Alberta Utilities Commission

ATCO GAS

2008-2009 General Rate Application
Phase I

November 13, 2008

ALBERTA UTILITIES COMMISSION
Decision 2008-113: ATCO Gas
2008-2009 General Rate Application Phase I
Application No. 1553052
Proceeding ID. 11

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Published by
Alberta Utilities Commission
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1 INTRODUCTION

ATCO Gas (AG or the Company), a division of ATCO Gas and Pipelines Ltd., initially filed a Phase I 2008-2009 General Rate Application (GRA) for ATCO Gas North (AGN) and ATCO Gas South (AGS) (the Application) on November 2, 2007. The Alberta Energy and Utilities Board (EUB or Board) by letter dated December 12, 2007, suspended the process due to submissions and objections of parties and the proposed establishment of the Alberta Utilities Commission (Commission or AUC) and directed AG to submit the application in January 2008 to the Commission. In the same letter, the Board directed AG to use a placeholder of the existing 38 percent common equity in its 2008 and 2009 revenue requirements until such time as the AUC issued further direction on the process to consider AG's request for an increase to that common equity percentage for the test years in question. AG filed its Application with the Commission on January 2, 2008 without changes, adjustments or alterations.[1]

The Commission issued a Notice of Proceeding that was distributed by e-mail on January 3, 2008 to the parties on the AG 2003-2004 GRA Phase I and Phase II, and on the AG 2005-2007 GRA distribution lists and was published in major Alberta newspapers on January 7, 2008. In addition, the notice was posted on the Commission's website on January 3, 2008.

The Commission made a number of rulings during the proceeding. By letter dated March 7, 2008, the Commission directed AG to respond to a number of information requests that The City of Calgary (Calgary) and the Office of the Utilities Consumer Advocate (UCA) argued were unresponsive. In addition, by letter dated May 7, 2008, the Commission determined it was not appropriate for the Consumer Group (CG) to respond to a number of information requests submitted by the UCA. Furthermore, by letter dated May 16, 2008, the Commission ruled that certain portions of Calgary's evidence should be removed from this proceeding and dealt with as part of the forthcoming ATCO Utilities Evergreen (Evergreen) proceeding, which is to deal with Information Technology (IT) and Customer Care and Billing (CC&B) pricing for 2008 and beyond.

A public hearing was convened in Edmonton, on May 29, 2008, before Commission Chair, Mr. Willie Grieve, Commissioners Mr. Bill Lyttle and Mr. Allen Maydonik Q.C. Parties filed written argument and reply on July 7 and on August 15, 2008, respectively. Accordingly, the Commission considers that August 15, 2008 was the close of record for this proceeding.

[1] AG had originally filed its 2008-2009 GRA Phase I (Application 1544779, ID 8) with the EUB on November 2, 2007. Given certain submissions and objections raised by parties to the process proposed by the EUB and the enactment of the AUC Act, which provided for the establishment of the AUC, effective January 1, 2008, the EUB considered that it would be appropriate to restart the proceeding as an AUC process. Therefore, on December 12, 2007, the EUB suspended the process for Application 1544779.

Appendix 1 lists the parties who participated in the hearing.

1.1 Legislative Framework

The Application before the Commission is governed the *Gas Utilities Act*, RSA 2000 c. G-5 (GU Act), the *Public Utilities Act*, RSA 2000 c. P-45 (PU Act), and the *Alberta Utilities Commission Act*, SA 2007 c. A-37.2 (AUC Act) and enactments adopted under these Acts. More specifically, in relation to the Application, the Commission has the power to set just and reasonable rates, under subsection 36(a) of the GU Act and fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of an owner of a gas utility, under subsection 36(b) of the GU Act. In fixing just and reasonable rates, the Commission shall determine a rate base for the property of the owner of a gas utility used or required to be used to provide service to the public within Alberta and, on determining a rate base, fix a fair return on the rate base, in accordance with section 37 of the GU Act. Also, subsection 40(a) of the GU Act provides that, in fixing just and reasonable rates, the Commission may consider all revenues and costs of an owner of a gas utility that are in the Commission's opinion applicable to the whole of the fiscal year in which a proceeding is initiated.

In its disposition of the Application, the Commission must fix just and reasonable rates. Of note is subsection 44(3) of the GU Act which clearly states that the burden of proof is on the owner of a gas utility to show that increases, changes or alterations to rates are just and reasonable.

The PU Act has similar provisions to those listed above contained in the GU Act. The Commission notes that the PU Act applies to the Application as a result of sections 59 and 60 of the GU Act.

The AUC Act grants the Commission general powers which apply to all applications and related proceedings. Under this Act, the Commission has enacted Rule 001, *Rules of Practice,* which applies to proceedings before the Commission.

