and agencies:

> First, it prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers. Second, it ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder. Third, it specifically seeks to prevent favoritism toward investors to the detriment of ratepayers affected by the transaction.
>
> (P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 *Energy L.J.* 233, at p. 234)

115 The concern with which Canadian regulators view utilities under their jurisdiction that are speculating in land is not new. In *Re Consumers' Gas Co.*, E.B.R.O. 341-I, June 30, 1976, the Ontario Energy Board considered how to deal with a real estate profit on land which was disposed of at an after-tax profit of over $2 million. The Board stated:

> The Station "B" property was not purchased by Consumers' for land speculation but was acquired for utility purposes. This investment, while non-depreciable, was subject to interest charges and risk paid for through revenues and, until the gas manufacturing plant became obsolete, disposal of the land was not a feasible option. If, in such circumstances, the Board were to permit real estate profit to accrue to the shareholders only, it would tend to encourage real estate speculation with utility capital. In the Board's opinion, the shareholders and the ratepayers should share the benefits of such capital gains. [Emphasis added; para. 326.]

116 Some U.S. regulators also consider it good regulatory policy to allocate part or all of the profit to offset costs in the rate base. In *Re Boston Gas Co.*, 49 P.U.R. 4th 1 (Mass. D.P.U. 1982), the regulator allocated a gain on the sale of land to ratepayers, stating:

> The company and its shareholders have received a return on the use of these parcels while they have been included in rate base, and are not entitled to any additional return as a result of their sale. To hold otherwise would be to find that a regulated utility company may speculate in nondepreciable utility property and, despite earning a reasonable rate of return from its customers on that property, may also accumulate a windfall through its sale. We find this to be an uncharacteristic risk/reward situation for a regulated utility to be in with respect to its plant in service. [Emphasis added; p. 26.]

117 Canadian regulators other than the Board are also concerned with the prospect that decisions of utilities in their regulated business may be skewed under the undue influence of prospective profits on land sales. In *Re Consumers' Gas Co.*, E.B.R.O. 465, March 1, 1991, the Ontario Energy Board determined that a $1.9 million gain on sale of land should be divided equally between shareholders and ratepayers. It held that

> the allocation of 100 percent of the profit from land sales to either the shareholders or the ratepayers might diminish the recognition of the valid concerns of the excluded party. For example, the timing and intensity of land purchase and sales negotiations could be skewed to favour or disregard the ultimate beneficiary. [para. 3.3.8]

118 The Board's principle of dividing the gain between investors and ratepayers is consistent, as well, with *Re Natural Resource Gas Ltd.*, RP-2002-0147, EB-2002-0446, June 27, 2003, in which the Ontario Energy Board addressed the allocation of a profit on the sale of land and buildings and again stated:

> The Board finds that it is reasonable in the circumstances that the capital gains be shared equally between the Company and its customers. In making this finding the Board has considered the non-recurring nature of this transaction. [para. 45]

119 The wide variety of regulatory treatment of such gains was noted by Kerans J.A. in *TransAlta (1986)*, at pp. 175-76, including *Re Boston Gas Co.* mentioned earlier. In *TransAlta (1986)*, the Board characterized TransAlta's gain on the disposal of land and buildings included in its Edmonton "franchise" as "revenue" within the meaning of the *Hydro and Electric Energy Act*, R.S.A. 1980, c. H-13. (The case therefore did not deal with the power to impose conditions "the Board considers necessary in the public interest".) Kerans J.A. said (at p. 176):

> I do not agree with the Board's decision for reasons later expressed, but it would be fatuous to deny that its interpretation [of the word "revenue"] is one which the word can reasonably bear.

Kerans J.A. went on to find that in that case "[t]he compensation was, for all practical purposes, compensation for loss of franchise" (p. 180) and on that basis the gain in these "unique circumstances" (p. 179) could not, as a matter of law, be characterized as revenue, i.e. applying a correctness standard. The range of regulatory practice on the "gains on sale" issue was similarly noted by Goldie J.A. in *Yukon Energy Corp. v. Utilities Board* (1996), 74 B.C.A.C. 58 (Y.C.A.), at para. 85.

120 A survey of recent regulatory experience in the United States reveals the wide variety of treatment in that country of gains on the sale of undepreciated land. The range includes proponents of ATCO's preferred allocation as well as proponents of the solution adopted by the Board in this case:

> Some jurisdictions have concluded that as a matter of equity, shareholders alone should benefit from any gain realized on appreciated real estate, because ratepayers generally pay only for taxes on the land and do not contribute to the cost of acquiring the property and pay no depreciation expenses. Under this analysis, ratepayers assume no risk for losses and acquire no legal or equitable interest in the property, but rather pay only for the use of the land in utility service.
>
> Other jurisdictions claim that ratepayers should retain some of the benefits associated with the sale of property dedicated to utility service. Those jurisdictions that have adopted an equitable sharing approach agree that a review of regulatory and judicial decisions on the issue does not reveal any general principle that requires the allocation of benefits solely to shareholders; rather, the cases show only a general prohibition against sharing benefits on the sale property that has never been reflected in utility rates.
>
> (P. S. Cross, "Rate Treatment of Gain on Sale of Land: Ratepayer Indifference, A New Standard?" (1990), 126 *Pub. Util. Fort.* 44, at p. 44)

Regulatory opinion in the United States favourable to the solution adopted here by the Board is illustrated by *Re Arizona Public Service Co.*, 91 P.U.R. 4th 337 (Ariz. C.C. 1988), at p. 361:

> To the extent any general principles can be gleaned from the decisions in other jurisdictions they are: (1) the utility's stockholders are not *automatically* entitled to the gains from all sales of utility property; and (2) ratepayers are not entitled to all or any part of a gain from the sale of property which has never been reflected in the utility's rates. [Emphasis in original.]

121 Assets purchased with capital reflected in the rate base come and go, but the utility itself endures. What was done by the Board in this case is quite consistent with the "enduring enterprise" theory espoused, for example, in *Re Southern California Water Co.*, 43 C.P.U.C. 2d 596 (1992). In that case, Southern California Water had asked for approval to sell an old headquarters building and the issue was how to allocate its profits on the sale. The Commission held:

> Working from the principle of the "enduring enterprise", the gain-on-sale from this transaction should remain within the utility's operations rather than being distributed in the short run directly to either ratepayers or shareholders.
>
> The "enduring enterprise" principle, is neither novel nor radical. It was clearly articulated by the Commission in its seminal 1989 policy decision on the issue of gain-on-sale, D.89-07-016, 32 Cal. P.U.C.2d 233 (*Redding*). Simply stated, to the extent that a utility realizes a gain-on-sale from the liquidation of an asset and replaces it with another asset or obligation while at the same time its responsibility to serve its customers is neither relieved nor reduced, then any gain-on-sale should remain within the utility's operation. [p. 604]

122 In my view, neither the Alberta statutes nor regulatory practice in Alberta and elsewhere dictates the answer to the problems confronting the Board. It would have been open to the Board to allow ATCO's application for the entire profit. But the solution it adopted was quite within its statutory authority and does not call for judicial intervention.

F. *ATCO's Arguments*

123 Most of ATCO's principal submissions have already been touched on but I will repeat them here for convenience. ATCO does not really dispute the Board's ability to impose conditions on the sale of land. Rather, ATCO says that what the Board did here violates a number of basic legal protections and principles. It asks the Court to clip the Board's wings.

124 Firstly, ATCO says that customers do not acquire any proprietary right in the company's assets. ATCO, rather than its customers, originally purchased the property, held title to it, and therefore was entitled to any gain on its sale. An allocation of profit to the customers would amount to a confiscation of the corporation's property.

125 Secondly, ATCO says its retention of 100 percent of the gain has nothing to do with the so-called "regulatory compact". The gas customers paid what the Board regarded over the years as a fair price for safe and reliable service. That is what the ratepayers got and that is all they were entitled to. The Board's allocation of part of the profit to the ratepayers amounts to impermissible "retroactive" rate setting.

126 Thirdly, utilities are not entitled to include in the rate base an amount for *depreciation* on land and ratepayers have therefore not repaid ATCO any part of ATCO's original cost, let alone the present value. The treatment accorded gain on sales of depreciated property therefore does not apply.

127 Fourthly, ATCO complains that the Board's solution is asymmetrical. Ratepayers are given part of the benefit of an increase in land values without, in a falling market, bearing any part of the burden of losses on the disposition of land.

128 In my view, these are all arguments that should be (and were) properly directed to the Board. There are indeed precedents in the regulatory field for what ATCO proposes, just as there are precedents for what the ratepayers proposed. It was for the Board to decide what conditions in these particular circumstances were necessary in the public interest. The Board's solution in this case is well within the range of reasonable options, as I will endeavour to demonstrate.

1. <u>The Confiscation Issue</u>

129 In its factum, ATCO says that "[t]he property belonged to the owner of the utility and the Board's proposed distribution cannot be characterized otherwise than as being confiscatory" (respondent's factum, at para. 6). ATCO's argument overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the regulator sets the return on investment, not the marketplace. In *Re Southern California Gas Co.*, 118 P.U.R. 4th 81 (C.P.U.C. 1990) ("*SoCalGas*"), the regulator pointed out:

> In the non-utility private sector, investors are not guaranteed to earn a fair return on such sunk investment. Although shareholders and bondholders provide the initial capital investment, the ratepayers pay the taxes, maintenance, and other costs of carrying utility property in rate base over the years, and thus insulate utility investors from the risk of having to pay those costs. Ratepayers also pay the utility a fair return on property (including land) while it is in rate base, compensate the utility for the diminishment of the value of its depreciable property over time through depreciation accounting, and bear the risk that they must pay depreciation and a return on prematurely retired rate base property. [p. 103]

(It is understood, of course, that the Board does not appropriate the actual proceeds of sale. What happens is that an amount *equivalent* to two-thirds of the profit is included in the calculation of ATCO's current cost base for rate-making purposes. In that way, there is a notional distribution of the benefit of the gain amongst the competing stakeholders.)

130 ATCO's argument is frequently asserted in the United States under the flag of constitutional protection for "property". Constitutional protection has not however prevented allocation of all or part of such gains to the U.S. ratepayers. One of the leading U.S. authorities is *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (D.C. Cir. 1973). In that case, the assets at issue were parcels of real estate which had been employed in

mass transit operations but which were no longer needed when the transit system converted to buses. The regulator awarded the profit on the appreciated land values to the shareholders but the Court of Appeals reversed the decision, using language directly applicable to ATCO's "confiscation" argument:

> We perceive no impediment, constitutional or otherwise, to recognition of a ratemaking principle enabling ratepayers to benefit from appreciations in value of utility properties accruing while in service. We believe the doctrinal consideration upon which pronouncements to the contrary have primarily rested has lost all present-day vitality. Underlying these pronouncements is a basic legal and economic thesis — sometimes articulated, sometimes implicit — that utility assets, though dedicated to the public service, remain exclusively the property of the utility's investors, and that growth in value is an inseparable and inviolate incident of that property interest. The precept of private ownership historically pervading our jurisprudence led naturally to such a thesis, and early decisions in the ratemaking field lent some support to it; if still viable, it strengthens the investor's claim. We think, however, after careful exploration, that the foundations for that approach, and the conclusion it seemed to indicate, have long since eroded away. [p. 800]

The court's reference to "pronouncements" which have "lost all present-day vitality" likely includes *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (1976), a decision relied upon in this case by ATCO. In that case, the Supreme Court of the United States said:

> Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock. [p. 32]

In that case, the regulator belatedly concluded that the level of depreciation allowed the New York Telephone Company had been excessive in past years and sought to remedy

the situation in the current year by retroactively adjusting the cost base. The court held that the regulator had no power to re-open past rates. The financial fruits of the regulator's errors in past years now belonged to the company. That is not this case. No one contends that the Board's prior rates, based on ATCO's original investment, were wrong. In 2001, when the matter came before the Board, the Board had jurisdiction to approve or not approve the proposed sale. It was not a done deal. The receipt of any profit by ATCO was prospective only. As explained in *Re Arizona Public Service Co.*:

> In *New York Telephone*, the issue presented was whether a state regulatory commission could use excessive depreciation accruals from prior years to reduce rates for future service and thereby set rates which did not yield a just return. . . . [T]he Court simply reiterated and provided the reasons for a ratemaking truism: rates must be designed to produce enough revenue to pay current (reasonable) operating expenses and provide a fair return to the utility's investors. If it turns out that, for whatever reason, existing rates have produced too much or too little income, the past is past. Rates are raised or lowered to reflect current conditions; they are not designed to pay back past excessive profits or recoup past operating losses. In contrast, the issue in this proceeding is whether for ratemaking purposes a utility's test year income from sales of utility service can include its income from sales of utility property. The United States Supreme Court's decision in *New York Telephone* does not address that issue. [Emphasis added; p. 361.]

