Alberta Energy and Utilities Board

DECISION-2001-110

METHODOLOGY FOR MANAGING GAS SUPPLY PORTFOLIOS AND DETERMINING GAS COST RECOVERY RATES PROCEEDING AND GAS RATE UNBUNDLING PROCEEDING

PART B-1: DEFERRED GAS ACCOUNT RECONCILIATION FOR ATCO GAS

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CONTENTS

ALBERTA ENERGY AND UTILITIES BOARD
Calgary, Alberta

GCRR METHODOLOGY PROCEEDING AND	
GAS RATE UNBUNDLING PROCEEDING	**Decision 2001-110**
PART B-1: DEFERRED GAS ACCOUNT	**Application No. 2001040**
RECONCILIATION FOR ATCO GAS	**File No. 5680-1**

1 INTRODUCTION

The Alberta Energy and Utilities Board (EUB or the Board) held two proceedings concerning gas commodity cost recovery methods, which encompassed related material and included a review of outstanding Deferred Gas Account (DGA) reconciliations. Described in greater detail below is the process and the scope of the proceedings and the nature of the resulting decisions.

1.1 Scope of Part B-1 of this Decision

In its determinations, the Board has decided that it is appropriate to set out its findings into three parts:

- Part A, Decision 2001-75 dated October 30, 2001 dealt with gas cost recovery rate (GCRR) and policy issues for gas utilities regulated by the Board,
- Part B-1 (this Decision) deals with the review and reconciliation of previous DGAs for ATCO Gas – South (AGS) only, and the issue of allocation of DGA balances between Option A and B customers[1] of ATCO Gas-North (AGN) and AGS.
- Part B-2 will deal with the reconciliation of previous DGAs for AGN and will be issued at a later date.

1.2 Scope and Schedule of Proceedings

On February 14, 2001 the Board issued a notice to convene a public hearing amongst interested parties and the Alberta natural gas utilities regulated by it. The proceeding was known as Methodology For Managing Gas Supply Portfolios And Determining Gas Cost Recovery Rates - Application No. 2001040 (Methodology Proceeding).

The EUB initiated the proceeding to deal with the positions of the utilities and consumers on the methods that could be used to manage the gas supplies for sales customers, and to determine a GCRR on a going forward basis. Issues to be addressed included, but were not limited to:

- Techniques for management of gas supply portfolios for sale customers, for example, use of AECO C index supplies, storage, long-term contracts, financial hedging, and company-owned production (COP).

[1] Option A refers to sales service customers in Rate 1, comprising mainly residential customers; Option B refers to customers in all other rates.

- Frequency of GCRR adjustments, as they might relate to a seasonal, annual, or other period basis.
- Methods to determine the requirement for a GCRR adjustment, for example, formula based guidelines vs. present DGA balance guidelines.
- Methods to forecast gas volumes and costs, relative to setting the GCRR.

The EUB also considered outstanding matters as they pertained to the 2000 summer period and 2000/2001 winter period DGA balances of AGN and AGS. This review examined the prudence of strategies used by the companies in the use of COP and Carbon storage, and any resulting required GCRR adjustments.

The EUB received submissions from the organizations or their representatives listed in Appendix 1 of this Decision in accordance with the following schedule:

Register as an Intervener	March 2, 2001
Submissions to EUB by Utilities and Interveners	March 16, 2001
Information Requests to Participants on Submissions	March 23, 2001
Information Responses	March 30, 2001
Reply Submissions (if any)	April 6, 2001

A public hearing, originally scheduled to begin April 17, 2001 in Edmonton, was held in Calgary for nine days commencing on April 30, 2001, before Board members Dr. B. F. Bietz and Mr. T. M. McGee, with Mr. B. T. McManus, Q.C. chairing.

On April 4, 2001, the EUB issued a notice to convene another public hearing amongst interested parties and the Alberta natural gas utilities. The proceeding was known as Gas Rate Unbundling - Application No. 2001093 (Unbundling Proceeding).

The EUB initiated the proceeding to deal with the positions of the utilities and customers on the proper allocation of costs between the utilities' transportation and gas procurement functions. The purpose of reviewing this allocation was to ensure that independent gas marketing companies were provided a fair opportunity to provide alternative service to gas customers.

The public hearing convened on May 23, 2001 and lasted five days before Board members Dr. B. F. Bietz and Mr. T. M. McGee, with Mr. B. T. McManus, Q.C. chairing.

During the Methodology Proceeding it was decided to combine the argument and reply process for both the Methodology Proceeding and the Unbundling Proceeding. Included as part of the evidence for both proceedings was the record from Application numbers 2001017, 2001020, 2001030 and 2001070, applications regarding the sale of certain AGN COP facilities, including those of the Viking field.

On November 14, 2001 AGN and the customer representatives of the North Core Committee (NCC) submitted Opening Statements containing a Joint Recommendation concerning resolution of the Viking Sale Review and Variance proceeding, Application No. 1244045 (the Viking R&V

Proceeding). As a result the parties requested that the Board defer its Decision with respect to the Reconciliation of the DGA and GCRRs for AGN for the summer 2000 and winter 2000/2001 until such time as a Board decision on the R&V had been issued. As there were no issues other than those raised by the NCC, the Board will therefore defer its decision with respect to matters dealing with AGN and only deal with the reconciliation matters related to AGS in this Decision.

2 DEFERRED GAS ACCOUNT (DGA) PROCEDURES

ATCO Gas is an operating division of ATCO Gas and Pipelines Ltd. (AGPL). AGPL was formerly known as Canadian Western Natural Gas Company Limited (CWNG). In 2000, through a corporate restructuring within the ATCO Group of companies, AGPL acquired Northwestern Utilities Limited (NUL). NUL was subsequently wound-up into AGPL on January 1, 2001. Within ATCO Gas, whose business includes the distribution and supply of natural gas to its customers, there are also two divisions, ATCO Gas – South and ATCO Gas – North, each of which has separate franchise areas. References in this Decision to ATCO Gas apply to AGS, AGN or both, as the case may be.

The businesses of AGS and AGN were previously carried on by CWNG and NUL, respectively. ATCO Gas's supply function has historically utilized a gas contract year that begins November 1 and has included two periods: a winter period from November through March and a summer period from April though October. Each period has ordinarily maintained distinct GCRRs and has been subject to separate DGA reconciliations.

2.1 Current DGA Procedures

Under the procedures previously approved by the EUB respecting ATCO Gas's DGAs and the reconciliation of gas supply costs, customers are charged with the actual cost of gas supplies experienced by ATCO Gas. In the past, ATCO Gas has been making separate applications for each GCRR applicable to the winter and summer periods.

The DGA procedures have been set up by the EUB to account for ATCO Gas's gas supply costs. The DGA procedures permit ATCO Gas to recover gas commodity costs in a manner that ensures its customers pay neither more nor less than the cost of gas actually incurred by it in acquiring the gas supplied to them. Conversely, these procedures also have the effect of providing that the shareholder of AGPL does not gain or lose as a result of fluctuations in the market price of gas.

A GCRR is calculated by adding the balance in the DGA at the end of the preceding winter/summer period to the gas costs forecast for the upcoming winter/summer period and dividing the result by the forecast winter/summer period gas sales volume. Including the DGA balance from the previous winter/summer period ensures that any cumulative under-/over-recovery from that period will be collected/refunded in the upcoming winter/summer period, if the weather is normal and actual sales equal forecast sales.

In practice, actual cumulative gas costs may vary considerably from gas cost recoveries, particularly at times when prices for natural gas experience volatility in the market place. With the objective of minimizing DGA balances, the EUB has directed that, should a significant change in gas supply costs occur during a period, ATCO Gas should apply to the EUB for an adjustment to the GCRR. The EUB specified the tolerance level that ATCO Gas should use to determine when to apply to adjust its GCRR to be the greater of ±3% or ±$2 million, relative to the gas costs forecast for the particular period.

3 PRUDENCE

3.1 General Position of Parties

Calgary

Calgary opposed the approval of the 2000/2001 winter period GCRRs on the ground that gas costs were not prudently incurred.

In reply argument, Calgary noted the following definition of prudence for regulatory purposes:

> Prudence: Carefulness, precaution, attentiveness, and judgment, as applied to action or conduct. That degree of care required by the exigencies or circumstances under which it is exercised. This term, in the language of the law, is commonly associated with "care" and "diligence" and contrasted with "negligence."[2]

Calgary argued that in asking the Board to rule on whether a utility has been "prudent" as opposed to "negligent," interveners were asking the Board to apply long-established legal principles. It stated that the test is "what would a reasonable utility operator have done in the circumstances."

Calgary argued that the particular circumstances of December 2000 and January 2001 should be the focus in this case. It noted the Board had taken extraordinary measures to deal with the unprecedented gas price increases in those months. Calgary also noted that AGN's customers had been asking for increased COP to alleviate gas price increases, and AGS's customers had examined AGS on the possibility of producing reserves at its Carbon storage facility (Carbon).

Calgary countered AGS's argument that AGS could not be subjected to the recommended disallowances. Calgary argued that it was not aware of any common-law principle that the financial impact of a damages award had any relevance to a finding of negligence or imprudence. Calgary also noted that AGS had focused on the impact only on its operating divisions, not on AGPL or its affiliates.

Calgary also countered AGS's argument that AGS was not compensated for imprudence in its return on equity (ROE). Calgary noted that in previous AGS argument and testimony regarding ROE, gas supply risk and risk of disallowances were considered.

[2] Black' s Law Dictionary, Fifth Edition

Calgary noted that AGS had cross-examined ENMAX's witness, Dr. Overcast, with respect to ROE. Calgary submitted that this evidence should be disregarded, as Dr. Overcast was not a qualified ROE witness and had qualified his responses on that basis.

Calgary noted examples where gas utilities had been found to be imprudent in executing gas price management programs and had had funds disallowed by the respective utilities Boards in Manitoba and Ontario. It noted that these boards had dealt with the same issues as in this case, and had ruled that it was shareholders, not customers, who bear the risk of imprudent actions by management. Calgary argued that this evidence clearly showed that gas costs in the risk of regulatory disallowances were contemplated when setting ROE for AGS.