The legislative intent is straightforward. The utility company must apply to the Commission for any changes in rates and demonstrate to the Commission that the rates it proposes are just and reasonable and not unjustly discriminatory. This type of regulatory scheme is not the norm in Canada's market economy. It is adopted by legislators where essential or important services, such as the natural gas distribution services in this case, are provided to customers by monopoly suppliers. In normal competitive markets, it is the operation of competitive market forces that establishes and maintains a balance between competing companies and the customers they seek to serve. Where, as here, there is no competitive market, the legislature has stepped in to provide a regulatory scheme designed to establish and maintain a balance between monopoly companies and their customers. It has done so by establishing the Commission as an expert independent quasi-judicial tribunal whose duty it is to establish a balance between customers and monopoly companies that it is assumed by legislators would not be possible but for regulation. In order to achieve the balance envisioned by the legislators, the Commission must consider both the interests of the regulated companies and their customers and make its decisions in accordance with its governing legislation while conducting itself in accordance with the principles of natural justice and procedural fairness.

Just as the Applicant must demonstrate that the rates (or revenue requirement at this stage of the proceeding) it proposes are just and reasonable, the Commission has its duty to use its expertise to test the case presented by the Applicant. The Commission does this by asking written interrogatories and asking questions in oral public hearings designed to gather more information, challenge assumptions and facts, and ensure that the combination of facts, theories and logic that led to the Applicant's proposals properly achieve the public interest objective of creating a balance between the interests of the Applicant and its customers that results in rates that are just and reasonable. In cases, such as the one before the Commission, where interveners participate, they do so to ensure that the Commission, in its assessment of the public interest, is aware of the interests the interveners represent and often propose different facts, theories, logic and opinions for the Commission's consideration. Interveners ask interrogatories and conduct oral cross examination to test the case of the Applicant and in some cases each other. Also, as in this case, they may call evidence to rebut or cast doubt on the Applicant's case and to propose outcomes that reflect their conception of the balance between the monopoly supplier and its customers that best achieves the public interest. The Commission also asks written interrogatories of the interveners and asks questions in oral public hearings in order to, once again, gather more information, challenge assumptions and facts, and ensure that the combination of facts, theories and logic result in a balanced public interest outcome.

The regulatory process is not in the nature of a *lis inter partes* where the Commission is expected to play a less active role and judge between two or more conflicting cases brought before it; and the presence of interveners does not transform the nature of the regulatory process into a *lis inter partes*. It remains for the Commission, as a neutral and impartial decision maker, to ensure that all of the evidence before it is tested and considered, so that to the greatest possible extent, the public interest balance between the monopoly company and all of its customers (including those that are not represented by interveners) is achieved.

In reaching the determinations contained within this Decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Commission’s reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter. However, the Commission notes that the First Nations intervention in this proceeding was not of assistance to the Commission in making a decision and, therefore, is not referred to in this Decision.

1.2 Process

In this hearing, a number of issues arose in relation to the rebuttal evidence filed by AG on May 20, 2008. The UCA filed a motion on May 27, 2008 to strike new evidence in the AG rebuttal evidence. The UCA argued that the new evidence could not be addressed in the short timeframe before the hearing and resulted in extreme prejudice to interveners. On May 29, 2008, the Commission received written submissions on the motion and heard additional submissions from parties at the beginning of the hearing. The Commission ruled on UCA’s motion, as contained in Appendix 3. The Commission acknowledged in the ruling that interveners had to deal with extensive rebuttal evidence which was filed close to the beginning of the hearing. To address the difficulty this presented to interveners, the Commission directed that the steps as set out in the ruling, which were designed to redress the balance and ensure a fair process.

On June 10, 2008, the Commission noted that Calgary had raised concerns during its cross-examination of the AG panel[2] that certain statements remained in the rebuttal evidence despite the May 16, 2008 ruling, which directly refuted Calgary's impugned evidence relating to IT and CC&B matters. The Commission referred to its ruling of May 16, 2008 which summarized the scope of IT and CC&B matters which fall within the scope of this Proceeding. As a result of that ruling, the Commission stated that any references on the record to Calgary's evidence which was not within the scope of this proceeding was struck, including references later filed in AG's rebuttal evidence. The Commission added that it would disregard any references relating to Calgary's evidence that was struck.

In its oral ruling on May 29, 2008 the Commission reiterated that, the IT and ATCO I-Tek Business Services (ITBS) Governance costs were removed from the record of this proceeding and moved to the Evergreen proceeding. Also, the Commission stated that implicit in that ruling, was that any other references in the rebuttal evidence, not identified in the ruling but related to the new evidence, were excluded.

However, further motions were filed after the hearing was completed in regard to references to IT and CC&B matters on the record. The Commission ruled on a motion by Calgary on June 27, 2008 and on one by AG on July 24, 2008.

In argument, Calgary raised a number of issues regarding process, which the Commission must comment on as they impugn the fairness of this proceeding. First, the introduction of new evidence through rebuttal was again raised. The Commission points to its ruling of May 29, 2008 and the steps set out by the Commission to address the concerns regarding new evidence contained in the rebuttal and the extensive nature of the rebuttal evidence. First, the Commission reduced the amount of information in the rebuttal evidence by determining that the following information was new and not properly rebuttal evidence and struck it from the record of the proceeding:

- the Towers Perrin compensation review report which AG applied to withdraw including all references to it on the record, and
- the IT and ITBS governance costs in the rebuttal evidence from page 100, line 26 to page 102, line 4 inclusive, and attachment 22 (this evidence will be dealt with as part of the forthcoming Evergreen proceeding.)