131 More recently, the allocation of gain on sale was addressed by the California Public Utilities Commission in *SoCalGas*. In that case, as here, the utility (SoCalGas) wished to sell land and buildings located (in that case) in downtown Los Angeles. The Commission apportioned the gain on sale between the shareholders and the ratepayers, concluding that:

> We believe that the issue of who owns the utility property providing utility service has become a red herring in this case, and that ownership alone does not determine who is entitled to the gain on the sale of the property providing utility service when it is removed from rate base and sold. [p. 100]

132 ATCO argues in its factum that ratepayers "do not acquire any interest, legal or equitable, in the property used to provide the service or in the funds of the owner of the utility" (para. 2). In *SoCalGas*, the regulator disposed of this point as follows:

> No one seriously argues that ratepayers acquire title to the physical property assets used to provide utility service; DRA [Division of Ratepayer Advocates] argues that the gain on sale should reduce future revenue requirements not because ratepayers own the property, but rather because they paid the costs and faced the risks associated with that property while it was in rate base providing public service. [p. 100]

This "risk" theory applies in Alberta as well. Over the last 80 years, there have been wild swings in Alberta real estate, yet through it all, in bad times and good, the ratepayers have guaranteed ATCO a just and equitable return on its investment in *this* land and *these* buildings.

133 The notion that the division of risk justifies a division of the net gain was also adopted by the regulator in *SoCalGas*:

> Although the shareholders and bondholders provided the initial capital investment, the ratepayers paid the taxes, maintenance, and other costs of carrying the land and buildings in rate base over the years, and paid the utility a fair return on its unamortized investment in the land and buildings while they were in rate base. [p. 110]

In other words, even in the United States, where property rights are constitutionally protected, ATCO's "confiscation" point is rejected as an oversimplification.

134 My point is not that the Board's allocation in this case is necessarily correct in all circumstances. Other regulators have determined that the public interest requires a different allocation. The Board proceeds on a "case-by-case" basis. My point simply

is that the Board's response in this case cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what are regarded in comparable jurisdictions as appropriate regulatory responses to the allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. The Board's decision is protected by a deferential standard of review and in my view it should not have been set aside.

2. The Regulatory Compact

135 The Board referred in its decision to the "regulatory compact" which is a loose expression suggesting that in exchange for a statutory monopoly and receipt of revenue on a cost plus basis, the utility accepts limitations on its rate of return and its freedom to do as it wishes with property whose cost is reflected in its rate base. This was expressed in the *Washington Metropolitan Area Transit* case by the U.S. Court of Appeals for the District of Columbia Circuit as follows:

> The ratemaking process involves fundamentally "a balancing of the investor and the consumer interests". The investor's interest lies in the integrity of his investment and a fair opportunity for a reasonable return thereon. The consumer's interest lies in governmental protection against unreasonable charges for the monopolistic service to which he subscribes. In terms of property value appreciations, the balance is best struck at the point at which the interests of both groups receive maximum accommodation. [p. 806]

136 ATCO considers that the Board's allocation of profit violated the regulatory compact not only because it is confiscatory but because it amounts to "retroactive rate making". In *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684, Estey J. stated, at p. 691:

> 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.

137 As stated earlier, the Board in this case was addressing a prospective receipt and allocated two thirds of it to a prospective (not retroactive) rate-making exercise. This is consistent with regulatory practice, as is illustrated by *New York Water Service Corp. v. Public Service Commission*, 208 N.Y.S.2d 857 (1960). In that case, a utility commission ruled that gains on the sale of real estate should be taken into account to reduce rates annually over the following period of 17 years :

> If land is sold at a profit, it is required that the profit be added to, i.e., "credited to", the depreciation reserve, so that there is a corresponding reduction of the rate base and resulting return. [p. 864]

The regulator's order was upheld by the New York State Supreme Court (Appellate Division).

138 More recently, in *Re Compliance with the Energy Policy Act of 1992*, 62 C.P.U.C. 2d 517 (1995), the regulator commented:

> . . . we found it appropriate to allocate the principal amount of the gain to offset future costs of headquarters facilities, because ratepayers had borne the burden of risks and expenses while the property was in ratebase. At the same time, we found that it was equitable to allocate a portion of the benefits from the gain-on-sale to shareholders in order to provide a reasonable incentive to the utility to maximize the proceeds from selling such property and compensate shareholders for any risks borne in connection with holding the former property. [p. 529]

139 The emphasis in all these cases is on balancing the interests of the shareholders and the ratepayers. This is perfectly consistent with the "regulatory compact" approach reflected in the Board doing what it did in this case.

3. Land as a Non-Depreciable Asset

140 The Alberta Court of Appeal drew a distinction between gains on sale of land, whose original cost is not depreciated (and thus is not repaid in increments through the rate base) and depreciated property such as buildings where the rate base does include a measure of capital repayment and which in that sense the ratepayers have "paid for". The Alberta Court of Appeal held that the Board was correct to credit the rate base with an amount equivalent to the depreciation paid in respect of the buildings (this is the subject matter of ATCO's cross-appeal). Thus, in this case, the land was still carried on ATCO's books at its original price of $83,720 whereas the original $596,591 cost of the buildings had been depreciated through the rates charged customers to a net book value of $141,525.

141 Regulatory practice shows that many (not all) regulators also do not accept the distinction (for this purpose) between depreciable and non-depreciable assets. In *Re Boston Gas Co.* for example (cited in *TransAlta (1986)*, at p. 176), the regulator held:

> . . . the company's ratepayers have been paying a return on this land as well as all other costs associated with its use. The fact that land is a nondepreciable asset because its useful value is not ordinarily diminished through use is, we find, irrelevant to the question of who is entitled to the proceeds on the sales of this land. [p. 26]

142 In *SoCalGas*, as well, the Commission declined to make a distinction between the gain on sale of depreciable, as compared to non-depreciable, property, stating: "We see little reason why land sales should be treated differently" (p. 107). The decision continued:

> In short, whether an asset is depreciated for ratemaking purposes or not, ratepayers commit to paying a return on its book value for as long as it is used and useful. Depreciation simply recognizes the fact that certain assets are consumed over a period of utility service while others are not. The basic relationship between the utility and its ratepayers is the same for depreciable and non-depreciable assets. [Emphasis added; p. 107.]

143 In *Re California Water Service Co.*, 66 C.P.U.C. 2d 100 (1996), the regulator commented that:

> Our decisions generally find no reason to treat gain on the sale of nondepreciable property, such as bare land, different[ly] than gains on the sale of depreciable rate base assets and land in PHFU [plant held for future use]. [p. 105]

144 Again, my point is not that the regulator *must* reject any distinction between depreciable and non-depreciable property. Simply, my point is that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. ATCO's attempt to limit the Board's discretion by reference to various doctrine is not consistent with the broad statutory language used by the Alberta legislature and should be rejected.

4. Lack of Reciprocity

145 ATCO argues that the customers should not profit from a rising market because if the land loses value it is ATCO, and not the ratepayers, that will absorb the loss. However, the material put before the Court suggests that the Board takes into account both gains *and* losses. In the following decisions the Board stated, repeated, and repeated again its "general rule" that

> the Board considers that any profit or loss (being the difference between the net book value of the assets and the sale price of those assets) resulting from the disposal of utility assets should accrue to the customers of the utility and not to the owner of the utility. [Emphasis added.]

(See *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984, at p. 17; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84115, October 12, 1984, at p. 12; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984, at p. 23.)

146 In *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984, the Board reviewed a number of regulatory approaches (including *Re Boston Gas Co.*, previously mentioned) with respect to gains on sale and concluded with respect to its own practice, at p. 12:

> The Board is aware that it has not applied any consistent formula or rule which would automatically determine the accounting procedure to be followed in the treatment of gains or losses on the disposition of utility assets. The reason for this is that the Board's determination of what is fair and reasonable rests on the merits or facts of each case.

147 ATCO's contention that it alone is burdened with the risk on land that *declines* in value overlooks the fact that in a falling market the utility continues to be

entitled to a rate of return on its original investment, even if the market value at the time is substantially less than its original investment. As pointed out in *SoCalGas*:

> If the land actually does depreciate in value below its original cost, then one view could be that the steady rate of return [the ratepayers] have paid for the land over time has actually overcompensated investors. Thus, there is symmetry of risk and reward associated with rate base land just as there is with regard to depreciable rate base property. [p. 107]

II. Conclusion

148 In summary, s. 15(3) of the AEUBA authorized the Board in dealing with ATCO's application to approve the sale of the subject land and buildings to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" (GUA, s. 22(1)), the Board made an allocation of the net gain for the public policy reasons which it articulated in its decision. Perhaps not every regulator and not every jurisdiction would exercise the power in the same way, but the allocation of the gain on an asset ATCO sought to withdraw from the rate base was a decision the Board was mandated to make. It is not for the Court to substitute its own view of what is "necessary in the public interest".

III. Disposition

149 I would allow the appeal, set aside the decision of the Alberta Court of Appeal, and restore the decision of the Board, with costs to the City of Calgary both in this Court and in the court below. ATCO's cross-appeal should be dismissed with costs.

APPENDIX

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

Jurisdiction

13 All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.

Powers of the Board

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB and the PUB that are granted or provided for by any enactment or by law.

(2) In any case where the ERCB, the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion.

(3) Without restricting subsection (1), the Board may do all or any of the following:

(a) make any order that the ERCB or the PUB may make under any enactment;

(b) with the approval of the Lieutenant Governor in Council, make any order that the ERCB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(c) with the approval of the Lieutenant Governor in Council, make any order that the PUB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

(e) make an order granting the whole or part only of the relief applied for;

(f) where it appears to the Board to be just and proper, grant partial, further or other relief in addition to, or in substitution for, that applied for as fully and in all respects as if the application or matter had been for that partial, further or other relief.

Appeals

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

. . .

Exclusion of prerogative writs

27 Subject to section 26, every action, order, ruling or decision of the Board or the person exercising the powers or performing the duties of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court.

Gas Utilities Act, R.S.A. 2000, c. G-5

Supervision

22(1) The Board shall exercise a general supervision over all gas utilities, and the owners of them, and may make any orders regarding equipment, appliances, extensions of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

(2) The Board shall conduct all inquiries necessary for the obtaining of complete information as to the manner in which owners of gas utilities comply with the law, or as to any other matter or thing within the jurisdiction of the Board under this Act.

Investigation of gas utility

24(1) The Board, on its own initiative or on the application of a person having an interest, may investigate any matter concerning a gas utility.