Calgary argued that, in setting a fair rate of return, the Board presumes prudent action, and that it would be unreasonable for the Board to incorporate a premium in rate of return on common equity to compensate the utility for imprudent or negligent action. Calgary argued that as it is the shareholders that hire management, it is the shareholders who should be ultimately responsible for the actions of management.

CCA

In reply CCA noted ATCO Gas devoted a significant amount to the discussion of prudence in its argument. CCA submitted that utility regulation is very clear on this issue. Utilities must act in the best interests of their customers while being entitled to a fair return on their capital and a return of their capital. If utilities are not acting in the best interests of their customers, then they face prudence reviews. Findings of imprudence can impact a company's overall return. In the cases of both Carbon Storage and COP, ATCO Gas is not attempting to minimize customers' rates but is focusing on a strategy to maximize shareholders' gains.

The CCA considered that the utilities rate of return on rate base specifically included the risk of disallowance of gas costs and noted the position of ATCO Gas that the imprudence issues were strictly gas cost issues. However, the CCA argued, it was more appropriate to consider that imprudence could apply with respect to both Carbon and COP, as both were rate base assets on which ATCO Gas or predecessor companies had been receiving a return for decades. ATCO Gas must act prudently when acting on behalf of its customers. All stakeholders expected the actions of a public utility to be reasonable and prudent. In return for acting reasonably and prudently, the public utility received the benefits of the return on and return of capital that is invested in "used and useful" assets.

The CCA argued that the size of the disallowances proposed by customers must be viewed against the size of the gains ATCO Gas was trying to obtain for its shareholders. It appeared to the CCA that ATCO Gas's strategy was to remove Carbon and COP from rate base while minimizing the value allocated to customers and to maximize the gain credited to the shareholders. The CCA did not view it appropriate to measure the value of disallowances against the allowed rate of return for a specific year. The CCA noted that the rates of return on COP were collected from the 1920's and on Carbon from the mid 1960's.

MI/PICA

With regard to prudence issues concerning Carbon, the MI and PICA submitted a joint argument which submitted that AGS had unfairly represented the evidence. For example, with respect to utilization of base gas to mitigate gas costs,[3] ATCO had received Information Requests and Evidence from the Consumer Group[4] on September 21 and October 27, 2000 respectively with respect to the value of cushion gas to customers. Therefore, MI/PICA submitted that ATCO could not construe customer interest in base gas as an after the fact review.

NCC

The NCC observed that ATCO submitted "…that a prudency review, based purely on hindsight is inappropriate."[5] and in support of its position, ATCO referred to Decision 2000-01[6] and stated that "…the review should only consider the circumstances, which <u>were known or ought to have been known at the time the decision was made</u>."[7] [emphasis added by the NCC]. The North Core group did not oppose this interpretation of the decision, however the NCC argued that matters pertinent to a prudence review were known at the time the decision was made by ATCO Gas not to enhance production:

> The NCC argued that having ignored customers repeated requests to increase production, the management of ATCO Gas had chosen to assume the risk that its decisions would be held by the Board to be imprudent. In the end result, ATCO Gas had disregarded the regulatory compact that required a utility to "provide utility service in a safe and efficient manner at the lowest possible cost.[8]
>
> The NCC submitted that by definition, a determination of prudence requires an after-the-fact review of the utility's actions. Given its definition of "utility service", ATCO's actions were not prudent and had resulted in millions of dollars of unnecessary costs being included in the gas component of its rates for the two GCRR periods in question.

The NCC noted that ATCO concluded its discussion of this issue by stating:

> The disallowance of gas costs in the present case would be wholly unfair and could have <u>serious implications for the financial integrity of the Company</u>.[9]

Given that these costs were foisted unnecessarily on core customers, the NCC argued that this statement had a hollow ring.

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[3] MI Argument, pp. 5-6
[4] A group of intervenors which participated in the Affiliate Transaction Proceeding, Application Numbers 2000233 and 2000234
[5] Argument p. 13
[6] ESBI Alberta Ltd. 1999/2000 General Rate Application, Phase I and Phase 2
[7] Argument p. 15
[8] Exhibit 78, Evidence Overview, p. 1, 3rd paragraph
[9] Argument p. 21

The NCC further stated that, in suggesting that the review would be "fundamentally unfair," ATCO quoted Mr. Engler's comment that it "could wipe out the earnings of the company in one year …. ."[10] However, the NCC noted, it was not the customers who ignored the risk of taking steps that were not only in the best interest of customers, but logical in the circumstances. The NCC submitted that ATCO had the onus of proving that its actions were prudent and this should not be determined based on the "magnitude" of a particular disallowance.[11]

The NCC argued that with a sale pending, ATCO's Board of Directors was conflicted. The NCC further submitted that ATCO did not act in the customers' best interests.

3.2 General Position of ATCO Gas

ATCO Gas submitted that the purpose of the reconciliation review was to ensure that customers had paid all prudently incurred costs related to the supply of the regulated service offering. It stated that central to this determination was the meaning of "prudently incurred costs." It noted that a review of Board decisions had failed to provide a clear definition of "prudent."

ATCO Gas provided the definition from Webster's New 20th Century Dictionary of the English Language as follows:

> Prudent:
>
> 1. Capable of exercising sound judgment in practical matters.
> 2. Cautious or discreet in conduct; circumspect; sensible; not rash.
> 3. Characterized, dictated, or directed by prudence; as, *prudent* measures.
>
> Synonyms- circumspect, discreet, cautious, judicious, careful, considerate, sagacious, thoughtful, provident, frugal, economical.

ATCO Gas stated that a "prudent" decision would be one that was sensible, cautious, and reflected good judgment. It argued that to be found "imprudent" a decision would have to be rash and reflect bad judgment. It argued that a disallowance would have to find that there had been something more than recognition that costs were higher than they otherwise could have been.

ATCO Gas submitted that a prudence review based purely on hindsight was inappropriate. It noted the testimony of Mr. Engler:

> ...the Board should resist the temptation to judge either an act of commission or an act of omission. Where common sense or general accepted management principles are involved, they should be careful to look at the circumstances that existed at the time, not do it after the fact. I think that's the number one principle that should be in place.[12]

[10] Argument p. 22
[11] Argument p. 23
[12] GCRR Tr. Volume 12, pp. 1332-1333

ATCO Gas argued that its position was supported by past practice of the Board. It stated that the appropriate standard was the "known or should have known standard for prudence review." It submitted that as long as the utility had been operating within the established rules or guidelines, then the outcome was prudent.

ATCO Gas argued that "so long as we did what we said we were going to do, we have behaved prudently."[13] It argued that the rules by which it would be judged must be set up front. It argued that, in the present case, these rules referred to those applied in respect of gas acquisition activities. It stated that the mechanism or the mechanics of the DGA process was separate from the rules or guidelines applicable to the prudence determination.

ATCO Gas submitted that any review of its DGA reconciliations involving the issue of prudence should preclude the use of hindsight and should only examine whether the decision was prudent given the circumstances known at the time. It maintained that it was operating within the established rules or guidelines as they existed and, therefore, an after-the-fact review of the outcome of applying the rules or guidelines would be completely unfair. In support of its position it referred to discussion by the Board in previous decisions, which acknowledged that a review involving prudence should only consider the circumstances that were known, or ought to have been known, at the time. In addition, ATCO Gas stated that it made greater efforts to ensure that all interested parties knew of its plans before the fact. It assumed that this knowledge would mean that, when an after-the-fact review was made, so long as ATCO Gas did what it said it was going to do, it behaved prudently.

ATCO Gas submitted that it should not be subject to a hindsight review simply because extreme events caused customers to change their minds about the previously agreed upon gas supply service. It argued that the primary "rule" governing the current gas portfolio structure was the generally accepted objective of "lowest cost over the long term." But argued AltaGas, extraordinary events that occurred during the 2000/2001 winter period had caused interveners to rapidly change their objective to "price stability" without regard to the feasibility and time needed to make a corresponding adjustment in the established, on-going portfolio.

ATCO Gas stated that Calgary and the NCC had asked the Board to take action in a manner that would reduce the earnings of ATCO Gas to such a level that would result in negative earnings for 2001 related to costs which had no potential upside for the Company. It countered the Calgary argument that it was compensated for this risk through its ROE, stating that it did not view this significant asymmetric risk to have been even remotely considered by the Board in the setting of the appropriate return. ATCO Gas also argued that the industrial groups, which most rate of return experts would use as a sample of similar risk, did not face this risk.

ATCO Gas noted that gas supply costs substantially overshadow revenue requirement. It also noted the evidence of ENMAX's witness, Dr. Overcast:

> ...that investors look at the GCRR and the DGA and say it has no impact on earnings, and no risk; and hence, there's no compensation for that built-in. Now, if

[13] GCRR Tr. Volume 10, p. 1068

> you'd had a history of - I mean, there's some jurisdictions where there's gas cost disallowances every year and the market looks that those disallowances. There may be some premium in their return associated with that, but by and large, for a utility that's had a GCRR DGA without disallowances for a few years, my assumption would be there's no return built-in for that.[14]

3.3 Views of the Board

The Board will set out its general views on prudence in this section.

In Decision 2000-01, in the context of an application by an electric utility, the Board noted that:

> In most cases [prudence] involves an evaluation of whether or not a decision reflects good judgement and discretion and is reasonable in the circumstances which were known, or reasonably should have been known, when the decision was made.
>
> The concept of prudence is used to determine whether, at a particular time in question, an arrangement is or was appropriate and reasonable given the circumstances known or which ought to have been known.[15]

The Board earlier applied this test in the context of a prudence review for gas utilities in Decision E95079, concerning Nova Gas Transmission Ltd.[16] In that decision the Board determined that, in addition to the usual concept of prudence, additional elements could be part of the prudence standard to address the particular circumstances at hand.[17]

The Board considers that there are particular circumstances to consider when assessing the prudence of actions carried out by the owner of a public utility. Given the unique relationship between a public utility and its customers, the Board believes there is an additional element to consider in a prudence review. The Board agrees with the CCA that a prudent owner of a public utility must not only exercise good judgement and act in a reasonable and appropriate manner, but must do so in light of a duty to act in the best interests of its customers, while being entitled to a fair return on its capital and a return of its capital.