Second, the Commission provided interveners with an opportunity to ask information requests of AG on new information in the rebuttal evidence, and AG was directed to reply within two days so that interveners had an opportunity to review the responses and ask questions of the AG witness panel. The Commission invited parties to bring forward any issue resulting from the proposed schedule if it proved to be problematic for the parties. Third, the Commission adjourned the hearing for one day to allow interveners time to prepare their information requests. Fourth, the Commission provided an opportunity for interveners to file additional evidence by the end of the hearing, or sometime during the hearing if interveners determined it was required.

The Commission notes that interveners made information requests of AG and to which AG replied in keeping with the above-mentioned schedule. Also, although invited to do so by the

[2] Transcript Volume 6, pages 1196 through 1211

Commission in its ruling, neither Calgary nor any other intervener raised any issues regarding the proposed information request schedule or responses received from AG. The Commission made it clear in its ruling that if any intervener had an issue arising from its ruling, the intervener could raise the matter again. In addition, interveners had time and an opportunity to cross-examine the AG witness panel on its evidence including the rebuttal evidence. During the hearing, interveners did not raise any issues with the steps implemented by the Commission to afford interveners an opportunity to address the AG rebuttal evidence and to prepare their case. Furthermore, the Commission provided Calgary with clarification as to evidence that was struck from the record, during and after the hearing.

The Commission notes Calgary's observation about apprehension of bias in suggesting that the Commission was complicit with the approach taken by AG in its rebuttal evidence. The Commission is of the view that the observation is without basis. This proceeding was conducted in accordance with the AUC Rule 001, *Rules of Practice* and the process schedule set out for this proceeding was designed to provide parties with time and opportunity to ask information requests and file evidence, and in sum prepare their case. While the proceeding schedule was adhered to, the Commission notes that AG had in its possession some of the new evidence, well before the date for rebuttal evidence and had the option of amending its Application or filing it before the deadline for rebuttal evidence. Doing so may have reduced the need to file extensive rebuttal evidence which led to the procedural fairness issues set out above and discussed at length. However, the Commission does not direct a party's case, other than process. When fairness issues arise, the Commission may vary its process in a proceeding, which it did in this case, so that the hearing proceeds without prejudice to the parties in an efficient manner. Nevertheless, the Commission agrees that the conduct of the hearing would have been improved significantly had AG filed information that had previously been requested in interrogatories immediately upon that information being available instead of waiting until much later and filing it as part of a package of rebuttal evidence. As a result, the Commission will consider, when it considers minimum filing requirements (MFR), whether rules dealing with the timeliness of disclosure for relevant information should be established.

Calgary stated that it has drawn an implication that because of how the Commission asked some questions, the Commissioners' minds were made up prior to hearing all of the evidence. In regulatory proceedings the Commission's responsibility is not just to seek information and clarify the position of the parties before it, it is also to test the case of the applicant and test the case of interveners. A regulatory proceeding is not a *lis inter partes.* The Commission cannot restrict its freedom to carry out its public interest duty to gather information and test the evidence of all witnesses and parties in the most effective way possible in the specific circumstances as they might arise. Parties cannot draw any inferences about what the Commission might ultimately decide with respect to any party's position from the questions asked by the Commission as information requests, examination by Commission counsel or questions asked by individual Commissioners.

Based on the above, the Commission is of the view that interveners were afforded procedural fairness and the proceeding was conducted in accordance with the principles of natural justice, as interveners had ample opportunity to test the case before the Commission.

2 PRESUMPTION OF PRUDENT MANAGEMENT

The parties made the following submissions regarding the presumption of prudence and its application to forecasts in the current proceeding.

AG submitted that a presumption of prudent management applies to all of its managerial decisions, including forecasts prepared for the purposes of a GRA proceeding.[3] While AG acknowledged that the Board had previously found, in Decision 2006-004,[4] that the presumption of prudence does not apply to forecasts, AG submitted that that finding is contrary to law which is binding upon the Commission.[5] In support of this assertion, AG cited the decision of the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*[6] (DGA Decision) at paragraph 72:

> However, in the context of rate setting, the starting point for scrutinizing management decisions is the presumption that it is in the utility's interest to make prudent decisions which also reflect the interests of its customers, by avoiding needless expenditure. That presumption will matter only when the scales are evenly balanced.

AG also cited paragraph 66 of the DGA Decision, in which the Court of Appeal quoted a publication of The National Regulatory Research Institute of Ohio State University:

> A presumption of prudence triggers an onus of proof on the party impugning managerial decisions. However, if that presumption is rebutted, a public utility's decision will be reviewed, applying an objective test of reasonableness to the facts and circumstances surrounding the decision, without relying on hindsight: The Prudent Investment Test, p. 93.