. . .

Designated gas utilities

26(1) The Lieutenant Governor in Council may by regulation designate those owners of gas utilities to which this section and section 27 apply.

(2) No owner of a gas utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them,

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

. . .

Prohibited share transactions

27(1) Unless authorized to do so by an order of the Board, the owner of a gas utility designated under section 26(1) shall not sell or make or permit to

be made on its books any transfer of any share or shares of its capital stock to a corporation, however incorporated, if the sale or transfer, by itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the gas utility.

. . .

Powers of Board

36 The Board, on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed afterwards by the owner of the gas utility,

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board,

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,

(d) require an owner of a gas utility to establish, construct, maintain and operate, but in compliance with this and any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the gas utility reasonably warrants the original expenditure required in making and operating the extension, and

(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

Rate base

37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

Excess revenues or losses

40 In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines has been due to undue delay in the hearing and determining of the matter, and

(d) the Board shall by order approve

(i) the method by which, and

(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

General powers of Board

59 For the purposes of this Act, the Board has the same powers in respect of the plant, premises, equipment, service and organization for the production, distribution and sale of gas in Alberta, and in respect of the business of an owner of a gas utility and in respect of an owner of a gas utility, that are by the *Public Utilities Board Act* conferred on the Board in the case of a public utility under that Act.

Public Utilities Board Act, R.S.A. 2000, c. P-45

Jurisdiction and powers

36(1) The Board has all the necessary jurisdiction and power

(a) to deal with public utilities and the owners of them as provided in this Act;

(b) to deal with public utilities and related matters as they concern suburban areas adjacent to a city, as provided in this Act.

(2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

(3) The Board has, and is deemed at all times to have had, jurisdiction to fix and settle, on application, the price and terms of purchase by a council of a municipality pursuant to section 47 of the *Municipal Government Act*

(a) before the exercise by the council under that provision of its right to purchase and without binding the council to purchase, or

(b) when an application is made under that provision for the Board's consent to the purchase, before hearing or determining the application for its consent.

General power

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that

the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

Investigation of utilities and rates

80 When it is made to appear to the Board, on the application of an owner of a public utility or of a municipality or person having an interest, present or contingent, in the matter in respect of which the application is made, that there is reason to believe that the tolls demanded by an owner of a public utility exceed what is just and reasonable, having regard to the nature and quality of the service rendered or of the commodity supplied, the Board

(a) may proceed to hold any investigation that it thinks fit into all matters relating to the nature and quality of the service or the commodity in question, or to the performance of the service and the tolls or charges demanded for it,

(b) may make any order respecting the improvement of the service or commodity and as to the tolls or charges demanded, that seems to it to be just and reasonable, and

(c) may disallow or change, as it thinks reasonable, any such tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any provisions of any contract existing between the owner of the public utility and a municipality at the time the application is made that the Board considers fair and reasonable.

Supervision by Board

85(1) The Board shall exercise a general supervision over all public utilities, and the owners of them, and may make any orders regarding extension of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

. . .

Investigation of public utility

87(1) The Board may, on its own initiative, or on the application of a person having an interest, investigate any matter concerning a public utility.

(2) When in the opinion of the Board it is necessary to investigate a public utility or the affairs of its owner, the Board shall be given access to and may use any books, documents or records with respect to the public utility and in the possession of any owner of the public utility or municipality or under the control of a board, commission or department of the Government.

(3) A person who directly or indirectly controls the business of an owner of a public utility within Alberta and any company controlled by that person shall give the Board or its agent access to any of the books, documents and records that relate to the business of the owner or shall furnish any information in respect of it required by the Board.

Fixing of rates

89 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges, or schedules of them, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed subsequently by the owner of the public utility;

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a public utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board;

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed subsequently by the owner of the public utility;

(d) repealed;

(e) require an owner of a public utility to establish, construct, maintain and operate, but in compliance with other provisions of this or any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the public utility reasonably warrants the original expenditure required in making and operating the extension.

Determining rate base

90(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed subsequently by an owner of a public utility, the Board shall determine a rate base for the property of the owner of a public utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the public utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a public utility is entitled to earn on the rate base, the Board shall give due consideration to all those facts that, in the Board's opinion, are relevant.

Revenue and costs considered

91(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of such a period,

(b) the Board shall consider the effect of the *Small Power Research and Development Act* on the revenues and costs of the owner with respect to the generation, transmission and distribution of electric energy,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines is just and reasonable,

(d) the Board may give effect to such part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines has been due to undue delay in the hearing and determining of the matter, and

(e) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as

determined pursuant to clause (c) or (d), is to be used or dealt with.

Designated public utilities

101(1) The Lieutenant Governor in Council may by regulation designate those owners of public utilities to which this section and section 102 apply.

(2) No owner of a public utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of them,

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a public utility designated under subsection (1) in the ordinary course of the owner's business.

Prohibited share transaction

102(1) Unless authorized to do so by an order of the Board, the owner of a public utility designated under section 101(1) shall not sell or make or permit to be made on its books a transfer of any share of its capital stock to a corporation, however incorporated, if the sale or transfer, in itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility.

. . .

Interpretation Act, R.S.A. 2000, c. I-8

Enactments remedial

10 An enactment shall be construed as being remedial, and shall be given the fair, large and liberal construction and interpretation that best ensures the attainment of its objects.

Appeal dismissed with costs and cross-appeal allowed with costs, MCLACHLIN C.J. *and* BINNIE *and* FISH JJ. *dissenting*.

Solicitors for the appellant/respondent on cross-appeal: McLennan Ross, Calgary.

Solicitors for the respondent/appellant on cross-appeal: Bennett Jones, Calgary.

Solicitor for the intervener the Alberta Energy and Utilities Board: J. Richard McKee, Calgary.

Solicitor for the intervener the Ontario Energy Board: Ontario Energy Board, Toronto.

Solicitors for the intervener Enbridge Gas Distribution Inc.: Fraser Milner Casgrain, Toronto.

Solicitors for the intervener Union Gas Limited: Torys, Toronto.

In the Court of Appeal of Alberta

Citation: ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board), 2008 ABCA 200

Date: 20080527
Docket: 0501-0102-AC
0501-0171-AC
0701-0048-AC
Registry: Calgary

Between:

ATCO Gas and Pipelines Ltd.

Appellant

- and -

Alberta Energy and Utilities Board

Respondent

- and -

The City of Calgary and Utilities Consumer Advocate

Interested Parties

The Court:

The Honourable Madam Justice Elizabeth McFadyen
The Honourable Madam Justice Constance Hunt
The Honourable Mr. Justice Frans Slatter

Memorandum of Judgment

Appeals from Decisions of the
Alberta Energy and Utilities Board:
U2005-133 Dated the 25th day of March, 2005
2005-063 Dated the 15th day of June, 2005
2007-005 Dated the 5th day of February, 2007

Memorandum of Judgment

The Court:

[1] The appellant was granted leave to appeal on certain issues arising from three decisions of the respondent Board: Decisions U2005-133, 2005-063 and 2007-005. Those decisions all relate to the Carbon storage facility owned by the appellant, which has for decades been a part of the appellant's regulated gas business. That business is operated through a division of the appellant known as ATCO Gas South ("AGS"). The fundamental issue is whether the Carbon storage facility continues to be used or required to be used to provide service in the context of the appellant's regulated business given the changes that have occurred in the industry, and in the facility's function.

Facts

[2] The appellant's gas storage facility located near Carbon, Alberta started out as a producing gas field. From 1959 to 1967 the Carbon field was used to supply gas to the appellant's customers.

[3] In 1967 the Carbon field was converted to a storage reservoir. From time to time gas was injected into the Carbon storage reservoir under high pressures. Later on, the gas would be withdrawn from the storage reservoir to meet demand. Gas could be purchased for injection into the reservoir in the summer months when prices were typically lower, and withdrawn in the winter months as needed. The storage reservoir was also used to manage peak utility supply requirements, for utility risk mitigation, and for system load balancing.

[4] The appellant has seldom, if ever, needed or been able to use the total storage capacity of the Carbon reservoir in its regulated gas business. From time to time the excess capacity was leased to third parties, and the capacity of the reservoir was even increased at times for the sole purpose of leasing the new capacity to other users. For example, between 1986 and 1991 the appellant used approximately 25% of the capacity. After 1992 its use of the capacity increased to 38%. However, in the 2001, 2005 and 2006 storage seasons all the capacity was leased to ATCO Midstream Ltd., an affiliate of the appellant.

[5] All the capital costs associated with the Carbon storage reservoir have been included in the appellant's rate base since the storage reservoir was first developed. Revenues received from the leasing of excess storage capacity to third parties were used to offset the overall revenue requirements of the appellant, thereby reducing the amount that would otherwise be recovered from customers through rates. Thus the revenue earned from leasing out parts of the Carbon storage facility has always been included by the Board in the calculation of the appellant's rates.

[6] In more recent years, the structure of the Alberta gas utility business has been changed by legislation. The previously integrated gas utilities (that provided gas services from the gas field to the retail customer) were divided, and different entities were assigned different functions in the overall gas system. The appellant was required to divest itself of its retail gas supply business, and in 2004 Direct Energy Regulated Service ("DERS") took over that service as the default supplier. The appellant no longer sells gas to customers, but now only operates a gas distribution business, consisting of the transportation of gas for third parties. As a result, the appellant no longer needs a gas storage facility as a part of its regulated

business, and indeed it even argues that it is prohibited by legislation from operating any gas storage facility. The Board has determined that the Carbon storage facility is no longer required for utility operational purposes related to the appellant's regulated gas distribution business. The gas storage business itself is not regulated.

[7] Since about 2000, the appellant has taken the position that the Carbon storage facility is no longer "used or required to be used to provide a service to the public", and is therefore not properly part of its rate base under s. 37 of the *Gas Utilities Act*, R.S.A. 2000, c. G-5. Its various efforts to obtain confirmation from the Board to that effect led eventually to the orders that are now under appeal.

[8] The Board established a procedure to resolve the matter, approaching the underlying issues in stages. The procedure (discussed in detail in Decision 2005-063) took longer than anticipated, and on March 8, 2005 the appellant wrote to the Board, effectively attempting to unilaterally withdraw the Carbon storage facility from its rate base. In decision U2005-133 the Board ruled that the appellant could not unilaterally withdraw assets from the rate base. The Board also issued an Interim Order preserving the status quo until the process had run its course. As the Board later stated in Decision 2005-063, at pg. 6: "It is contemplated that at the time that the Interim Order is terminated, the Board will address any required adjustments between AGS and ratepayers to reflect the Board's jurisdictional and rate base findings." Interim Order U2005-133 is one of the orders presently under appeal. There is no direct challenge in this appeal to the ability of the Board to issue interim orders preserving the status quo while it considers issues before it.

[9] The next phase of the process considered four "Preliminary Questions". In Decision 2005-063 the Board stated and answered the questions as follows:

(1) In general, once an asset or capital expenditure has been approved by the Board for inclusion in rate base, what should be the criteria for removing it from rate base at the request of the utility? The Board decided that an asset is removed from the rate base when the Board (and not the utility) concludes that it is no longer "used or required to be used to provide service to the public".

(2) In general, is it appropriate for the Board to attach conditions to the removal of an asset from rate base that would require the utility to add the asset back into the rate base at some future time should subsequent application by the Board of the criteria identified in Question 1 lead to a different result? The Board concluded that such a condition would not be appropriate, workable or reasonable in most circumstances.

(3) In general, to what extent can (should) the Board direct a utility to deal with a particular asset presently included within rate base in a specific manner? The Board concluded that it has such a jurisdiction, but that normally it would leave the operation and management of the regulated business to the utility.