The Board agrees with ATCO that a prudence review ought not to be based on hindsight. Webster's Dictionary defines hindsight as "perception of the nature and demands of an event after it has happened."[18] Applying this definition to the current context, the Board ought not to impute knowledge to the owner of a utility that the owner of the utility could not reasonably have known at the time the utility made the decision being reviewed. The Board notes that two

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[14] GCRR Tr. Volume 7, p. 807

[15] See also Board Decision E93094: Alberta Power Limited and Edmonton Power TransAlta Utilities Corporation , p. 105.

[16] At p.19

[17] The additional element was that the transaction, which was the subject of Decision E95059, should be assessed for prudence assuming not only that it was entered into by reasonable, informed parties, but additionally that the parties were at arm's length.

[18] *Webster's Ninth New Collegiate Dictionary*, Merriam-Webster, 1986, p.571.

American public utilities commissions have also held that a prudence review should not be made on the basis of hindsight.[19]

In summary, a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take into account the best interests of its customers, while still being entitled to a fair return.

4 AGS - 2000 SUMMER PERIOD DGA RECONCILIATION

In this section the Board will consider whether there are any issues, including prudence issues, related to the DGA reconciliation for the period in question. As a consequence of dealing with this issue, the Board will also address the 2001 summer period GCRR.

4.1 Position of Parties

No comments particular to the summer period were received from the Interveners.

4.2 Position of AGS

ATCO Gas submitted that there was no cross-examination of its panel nor any submission by interested parties of contentious issues related to the 2000 summer period and therefore, the Board should accept AGS's reconciliation of actual gas costs and actual gas cost recoveries for the 2000 summer period.

4.3 Views of the Board

The Board has reviewed the submissions of the parties and notes that none of the interested parties presented evidence with respect to outstanding issues relating to the 2000 summer period GCRRs, previously approved on an interim refundable basis. Therefore the Board will approve the GCRRs as final for the 2000 summer period. The Board also accepts AGS's reconciliation of actual gas costs and actual gas cost recoveries for the 2000 summer period.

The Board notes that the GCRRs for the 2001 summer period were approved on an interim refundable basis in Order U2001-062 and Decision 2001-58, subject to the outcome of issues to be reviewed in this proceeding. None of the interested parties presented evidence with respect to such unresolved matters. Therefore, the Board approves as final the 2001 summer period GCRRs.

[19] See *In re Western Mass. Elec. Co*., 80 PUR 4th at 501 and *In re Consolidated Edison Co. of N.Y., Inc. Opinion No. 79-1* (N.Y. 1979), 5-6, both cited in Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice* (Arlington, Public Utilities Reports, Inc. 1993) at 340-341

5 AGS - 2000/2001 WINTER PERIOD DGA RECONCILIATION

In this section the Board will review issues dealing with the reconciliation of the 2001 winter period DGA. The only issue raised by interested parties pertained to the prudent management by AGS with respect to producing facilities and storage that affected the winter period in question. The Board notes that AGS, in order to provide some context to the specific prudence issues, made general submissions relating to certain gas supply matters.

AGS submitted that the operational requirement for Carbon in utility service has diminished and that it was seeking approval to remove Carbon from regulation. AGS considered that the only way to dispel the controversy surrounding the mixed use of regulatory utility and non-regulatory market functions for Carbon was to remove it from utility service.

AGS submitted that it has maintained the required gas supply portfolio expertise in order to accommodate the current gas market environment, meet customers' needs, and to meet the Board's directions in regard to gas supply. Therefore submitted AGS, it was not imprudent in respect of acquiring gas supplies.

AGS submitted that it was concerned with the propensity of interested parties to engage in hindsight review on the outcomes of negotiated settlements, which are normally subject to confidential terms, and argued that the prudence of its actions should be judged on the basis of whether it undertook the steps agreed to in the negotiations. It stated that, if in hindsight, the outcome was not what was expected, or was misunderstood by a party to the negotiations, the party could claim it is aggrieved and effectively prevent AGS from mounting its defense because of the cloak of confidentiality surrounding the original discussions.

5.1 Carbon Base Gas Production

In this section the Board will review the issue of prudence as it pertains to the use of base gas at Carbon and whether or not base gas should have been produced during the winter period. This issue will be considered in the context of the winter period of 2000/2001 as it affects AGS and its customers.

5.1.1 Positions of Parties

Calgary

Calgary noted AGS's argument that Carbon base gas was a rate base asset and that none of the other interveners thought it was reasonable for a regulated utility to be expected to sell its regulated assets to defer high gas costs. Calgary stated that it presumed that AGS was referring to the general question on the sale of rate base assets that its counsel put to witnesses during the GCRR inquiry. Calgary submitted that the Board should give little weight to AGS's attempt to further its arguments on Carbon cushion gas production through cross-examination of other parties during the proceeding. Calgary portrayed this argument as an abuse of process. Calgary also argued that whether or not the Carbon cushion gas was a "rate base asset" or "regulated asset" was not relevant to the issue in question. Calgary submitted that cushion gas was nothing more than COP under another name.

Calgary countered AGS's argument that base gas production should be dealt with in a general rate application (GRA). Calgary noted that the Notice of Proceeding for the GCRR Methodology Proceeding specifically included discussion of "the prudence of strategies used for COP and Carbon storage." Calgary argued that if AGS had wished to ask the Board for a Review and Variance with respect to the scope of the GCRR Methodology Proceeding, this procedure should have been done prior to the start of that proceeding, not after both that proceeding and the GRA have been completed.

Calgary noted and agreed with AGS's position that an owner of a commercial storage facility would seriously consider the full implications. and come to a mitigating decision, before deciding to blowdown part of the facility's underlying base gas. However, it argued that AGS had not even considered the option of base gas production, and submitted that this lack of consideration of alternatives was imprudent. Calgary argued that the likely reason why AGS had not considered base gas production was that Carbon now serves two purposes: regulated utility service, and non-regulated market purpose.

Calgary argued that until the Board approves a transfer of Carbon, its only purpose is regulated utility service. Calgary also argued that AGS's views on Carbon implied that AGS was inherently conflicted as to the use of Carbon for its regulated and non-regulated uses. It was therefore virtually impossible for AGS to be making proper and prudent decisions for the benefit of ratepayers.

Calgary noted the relationship between AGN and AGS and their affiliate, ATCO Midstream. Calgary stated that it was at a loss to understand how AGS could enter into a non-arms length transaction with an affiliate, without either a code of conduct or an open tender process, and then question why parties would scrutinize such transactions. Calgary argued that the use of ATCO Midstream in the gas procurement process added to the complexity of the process and made the issue of prudence all the more important. Calgary noted it was possible that some ATCO Gas affiliate was making money on the purchase of gas. Calgary also noted that AGS had engaged KPMG LLP, Chartered Accountants, (KPMG) to undertake a compliance or financial audit with respect to its gas purchases with ATCO Midstream. Calgary further noted that KPMG were not asked to audit information related to Carbon. Calgary stated that, based on the scope limitation placed on the work of KPMG and the nature of their engagement, the KPMG audit did nothing to alleviate Calgary's concerns. It argued that if AGS had truly wished to clear up concerns, it should have sat down with its customers and determined what the appropriate terms of reference should be for an audit. Calgary submitted that the audit had proved nothing and customers should not bear any of the costs associated with the audit.

Calgary argued that it was crucial that a distinction be made between working gas capacity and base gas volumes at Carbon. Calgary rebutted AGS's position that the production of base gas is a storage issue more properly dealt with in a GRA, rather than in a DGA proceeding. Calgary argued that base gas volumes were indigenous gas reserves, and the production of base gas, with its associated value and royalty cost, flows to the sales customers through the DGA as COP.

Calgary noted that in the 1995/96 and the 1996/97 winter periods, base gas was produced as COP and the value associated with this production flowed through the DGA. Calgary noted that in a reconciliation of production volumes, CWNG confirmed that a total of 5.7 petajoules (PJ) were included in the COP. Calgary noted that this quantity was comprised of 3.7 PJ of "phantom gas"[20] and 2.0 PJ of base gas. The base gas production was noted to be consistent with EUB production records. Calgary noted that the phantom gas production was a one-time adjustment to re-instate the full working gas capacity that CWNG had in 1975. It stated that the injected natural gas had been leaner than natural gas withdrawals, therefore the volume of natural gas required to sustain the same amount of energy increased over the period from 1975 to 1995. Calgary noted that in the 1995/1996 winter period, CWNG reflected the royalty cost of the base gas leaning (adjustment for heating value differences) in the DGA.

Calgary noted that there was potential for additional costs to accrue to customers as a result of AGS's position at Carbon and that AGS had yet to incur the royalty cost associated with 5 PJ of gas delivered to a third party as a result of a drainage settlement negotiated with that party. Calgary also noted that in the event that base gas was produced, royalties would be payable on that gas.

Calgary argued that in the event of a Carbon blow-down or base gas production, the base gas production would flow to the benefit of customers through the DGA and displace other gas purchases. It noted that this was identical to the methodology used for the delivery of COP and was also consistent with the methodology used for the delivery of gas during the blow-down phase of Bow Island storage. It noted that at Bow Island, customers had received all of the cushion gas volumes at the royalty cost of gas. Calgary argued that, similarly, base gas volumes at Carbon are indigenous gas volumes that, when produced to market, are accounted for in the same manner as all indigenous gas volumes owned by AGS. Calgary submitted that, therefore, Carbon base gas production was a DGA issue and the costs and benefits rest with the customer.

Calgary submitted that consideration should also be given to the relationship between other COP sites in the Carbon area and Carbon. It noted the Sproule report, *Geological and Engineering Review of the Carbon Storage Scheme*, which described potential drainage of Carbon by both AGS's wells and competitive wells. Calgary argued that the reserves associative with Carbon COP and the Carbon base gas were entwined, each with an influence upon the other. As evidence of this, it noted testimony of AGS to the effect that it could not divest itself of Carbon non-unit lands at the time when ATCO Gas was intending to divest itself of all company owned reserves. Calgary rebutted AGS's position that production from its non-unit wells was not producing base gas. It argued that AGS's proposed disposition of Carbon was based only on historical records of production and did not constitute a proper reservoir communication study.