As a result of the presumption of prudent management, AG submitted, it was only where a forecast has been challenged that there was an ability to substitute a different forecast for that of ATCO Gas. If the forecast was not successfully challenged, then the utility continues to have the benefit of the presumption of prudence. This approach reflects the onus of proof required to impugn managerial decisions, according to AG's interpretation of the findings of the Court of Appeal in the DGA Decision.[7]

AG cited various U.S. authorities that considered the concept prudence generally,[8] as well as the presumption of managerial "good faith".[9] With respect to the concept of management "good faith," AG noted that the National Energy Board, in reasons issued in 2003, stated that:

> ..[it] accepts the regulatory presumption of management good faith when utilities budget and make operating expenditures.[10]

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[3] AG Argument, page 6
[4] Decision 2006-004 – ATCO Gas 2005-2007 General Rate Application Phase I Application (Application 1400690) (Released: January 27, 2006). See also Decision 2006-014 for Errata to this Decision (Released February 24, 2006)
[5] AG Reply Argument, page 8
[6] 2005 ABCA 122
[7] AG Argument, page 7
[8] AG Argument, Appendix I, pages 112-115
[9] AG Argument , pages 8 and 9

AG stated that this implied that the NEB confirms that the presumption of prudence applies to a utility's forecasts.[11]

Referring to an excerpt cited from one U.S. authority, AG indicated that:

> The presumption of prudence means that the Commission cannot reject ATCO Gas' Application, including its forecasts, because the Commission, or an intervener, simply would prefer to do something differently than the way that ATCO Gas' management acted. Rather, the presumption of prudence can only be rebutted if the action taken by the utility was "excessive or unwarranted or incurred in bad faith".[12]

Applying the concept of "good faith" to forecasts, AG went on to state that:

> While the nature of actual expenditures and historic decisions allows for a more definite determination of whether managerial decisions were made in good faith and were reasonable, forecasts are necessarily more judgmental. In either case, expenses, or forecast expenses, are not to be disallowed or reduced unless they are clearly excessive, unwarranted or incurred in bad faith.[13]

AG indicated that it was entitled to a presumption of prudence with respect to the Application regarding its incurred costs, opening plant balance, and its forecasts.[14] It stated that the role of interveners and the Commission was to then challenge and clarify the Application with Information Requests. Interveners file their own evidence, which is subsequently challenged and clarified by AG and by the Commission through Information Requests. Rebuttal Evidence is then filed. AG submitted that its Rebuttal Evidence refuted every challenge made to its evidence by interveners and the Commission, and that as such, it continues to have the benefit of the presumption of prudence.

AG then submitted that there has been no evidence presented during this GRA to suggest that a disallowance or reduction of expenses or forecast expenses is warranted and submitted that the presumption of prudent management has not been rebutted in this GRA.[15]

Both UCA and Calgary took note of AG's assertion that the presumption of prudent management applies to all of AG's managerial decisions.[16] The UCA argued that this position was inconsistent with previous Board decisions as well as recent Alberta Court of Appeal decisions that relate specifically to AG.[17] In particular, the UCA stated that:

> 1. Although a presumption of prudence applies to some "managerial decisions", it does not apply to forecasts, notwithstanding Mr. Engler's comments.[18]

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[10] AG Argument, Appendix I, page 118, citing TransCanada PipeLines Limited Tolls and Tariff, RH-1-2002, NEB Reasons for Decision, July 2003, page 16
[11] Ibid
[12] AG Argument, page 8 (citing authority) and page 9 (AG quote)
[13] AG Argument, page 10
[14] AG Argument, page 9
[15] AG Argument, page 10
[16] AG Argument, page 6
[17] UCA Reply Argument, page 2
[18] Transcript Volume 5, page 867, lines 15-19

2. In those limited circumstances in which the presumption of prudence does apply, the presumption can be challenged on reasonable grounds.[19]

Each of UCA, Calgary and CG took issue with AG's interpretation of the DGA Decision and indicated that AG had improperly implied that that decision confirmed that the presumption of prudence applied to forecasts. Rather, the UCA submitted, the DGA Decision dealt with a prudence review of a strategy previously implemented and did not relate to forecast costs.[20] Calgary similarly distinguished the DGA Case as not relating to "prospective ratemaking whatsoever" but as rather an "*ex poste* review by the Board of the ATCO gas withdrawal strategy".[21] CG submitted that the Court of Appeal in the DGA Decision did not state, with the clarity alleged by AG, that the management of a utility enjoys an unconditional presumption of prudence.[22]

Calgary expressed its concern that AG was "bootstrapping this case [the DGA Decision] to have the Commission sanction a shifting of the onus and burden of proof from itself, as the applicant, to interveners to rebut ATCO's application."[23]

With respect to the American case law cited by AG in support of its argument that the presumption of prudence should include forecast costs, the UCA distinguished such authorities as being cases that either considered previously incurred expenditures (such as the *Southwestern Bell*[24] case) or that involved utilities that were not regulated based on legislation[25] which specifically contemplated future test years and the resulting requirement for forecasts.[26] Calgary similarly submitted that the primary case relied on by AG in support of its assertion that the presumption of prudence should apply to forecasts – *Southwestern Bell* – actually refers to prudence in the past tense.[27]

Calgary also stated that AG's discussion of prudence in Appendix 1 of its argument did not address the issue as to whether the Board's findings in Decision 2006-004 on the presumption of prudence were invalid or superseded. Calgary submitted that it was still the onus of the utility to demonstrate that a cost incurred or a cost forecasted to be incurred, will be or was in fact prudent as the case may be.[28]