(4) What is the appropriate scope for the Board to adopt in conducting an examination of whether or not Carbon is used or required to be used to provide service to the public or

should otherwise remain in rate base? In particular, the Board would like submissions and argument, without reliance on detailed operational or technical Carbon specifics, on which of the following uses or potential uses of Carbon can (should) the Board consider in addressing this question:

(a) historical uses.
(b) proposed uses.
(c) possible contingent uses by AGS should obligations presently being performed by DERS revert to AGS.
(d) potential alternative uses by AGS, ATCO Pipelines or DERS.

The Board concluded that the only possible relevant uses (to be considered in the next phase of the process) would be the use of the Carbon storage facility for revenue generation purposes, or for distribution system load balancing.

Decision 2005-063 is the second of the orders presently under appeal.

[10] In Decision 2006-098 (which is not presently under appeal) the Board concluded that the Carbon storage facility was not required for load balancing of the appellant's distribution system. The Board confirmed that the appellant no longer had any operational need for a gas storage facility as a part of its regulated business, and that there was no operational reason to include the Carbon storage facility within the rate base. The only remaining reason to keep the Carbon storage facility within the rate base would, therefore, be to generate revenue which could be used to reduce the rates otherwise payable by customers.

[11] The Board then embarked on the last phase of the process, which was a determination of whether an asset that has no functional or operational use could be kept in the rate base for revenue generation purposes, as well as several related questions. In Decision 2007-05 the Board first determined that there were no legal impediments to the appellant owning a storage facility, so long as it was not used to provide retail gas services. The Board secondly confirmed its view that "it has the overriding legislative responsibility to review and approve which assets are in rate base."

[12] On the central question, the Board decided: "Ordinarily, revenue generation on a stand-alone basis would likely not satisfy the used or required to be used test for inclusion in rate base." The Board concluded, however, that the Carbon storage facility was unique, in that, in addition to its operational role, it had always provided some revenue generating service by the leasing of excess storage capacity. While the Carbon storage facility no longer had any utility operational purpose, in the Board's view:

> . . . it is not material whether or not revenue generation was a stand-alone use or an ancillary use associated with a utility service or function whose purpose was to indirectly offset the costs of providing this utility functionality. It is clear that there has been a unique course of dealing acceptable to all parties with respect to Carbon. Revenue generation has been an integral, long-standing and accepted use of Carbon for approximately forty years driven by the specific characteristics of the Carbon assets. As a consequence, revenue from Carbon has been used to offset regulated revenue requirement and has been part of the

> Board's determination of just and reasonable rates to customers for the same extensive period. This aspect of the Carbon assets continues today and the Board sees no reason why Carbon should be considered as no longer used or required to be used for this purpose. (at pp. 26-7)

Decision 2007-05 also concluded that the removal of the Carbon storage facility from the regulated business would be a "disposition" under section 26(2)(d) of the *Gas Utilities Act*, and thus would require the approval of the Board. Decision 2007-05 is the third of the orders presently under appeal.

[13] The appellant applied for and was granted leave to appeal the following issues arising from Decisions U2005-133, 2005-063 and 2007-005:

1. Did the Board err in law or jurisdiction when it included the Carbon facilities in the rate base as an asset "used or required to be used to provide service to the public within Alberta" when the only function of those facilities is to generate revenue?

2. Does the *Roles, Relationships and Responsibilities Regulation* under the *Gas Utilities Act*, prohibit ATCO Gas South from operating the Carbon facilities and if so, is the Board unable to assert further jurisdiction over the Carbon facilities?

3. Can the Board require an owner of a gas utility to continue to include an asset in the rate base or restrict an owner from withdrawing a specific asset from its gas distribution system once an asset has been included in a past rate base?

4. Did the Board err in determining that a change in use of the Carbon facilities is a "disposition" for the purposes of section 26 of the *Gas Utilities Act*?

5. Did the Board commit any other error the panel hearing the appeal identifies and is prepared to entertain?

[14] The City of Calgary and the Utilities Consumer Advocate did not apply to the Court for intervener or any other status, but purported to participate in these appeals as "interested parties". Absent any objection by the parties, the Court has considered their submissions on this occasion.

Standard of Review

[15] The test for selecting the standard of review was comprehensively set out in ***Pushpanathan v. Canada (Minister of Employment and Immigration)***, [1998] 1 S.C.R. 982, and recently re-examined in ***Dunsmuir v. New Brunswick***, 2008 SCC 9 at paras. 55, 64. It is appropriate to identify or advert to the standard of review in all cases. However, it is not necessary to perform a fresh standard of review analysis in every case if the standard of review has already been set for the type of question in issue: ***Dunsmuir*** at paras. 57, 62.

[16] The case law discloses that the following standards of review have been identified for reviewing decisions of the Board under the *Gas Utilities Act*:

(a) Questions of jurisdiction are reviewed for correctness: ***ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)***, [2006] 1 S.C.R. 140, 2006 SCC 4 (the ***Stores Block*** decision) at para 21. "Jurisdiction" is however defined narrowly, and relates only to the ability of the Board to embark on the inquiry. The validity of the result, even on what might be called a "threshold" issue, is not necessarily "jurisdictional": ***Council of Canadians with Disabilities v. Via Rail Canada Inc.***, 2007 SCC 15, [2007] 1 S.C.R. 650 at paras. 89, 96, 106.

(b) The interpretation of the *Gas Utilities Act* is a question of law within the expertise of the Board, and such questions are reviewed for reasonableness: ***TransCanada Pipeline Ventures Ltd. v. Alberta (Energy and Utilities Board)***, 2008 ABCA 55 at paras. 17-20. All the important issues in this appeal fall within this category.

(c) Whether a particular asset should be included in the rate base is neither a question of law, nor a question of jurisdiction, and no appeal lies:

> "Once the interpretation is determined, whether a particular item is to be brought within the rate basis is essentially a question for the judgment of the board which does not involve a question of jurisdiction or law": ***Alberta Power Ltd. v. Alberta (Public Utilities Board)*** (1990), 72 Alta. L.R. (2d) 129, 102 A.R. 353 (C.A.) at pg. 149.

The proper interpretation of the statutory definition of the rate base is, however, a question of law reviewed for reasonableness.

Since the jurisprudence has established the standard of review to be used with respect to questions of the type presented in these appeals, it is not necessary to conduct a fresh standard of review analysis: ***Dunsmuir,*** *supra.*

[17] The appellant argues that the issues under appeal raise jurisdictional questions, namely whether the Board has any authority over assets that serve no purpose in the utility system other than to generate revenue, and whether the Board has any authority to require that assets remain with the regulated business, even though the utility considers them no longer to be a part of the rate base. These questions raise, at most, issues about the proper interpretation of the definitional provisions of the *Gas Utilities Act,* and are not properly categorized as jurisdictional in nature.

[18] ***Dunsmuir*** explained the concept of reasonableness at para. 47 as follows:

> Reasonableness is a deferential standard animated by the principle that underlies the development of the two previous standards of reasonableness: certain questions that come before administrative tribunals do not lend

> themselves to one specific, particular result. Instead, they may give rise to a number of possible, reasonable conclusions. Tribunals have a margin of appreciation within the range of acceptable and rational solutions. A court conducting a review for reasonableness inquires into the qualities that make a decision reasonable, referring both to the process of articulating the reasons and to outcomes. In judicial review, reasonableness is concerned mostly with the existence of justification, transparency and intelligibility within the decision-making process. But it is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law.

The Board's interpretations of the various provisions of the *Act* must accordingly be reviewed to see whether they are "justifiable, transparent and intelligible", and fall within the "range of possible, acceptable outcomes which are defensible in respect of the facts and law."

Including Revenue Generating Assets in the Rate Base

[19] The first question on which leave was granted is:

> 1. Did the Board err in law or jurisdiction when it included the Carbon facilities in the rate base as an asset "used or required to be used to provide service to the public within Alberta" when the only function of those facilities is to generate revenue?

[20] Section 37 of the *Act* provides:

> In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for *the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta* and on determining a rate base it shall fix a fair return on the rate base.

The issue is whether an asset which merely generates revenue is "used" to provide a service, or whether only assets that have a functional or operational role in the system qualify for inclusion in the rate base.

[21] These appeals raise no factual issue about the role that the Carbon storage facility plays in the appellant's gas distribution system. The Board has held that it plays no operational role, and its only present contribution is to generate revenue that would reduce rates. This is not, therefore, a case on whether a particular asset should be included in the rate base, something that (as just noted) is neither a question of law nor of jurisdiction. Rather, the issue here is an extricable question of law: whether revenue generation by the Carbon storage facility qualifies as "use" under the proper interpretation of the statute. As noted, the standard of review on this issue is reasonableness. The Board's decision must be examined to see if it is within the range of "possible, acceptable outcomes which are defensible in respect of the facts and law.": ***Dunsmuir***, *supra.*

[22] It is contrary to the general approach to utility regulation to suggest that assets can be included in the rate base merely because they generate revenue that could serve to reduce rates. The Board recognized this when it said in Decision 2005-063 at pg. 16:

> With respect to revenue generation as a stand-alone use of an asset, the Board believes it would have difficulty approving the inclusion in revenue requirement of costs associated with a new asset, where the function of the asset was unconnected to utility service and where its sole purpose was to generate revenue to offset rates otherwise payable.

The Board confirmed this view in Decision 2007-05 at pg. 26:

> Ordinarily, revenue generation on a stand alone basis would likely not satisfy the used or required to use test for inclusion in rate base.

The Board, however, found that the Carbon storage facility was unique, because of its historical role as both an operational part of the system and as a source of revenue from the leasing of surplus capacity. It used this history to justify its conclusion that the Carbon storage facility met the requirements of s. 37.

[23] The Board's interpretation of the section is unreasonable for several reasons. Firstly the Board relied largely on the historical role that the Carbon storage facility played in the system, as opposed to its present or future use. Section 37 of the *Act* is primarily forward looking. The Board's jurisdiction is to set rates "afterwards", that is for the future: ***Northwestern Utilities v. City of Edmonton***, [1979] 1 S.C.R. 684 at pg. 691. The words "used or required to be used" are intended to identify assets that are presently used, are reasonably used, and are likely be used in the future to provide services. Specifically, the past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system. The fact that the Carbon storage facility was previously used to provide service may provide some context, but it is largely irrelevant to whether that asset should remain in the rate base.

[24] Secondly, the Board itself decided in Decision 2005-063 at pg. 15 that historical uses of the property were largely irrelevant:

> In the Board's view, historical uses which are no longer employed at a facility would not typically be relevant in determining whether the asset is used or required to be used today. This would be particularly true where obsolescence is involved or where fundamental changes may have occurred in the regulatory or market régime.

However in identifying the "unique" features of the Carbon storage facility in Decision 2007-005 that justified keeping the facility in the rate base, the Board relied almost entirely on historical factors. They were summarized in the Board's factum as follows:

- Carbon represents an exceptional and unique asset in the history of regulated utilities in Alberta.
- Carbon Storage was initially acquired as a company-owned gas production asset, then converted to a storage facility and expanded over a period of roughly 40 years.

- Company-owned production (COP) from the associated Producing Properties continued throughout this period and to the present.
- Carbon has had multiple utility uses throughout its history, including COP operational security, system balancing, peaking supply, emergency use and revenue generation.
- The acquisition and operation of the Producing Properties have been intertwined with the acquisition, development, protection and evolution of Carbon Storage, such that Carbon has generally been considered by the Appellant, customers and the Board to be a single set of assets.
- Revenue generation has been one of the continuing uses of Carbon since it was converted to a storage facility.
- Some of Carbon's capacity has been leased to third parties since 1967 and lease payments from these parties has always been used to offset utility customer rates.
- Since 1972, it has been accepted by the Appellant and customers that the majority of Carbon capacity be used for revenue generation.
- Although Carbon's use for operational purposes was intermittent and variable, and ultimately declined altogether, the revenue generated from third party leases has had a very significant impact on customer rates for most of Carbon's existence.