Calgary argued that the value of Carbon base gas rests with the customer and that, as the utility is charged with the responsibility of managing this asset, AGS was obliged to manage Carbon base gas in a matter that would be in the best interests of customers. Calgary noted that Carbon is not a commercial operation that AGS could operate for the benefit of other members of the ATCO

[20] The quantum of energy required to adjust for the injection and withdrawal of volumes of gas over time with differing heating values.

Group. Calgary submitted that AGS was responsible for gas supply management and maintenance of a diversified supply portfolio.

Calgary noted its evidence regarding the supply alternative of base gas production, commencing December 1, 2000. The evidence submitted that a proactive approach to supply management could have saved the sales customers $33 million through the production of 5 PJ of base gas. It stated that as natural gas prices increased to record levels in December 2000 and January 2001, AGS had done nothing to try and mitigate the gas costs affecting sales customers.

Calgary noted that the consequence of base gas production was a small reduction in withdrawal capacity amounting to 36 terajoules (TJ) per day, which amounted to approximately 5 per cent of the total withdrawal capacity. Calgary argued that the least cost alternative to replacement of lost withdrawal capacity would be the drilling of one horizontal well at an estimated cost of between $1.5 million and $5 million. Calgary argued that this would have been a small price to pay to obtain the $33 million dollar benefit of base gas production.

Calgary argued that AGS had not considered this alternative, but stuck to its regimented plan of predetermined withdrawal volumes. It argued that this passive approach to supply management contravened AGS's responsibility to deliver gas at the least possible cost. Calgary argued that not only had AGS ignored the supply cost reduction of base gas production, but also that AGS had also sacrificed all of the withdrawal capability that was held for use by sales customers.

CCA

The CCA took issue with AGS's argument concerning cushion gas blow-down. Specifically, the CCA did not agree that cushion gas is a fixed asset. It argued that cushion gas is simple natural gas, indistinguishable from working gas or natural gas that is burned. The CCA submitted that it is imprudent to deem a particular amount of gas as a fixed asset, and apply a strategy to transfer a significant increase in value of that asset to an affiliate, while failing to use all possible options, including all available natural gas, to ensure that the GCRR is kept to a minimum.

MI

The MI supported the position of Calgary which was also consistent with the evidence filed by the Consumer Group in the Affiliate Transaction Proceeding, that demonstrated AGS should have produced up to 5 PJ of Carbon base gas as COP.

The MI noted in comparison that AGS had forecast that it would produce 3.7 PJ of phantom gas during the 1995/1996 winter period to reduce the volume of base gas to retain the working cycle. The MI argued that production of Carbon base gas would have been a valuable alternative from a customers' point of view.

The MI submitted that, as AGS was aware of the customers' interest in pursuing the base gas option through the Consumer Group evidence filed on November 27, 2000 in the Affiliate Transaction Proceeding, it could have brought forward a plan to customers and the Board for the use of base case to reduce costs. The MI also argued that there was ample pricing information available to AGS that would have allowed it to assure a cost saving to customers while retaining the ability to replace the 5 PJ of base gas after the 2000/2001 winter season.

The MI argued that AGS placed the interests of ATCO Midstream ahead of its customers. Accordingly, the MI submitted that AGS, as particularly demonstrated by the evidence of Calgary, had not prudently managed the Carbon rate base assets in the best interests of customers and should be held accountable and responsible for acts of omission. The MI further argued that customers should be compensated for this imprudence.

PICA

PICA, with the MI, argued that AGS had received Information Requests and Evidence from the Consumer Group as early as September 21, 2000 and October 27, 2000, respectively, concerning utilization of base gas to mitigate gas costs and the value of cushion gas to customers.[21] Accordingly, PICA submitted AGS could not try to construe customer interest in base gas as an "after the fact" review.

PICA stated that AGS should have known it could have produced cushion gas, based on its experience with previous winter period adjustments to base gas volumes, and should have locked in replacement gas at the savings noted by PICA and the MI.[22] PICA believed that the statement by ATCO that "the use of cushion gas just never entered our mind"[23], sounded like an act of omission. PICA, with the MI, submitted that AGS should be held responsible for such acts of omission.

PICA considered that AGS had an opportunity to use base gas and reinject it later at a saving. Although AGS stated it believed "the treatment of the replacement gas required to restore the capability of the Carbon storage facility is uncertain and speculative,"[24] and while AGS might have incurred royalties on base gas, PICA believed that the forward strips at the time indicated AGS could have locked-in replacement gas from the following summer period with a $12.5 to $13.5 million net benefit to customers. PICA claimed that the information was available from industry publications and the December 2000, and January 2001 GCRR filings. PICA, with the MI, submitted that AGS failed to substantiate its claim regarding the uncertain and speculative treatment of replacement gas and also failed to substantiate the claim that "the timely replacement of 5 PJ could have doubled the cost of the Carbon storage asset."[25]

PICA and MI jointly argued that the evidence, prepared by Mr. Robert Liddle, indicated that production of Carbon base gas was a more valuable alternative from a customer's point of view than the proposed lease to ATCO Midstream.

PICA/MI also argued that if AGS wished to rely on the position it could not, or would not, exercise management judgement without prior customer approval, AGS could have brought

[21] MI Argument, pp. 5-6, cited in PICA Reply Argument at p. 4
[22] MI Argument, pp. 5-6, cited in PICA Reply Argument at p. 4
[23] ATCO Argument , p. 10, cited in PICA Reply Argument at p. 4
[24] ATCO Argument, p.31, cited in PICA Reply Argument at p. 5
[25] ATCO Argument, p. 32, cited in PICA Reply Argument at p. 5

forward a plan to customers and the Board for the use of base gas to reduce costs. PICA/MI noted that, AGS was aware of the customer's interest in pursuing the base gas option through the Consumer Group evidence filed on November 27, 2000, in the Affiliate Transaction Proceeding.

5.1.2 Position of AGS

AGS noted that the use of Carbon base gas and phantom gas had been canvassed in the 1998 GRA, the February 2001 GRA Hearing, and again in the Methodology Hearing. It argued that Calgary had assumed that base gas could be produced at will from an active, operating storage facility. AGS noted with respect to Carbon:

- Phantom gas "accumulated" in Carbon over time. This was caused by different means of accounting for gas; storage transactions are measured in energy units, while the physical operation of the facility uses volume units. Some storage unit activity is also pure production. These effects led to an unacceptable increase in base gas volume, which AGS corrected in 1995/1996 and 1996/1997, to restore Carbon operating capacity.
- The Carbon storage facility has been considered a used and useful asset. The Board had previously noted that the discussion of the operation of Carbon was a GRA matter.

AGS stated that the production of base gas below the original level at the active storage operation would impair Carbon. It also stated that base gas is a rate base asset and that the proper forum for debating the disposition of a rate base asset would be in a GRA.

AGS considered that no matter what action it took with regard to the production of base gas, it could be viewed as being imprudent had it not achieved a full airing of the relevant facts and issues before the Board. It submitted that Calgary's position on base gas ignored regulatory oversight, was completely dependent on hindsight and should be dismissed outright.

In reply argument, AGS submitted that Calgary did not understand the circumstances surrounding the delivery of 5 PJ of gas to a third party as part of the Carbon drainage settlement. It stated that this action was undertaken to support the integrity of the Carbon storage facility. It stated that the record was clear that its actions were part of prudent storage asset management.

AGS countered the Calgary statement that Carbon was not a commercial operation. It noted that the balance of Carbon storage not needed for utility operations had been utilized on a commercial basis since 1972.

5.1.3 Views of the Board

In conducting a prudence review, it is necessary to examine information and circumstances that were available or that the utility ought reasonably to have known at the time the utility made its decisions, as set out in Section 3.3 of this Decision. In this section, the Board will assess the circumstances and information that were available at the time AGS made decisions with respect to the use of base gas. In carrying out this assessment, the Board considers it useful to focus on the distinction between working gas and base gas.

While working gas is included in the GCRR when withdrawn, base gas is not included in the GCRR unless produced. Therefore, an explanation of the distinction is important here. Working gas is gas which is injected and withdrawn on a cyclical basis, i.e., gas inventory. It is used to provide additional supply to the system during peak demand periods or during emergencies. The cycle generally involves injecting gas in periods of low demand and withdrawing the gas in periods of high demand, usually when prices are higher.

The Board agrees with AGS that base gas (or cushion gas) is a rate base asset and is the gas that is retained in the storage facility to provide the necessary minimum pressure required to meet the minimum design deliverability. It is the quantity of gas in excess of which the working gas cycle operates. When the working gas cycle has exhausted the inventory, storage is considered empty and must be replenished before more withdrawals can be made. A company will not be able to withdraw more gas than was injected during the 12 month period from a storage facility which is designed to have a single turn over cycle each 12 month period, without negatively impacting the integrity of the working gas cycle.

The Board understands, based on AGS's evidence, that it is possible to draw down the base gas, but that there are consequences to such an action, such as an effect on deliverability and rate base accounting concerns. The Board also understands that the problems created by drawing down the base gas can have several solutions depending on the desired outcome. The Board notes, for example, that Calgary suggested that a new horizontal well would restore the withdrawal capacity of 36 TJ/day if 5 PJs of base gas were withdrawn. The Board also notes that other solutions might include, but are not limited to, additional compression, more wells or simply replacing the base gas.

The Board notes that each of the foregoing solutions would involve necessary spending for capital additions, which would be added to rate base. The Board recognizes that each solution would be analyzed differently from an economic perspective depending on its timing and the desired result. If additional compression is selected, for example, the economic analysis must consider the capital cost, the associated ROE, and related financing and operating costs. The revenue requirement of such an alternative will be unique and will need to be compared to the revenue requirement of other alternatives. Similarly, if replacing the base gas at a later date is the alternative selected, then the revenue requirement that is necessary to cover the cost of the new base gas investment will also be unique and can be compared to the revenue requirements of all the alternatives studied. Over and above the consideration of the economics is consideration of intangible advantages and disadvantages. The Board can envision complicating factors. For example, if the base gas was replenished it would have a cost that may or may not be combined with the existing base gas cost which presently has no cost. If, at a later date, withdrawal of base gas is necessary, a decision would have to be made as to which gas comes out first, or whether it is mixed (i.e., is it last-in first-out, first-in first-out, or some other accounting method). Additionally the provincial government's position with respect to royalties would have to be considered. The answers to these questions could influence the choice of the preferred action, and one of the choices might be to do nothing.