Also referring to Decision 2006-004, UCA stated that the Board, recognizing the submissions of the Canadian Federation of Independent Business (CFIB), concluded that forecasts cannot be presumed to be prudent, correct or reasonable.[29] The UCA cited the conclusion of the Board in Decision 2006-004 and stated that that decision summarizes the standard of review to be followed by the Commission and is not in conflict with the DGA Decision.[30]

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19 UCA Reply Argument, pages 2 and 3
20 UCA Reply Argument, page 3
21 Calgary Reply Argument, page 3
22 CG Reply Argument, page 3
23 Calgary Reply Argument, page 3
24 *Missouri ex rel. Southwestern Bell Tel. Co. v. Mos. PSC*, 262 U.S. 276 (1923)
25 *Public Utilities Act*, section 91(1)(a)
26 UCA Reply Argument, page 7
27 Calgary Argument, page 4
28 Calgary Reply Argument, page 4
29 UCA Reply Argument, page 5
30 Ibid

Calgary submitted that the AG submissions on the presumption of prudence resolved into a "tautology of countervailing positions."[31] Calgary noted that the Board, in Decision 2006-004, differentiated between looking at a decision *ex poste*, for example with respect to a past investment decision, versus a forecasted cost being examined *ex ante* in a prospective GRA setting.[32] Calgary submitted that:

> … for ATCO to mix these two together, and suggest that they apply equally, is a circular argument, insofar as if a forecasting decision is accorded a presumption of prudence, then axiomatically the decision can never be reviewed after the fact on a prudence basis, because ATCO will always argue that it had the benefit of the presumption of prudence on an *ex ante* basis.[33]

The interveners expressed various concerns with the effect that a presumption of prudence, as interpreted by AG, would have on the burden of proof in the context of a GRA.

The UCA stated its concern that adopting the AG position that "[m]anagement of the utility is assumed to be reasonable and prudent in determining the costs of doing business", would effectively eliminate the necessity for meaningful regulatory oversight and the evaluation of utility applications by interveners and the Commission.[34]

And further, after quoting Bonbright's *Principles of Public Utility Rates*:

> The UCA is of the opinion that these kinds of statements confirm the authority of interveners and regulatory authorities to "test" a utility's forecast of costs including all of the underlying assumptions. There is no suggestion that anything should be taken for granted simply because it is contained in the utility's application. Similarly, the concept of prudence is generally limited to consideration of already-experienced expenditures.[35]

CG commented on the proper onus in a rate proceeding by stating that it was fundamental to prospective test year regulation that the onus was upon the utility to prove its case since the utility has a natural incentive to come forward with forecasts of higher costs and lower revenues to mitigate its forecast risk.[36]

Further, CG did not agree there was a general presumption of prudence in the area of utility operations and utility regulation. CG submitted that in a forward test year jurisdiction the onus was clearly on the utility to show its forecasts were based on prudent assumptions and were supported by evidence. These assumptions, CG submitted, not only include economic assumptions, such as inflation rates and customer growth, but also assumptions relative to the utility's business plans and strategies for delivering reliable utility service at least cost.[37]

CG submitted that adopting a presumption of prudence effectively shifts the onus to interveners and that given the asymmetry in information:

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31 Calgary Reply Argument, page 5
32 Calgary Reply Argument, page 6
33 Ibid
34 UCA Argument, page 3, quoting AG's 2005-2007 GRA Rebuttal Evidence
35 UCA Argument, pages 5 and 6
36 CG Argument, pages 5 and 6
37 CG Argument, page 5

> …such a premise is unreasonable and would remove the regulator's oversight of the monopolies operations to the detriment of customers. The proper testing and review of a utility's forecasts and variances from actual is part of a proper balancing of the interests of shareholders and customers and in the overall public interest.[38]

With respect to the issue of the burden of proof, Calgary submitted:

> The onus to demonstrate the reasonability of its forecast lies with ATCO and ATCO alone. With respect, the AEUB properly handled this matter in Decision 2006-004, and nothing has come to light since that time to suggest otherwise. Moreover, the Alberta Court of Appeal decision in the DGA Case took place prior to the issuance of Decision 2006-004, and as far as Calgary is aware, no other utility has ever claimed a presumption of prudence with respect to its forecasting in a GRA and as well has never suggested that the operation of the presumption would be to shift the burden of proof to Interveners.[39]

Commission Findings

Presumption of Prudence - Generally

As noted by the UCA in its argument,[40] the Board addressed the presumption of prudence generally in Decision 2005-120,[41] in which it made the following comments regarding the proper test for prudence, the proper application of the presumption of prudence and the Court of Appeal's approval of same:

> In Decision 2001-110 the Board established the following test for prudence at page 10:
>
>> 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.
>
> The Alberta Court of Appeal has upheld the Board's articulation of the prudence test [in the DGA Decision], stating:
>
>> In this case, in determining to uphold ATCO's decision unless satisfied ATCO has acted unreasonably, the Board correctly acknowledged the presumption of prudence. The test it articulated to be applied in reviewing the prudence and reasonableness of ATCO's decisions is reasonable.[42]
>
> Although the Board will start with the presumption, confirmed by the Alberta Court of Appeal, that AltaLink has acted prudently, the presumption can only be confirmed or overturned through an examination of the information and circumstances that were available to AltaLink or that it ought to have known at the time it executed decisions in respect of the direct assigned projects. The Board's prudence review will assess if the actions undertaken by AltaLink were reasonable, demonstrated good judgment, and were undertaken with the best interests of customers in mind. An examination of these issues