The reasoning in the two Decisions is inconsistent, making the overall conclusion unreasonable.

[25] Thirdly, the only reasonable reading of s. 37 is that the assets that are "used or required to be used" to provide service are only those used in an operational sense. It strains the meaning of the word "used" when applied to "property" to suggest that merely accounting for the revenue generated by the asset constitutes "using" the asset.

[26] Fourthly, while the Board sometimes identified revenue generation as a "use"of assets, it also sometimes identified revenue generation as a "service". The test in the statute is whether the assets are "used" to "provide service". In Decision 2007-005 at pp. 1, 19 the Board said:

> In this decision the Board has determined that the Carbon storage and associated production assets are used or required to be used for *purposes of generating revenue* to offset customer rates. . . . accordingly, it is appropriate for the Carbon assets to remain in regulated rate base subject to the Board's jurisdiction.
>
> The purpose of this decision is to determine whether or not Carbon is used or required to be used or should otherwise remain in rate base in order to provide *a revenue generation service* for the benefit of regulated customers. (Emphasis added)

In the utility regulatory regime "revenue generation" cannot reasonably be regarded as a "service". The delivery of gas is the "service": s. 28(e) of the *Act* defines "gas distribution service" as "the service required to transport gas to customers by means of a gas distribution system". Therefore, the issue is whether the Carbon storage facility is required to transport gas to customers, not whether it is required to generate revenue.

[27] Fifthly, while the Board noted that "fundamental changes" in the regulatory regime might change the status of an asset, the Board failed to give effect to the fact that the present issue respecting the use of the Carbon storage facility came about largely because of just such a change. The regulatory regime has changed radically and the operations of the traditional integrated utility have now been split among a number of players. For many years the Carbon storage facility played a dual role as an operational asset, as well as a generator of revenue from the leasing of surplus capacity. Under the present circumstances, the Carbon storage facility has no operational role at all. The Board found in Decision 2007-05 at pp. 26-7 that: "it is not material whether or not revenue generation was a stand-alone use or an ancillary use associated with a utility service or function whose purpose was to indirectly offset the costs of providing this utility functionality." The failure to recognize the fundamental change in the role played by the Carbon storage facility once it lost all of its operational purposes was unreasonable.

[28] Finally, the Board over-emphasized that for over 40 years the Carbon storage facility was included in the rate base. The facility always had excess capacity, and the Board noted all its revenues and expenses were included in setting rates, something that is unusual in utility regulation. All concerned were content with that arrangement, and in this respect the Carbon storage facility probably is unique, as the Board held. The reasons why no one challenged these long standing arrangements are undoubtedly complex, but the failure to object in the past does not create any kind of estoppel preventing the present appeal. If the Carbon storage facility does not now meet the requirements of s. 37, the appellant is entitled to a ruling to that effect.

[29] The *Act* does not contain any provision or presumption that once an asset is part of the rate base, it is forever a part of the rate base regardless of its function. The concept of assets becoming "dedicated to service" and so remaining in the rate base forever is inconsistent with the decision in ***Stores Block*** (at para. 69). Such an approach would fetter the discretion of the Board in dealing with changing circumstances. Previous inclusion in the rate base is not determinative or necessarily important; as the Court observed in ***Alberta Power Ltd. v. Alberta (Public Utilities Board)*** (1990), 72 Alta. L.R. (2d) 129, 102 A.R. 353 (C.A.) at pg. 151: "That was then, this is now".

[30] Regulation of the gas utility does not give the end customers an ownership interest in the assets of the utility: ***Stores Block*** at paras. 63-68. The end customers are entitled to service, not assets. The service that they are entitled to is the delivery of gas on reasonable and just terms, not revenue generation. Just as the end customers have no ownership interest in the assets of the utility, they have no interest in the profits, unregulated revenues, or unregulated businesses of the utility. The value of economic assets is often largely determined by the revenues they can generate, and if the end customers are not entitled to any ownership interest in the assets, they are likewise not entitled to any interest in the cash flow generated by those assets: ***Stores Block*** at para. 78. The end customers are entitled to receive gas delivery services from the utility, not revenue-generating services or gas rate subsidization.

[31] The view that the Carbon storage facility could remain in the rate base purely to generate revenue is not one that the section can reasonably bear. The first question upon which leave was granted is answered in the affirmative.

The Remaining Questions

[32] The Board's answers to Questions 2, 3 and 4 were predicated on its conclusion that the Carbon storage facility could be kept in the rate base as a revenue generating asset. Our conclusion to the contrary undermines the assumption on which the Board answered these remaining questions, and the basis on which leave to appeal was granted. In the circumstances, it is neither necessary nor advisable to answer the remaining questions at this time.

Conclusion

[33] In conclusion, the questions on which leave was granted should be answered as follows:

1. Did the Board err in law or jurisdiction when it included the Carbon facilities in the rate base as an asset "used or required to be used to provide service to the public within Alberta" when the only function of those facilities is to generate revenue? Yes.

2. Does the *Roles, Relationships and Responsibilities Regulation* under the *Gas Utilities Act*, prohibit ATCO Gas South from operating the Carbon facilities and if so, is the Board unable to assert further jurisdiction over the Carbon facilities? No answer is appropriate at this time.

3. Can the Board require an owner of a gas utility to continue to include an asset in the rate base or restrict an owner from withdrawing a specific asset from its gas distribution system once an asset has been included in a past rate base? No answer is appropriate at this time.

4. Did the Board err in determining that a change in use of the Carbon facilities is a "disposition" for the purposes of section 26 of the *Gas Utilities Act*? No answer is appropriate at this time.

[34] The appeals are allowed and the matter is remitted to the Alberta Utilities Commission to be dealt with in a manner consistent with these reasons.

Appeal heard on May 9, 2008

Memorandum filed at Calgary, Alberta
this 27th day of May, 2008

McFadyen J.A.

Hunt J.A.

Slatter J.A.

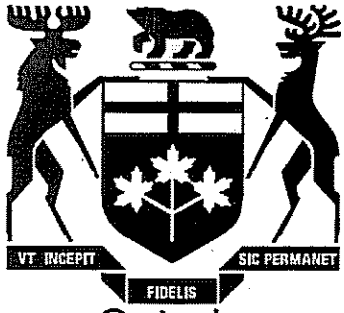
Appearances:

H.M. Kay, Q.C., L.E. Smith, Q.C. and L.A. Goldbach
for the Appellant

A.E. Domes and B.C. McNulty
for the Respondent

T.D. Marriott
for the Utilities Consumer Advocate

R.B. Brander and P.L. Quinton-Campbell
for the City of Calgary



Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2005-0551**

VOLUME: **2**

DATE: **June 20, 2006**

BEFORE:	**Gordon Kaiser**	**Presiding Member and Vice Chair**
	Cynthia Chaplin	**Member**
	Bill Rupert	**Member**

pipeline balancing service, and F24-S.

MR. THOMPSON: Right.

MR. ISHERWOOD: And I'd also throw into this mix as well incremental deliverability above what would be allocated to a large power general customer under general T1 contract. All four of those services would require Union to build more deliverability.

And for us to attract the capital to do that, we would definitely need to have a forbearance type of model, more than likely. To the extent we didn't have that, our proposal or our suggestion was we would go out on the market and try and purchase that same service.

MR. THOMPSON: But this is where I'm confused with what you described as the forbearance type of model. To me, forbearance comes after the Board has regulated for a while. Here you've got services that haven't even been approved before. And so it sounds to me like you're asking the Board to exercise market-based rate-making authority and approve these under the auspices of a market-based price signal regime. Is that really what you're asking for?

MR. BAKER: No. Not really, because if you look at what we have today, you can say that we have a market-based pricing regime. But we don't have the economic incentive to go out and look to develop and commit capital to new storage or new storage deliverability.

There are risks associated with doing that in terms of developing that kind of business. So, to the extent that

we commit capital and we develop an asset and we sell it into the market at a market-based rate, under today's framework the majority of that value goes back. It's not a framework that compensates someone like Union to go out and take the risk to develop those kinds of assets and commit the capital to them.

MR. THOMPSON: So what is it you're asking the Board to approve with respect to these new services? Or are you just telling us: This is what we plan to do, leave us alone.

MR. BAKER: No, I think it's definitely related to what we're dealing with in this hearing. It is saying that the market for those services, the exfranchise wholesale market, is competitive, that market-based rates are supportable, and on that basis we would go forward and we would look to sell those services at rates that would be sufficient enough for us to commit the capital and develop those assets.

MR. THOMPSON: The Board will approve words but nothing else? Is that the idea?

MR. BAKER: I don't see the distinction to the extent that there is a determination that there's forbearance from the existing exfranchise wholesale storage market. To the extent that we developed new assets and sold those services as part of that market, I would see that as being one and the same thing.

MR. THOMPSON: Are these services, then, part of the exfranchise market? I thought some of them would be for infranchise customers.

MR. ISHERWOOD: I think they're primarily for the exfranchise market. We did talk about the settlement agreement covers off the -- or more nominations, for example, applying to U7 and T1, in some circumstance. But the upstream and downstream service in the F24-S is primarily for the exfranchise market.

MR. THOMPSON: Okay. Well, can you help me with how the Board or anybody else could get a handle on the kinds of returns that you would be deriving from these services under your proposal, or is that going to be beyond the purview of anybody's scrutiny?

MR. BAKER: For which, the services that you just -

MR. THOMPSON: These new services that you say are storage-related but needed by the gas-fired generators, primarily.

MR. BAKER: Again, to the extent that -- we would take a look at the capital that would be required, and to the extent that we went out with an open season and we got bids from certain customers for those service, we would look at that and say are the values sufficient enough for us to support the allocation of capital and develop those assets.

So again, that's the process. There could be a lot of different terms. Some parties may be prepared to commit to a 10-year term for service, some for a 5-year. And that's the issue that we face in terms of trying to commit capital

and develop assets, particularly on the storage side, is that the market is not homogeneous, not everybody is out there willing to bid 10- or 20-year terms for storage contracts.

So to the extent that a party was only willing to bid for a five-year term, for us to get the capital, they would need to pay a higher price to compensate us for the risk of what might happen on the capacity on the back end after that primary contract.

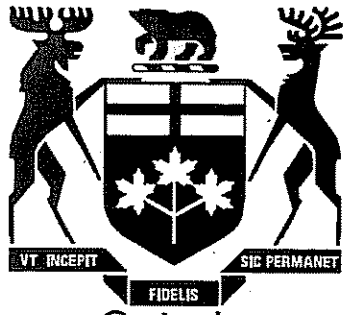
MR. HENNING: Mr. Thompson, if I might add something that may help in terms of that.

Within the United States framework, when they choose for a new facility to forbear, or their parlance would be to grant market-based rates authority for those services, there is no cost-of-service calculation, because there is no filing of the costs. It is deemed to be the marketplace itself in those competitive services that disciplines prices, and so there is no calculated rate of return.

MR. THOMPSON: Well, there's a difference between market-based rate authority, at least as far as Union is concerned, and forbearance. Market-based rate authority engages the Board's rate-making power, and so it has the power to scrutinize what's goes on.

MR. BAKER: To be clear, we're seeking forbearance in prices, market-based prices that are determined in the marketplace.