The Board notes Calgary's observation that base gas had been withdrawn in the past and treated as COP for which royalties were paid. The Board also notes that AGS explained that those withdrawals were in conjunction with an adjustment made to the base gas to compensate for differing energy values being injected and withdrawn, i.e., a rebalancing of the working gas and base gas to account for the energy differences of the volumes being cycled. AGS also stated that the gas was not withdrawn with the express purpose of offsetting high gas prices.

The Board agrees with AGS that, without considering certain corrective actions, production of base gas could impair Carbon's operational parameters, such as deliverability or working gas capacity. Before AGS makes a determination regarding production of base gas the Board would expect that AGS would evaluate various alternatives and the economic implications of the alternatives. If the alternative selected involved the production of base gas, then the Board agrees with Calgary that the volumes produced would be part of the gas supply, treated as COP, and would be dealt with in the DGA process. Also, if the alternative selected involved the addition of new facilities or assets to rate base, the Board agrees with AGS that those expenditures would ultimately be reviewed in a GRA. The Board considers that, if AGS proposed to produce base gas, it would be a disposition of a rate base asset subject to prior approval of the Board pursuant to a specific application. Under section 25.1 of the *Gas Utilities Act* (GUA) and section 91.1 of the *Public Utilities Board Act* (PUBA), the Board must approve the disposition of any property owned by a utility that is not in the ordinary course of business.

While the Board recognizes that there is merit in considering the various options and their financial consequences, the Board is not persuaded at this time that AGS acted imprudently by not producing Carbon base gas during the 2000/2001 winter period. The Board is satisfied that a decision to produce base gas would best be done with full knowledge of the impact and the remedies before taking such action.

In Decision 2000-75, (Part A: GCRR Methodology and Gas Rate Unbundling) the Board stated the following:

> The Board notes that there are already physical hedge assets owned by the utilities. In the case of ATCO Gas, there are specific company owned gas production assets and gas storage assets that can, by nature, provide gas price hedging. The treatment of COP assets has been addressed by the NCC in its proposal that the costs savings of company owned gas production should be passed to all Core consumers via a credit to base rates, while the gas commodity rate should be charged at the market price for gas. This proposal for COP is discussed further in section 5.1 of this Decision.
>
> The Board considers that the use of storage facilities as a price hedging mechanism presents some of the same attributes as COP. In both cases the facilities can be described as "legacy assets", assets that have been paid for by all gas consumers in the previously fully regulated market. In both cases, crediting the benefits arising from the facilities directly to the gas commodity rate creates an economic bias towards regulated gas rate offerings, and implies that customers taking competitive gas supply do not receive any of the benefits from these assets. The Board is of the view that both of these results are undesirable.

> Therefore, the Board directs that company storage facility costs and benefits related to gas price stabilization or hedging are to be treated in accordance with the NCC COP Rider proposal. The gas withdrawn from storage will be valued at the current GCRR portfolio cost for inclusion in gas commodity rates. The net benefits (or costs) achieved using utility storage assets will be credited to base rates on a per gigajoule basis. Customers, whether they elect to receive gas from the utility or from a marketer, will share in the benefits arising from utility storage.
>
> Based on the evidence before the Board, only the AGS Carbon storage facility meets the criteria of being company owned storage used primarily as a physical hedge mechanism. The Board notes that AGS has filed an application, dated July 18, 2001, to commence a process to remove this facility from utility operation. Until such time as the Carbon facility is removed from regulated service, the Board expects AGS to operate the Carbon storage facility for the benefit of customers, and to allocate the costs and benefits of that facility in the manner described herein to the account of AGS Core customers paying towards the Carbon facility in their rates.

Given the foregoing with respect to the ongoing management and use of Carbon for the benefit of both the company and customers, the Board directs AGS (for as long as AGPL is the owner of Carbon) to examine the options in order to either develop a contingency plan or to restate the operating parameters for storage. The Board considers that it would be useful for AGS, at the next GRA, to provide the revenue requirement attached to each alternative in order for interested parties to gain an appreciation of the differing complexities and consequences of the choices available.

5.2 Carbon Working Gas Utilization

In this section the Board will review the issue of prudence as it pertains to the use of working gas at Carbon and whether or not working gas was utilized in a prudent manner. This issue will be considered in the context of the winter period of 2000/2001 as it affects AGS and its customers.

5.2.1 Positions of the Parties

AIPA

AIPA expressed support for the positions of PICA and the MI that AGS had not prudently managed Carbon in the best interests of customers.

Calgary

Calgary submitted that AGS was imprudent in altering its use of Carbon to a fixed 100% load factor monthly withdrawal during the 2000/2001 winter period. It noted that the issue was not that customers had not received the benefit of the difference between the cost of gas injected and the cost of gas withdrawn, or the average benefit of storage capacity. Calgary argued that AGS had had the ability to use Carbon at a low load factor (approximately 30%) and had not done so. Calgary argued that AGS “gave” that deliverability to its affiliate, ATCO Midstream.

Calgary argued that by holding flexible storage and using it for base supply, AGS was squandering the premium involved in this peaking supply. Calgary noted that AGS had agreed that storage has a value. It argued that the method developed by its witness, Mr. VanderSchee, provided a method of evaluating Carbon flexibility on an ex ante basis. Calgary argued that it was irrelevant whether or not AGS had optimized the value of Carbon in previous years. Calgary argued that it was also irrelevant whether or not ATCO Midstream was the beneficiary of the squandered flexibility. Calgary argued that all that should matter to the Board is whether AGS was prudent or imprudent in failing to use the flexibility of Carbon in the 2000/2001 winter period.

Calgary noted AGS's statement that ATCO Midstream did not, or could not, know what AGS was doing at Carbon with its withdrawal flexibility. Calgary further noted that ATCO Midstream is paid $1,000,000/year by AGS to manage Carbon and gas procurement for AGS, and that AGS is a large customer of ATCO Midstream. Calgary suggested that the AGS statement strained credibility.

Calgary contended that AGS, in argument, attempted to introduce new evidence and evidence from prior proceedings. Calgary argued that AGS's latest reservoir analysis should be disregarded and that the Board should draw the appropriate adverse inference as to why AGS had not raised this evidence during the hearing.

Calgary submitted that in past rate cases, particularly the 1997/1998 GRA, CWNG defended its use of Carbon and the need for storage flexibility. Calgary referred to Exhibit 54[26] to demonstrate that AGS had used this flexibility in the past, but had changed to 100% monthly load factor withdrawals for the 2000/2001 winter period. Calgary also submitted that this change in working gas utilization was done without consultation with customers, or approval from the Board. Calgary rebutted the AGS position that customers had been forewarned by noting that the "warning" had constituted one bullet point in a slide presentation given to customers in February 2000.[27] It also noted that the January 2000 RiskAdvisory Report that had outlined the many advantages of storage and the need for a utility to consider all options prior to making any decisions.

Calgary argued that flexible withdrawal capability indisputably has a value. It noted that AGS sales customers have up to 300 TJ per day of withdrawal capability at Carbon and that AGS withdrew storage inventory at a flat, fixed rate for each of the winter months. It argued that, as a result, customers' gas supply costs were higher than would otherwise have been the case.

Calgary proposed that the value of lost storage flexibility which AGS gave to its affiliate, ATCO Midstream, should be calculated on a forward-looking approach. Calgary referenced Exhibit 81, a report by its witness Mr. VanderSchee. Using the value which AGS gave to ATCO Midstream as a surrogate for the value which AGS could have achieved if it had retained the withdrawal

[26] Graph titled "Carbon Storage–ATCO Gas South Withdrawals" for the winter periods 1995/96 to 2000/01
[27] Exhibit 34 – Joint Statement of the City of Calgary and ATCO Gas regarding the attached slide titled "ATCO Gas South 2000/2001 Storage Recommendation".

flexibility and operated Carbon as it had in past, Calgary's witness estimated this lost value to be $8.9 million over the course of the winter period.

Calgary argued that AGS had given up the optionality at Carbon storage by not using the flexibility it had to increase and decrease withdrawals in response to changing prices and that Calgary submitted Exhibit 81 as evidence to establish a value of the flexibility AGS had not used effectively, as evidence. The report described a method of using ex –ante price forecasts to assist in making decisions on whether or not, on any given day, withdrawals should be made and the quantity that should be selected.

Mr. VanderSchee's report states:

> …..storage use flexibility provides an "option value" to storage holders. Possessing flexibility in daily winter storage withdrawal levels allows a company to shift its storage withdrawals to higher gas price days over the winter and avoid paying these elevated prices. Gas purchases would be shifted to lower price days (and storage withdrawals would be decreased on these days). Additional cost savings may result from decreasing operational and liquidity costs often associated with high demand gas periods. By properly managing this available flexibility, a utility with storage withdrawal flexibility can expect to realize cost savings over storage holders who do not possess this flexibility.

The report further states:

> AGS generally had two choices available to it on a daily basis. It could (1) increase its storage withdrawals on that day (but therefore leading to less withdrawals during some future period); or (2) decrease its storage withdrawals on that day (therefore leading to increased withdrawals during some future period). To determine which of these actions may yield cost savings, one needs to consider forward market prices for the remainder of the winter.
>
> On each day of the winter, forward prices for AECO C are generally available for rest-of-month contracts ("RM", i.e. on November 3, a RM contract would be for a term of November 4 to November 30), and forward month contracts. From these prices, and their relative values compared to the daily gas price, one can determine the optimal daily storage use decision.
>
> First one must determine how much gas to withdraw from storage on that day. Generally, if current day gas prices are relatively high compared to forward market prices, one will be more likely to withdraw increased gas volumes (up to contracted capacity) from storage. If, conversely, current day gas prices are relatively low compared to forward market prices, one will be more likely to withdraw no gas from storage, but rather "roll-over"[28] storage to future periods.

[28] Roll-over involves leaving planned storage withdrawals in storage, replacing these volumes with day gas purchases, and selling these volumes in a future time-period.

> There will be a financial motivation for either increasing storage withdrawals rolling-over storage; this will in turn be the earned value from using the flexibility available in storage.

The report concludes:

> In total, the economic cost to customers of AGS not using their storage flexibility over the winter of 2000/2001 was at least \$8.9 million, but possibly a value as high as \$9.0 to \$10.0 million.