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38 CG Argument, page 6

39 Calgary Reply Argument, page 4

40 UCA Reply Argument, pages 7 and 8

41 Decision 2005-120 – AltaLink Management Ltd., Reconciliation of Direct Assigned Project Capital Deferral Accounts for May 1, 2002 to April 30, 2004 (Application 1359518) (Released: November 22, 2005), page 3

42 See *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)* 2005 ABCA 122 at page 14

> requires AltaLink to fully explain and support overall project costs and project cost components. The Board must ensure that this onus is met particularly if there are project components that have large differences between forecast and actual costs, appear to be high relative to industry norms, or involve affiliate transactions.

The Commission adopts the basic test for prudence set out in the above reasons, as well as the Board's articulation of the manner in which to apply the presumption of prudence noted above, as the starting point for its analysis of whether it is appropriate to apply that test to forecast amounts.

Presumption of Prudence - Forecasts

The Commission has considered the observations and findings of the Board in Decision 2006-004 which specifically dealt with the issue of the presumption of prudence and its inapplicability to forecasts and in particular, the following passages:

> The Board agrees with CG that it is appropriate for the Board to use the best information available to assess the debenture rate forecast. AG asserted that it would be inappropriate to consider an updated forecast because it would be using hindsight to assess the prudence of the forecast.[176] **The Board maintains that prospective forecasts should be assessed for reasonableness and that there is no presumption of prudence with respect to consideration of forecasts.**[43] [emphasis added]
>
> [176] AG Argument, page 25

And:

> The Board also agrees with interveners, and in particular with the views of the CFIB as summarized above, **that forecasts cannot be presumed to be prudent, correct or reasonable**. The statutory burden of proof to show that the applied for rates, tolls and charges are just and reasonable, rests with the utility.[216] This burden of proof can not be switched to interveners through the filing of an application or through the submission of cost projections and forecasts and supporting materials.
>
> **The Board considers that managerial prudence is a concept more appropriate to a consideration of prior actions taken by utility management that become the subject of a retrospective review by the Board[217] rather than to a review by the Board of prospective forecasts**. Recognizing that the utility has the burden of proof, the Board must assess the reasonableness of the utility's forecasts by considering the evidence before it, including evidence related to the forecasting methodologies used by the utility and historical information on forecasting accuracy, and then apply its own judgment and expertise in order to fulfill its statutory obligation of fixing just and reasonable rates.[44] [Emphasis added]
>
> [216] See for example, Section 44(3) of the *Gas Utilities Act* RSA. 2000 c. G-5 and Section 103(3) of the *Public Utilities Board Act* RSA 2000 c.P-45
>
> [217] See for example 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*, dated December 12, 2001, upheld on appeal to the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122

[43] Decision 2006-004, page 39

[44] Ibid, pages 49-50

The Commission has also considered the legislation which sets out its rate-setting function, including subsection 40(a) of the GU Act, noted above under "Legislative Framework", in which the Commission's role to "consider" all revenues and costs when fixing just and reasonable rates is set out. Similarly, subsection 4(3) of AR 186/2003[45] requires that the Commission make a determination as to the prudent costs incurred by a gas distributer:

> (3) A gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor to meet the requirements of subsection (1). [emphasis added]

Within this legislative framework – in a prospective rate-setting context – to apply a presumption of prudence to forecasts would be to essentially fetter the Commission's ability to consider all revenues and costs and to determine whether those costs were or were to be prudently incurred. It would also, in the Commission's view, prevent the Commission and interveners from properly testing those forecasts and would effectively and improperly shift the burden of proof which is squarely placed on AG by subsection 44(3) of the GU Act as noted above under "Legislative Framework".

The arguments presented by AG have not convinced the Commission to change its position from that clearly articulated by the Board in Decision 2006-004 on the same issue. In particular, the Commission is of the view that the conclusions and findings of the Board in Decision 2006-004 with respect to the applicability of the presumption of prudence to forecasts are not in contravention of the DGA Decision as was argued by AG. The Court of Appeal in the DGA Decision did not consider the applicability of the presumption of prudence to forecasts; that issue was not in front of the Court of Appeal in that proceeding and, in the Commission's view, cannot be inferred from the Court of Appeal's findings in the DGA Decision.

Applying the Presumption of Prudence

Having considered the arguments and authorities cited in this proceeding, the Commission summarizes its understanding of when and how the presumption of prudence is to be employed. Three time periods are employed for the purposes of this analysis. First, past years for which just and reasonable rates approved by a regulator were in effect -- in this case 2005, 2006 and 2007(past years). Second, the last year before the year for which new rates are being requested -- in this case 2007 (the base year). Third, the years for which an application for new rates has been filed -- in this case 2008 and 2009 (the test years).

The Court of Appeal in the DGA Decision stated at paragraph 72:

> However, in the context of rate setting, the starting point for scrutinizing management decisions is the presumption that it is in the utility's interest to make prudent decisions which also reflect the interests of its customers, by avoiding needless expenditure. That presumption will matter only when the scales are evenly balanced.