MR. THOMPSON: I understand that. And so nobody will have the power to scrutinize what goes on with these



Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2005-0551

VOLUME: 4

DATE: June 27, 2006

BEFORE:	**Gordon Kaiser**	**Presiding Member and Vice Chair**
	Cynthia Chaplin	**Member**
	Bill Rupert	**Member**

year to year.

MR. KAISER: You have indicated that if the regulatory regime changed and you got to keep all of the premium and you got to go to market-based prices, you would increase your investment in this activity. Did I understand that right?

MR. BAKER: We would certainly take a much harder look at the investment opportunities that we see on the storage side; that's correct.

MR. KAISER: Have you done any studies of that?

MR. BAKER: No. We have been out of -- when we step back and look at it, based on the framework we have, we haven't been able to look hard at what else we would want to do with the framework, in terms of going out and amassing a land position or looking at potential developments in terms of greenfield storage. So we, as Union Gas, have not done that.

MR. KAISER: Dr. Schwindt, I just have one question for you. When we started this whole exercise, we were -- they went out and hired a high-priced economist like you experienced in competition policy to define whether these markets were competitive or not, and then to apply the appropriate pricing regime, but then it seems that the lawyers took over and forgot about the economic principles.

We have these dispatchable power people, and you say that that is a competitive market, we heard from Mr. Isherwood, but yet they get a piece of their capacity on a cost-based basis.

1. 2006 YEAR-END DEFERRAL ACCOUNT BALANCES

At the end of December 2006, the balances accumulated in Union's Board-approved deferral accounts total a credit of $179.570 million. This amount consists of $197.803 million in credits in gas supply-related deferral accounts (the majority of which is managed through the Quarterly Rate Adjustment Mechanism ("QRAM")), $16.990 million in credits in Storage and Transportation related deferral accounts, and $35.224 million in debits in the Other deferral accounts. Individual account balances are shown at Tab 1, Schedule 1. Each account balance includes interest up to December 31, 2006. Interest is computed monthly on the opening balance of each account. The applicable interest rate used is the short-term debt rate of 4.15% approved by the Board in the RP-2003-0063 proceeding.

Deferral account balances have been categorized into three types: Gas Supply deferral accounts, S&T deferral accounts and Other deferral accounts. The balances for each account are discussed below.

GAS SUPPLY DEFERRAL ACCOUNTS

The balances recorded in the following gas supply related deferral accounts were examined in each of Union's four QRAM applications in 2006.

179-105	North Purchased Gas Variance Account ("PGVA")
179-100	TCPL Tolls and fuel – Northern and Eastern Operations area
179-106	South PGVA
179-109	Inventory Revaluation
179-107	Spot Gas Variance Account

Union's Board-approved QRAM process establishes reference prices for selected gas supply-related deferral accounts and the prospective recovery, or refund, of the projected balances of these accounts including interest, over the following 12 month period. Variances between the forecast and actual prospective recovery amounts are tracked and included in the amounts prospectively recovered in future QRAM proceedings.

Under the QRAM process, the actual year-end deferral account balances are subject to the Board's final approval. In this application, Union is seeking that approval. The Board approved all four of Union's QRAM applications in 2006.

The balances for the two other gas supply related deferral accounts are not prospectively recovered or refunded as part of the approved QRAM process. These accounts are as follows:

Account No. 179-108 UDC

Account No. 179-89 Heating Value

Account No. 179-108 Unabsorbed Demand Costs

The credit balance of $0.708 million in the Unabsorbed Demand Costs ("UDC") account is the difference between the actual UDC incurred by Union and the amount of UDC included in rates as approved by the Board.

During 2006 Union experienced excess supply of 12.680 PJs due to both planned UDC and reduced demand caused by weather being 14% warmer than normal. The 2006 weather normal is set by the blended 70:30 (30 year average/20 year trend) weather normal methodology in accordance with the Board's RP-2003-0063 Decision. In response to the warmer than normal weather in 2006, Union reduced a portion of its planned purchases through the spring and summer to balance demand and supply. The resulting unfilled pipe capacity was sold for the then-current market prices which minimized UDC to the extent possible. The favourable cost variance more than offset the unfavourable volume variance which resulted in less UDC overall than had been forecast. The explanation for the excess supply of 12.680 PJs is shown in Table 1 below:

Table 1

	Northern and Eastern Operations area (PJs)	Southern Operations area (PJs)	Total Franchise area (PJs)
Planned UDC	4.091	1.823	5.914
Weather-related UDC	2.713	4.053	6.766
Total UDC	6.804	5.876	12.680
% of Total	53.7%	46.3%	100.0%

A description of each item follows:

1. Planned UDC

   To meet peak customer demands across Union's franchise area and the targeted storage inventory levels at October 31, Union's 2006 supply portfolio included planned UDC of 4.091 PJs in the Northern and Eastern Operations area and 1.823 PJs in the Southern Operations area.

2. Weather-related UDC

   The weather through the 2006 heating season was abnormally warm, resulting in reduced demand across Union's franchise area. In the Northern and Eastern Operations area, the sales service and bundled direct purchase customers experienced reduced demand of 2.713 PJs due to weather. In the Southern Operations area, the sales service customers experienced reduced demand of 4.053 PJs. Union did not incur UDC on behalf of direct purchase customers in the

Southern Operations area because these customers manage their own supplies to meet their load balancing checkpoint targets.

3. Total Excess Supply

The result of the planned UDC and the reduced demand due to weather was 6.804 PJs (or 53.7% of the total) of excess supply in the Northern and Eastern Operations area and 5.876 PJs (or 46.3% of the total) in the Southern Operations area.

For 2006, Union's total UDC was $1.007 million. Union collected $1.692 million in rates and recorded an associated interest credit of $0.023 million. The result is a credit in the UDC deferral account of $0.708 million. Table 2 below provides the derivation of the UDC deferral account balances by operating area.

Table 2

	Northern and Eastern Operations area ($ 000s)	Southern Operations area ($ 000s)	Total Franchise area ($ 000s)
UDC Costs Incurred	541	466	1,007
Collected in Rates	(1,692)	-	(1,692)
Interest	(43)	20	(23)
(Credit)/Debit to Operations areas	(1,194)	486	(708)

A description of each item follows:

1. UDC Costs Incurred

   Union proposes to assign the total cost of $1.007 million to each operating area in proportion to the excess supply as calculated in Table 1. This results in UDC of $0.541 million for the Northern and Eastern Operations area and $0.466 million for the Southern Operations area.

2. Collected in Rates

   Board-approved rates for 2006 included $1.932 million associated with planned UDC in the North (RP-2003-0063, Rate Working Papers, Schedule 27, page 3). No UDC was planned for or included Southern rates. For 2006, Union actually recovered $1.692 million of the $1.932 million.

3. Interest

   Interest associated with UDC costs amounted to a credit of $0.043 million for the Northern and Eastern Operations area and debit of $0.020 million for the Southern Operations area for a net amount of $0.023 million.

4. (Credit)/Debit to Operations areas

The UDC deferral account has a net total credit balance of $0.708 million. The balance applicable to customers in the Northern and Eastern Operations area is a credit of $1.194 million. The balance applicable to customers in the Southern Operations area is a debit of $0.486 million.

Account No.179-89 Heating Value

The Heating Value deferral account captures the impact associated with the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates. The 2006 credit balance of $2.405 million is due to lower energy content in the gas delivered to customers than what was reflected in their gas supply rates.

STORAGE AND TRANSPORTATION DEFERRAL ACCOUNTS

Actual net revenues from storage and transportation services are deferred against the net revenues included in the rates approved by the Board in the RP-2003-0063 Rate Order. Balances in S&T deferral accounts are currently shared on a 75/25 basis between ratepayers and the shareholder. The current credit balance of $16.990 million represents the ratepayer portion in the following S&T deferral accounts.

Account No. 179-69 Transportation and Exchange Services

The balance in the Transportation and Exchange Services deferral account is the difference between actual net revenues for Transportation and Exchange Services including C1 Interruptible Transportation, Energy Exchanges, M12 Transportation Overrun, M12 and C1 Non-Loss-of-Critical-Unit Protected Firm Transportation, M12 Limited Firm/Interruptible Transportation and C1 Firm Short Term Transportation, and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $4.004 million is 75% of the variance between the Board-approved forecast of $0.688 million and actual net revenues of $6.027 million. The total variance of $5.339 million is primarily attributable to one customer's use of Union's M12 Overrun services; and exchange services sold as a result of warmer than normal weather.

Account No. 179-70 Short-Term Storage and Other Balancing Services

The balance in the Short-Term Storage and Other Balancing Services deferral account is the difference between actual revenues in excess of the costs to provide Short-term Storage and Other Balancing Services (including C1 Off-Peak Storage, Gas Loans, Consumers' LBA, Supplemental Balancing Services, C1 Firm Peak Storage, C1 Firm Short-Term Deliverability and M12 Interruptible Deliverability) and the forecast revenue in excess of the cost to provide these services as approved by the Board for ratemaking purposes.

Table 3 below shows the comparison of the actual 2006 net revenue sufficiency from Short-Term Storage and Other Balancing Services of $35.547 million to the net revenue sufficiency from Short-Term Storage and Other Balancing Services approved by the Board in 2004 of $6.793 million. The result for the year is an increase in net revenue from Short-Term Storage and Other Balancing Services of $28.754 million The cost of gas required to provide the for Short-Term Storage and Other Balancing Services is deducted from the revenue to calculate the net revenue sufficiency.

The credit balance in the Short-Term Storage and Other Balancing Services deferral account of $21.565 million is 75% of the variance between the Board approved forecast revenue in excess of the approved revenue requirement of $6.793 million and actual revenue excess of $35.547 million. The total variance of $28.754 million is primarily the result of increased sales of C1 peak storage services, off peak storage services and loan services.

Account No. 179-72 Long-Term Peak Storage Services

The balance in the Long-Term Peak Storage Service deferral account is the difference between actual revenue in excess of the costs to provide Long-Term Peak Storage Services including C1 Firm Peak Storage and the revenue forecast in excess of the cost to provide these services as approved by the Board for ratemaking purposes.

Table 3 below shows the comparison of the actual 2006 net revenue sufficiency for Long-Term Peak Storage Services of $5.510 million to the net revenue sufficiency for Long-Term Peak Storage Services approved by the Board in 2004 of $17.965 million. The result is a decrease from the Board approved net revenue from Long-Term Peak Storage Services of $12.455 million. The costs to provide Long-Term Peak Storage Services are deducted from the revenue to calculate the net revenue sufficiency. These costs include the cost of gas and the cost of owning and operating the storage facilities including depreciation, interest, income taxes and the allowed return to the shareholder.

The debit balance of $9.341 million is 75% of the variance between the forecast revenue in excess of the cost to provide long-term peak storage of $17.965 million approved by the Board for rate setting purposes and actual revenue net of the cost to provide long term peak storage service of $5.510 million. The decrease of $12.455 million is primarily due to an increase in deferred income tax expense of $10.524 million related to storage service as a result of the change in regulation for storage services provided to customers outside of Union's franchise area.

Table 3

Calculation of the Deferral Account Balances for Account Nos. 179-70 and 179-72
($ millions)

Line No.		Total	Deferral Accounts: Short-Term Storage and Other Balancing Services (No 179-70)	Deferral Accounts: Long-Term Peak Storage Services (No 179-72)
1	Actual storage revenue - 2006	89.510	45.940	43.570
2	Cost to provide service	48.453	10.393	38.060
3	Net revenue sufficiency (Line 1- Line 2)	41.057	35.547	5.510
4	Approved storage revenue - 2004	44.747	7.694	37.053
5	Cost to provide service	19.989	0.901	19.088
6	Net revenue sufficiency (Line 4- Line 5)	24.758	6.793	17.965
7	Variance (Line 3- Line 6)	16.299	28.754	(12.455)
8	Ratepayer portion deferred (Line 7 x 75%)	12.224	21.565	(9.341)
9	Deferral Account Balance	(12.224)	(21.565)	9.341

Accounting for deferred income taxes

Included in the actual cost to provide storage services in 2006 is an increase in deferred income tax expenses of $10.524 million resulting from the Board's decision in the Natural Gas Electricity Interface Review ("NGEIR") to refrain from regulating rates for storage services to customers outside Union's franchise area and rates for new storage services to customers within the franchise area.