CCA

The CCA submitted that, if utilities are not acting in the best interests of customers, they face prudence reviews, which can result in findings that impact overall return. In this regard, the CCA considered that AGS's strategies with respect to Carbon and COP were focused on maximizing shareholder gains rather than minimizing customer rates. In the CCA's view it was not appropriate to buy natural gas supply from the market when customers would benefit more from fixed price supplies, nor was it appropriate to remove from customers the value of natural gas that was used in conjunction with storage. The CCA considered that Carbon might have greater value as a production facility than as a storage facility.

Referring to the issue of risk and reward, the CCA submitted that, in return for acting prudently, a public utility receives the benefit of the return on and of capital invested in "used and useful" assets, but must also face the potential risk of disallowance of gas costs. The CCA expressed concern with ATCO Gas's plan to remove Carbon and COP from rate base, which appeared to include the strategy of minimizing the value attributable to customers while maximizing the gain to shareholders. The CCA pointed out that rates of return on COP and Carbon were collected since the 1920s and 1960s respectively, and that the size of the disallowance proposed by customers must be viewed against the magnitude of the gains that ATCO Gas is trying to obtain for shareholders. The CCA argued that, on the issue of risk and reward, the evidence of ATCO Gas's witness should be given reduced weight.

Edmonton

Edmonton argued that, as a general principle, the public interest required that utility operations be conducted with the view to ensuring that gas supplies for customers are provided in a manner that considers both cost and reliability. It also argued that customer needs should take precedence over possibly conflicting priorities, such as perceived opportunities for shareholder gains. Edmonton supported the claim of AGS customers to hold AGS accountable for its operation during the recent period of rapid market price escalations.

Edmonton acknowledged that it had no direct interest in the AGS Reconciliation hearing.

MI

The MI submitted that Calgary provided a convincing analysis with respect to Carbon that demonstrated there was a failsafe additional value of \$8.9 million of cost savings achievable on behalf of customers if AGS had exercised its deliverability rights to capture the optionality values (i.e., the variation in daily take from the Carbon storage reservoir).

The MI argued that AGS had unfairly represented the evidence with respect to the Carbon prudence issues.

The MI stated that AGS's current manner of storage operation changed considerably from its historical mode of operation, but AGS had failed to communicate such changes to customers. Noting that AGS had retained deliverability rights for up to 300 TJ/day, the MI argued that even if communications were not a concern, the circumstances evolving in the 2000/2001 winter period were still sufficiently extreme to warrant AGS exercising some "optionality value" at Carbon by taking more gas on days when gas prices were extremely high. The MI also argued that AGS's failure to realize the optionality values was imprudent in the sense that customers have a reasonable right to expect AGS will use good management judgment to respond to unique gas supply cost circumstances. The MI referred to the potential for a corresponding gain to have been achieved by ATCO Midstream based on the available deliverability not utilized by AGS. The MI submitted that there was no evidence on the record to refute that AGS could not have obtained the benefits of optionality for its customers rather than lease the facilities to ATCO Midstream

PICA

PICA supported the evidence submitted by the MI. PICA also submitted that AGS was departing from its own guidelines when it essentially turned over Carbon optionality to ATCO Midstream in an agreement not tested before the Board. It stated that there was no evidence on the record to show AGS could not have obtained the benefits of optionality for its customers rather than lease the facilities to ATCO Midstream.

PICA stated that the historical use of Carbon to meet operational requirements of AGS had been inextricably linked with its impact on gas prices. PICA stated that it was clear that withdrawals were typically high when the weather was cold. PICA noted that a company witness confirmed this, when he indicated, "the primary reason for having Carbon, is to meet those thermal swings on an instantaneous basis."[29]

PICA argued that AGS was also conscious of the impact of the rate of withdrawal of gas from Carbon on gas prices, whether for AGS or third-party customers. PICA submitted that this was demonstrated by the actions of CWNG during the Christmas period of 1996 when a compressor failure at Carbon reduced withdrawal capability during a period of cold weather. It noted that CWNG chose to limit withdrawals for utility purposes, even during a period when it would ordinarily have high withdrawals and maintain deliveries to third-party customers, because it thought it would minimize the market price impact.[30]

PICA submitted that in following a constant monthly withdrawal profile from Carbon in the 2000/2001 winter period, AGS would be fully aware such actions would have negative price

[29] Canadian Western Natural Gas Company Limited, 1997/98 GRA; Tr. p. 1183; L7
[30] Ibid, Tr. pp. 1333-1339

impacts (i.e., result in higher prices) in the marketplace during periods of cold weather. PICA stated that while AGS claimed it did not have the in-house trading expertise to implement Mr. VanderSchee's proposed program, it could have at least exercised the same flexibility in withdrawal patterns used to benefit customers in the past.

PICA/MI jointly argued that Exhibit 54 clearly demonstrated that there was a variation of inventory withdrawal in response to various factors, including the price of gas. In their view, it was clear AGS' manner of storage operation during the winter represented a considerable change from its historical mode of operation. Given the significance of the change, it was PICA/MI's position that AGS should have ensured communication of information to affected customers was clear, unmistakable and received. PICA/MI went on to state that even if communications were not a concern, the circumstances evolving in the winter of 2000/2001 were sufficiently extreme to warrant AGS exercising some "optionality value" at Carbon by taking more gas on days when gas prices were very high. PICA/MI argued that, as confirmed by AGS, it retained deliverability rights for up to 300 TJ/day, and therefore such an option was available and the physical capability in place.

PICA, reiterated the view that AGS had acted imprudently in its failure to utilize Carbon optionality and effectively utilize Carbon base gas. PICA argued that customers should not be expected to bear the costs associated with such imprudence.

5.2.2 Position of AGS

AGS argued that Calgary's position on the operation of the Carbon storage facility during the winter of 2000/2001 was without merit. It noted that Calgary's witness, Mr. VanderSchee, admitted that Calgary's proposed optionality program was a trading activity more complex and involved than the activity the Board had expressly rejected in Order 2000-161. It noted that Mr. VanderSchee was not aware of this decision prior to his appearance, and argued that this raised issues as to the relevance of his recommendations.

AGS stated that Calgary's interpretation that AGS had used Carbon storage withdrawals to respond to variations in gas prices, and not just to meet demand, was not correct. AGS stated that the primary use of Carbon historically was to meet the operational requirements of the pipeline system and not to respond to variation in gas prices. It also noted that the storage inventory had provided a physical price hedge, which in winter 2000/2001 had produced a substantial gas cost saving to customers. This was noted to be $60 million.

AGS stated that in 1999 it had recognized that the operational requirement for storage at Carbon was diminishing. It noted that it had provided reports from Ziff Energy and RiskAdvisory to interested parties on February 25, 2000. It stated that it had recommended not to use mechanisms to optimize storage optionality. It noted that discussions thereafter resulted in the 5 PJ arbitrage deal for 2000/2001, which was approved by the Board in Order U2000-183. AGS submitted that it has been consistent and clear with interested parties in its intended use of Carbon both historically, and during the change of operational requirement. Mr. Engler stated in testimony:

> We've looked at our operating requirements, and the evidence is clear: We don't need Carbon for operational purposes anymore.[31]

AGS stated that the evidence was clear that storage did not provide long-term benefits to customers through the DGA. It noted the evidence of Mr. Simard, who stated that in the long run, storage is a zero-sum game wherein the cost of the hedge would equal its corresponding benefit over the long-term. AGS noted that it was able to obtain storage services at prices that were lower than the embedded cost for Carbon.

AGS submitted that Calgary's proposal to capture optionality at Carbon involves a complex trading strategy that was explicitly not approved by the Board or other interested parties, was promoted in hindsight with the certain knowledge of the unprecedented 2000/2001 winter period gas price spike, and was enveloped in an untrue conspiracy theory that AGS's use of Carbon was to transfer an alleged benefit to ATCO Midstream.

> Mr. VanderSchee's scheme only works if you have physical gas in storage and certainty around the physical ability to withdraw that gas. You are, in essence, selling gas forward, you have to produce it. If you can't withdraw it because we're using -- because there is no deliverability available, then you can't enter that arrangement. Our "just take it" ability has been utilized in the past to meet operational needs, not to manage gas prices, and has always resulted in ATCO Midstream potentially having interruptible deliverability on any given day.[32]

AGS noted the evidence of RiskAdvisory, that the ability to capture the value of storage optionality is a complex skill that is best rewarded within the gas marketing community. It stated that fixed-price purchases and sales trades in the forward market would be required to implement a storage optionality program, and it did not have approval to enter into such transactions.

AGS criticized the proposed optionality program of Calgary. It stated that Calgary's evidence did not provide any insight into specific prices that would be used to trigger its optionality algorithm, or how to benchmark performance. It noted several other issues that would have to be clarified to protect the interests of all parties. AGS considered the preparation for implementation of a new program to be a very serious matter that would take a number of months to complete. It argued that Calgary had glossed over this point.

AGS argued that it was preposterous that Calgary would claim to assess storage optionality on a forward basis when Calgary's recommended disallowance was calculated commencing on November 1, 2000 for a program that was not even conceived until February/March 2001. It noted the testimony of Mr. VanderSchee to support this statement.

AGS countered the arguments of parties that ATCO Midstream was benefiting from Carbon deliverability left unused by AGS. It stated that use of Carbon was in keeping with its historic use through the winters of 1995/1996 to 2000/2001, and that the typical use had only been a

[31] Mr. J. Engler, AGS, Tr. Volume 15, pp 1729-1730
[32] Mr. J. Engler, AGS, Tr. Volume 15, p. 1730

fraction of the deliverability allocated to AGS. It stated that the pattern utilized in winter 2000/2001 provided, on average, no more or less withdrawal capability to ATCO Midstream than in previous winters. AGS noted that the deliverability was still its, and could not be sold on a firm basis by ATCO Midstream.

In reply argument, AGS submitted that the positions of Calgary, the MI/UM, and PICA relied on discussions that occurred during negotiations, which should be confidential.

In reply argument, AGS reiterated that the previous operation of Carbon had been centred on the operational requirements of the gas system, not on gas trading. It noted that the proposal by Mr. VanderSchee would require trading gas on a forward basis. It also noted that it had been criticized in 1998 for withdrawing too much gas too early, then facing increasing gas prices later.