At the time of an application for new rates to be applied in future years, such as the test years in this case, the Commission begins its analysis with the actual financial and operating results in the base year as filed by the utility. This information forms the base for the forecasts and projections

[45] AR 186/2003, *Roles, Relationships And Responsibilities Regulation* (under the *Gas Utilities Act*)

of revenue requirement in the test years. The base year results represent an amalgam of capital and operating expense decisions made by the utility in the base year and other past years. Because the utility's rates in the base year and other past years had been approved by regulation as just and reasonable and because the quality of service of the utility was also regulated, the interests of customers in receiving acceptable service at reasonable prices were protected by regulation. In that environment, any decisions made by the utility within those rate and quality guidelines can be presumed prudent insofar as the balance between the monopoly power of the utility and the interests of its customers is present. For example, decisions to reduce costs and even reduce capital expenditures during such a period should be presumed prudent but the presumption is rebuttable. Indeed, in this proceeding, as discussed in Section 7.5 dealing with the Viking Operating Centre, business decisions by the Company acting within its approved rates and taken in order to fulfill its service obligations and quality of service standards, are found to be prudent even though they were not consistent with the forecasts and projections upon which the rates had been established in the prior rate case.

In cases where capital costs are incurred during one of the past years, the effects of the capital cost decision are likely to carry over into the test years due to the need to recover the cost of the capital asset over its useful life. In such a case, the capital expenditure could be subject to a prudence review employing the test articulated by the Board and upheld by the Alberta Court of Appeal in the DGA decision. This is so because the balance between the interests of customers and the company is only partially present. That is, it is only present to the extent some of those capital costs have already been recovered in past years for which just and reasonable rates have been approved. Any past regulatory decisions or directions relating to the capital expenditure (if any) would be relevant to the prudence review because they would be relevant to the extent to which the utility’s and customers’ interests had already been balanced by the regulator.

Operating expenses and capital expenditures forecast by a utility to be incurred in the test years cannot be presumed prudent because the balance between customer and company interests that would be present in a competitive market is simply not present and no regulatory examination has yet occurred to counter balance the monopoly power of the utility. In the case of forecast expenditures for forward test years, the scales are clearly not balanced between a monopoly and its customers. If they were, legislators would not have identified and acted on a need for rate or service quality regulation of monopoly utility companies. The interpretation of the presumption of prudence proffered by AG would require the Commission to presume that all of a utility’s forecasts for the test years are prudent or reasonable and must be upheld unless an onus to prove otherwise is met by others. This is not the case. The provisions of the GU Act clearly stipulate that the onus is on the applicant to prove that the proposed rates (in this case, the revenue requirements) for the forward looking test years are just and reasonable.

While the Commission does not accept AG’s interpretation of the presumption of prudence, it does acknowledge that it is necessary for the Commission and interveners to test a utility’s forecasts and for the Commission, if it chooses to apply different forecasts, to do so based on the application of its own expertise to the evidence and arguments in evidence in the proceeding.

3 PROSPECTIVITY

The issue of prospectivity was raised by AG in the context of consideration by the Commission of updated actual results, or subsequent events that were not anticipated at the time forecasts were prepared.

AG stated that during this hearing and over the past number of hearings, the Commission (and its predecessor Board) has seemed to place increasing weight on having actual information available in order to determine what a reasonable revenue requirement should be. Given that Alberta is a prospective rate-setting jurisdiction, AG submitted that it is important for the Commission to establish what it feels is the appropriate balance between having current information upon which to judge forecasts and ensuring that the proper incentives are in place to encourage the right behavior by utilities.[46]

AG cited the questions about AG's treatment of its Viking Operating Centre, discussed later in this Decision, as an example of where an issue of prospectivity emerged. AG objected to intervener suggestions that downward adjustments should be made where actual results were lower than the forecast capital costs submitted by AG for the purposes of setting the test year revenue requirement.

AG stated that it would be "double jeopardy" if the Commission assesses a penalty if actual results are lower than forecast. In essence, AG submitted, the Commission would be saying that a utility must spend precisely the forecast capital that was reflected in the rates approved by the Commission.[47]

In response to AG's "double jeopardy" argument, the UCA submitted that AG ignored the fact that the higher than forecast expenditures were related to growth and that AG in fact achieved incremental earnings on these higher than forecast additions.[48] [49]

CG discussed prospectivity more generally, and acknowledged the reality that forward test year or prospective regulation of utilities in Alberta falls somewhat short of completely prospective regulation for a number of reasons.[50]

In a forward test year jurisdiction, CG submitted, the assumption was that the regulator ultimately approves a forecast level of costs and revenues based on a reasoned review of the evidence on the record. CG went on to describe its view of the process:

> …With rates set on the basis of forecasts, the utility is provided the opportunity to make productivity gains. The utility's actual costs and revenues may be different from forecasts due to productivity improvements or due to the very fact forecasts are forecasts and there is an inherent and real risk the forecast and actual results will not be the same. However, if the utility changes the fundamental assumptions on which the forecasts are predicated without due justification there may be valid reasons to question such decisions on a