Prior to 1997, Union recorded income tax expense using the tax allocation (deferred or normalized) method. Under this method the company's annual income tax expense

recorded in the accounts and recovered from customers in rates included both the amount of current and future income taxes payable in the year. Under the tax allocation method deferred income taxes expenses are recorded as a result of claiming capital cost allowance for income taxes in excess of depreciation recorded in the accounts. There was a match between the period of recovery from customers and the activity that gave rise to the obligation.

In the E.B.R.O. 493 / 494 (1997 Rates) proceeding Union proposed and the Board approved a change the accounting treatment of income taxes from a normalized or deferred basis to a flow-through basis. This change was made in advance of Union's merger with Centra to have a consistent approach to tax accounting following the merger.

Between 1997 and November 2006, Union's income tax expense was recorded using the flow through tax accounting methodology. Under flow through tax accounting, the company's income tax expenses recorded are income taxes currently payable only. Under Canadian generally accepted accounting principles ("GAAP"), rate-regulated entities are not required to record deferred (future) income tax expenses to the extent that these costs are expected to be recovered from customers in future rates. The impact of this change was to defer the recovery from customers of deferred income tax expenses from the period in which they were incurred to the period when the taxes are paid. To qualify as a rate regulated entity for the exemption for deferred taxes, a company must meet all of the following criteria:

a) Rates for services are subject to approval by a regulator;

b) Rates are designed to recover the cost of providing service; and

c) It is reasonable to assume that rates set to recover costs in the future can be charged to and collected from customers.

The following are excerpts from the Canadian Institute Chartered Accountants Handbook section 3465 guidance for accounting for income taxes for rate regulated entities:

DEFINITIONS AND BACKGROUND

.09 The following definitions have been adopted for purposes of this Section:

k) A rate-regulated enterprise is an enterprise that meets all of the following criteria:

(i) the rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products;

(ii) the regulated rates are designed to recover the cost of providing the services or products; and

(iii) it is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for amounts recorded as recoverable under the rate formula.

RATE-REGULATED ENTERPRISES

.102 A rate-regulated enterprise need not recognize future income taxes in accordance with this Section to the extent that future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. If future income taxes are not recognized in accordance with this Section, the rate-regulated enterprise should disclose the following, in addition to the information to be disclosed in accordance with paragraphs 3465.91-.92:

(a) the reason why future income tax liabilities and future income tax assets have not been recognized; and

(b) the amount of future income tax liabilities, future income tax assets and future income tax expense that have not been recognized. [JAN. 2000]

.104 Future income taxes would be recognized in accordance with the remainder of this Section to the extent that future income taxes are not expected to be included in the rates charged to customers in the future.

In November 2006, the Board issued its decision in the EB-2005-0551 proceeding, the NGEIR, to refrain from regulating rates for storage services to customers outside Union's franchise area and rates for new storage services to customers within the franchise area. This change in rate regulation for storage services meant that Union no longer met the criteria for rate regulated accounting set out in 3465.09 (k). Specifically, rates for these storage services are no longer approved by the regulator. Because there were deferred tax costs associated with activity in the 1997 to 2006 period related to the unregulated storage operations, and there is no future rate mechanism to allow recovery of these costs, Union recorded these expenses in accordance with section 3465.104.

Union has recorded deferred tax expense of $10.524 million related to the unregulated storage operations. These tax costs represent the portion of Union's unrecorded future income taxes from 1997 to 2006 related to the ex-franchise storage operation using the percentage of unregulated storage established in the NGEIR decision. The $10.524 million deferred tax expense has been included in the calculation of the amount of storage revenue to be refunded to ratepayers through the deferral accounts. The revenue required to recover the deferred tax expense is grossed up by $5.951 million to $16.475 million to recognize the current tax expense.

Union reflected the impact of the change in regulation in the 2006 financial results as this is when the Board determined that rates for these storage services would no longer be approved by the regulator, reflected in the overall cost of service revenue requirement and there is no future mechanism for recovering these costs. The result is reflected in the 2006 audited financial statements and disclosed in the Management Discussion & Analysis. The company's approach was reviewed by the external auditors Deloitte & Touche in connection with their year end audit and incorporated into their evaluation leading to their audit opinion accompanying the financial statements.

In addition, Union has retained the services of Ernst &Young to review and provide a written report on Union's application of accounting principles resulting from the Board's decision to forebear from regulating a portion of Union's storage operations. A copy of this report is attached as Appendix A.

Account No. 179-73 Other S&T Services

The balance in the Other S&T Services deferral account is the difference between actual net revenues for Other S&T Services including Off-System Capacity, Redirection/Name Changes, Ontario Production and Other S&T services and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $0.390 million is 75% of the variance between the Board-approved forecast of $0.460 million and actual net revenues of $0.980 million.

Account No. 179-74 Other Direct Purchase Services

The credit balance of $0.373 million in the Other Direct Purchase Services deferral account is 75% of the actual net revenues earned for Supplemental Load Balancing (T1 and R1) and T1 Storage Inventory Demand Charges. There were no revenues forecast in rates.

OTHER DEFERRAL ACCOUNTS

The other deferral account balances are discussed below.

Account No. 179-26 Deferred Customer Rebates/Charges

The Deferred Customer Rebates/Charges account has no balance. This account captures unclaimed cheques related to amounts refunded to customers that arose from the disposition of deferral balances as approved by the Board. Disposition of deferral accounts as approved by the Board in the EB 2005-0211 Rate Order were dealt with prospectively in rates from October 1 to December 31, 2006. As a result, no cheques were issued and none returned.

Account No. 179-56 Comprehensive Customer Information Program

The Comprehensive Customer Information Program captures the incremental costs associated with increasing customer awareness about changes in the natural gas market. No incremental costs were incurred in 2006 with respect to this Program. Union shall

close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No. 179-60 Direct Purchase Revenue and Payments

The credit balance of $0.171 million in the Direct Purchase Revenue and Payment deferral account is the difference between actual Delivery Commitment Credit ("DCC") payments made and the payment amount included in Board-approved rates. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No.179-75 Lost Revenue Adjustment Mechanism

The Lost Revenue Adjustment Mechanism ("LRAM") deferral account has a debit balance of $3.980 million which represents the difference between actual margin reductions related to Union's DSM activities and the margin reduction included in gas delivery rates as approved by the Board. This balance includes volume variances related to 2003, 2004, 2005 and 2006 DSM activities. Union proposes to dispose of the balance in the account of $3.980 million.

Tab 1, Schedule 2, page 1 provides the breakdown of the LRAM deferral account balance for each year from 2003 to 2006. Tab 1, Schedule 2, pages 2 to 5 provides the LRAM volumes and the corresponding revenue impacts related to 2003, 2004, 2005 and 2006 DSM activities respectively. The calculations for lost revenues reflect the Board's ruling

in RP-2001-0029 Decision with Reasons at paragraph 2.170 which requires that the year one impact of DSM activities is equivalent to 50% of the savings in the first year in which the DSM measure is undertaken.

The amount related to 2003 is a credit balance of $0.145 million (Tab 1, Schedule 2, page 2, line 15, column (n)) which is composed of the following:

- the variance between lost revenues resulting from the audited volumes of 38,860 10^3 m^3 and those reflected in rates
- less the lost revenues for 2003 DSM activities which were approved by the Board for disposition in EB-2006-0057.

The audit of 2004 DSM volumes is complete. The amount related to 2004 is a debit balance of $0.384 million (Tab 1, Schedule 2, page 3, line 15, column (n)) which is composed of the following:

- the variance between lost revenues resulting from the audited volumes of 55,611 10^3 m^3 and those reflected in rates
- less the lost revenues for 2004 DSM activities (based on 2004 pre-audit volumes of 59,148 10^3 m^3) which were approved by the Board for disposition in EB-2006-0057.

The amount of lost revenues related to 2005 is $2.280 million (Tab 1, Schedule 2, page 4, line 16, column (i)). The audit of 2005 DSM volumes is complete and Union is

proposing to dispose of the $2.280 million balance plus interest of $0.040 million through December 31, 2006 or a total of $2.320 million (Tab 1, Schedule 2, page 4, line 16, column (l)).

The variance related to 2006 is a debit balance of $1.421 million (Tab 1, Schedule 2, page 5, line 15, column (d)). The 2006 variance represents 50% of the forecasted volumes savings of 92,274 10^3 m^3. No 2006 DSM volume savings are reflected in 2006 rates. The process to finalize DSM balances includes an audit of Union's DSM evaluation report, review by the Audit Sub-Committee and communication to the DSM Consultative. Consistent with the desire of parties to dispose of deferral account balances in a timely manner, Union is proposing to dispose the forecast LRAM balance related to unaudited 2006 DSM activities at this time. The variances between the LRAM balances calculated out of audited and unaudited results have been decreasing, thus increasing Union's confidence in the accuracy of the unaudited numbers. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition.

Account No.179-102 Intra-Period WACOG Changes

The debit balance of $15.742 million in the Intra-Period WACOG account reflects the difference between the actual WACOG approved by the Board during the year and the WACOG approved for recovery in Union's delivery rates in the RP-2003-0063 proceeding related to inventory carrying costs, compressor fuel, customer supplied fuel

and unaccounted for gas. The WACOG approved for recovery in rates was $310.870 per $10^3 m^3$. The actual WACOG in 2006, approved by the Board in the four QRAM proceedings in 2006, ranged from a low of $389.207 per $10^3 m^3$ to a high of $468.942 per $10^3 m^3$.

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

No unauthorized storage overrun charges were incurred by customers electing unbundled service in 2006.

Account No. 179-110 Storage Rights Compensation Costs

The debit balance of $0.511 million in the Storage Rights Compensation deferral captures the differences between the actual compensation paid for storage rights and the amount included in rates approved by the Board in the RP-2003-0063 proceeding. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No.179-111 Demand Side Management Variance Account

This account records the difference between actual 2006 direct DSM costs incurred and the direct DSM budget included in rates for 2006. The debit balance of $7.213 million represents the difference between the direct DSM expenditure in 2006 of $11.182 million and $4.0 million included in rates, plus interest of $0.031 million through December 31,

2006. The Board approved direct DSM budget was $12.2 million for 2006 per EB-2005-0507.

Account No. 179-112 Deferred Gas Distribution Access Rule Costs

The Gas Distribution Access Rule ("GDAR") deferral account records the difference between the actual costs incurred to implement the process and system changes needed to achieve compliance with the GDAR and the costs included in rates as approved by the Board. Implementation of the process and system changes for EBT standards and Rate-ready ABC service for large volume customers is required by June 1, 2007. The required implementation date of the bill-ready service component of GDAR is currently January 1, 2008. The Company is continuing to incur costs to comply with the rule. In the EB-2005-0520 proceeding, the Board approved the recovery of an additional $18.2 million of capital in Union's 2007 rates to implement GDAR plus an additional $0.5 million in annual operating expenses. This spending is incremental to the amounts previously approved by the Board and does not include any costs required to be able to offer Vendor Consolidated Billing. The variance between the actual costs incurred and the costs included in rates will be calculated and recorded in the deferral account for disposition in a future proceeding when the project is complete. Disposition of any variance will be proposed in a future proceeding.