AGS countered the statements of Calgary, PICA, and the MI that ATCO Midstream had somehow profited from AGS's operation of Carbon, and stated that this was not supported by the facts.

In reply argument, AGS stated again that it would have had to trade in the forward gas market to undertake the VanderSchee proposal. It also noted that ATCO Midstream could not have profited from this strategy either, as it would have required firm capacity and physical inventory to do so. It submitted that customers were aware of its intentions with respect to Carbon storage operations, and that it could only be concluded that AGS was operating prudently.

5.2.3 Views of the Board

In conducting a prudence review, it is necessary to examine information and circumstances that were available or that the utility ought reasonably to have known at the time the utility made its decisions, as set out in Section 3.3 of this Decision. In this section the Board will assess the circumstances and information that were available at the time AGS made decisions with respect to the manner of withdrawal of working gas from Carbon and determine whether those decisions were prudent.

The Board notes that AGS stated that the operational requirements for Carbon in utility service have diminished and that it will be seeking to remove Carbon from regulation. The proposed removal of Carbon from regulation, however, is not the subject of this proceeding. Rather, the subject of this proceeding is a review of the actions of AGS with respect to the 2000/2001 winter period.

Storage has provided managers of gas supplies with a physical hedge and a peaking supply for many years, and the Board expects this principle of gas portfolio management to continue as long as utilities own storage. The Board also notes that there are a range of load factors and storage services available to managers of gas supplies. In particular, for as long as Carbon is a used and useful rate base asset, the Board in Decision 2001-75 provided for its continued use as a physical hedge and a peaking supply.

The Board notes that various Interveners raised issues of imprudence. The MI, PICA, Calgary, CCA and AIPA contended that AGS did not prudently manage Carbon storage in the best interests of customers. Calgary also argued that AGS had not used the low load factor capability of approximately 30% but had instead used a 100% load factor each month during the winter. Calgary argued that this manner of withdrawal resulted in customers' gas costs being higher than they otherwise would have been.

AGS operated Carbon in a significantly different manner during the 2000/2001 winter period than in previous periods. Exhibit 54 shows that in all previous winters since 1995/1996, there was considerable variation in the quantity of gas being withdrawn on a daily basis. In contrast, the exhibit also shows the basically flat pattern of withdrawal used by AGS during the 2000/2001 winter period. The Board accepts that the steady withdrawals from storage did not compromise delivery of supplies of gas to customers throughout the 2000/2001 winter period. Emergency requirements to increase storage withdrawals, such as responding to facility failures that would affect deliveries, also appear to be absent during that winter. AGS stated that the primary use of Carbon historically was to meet the operational requirements of the pipeline system and not to respond to variation in gas prices. However, the Board notes previous injections of gas in the summer period were made when prices were generally lower and withdrawals were made by AGS during the winter period when prices were higher.

Before and during the winter period of 2000/2001 gas price forecasts predicted that gas prices would be higher than recent historical levels. The issue is whether or not AGS could have, and should have, reduced the cost of gas to customers by utilizing the storage flexibility in its arrangement with ATCO Midstream which allowed AGS to withdraw the gas at times when the daily prices for spot purchases were higher than the cost of working gas.

AGS had the price forecasts available to it on which to base a strategy to mitigate the impact if it so chose. AGS had at its disposal up to 300 TJs per day of deliverability pursuant to the arrangement with ATCO Midstream, even though it had previously determined that it would only utilize a maximum of 140 TJs per day. The Board also notes that the deliverability for each month was fixed at a set rate for each month of the 2000/2001 winter period, varying from 73 TJs per day in March 2001 to 140 TJs per day in January 2001.

The Board notes AGS's position that on a prospective or forecast basis, the value of storage as a price hedge is reflected in forward gas prices. In other words, at the beginning of the storage injection season, when a company is deciding whether or not to store gas, the differential between summer and winter forward gas prices gives an indication of the value of storage for the upcoming winter season. However, the Board considers that the value of storage is determined differently once the winter withdrawal season begins. At the beginning of the withdrawal season, the value of the working gas is known, and the value of storage will be based on the differential between future gas prices and the actual cost of gas stored. The company optimizes the value obtained from storage by using working gas as much as possible on the days when gas prices are the highest, thereby capturing the value available from its flexible deliverability. The Board notes that there are different methods whereby the company can attempt to optimize that value. Historically, AGS has applied its judgement to determine and utilize a withdrawal strategy. By contrast, with its previous gas withdrawal strategies, for the 2000/2001 winter period AGS chose to set its storage withdrawals at a fixed rate for each month, and to maintain the same rate for each day of the month, regardless of market price.

The Board finds AGS's actions to be inconsistent with respect to the utilization of the deliverability under its control. The Board questions the prudence of designing and rigidly sticking to a withdrawal strategy with a maximum deliverability of 140 TJs per day, when AGS had the ability to use up to 300 TJs per day. The Board finds that AGS could have, and ought to have, maximized the value of the 'excess' deliverability by using it on days when prices were spiking or by selling the deliverability it did not intend to use (the difference between 300 TJs per day and the amount it planned to use each day). The Board finds that the utility was not acting in the best interests of customers by having AGS retain deliverability that it did not use for even a single day during the entire winter period.

While AGS stated that the customers were advised of its intention to operate in this fashion, the customers indicated that this was not their understanding. Clearly there was a misunderstanding between the parties. The Board encourages AGS to take greater care in its communications with customers in future, to avoid further misunderstandings. However, even if AGS had clearly communicated its intentions to the customers early on, this in and of itself would not have necessarily rendered prudent the actions of AGS. The question of whether a utility has acted prudently is not answered merely by examining whether the utility clearly communicated its proposed actions to customers in advance.

Calgary submitted that the VanderSchee Report estimated the value foregone to customers at $8.9 million. The MI and PICA submitted that the analysis demonstrated that the amount of $8.9 million represented the cost savings that would have been achievable had AGS exercised its deliverability rights to vary the daily takes. The Board also notes that AGS argued that Calgary's proposal to capture optionality at Carbon involved a complex trading strategy that was explicitly not approved by the Board or other interested parties and was promoted in hindsight with certain knowledge of the unprecedented 2000/2001 winter period gas price spike. The Board acknowledges that the methodology described by Mr. VanderSchee was something that AGS did not have at hand, but does not accept that it promotes a technique that is done with hindsight. Indeed, all GCRRs are put in place using a forecast of gas prices, and decisions and strategies are based on those forecasts. The Board sees the method described by Mr. VanderSchee as one that enhances the utility's ability to make decisions on the level of storage withdrawals each day as a new price forecast is available. The Board considers that the VanderSchee method is not complex and, as it is not a trading strategy, it does not appear to expose the customers to a high level of risk.

The Board considers that the methodology employed by Mr. VanderSchee would likely produce an optimal result that AGS could not have otherwise achieved. However, even absent the VanderSchee model, AGS could have increased withdrawals as it saw the price surge above the prices expected in its GCRR filing. Such action would have been consistent with AGS's past practice and would have likely produced savings in the cost of gas for the customer compared to the cost they experienced.

In Section 3.3, the Board found that prudence involves exercising good judgement and discretion, and making decisions that are reasonable based on the information which was known or ought reasonably to have been known at the time the decision was made. In addition, the Board noted that utilities must act in the best interests of customers, while being entitled to a fair return. In the circumstances described above, the Board considers that it would have been prudent for AGS to do one or more of the following:

- employ a decision making tool similar to that described by Mr. VanderSchee,
- continue to use its considerable experience to withdraw varying amounts of gas depending on market conditions, as it had done in the past, or
- sell in advance the firm deliverability that it had determined not to use.

Alternatively, AGS could have developed other strategies on its own to deal with the forecast high gas prices. The Board finds that by not using any of these options, AGS failed to exercise good judgement and discretion. Based on forecast information available to AGS at the time it made its decisions regarding the use of storage for the 2000/2001 winter period, it was not reasonable for AGS to rigidly adhere to a strategy based on flat daily withdrawals. The Board finds that AGS acted imprudently by not responding to the obvious fact that gas prices were increasing dramatically by utilizing its knowledge and experience to mitigate the higher cost of purchased gas by using storage.

This leads to the issue of quantifying the imprudence of AGS. First of all, the Board does not consider it reasonable to penalize AGS for the full $8.9 million identified by Mr. VanderSchee's report, as the specific method identified by Mr. VanderSchee was not available to AGS during the 2000/2001 winter period, nor was it identified by interveners prior to that time.

Secondly, there was no evidence before the Board specifically quantifying the other two options for prudent behaviour identified by the Board above. Only by using hindsight could the Board estimate the maximum amount customers could have saved through continuation of the variable withdrawal strategy or through sale of excess firm deliverability. As stated in Section 3.3, the Board considers that a prudence review ought not to be based on hindsight. In other words, the Board will not review the past actions of an owner of a utility armed with today's information. Thus, it is not possible to precisely quantify the amounts that AGS could have saved if either of these strategies were adopted.

In the absence of specific evidence that would have determined an amount AGS could have achieved by exercising its judgement as in past practice, the Board has arrived at a reasonable approximation of the amount that could have been saved through continuation of the variable withdrawals by considering factors such as volume, market price of gas, cost of gas in storage, availability of deliverability, and the number of days remaining during the withdrawal season. Based on these factors, the Board considers that $4 million is a reasonable estimate of the amount required to put customers in the position they would have been in if AGS had exercised good judgement in adopting one of the three strategies outlined above, or a comparable strategy.

AGS is directed to refund $4 million to customers via the DGA for the winter period 2000/2001 as part of the reconciliation to finalize the interim rates. The Board expects the refund to be credited to the 2001/2002 winter period DGA as a prior period adjustment. The Board also expects AGS to be more diligent in the future in achieving cost savings for customers and to investigate methodologies, such as the one presented by Mr. VanderSchee, that will assist it in making decisions when managing the withdrawals from Carbon for the customers benefit. The Board directs AGS to report on the outcome of its investigations at the next GCRR application.

6 AGN – 2000 SUMMER AND 2000/2001 WINTER PERIODS DGA RECONCILIATIONS

At the hearing in May 2001, the Board heard detailed evidence from members of the NCC regarding issues of AGN's prudent use of COP during the 2000 summer period and 2000/2001 winter period.

As stated in Section 1 of this Decision, on November 14, 2001, AGN and the customer representatives of the NCC submitted a Joint Recommendation to the Board regarding the Viking R&V Proceeding. As a Collateral Commitment to the Joint Recommendation or compromise reached by AGN and the NCC in the Viking R&V Proceeding, the NCC indicated that they would withdraw their prudence applications currently before the Board for AGN relating to the summer 2000 and winter 2000/2001 GCRR periods. In a subsequent letter dated November 22, 2001, the NCC further clarified that the intention of the compromise position was that the issue of prudence for AGN would be left open until the Board had issued its decision in the R&V application. Decision 2001-104, with respect to the Viking R&V Proceeding was issued on December 11, 2001.

The Board understands that the NCC will file an application with the Board to withdraw their objections regarding the prudence of AGN relating to the summer 2000 and winter 2000/2001 GCRR periods. The Board notes that the NCC was the only intervenor with respect to the AGN DGA reconciliation. It is the Board's policy to encourage utilities and customer groups to reach agreement where appropriate. Negotiation of issues can result in greater regulatory efficiency and enhance meaningful public participation provided that the negotiation process is fair and open. Based on these policy objectives, the Board will not deal with the AGN summer 2000 and winter 2000/2001 reconciliation in this Decision, but will defer its decision pending further submissions from the NCC in this regard.

7 ALLOCATION OF THE DGA BALANCE BETWEEN OPTION A AND B CUSTOMERS IMPLEMENTED DURING THE 2000/2001 WINTER PERIOD

In this section the Board will review issues that pertain to matters of allocation between customers who are served using either of the two options approved by the Board in Decision 2001-16 and implemented during the 2000/2001 winter period

7.1 Position of the Parties

AIPA

AIPA recommended that, to maintain the integrity of DGA balances for seasonal pricing, the balances be allocated on the basis of actual consumption in the respective periods, bearing in mind that Option B customers comprise annual customers with full year consumption and seasonal customers who consume for part of the year only. AIPA submitted that the carry-over winter period DGA balance at November 1, 2000 should be allocated on the basis of actual winter 2000/2001 consumption of the respective Option A and B customers.

In response to ATCO Gas's proposal for allocation of costs and recoveries of non-calendar sales to Option A and B customers on a monthly basis, AIPA submitted that the existing seasonal cost allocation process be continued, until the Board approves new or revised parameters pursuant to this proceeding.

CCA

The CCA considered that costs should be allocated based on annual volumes, and noted that the implementation of Options A and B was due to extraordinary circumstances, which should not lead to a change in cost responsibility for customers through changes in cost allocation or assignment. The CCA pointed out that use of an hourly cost assignment, as suggested by ATCO Gas, is impractical as most meters are not read on an hourly basis or even on a monthly basis, and the use of estimates or volumes for cost allocations will cause significant cost distortions.

Calgary

Calgary was opposed to the continuing distinction between Option A and Option B customers and stated that the distinction should be eliminated at the earliest possible time. Calgary took no position on the allocation of the DGA balance between Option A and Option B customers.

FGA

The FGA argued that the DGA should recognize monthly balances accruing to the respective Option A and B customers in order to maintain appropriate cost responsibility.

MI

The MI considered that cost causation is the most appropriate measure of fairness in this case. The MI submitted that gas costs should be allocated to Option A and Option B on the basis of monthly calendar sales.

PICA

PICA (for itself and on behalf of Canfor) recommended adoption of ATCO Gas' monthly matching and reconciliation of DGA costs and revenues for calculating Option A and Option B deferral amounts in each season.

7.2 Position of ATCO Gas

ATCO Gas recommended allocating both the costs and non-calendar sales recoveries to the Option A and B customers on a monthly basis as, in terms of allocating these cost and recoveries to the respective customer groups, this would provide the shortest period of time where consumption (calendar sales) could be related to the associated costs and non-calendar sales recoveries.

7.3 Views of the Board

The Board considers that ATCO Gas would be in the best position to most accurately determine the appropriate division of the DGA balances between the two groups of customers. The Board therefore approves the methods of allocation used by AGS in Decision 2001-79[33] and AGN in Decision 2001-80[33] in which they made refunds to customers in respect of the estimated balances in their respective DGA accounts to October 31, 2001.

8 SUMMARY OF BOARD FINDINGS AND DIRECTIONS

The following summary of Board findings and directions is provided for convenience only. Should there by any discrepancy between the summary and the body of the Decision, the Views of the Board stated in the body of the Decision will prevail.

1. Given the foregoing with respect to the ongoing management and use of Carbon for the benefit of both the company and customers, the Board directs AGS (for as long as AGPL is the owner of Carbon) to examine the options in order to either develop a contingency plan or to restate the operating parameters for storage. The Board considers that it would be useful for AGS, at the next GRA, to provide the revenue requirement attached to each alternative in order for interested parties to gain an appreciation of the differing complexities and consequences of the choices available. 19

2. AGS is directed to refund $4 million to customers via the DGA for the winter period 2000/2001 as part of the reconciliation to finalize the interim rates. The Board expects the refund to be credited to the 2001/2002 winter period DGA as a prior period adjustment .... 29.

3. The Board also expects AGS to be more diligent in the future in achieving cost savings for customers and to investigate methodologies, such as the one presented by Mr. VanderSchee, that will assist it in making decisions when managing the withdrawals from Carbon for the customers benefit. The Board directs AGS to report on the outcome of its investigations at the next GCRR application. 30

4. The Board therefore approves the methods of allocation used by AGS in Decision 2001-79 and AGN in Decision 2001-80 in which they made refunds to customers in respect of the estimated balances in their respective DGA accounts to October 31, 2001. 32

[33] Applications for the 2000/2001 Winter Period Gas Cost Recovery Rates

9 BOARD ORDER

Therefore the Board orders that:

1. ATCO Gas shall implement the directions set out in this Decision and summarized in Section 8.

2. For ATCO Gas – South, a Division of ATCO Gas and Pipelines Ltd.:

   (a) with respect to the 2000 summer period, the Gas Cost Recovery Rate of $3.346/GJ, effective April 1, 2000, and the increases thereto of $0.920/GJ for the period May 1, 2000 to June 30, 2000, and $1.319/GJ for the period July 1, 2000 to October 31, 2000, inclusive, approved on an interim refundable basis in Order U2000-152, dated March 29, 2000, Order U2000-177, dated April 28, 2000, and Order U2000-225, dated June 23, 2000, respectively, are confirmed as final for all natural gas consumption on and after July 1, 2000 to October 31, 2000, inclusive, based on actual or estimated meter readings.

   (b) with respect to the 2001 summer period for Option B customers in sales service rate classes other than Rate 1, the Gas Cost Recovery Rate of $7.294/GJ, effective April 1, 2001, and the reduction thereto of $2.885/GJ for the period July 1, 2001 to October 31, 2001, inclusive, approved on an interim refundable basis in Order U2001-062, dated March 28, 2001, and Decision 2001-58, dated June 29, 2001, respectively, are confirmed as final for all natural gas consumption on and after July 1, 2001 to October 31, 2001, inclusive, based on actual or estimated meter readings.

   (c) with respect to the 2001 summer period for Option A sales service customers in Rate 1, the Gas Cost Recovery Rate of $5.410/GJ approved on an interim refundable basis in Decision 2001-58, dated June 29, 2001, is confirmed as final for all natural gas consumption on and after July 1, 2001 to October 31, 2001, inclusive, based on actual or estimated meter readings.

Dated in Calgary, Alberta on December 13, 2001.

ALBERTA ENERGY AND UTILITIES BOARD

B. T. McManus, Q.C
Presiding Member

Dr. B. F. Bietz
Member

T. M. McGee
Member

APPENDIX 1 - THOSE WHO APPEARED AT THE HEARING

Principals and Representatives
Abbreviations used in Report

Methodology Proceeding

ATCO Gas and Pipelines Ltd. ATCO Gas.	Mr. L. E. Smith Ms. K. Illsey Mr. T.J. Simard Mr. J. Engler Mr. R. Trovato Mr. M. Hagan Mr. J. Gordon
Aboriginal Communities	Mr. J. Graves
Alberta Irrigation Projects Association (AIPA) and, Energy Users Association of Alberta (EUAA)	Mr. J. H. Unryn
AltaGas Utilities Inc. (AltaGas)	Mr. F. V. Martin Mr. L Heikkinen Mr. A. Mantei
City of Calgary (Calgary)	Mr. R. B. Brander Ms. P. Quinton-Campbell Dr. N. Carruthers Mr. H. Johnson Ms. N. Stewart Mr. K. VanderSchee Mr. P. Milne Mr. H. Vander Veen
City of Edmonton (Edmonton)	Mr. W. Follett
Consumers Coalition of Alberta (CCA)	Mr. J. A. Wachowich Mr. J. Todd Mr. J. Jodoin
ENMAX Energy Corporation (ENMAX)	Mr. L. A. Cusano Mr. D. Wood Mr. K. Willerton Dr. E. Overcast
Enron Canada Corp. (Enron)	Mr. H. Huber
EPCOR Energy Services (Alberta) Inc. (EPCOR)	Mr. H. Williamson Mr. E. de Palezieux

Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc, and Municipal Gas and Co-op Intervenors (FGA)	Mr. T. Marriott Mr. M. Heck Mr. D. Campbell Mr. D. Symon
Mirant Americas Energy Marketing Canada Ltd. (Mirant)	Ms. E. Decter Mr. T. Lange
Municipal Intervenors and Urban Municipalities (MI/UM)	Mr. C. McCreary Mr. R. Bruggeman
North Core Committee (NCC)	Mr. J. A. Bryan Mr. R. Liddle Ms. N. Stewart
Public Institutional Consumers Association (PICA)	Ms. N. McKenzie Mr. R. Retnanandan
EUB Board Panel	Mr. B. T. McManus, Q.C., Chairperson Dr. B. F. Bietz, Member Mr. T. M. McGee, Member
EUB Board Counsel	Ms. J. Hocking Mr. A. Domes
EUB Board Staff	Mr. W. Vienneau, CMA Mr. D. R. Weir, C.A. Mr. R. Armstrong, P.Eng