Account No. 179-113 Late Payment Penalty Litigation

The debit balance of $0.303 million in the Late Payment Penalty ("LPP") Litigation deferral account is the cost incurred in 2006 by Union in relation to late payment penalty litigation. Amounts include the Company's legal costs, costs of actuarial advice and the cost of analyzing historical billing records.

Account No. 179-114 Incremental OEB Cost Assessment

The debit balance of $1.541 million recorded in the Incremental OEB Cost Assessment account is the difference between the actual payments made in 2006 with respect to OEB cost assessments and the costs included in rates as approved by the Board effective January 1, 2005. Union shall close this deferral account effective January 1, 2007 in accordance with the Board's direction in the EB-2005-0520 Decision and Final Rate Order.

Account No. 179-115 Shared Savings Mechanism Variance Account

This account has a debit balance of $7.000 million related to DSM activity in 2005 and 2006. Tab 1, Schedule 3 provides the breakdown of the SSM variance account for each year. The account was established to record any shareholder incentive earned by the Company related to DSM activities in 2005 in accordance with the mechanism approved by the Board in the EB-2005-0211 proceeding. The account was continued for DSM activities in 2006 in accordance with the mechanism approved by the Board in the EB-2005-0507 proceeding.

Union has completed the audit of 2005 DSM activity and proposes to dispose of the debit balance of $4.102, which represents an incentive payment of $3.979 million and interest of $0.123 million through December 31, 2006.

This account has a debit balance of $2.898 million related to unaudited 2006 DSM activity. In an effort to recognize the desire of parties to move to a more timely disposition of deferral account balances, Union is proposing to clear the recorded SSM balance related to unaudited 2006 DSM activities. The SSM has been in existence for two years and Union is confident that the tracking process and assessment procedures are in place to produce an accurate calculation of the deferral account balance. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition.

Account No. 179-116 Interest on the Gain on the 2004 Cushion Gas Disposition

The establishment of this deferral account was directed by the Board in its EB-2005-0211 Interim Decision and Order dated June 10, 2005 to record interest on the gain on the 2004 cushion gas disposition starting April 26, 2005. On February 9, 2006, the Supreme Court of Canada released its Decision in the ATCO case. The Supreme Court of Canada found that ratepayers have no property interest in the assets of the utility. Further, the Supreme Court determined that the Alberta Energy and Utilities Board did not have jurisdiction to allocate part of the proceeds to ratepayers. In response to the Supreme Court's decision,

the Board reconvened the cushion gas proceeding. In June 2006, the Board released its Decision and Order regarding the cushion gas proceeding. In the decision and subsequent clarification letter, the Board determined that it does not have jurisdiction over the sale of cushion gas sale in accordance with Section 36 of the OEB act. In January 2007, the OEB provided further clarity to the June 2006 Decision. The Board decided that it does not have the jurisdiction to consider the proceeds of the cushion gas sale in setting rates. Furthermore, the Board ordered that "the original panel consider the extent to which, if any, the proceeds from the sale of cushion gas shall be allocated between ratepayers and the utility in light of our findings herein". Union is not proposing to dispose of the balance in this deferral account, pending the review by the original panel.

2. 2006 EARNINGS SHARING

Union's earnings for 2006 continue to be subject to the earnings sharing mechanism implemented by the Board for 2005. Earnings above the benchmark rate of return on equity, normalized for weather, will be shared equally between ratepayers and the Company.

Based on the actual year end results, Union's earnings for 2006 subject to earnings sharing before weather normalization were $98.023 million, a return on average common equity ("ROE") of 8.59%. Please see Appendix B for a copy of Union's 2006 Annual Report. For 2006, the benchmark ROE was 8.89%. Before normalizing earnings for

weather, there is no excess earnings to be shared with ratepayers, as the return to the shareholder was below the benchmark ROE by 0.30% resulting in a utility revenue deficiency of $3.425 million.

In 2006, weather in Union's franchise area was 14% warmer than the heating degree day forecast using the methodology approved by the Board to set rates. Actual heating degree days were 3,605 compared to a forecast of 4,178, a decrease of 573. The forecast methodology for 2006 used the 30-year historical average heating degree days weighted 70% and the 20-year historical trend heating degree days weighted 30%. This methodology was approved by the Board in setting the 2004 rates in the RP-2003-0063 rates proceeding.

The actual heating degrees days in 2006 of 3,605 were 419 heating degree days below the proposed 20 year trend methodology proposed in the 2004 rate case.

In confirming their decision in RP-2003-0063 in support of using weather normalized earnings in the earnings sharing calculation the Board noted that

> "…The risk of weather has always been borne by the shareholder and, in the absence of a longer term mechanism in place; earnings sharing on the basis of weather normalization is consistent with common regulatory practice and the Board's recent decision in the case of Enbridge."

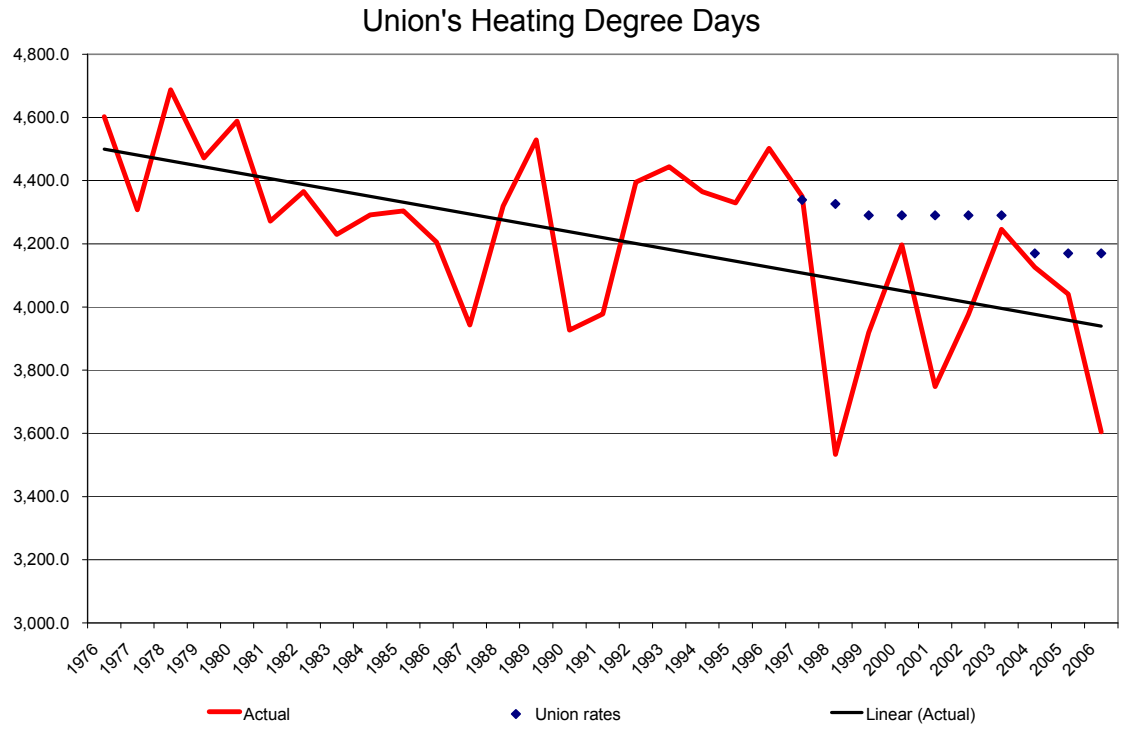
Union continues to believe that the shareholder risk associated with the Board approved weather normalization methodology is not balanced and the practice of weather normalizing earnings for sharing with the ratepayer produces unacceptable results. In

particular, weather normalizing earnings for the purposes of earnings sharing requires the utility to pay earnings to ratepayers that the company in fact never earned.

The graph below shows Union's actual heating degree days from 1976 to 2006, along with the linear regression trend line showing that weather is getting warmer, and the heating degree days underlying Board approved rates. In the past 10 years, 1997 to 2006, Union's shareholder has only experienced actual weather that has been warmer than Board approved (normal) with no opportunity related to colder than normal weather. The result is that Union has had to consistently plan and manage its operations to mitigate the impact of warmer weather on the shareholder. There is, however, no methodology available for normalizing the earnings impact of weather on operating costs or on S&T revenues.

During the same 10-year period, 1997 to 2006, Enbridge Gas Distribution ("EGD"), as reported in Exhibit J4.5 in EB-2006-0034, experienced 3 years where the actual weather was colder that the heating degree days approved by the Board in rates. One of these years, 2004, was the decision referred to by the Board in RP-2003-0063 where EGD's earnings sharing was weather normalized. While the Board has, in its' decision, relied on consistency in the practice of weather normalizing earnings sharing, there is no consistency in how normal weather has been set as evidenced by the fact that for EGD, weather for 7 of 10 years was warmer than normal and for Union, weather for 10 of 10 years was warmer than normal. EGD's shareholder was exposed to less risk than Union's

shareholder for the same period as a result of the methodology used for setting normal weather in rates.



In the 2006 earnings sharing calculation the normalization adjustment for the unfavourable variance in distribution margin related to warmer than normal weather is $31.172 million. This adjustment increases earnings by $19.913 million to $117.936 million, resulting in a normalized ROE of 10.33%. Compared to the actual ROE of 8.59%, this adjustment increases shareholder earnings by 1.74% that was not earned by the shareholder. Compared to the benchmark ROE of 8.89%, weather normalized earnings are higher by 1.44%. Paying one half of this hypothetical earnings amount, an amount not realized by the shareholder, to the rate payer ($12.879 million) reduces the actual shareholder earnings for 2006 from 8.59% to 7.87%.

The circumstances presented above illustrate the difficulties with an earnings sharing methodology and point to the need to address the method of weather normalization. Union recognizes the Board's commitment to eliminating earnings sharing mechanisms as part of an incentive regulation framework and its plans to review the weather normalization methodology.

The section below provides a detailed description of the earnings sharing calculation shown at Tab1, Schedule 4:

The starting point for the earnings sharing calculation is Union's actual reported earnings of $98.636 million. The following after-tax adjustments were made to arrive at earnings subject to sharing:

1. Corporate earnings are "grossed-up" by the amount recorded by Union for earnings sharing. This adjustment is necessary in order to arrive at an earnings value prior to earnings sharing.

2. The amount related to the shareholder's portion (10%) of the "base" storage and transportation net revenue is deducted. The base level of storage and transportation revenue as well as 90/10 ratepayer/ shareholder proportional sharing was approved by the Board in the RP-2003-0063 proceeding.

3. The shareholder portion (25%) of the storage and transportation revenue shared in excess of the base level is then deducted.

4. Consistent with the EB-2005-0211 settlement agreement, the amount recorded in the Shared Savings Mechanism Variance Account (Account No. 179-115) is removed from earnings.

5. A non-utility adjustment is then deducted from earnings.

6. Consistent with the Board's EB-2005-0189 decision, earnings are normalized for weather. Union's 2006 weather normalization adjustment is comprised of two parts.

   a) The first part of the adjustment represents the weather related revenue variance associated with the general service market (residential, commercial, small industrial).

   b) The second part of the normalization represents a weather related cost adjustment associated with unaccounted for gas ("UFG") and compressor fuel costs. On a weather normalized basis, consumption would have been higher and Union would have experienced lower compressor fuel and UFG costs. Therefore, the UFG and compressor fuel costs have been added back in order to properly capture the weather related cost effects.

Union is proposing that interest accrue on the earnings sharing amount due to ratepayers at Union's Board-approved short term rate, starting January 1, 2007. This approach is consistent with how the balance would have been treated had a deferral account been established to record the amount.