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[46] AG Argument, page 10
[47] Ibid, page 12
[48] UCA-AG-35(c)
[49] UCA Reply Argument, page 14
[50] CG Argument, page 6

> retroactive basis. The postponement of certain service centres and the resulting cost increases is a case in point.[51]

CG also noted that AG, in its Rebuttal, stated:

> The AUC should adopt a forecast based on the estimates provided by ATCO Gas in PICA.AG-03. This presents a reasonable balance. The Alberta model of regulation is established such that regulated utility companies are motivated to find efficiencies within the test period. The rewards for those efficiency improvements accrue to the shareholder during the test period and accrue to the customers from the end of the test period forward. ***The only way for this to happen is by having utility revenue requirement set on a prospective basis. That is, the utility revenue requirement should be based on the best available information prior to the test period.*** The price reduction achieved by ATCO Gas in 2008 was not anticipated in 2007. The benefits from this efficiency gain accrue to ATCO Gas in 2008. The forecast for 2010+ will be based upon the 2008 actual costs. In so doing, the benefits from the efficiency gain will accrue to customers from that point forward. {X143.01, p.30] {Emphasis added}[52]

CG stated that it did not agree with AG's interpretation of prospectivity in the above context and that the broader question here was whether information available to the Commission should or should not be used to test and adjust the forecast. CG submitted that the history of regulation in Alberta has taken into account the best available information, including any updates to reflect market conditions at the time of the hearing. Therefore, CG submitted, prospectivity effectively starts from the close of the hearing, rather than at the time of the application, as suggested by AG.[53]

Commission Findings

As a starting point, the Commission notes subsection 40(a)(i) of the GU Act parallels subsection 91(1)(a)(i) of the PU Act in allowing the Commission to consider all revenues and costs of an owner of a gas utility that are in the Commission's opinion applicable to the whole of the fiscal year in which a proceeding is initiated. In addition, subsection 91(1)(a)(ii) of the PU Act and subsection 40(a)(ii) of the GU Act permits a consideration of revenues and costs applicable to a subsequent fiscal year.

In Decision 2006-004, the EUB stated that the use of updated information has a role to play even in a prospective rate-setting environment:

> In recent years, when confronted with the question of whether or not to consider events that have occurred after the preparation of revenue requirement forecasts, the Board has usually taken the position that such information will be used in assessing the reasonableness and accuracy of the forecasts and the methodology utilized in preparing the forecasts. The Board has not, however, substituted the forecasts with the updated information, except with respect to certain specific forecast items. For example, the Board has updated interest rate forecasts in determining the cost of capital, income tax rates, opening balances for plant property and equipment and has excluded amounts forecast for capital projects that did not proceed.[6] The Board has determined that the use of updated information in these particular types of categories was in the overall public

[51] CG Argument, page 7
[52] Ibid
[53] Ibid, pages 7 and 8

> interest and had as its objective an appropriate revenue stream without undue benefit or detriment to the regulated utility. The utility has also always been able to update its application and its forecasts to reflect any unforeseen increases in costs. The Board continues to be of the view that this is the appropriate use of information that becomes available subsequent to the preparation of the forecasts underpinning an application.
>
> On the basis that the Board should have the best available information, the Board has expressed a preference in having actuals for the full year prior to the test year where possible. **Providing the Board with the best available information at the time it must make its decision, will assist the Board in determining a revenue requirement for the utility that most closely matches current expectations and conditions**. Properly considered, this should reduce the initial forecasting risk to the utility and reduce the possibility of overpayment by ratepayers.[54] [emphasis added]
>
> [6] See for example: Decision U97065 1996 Electric Tariff Applications Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation, Grid Company of Alberta, dated October 31 1997 (opening balances) (U97065 V1 and U97065 V2); Decision 2000-9 Canadian Western Natural Gas Company Limited Phase I, dated March 2, 2000 (risk free rate); Decision 2001-97 ATCO Pipelines South 2001/2002 General Rate Application Phases I and II, dated December 12, 2001(opening balances, income tax rate adjustment); Decision 2003-100 ATCO Pipelines 2003/2004 General Rate Application Phase I, dated December 2, 2003 (opening balances, disallowance of costs for cancelled project, income tax rate adjustment).

The Commission agrees with the Board's comments cited above, and continues to hold that an appropriate balance can be struck which allows for a utility to plan and budget according to its forecasts but that also provides the Commission with sufficient current information to enable it to assess the reasonableness of those forecasts. It is expected that a utility will put forth its best possible case in making an application for its revenue requirement. That best possible case should reflect information available to the utility that may reasonably form part of its Application and any updates thereto.

Given the reality that the Commission expects to receive the most up-to-date information during a proceeding and that AG and other utilities bring evidence of increasing costs during a proceeding as it becomes available, the Commission agrees with CG's submission that prospectivity effectively starts from the close of the proceeding, rather than at the time of the application. This is the practical consequence of having a proceeding that runs into the year for which a rate application is made and ensuring that the Commission has the best possible information before it in order to make a decision on that application.

Regarding the "double jeopardy" argument raised by AG, while the Commission confirms the findings of the Board in Decision 2006-004 with respect to its ability to take into account information that becomes available after the date the forecasts were prepared to make adjustments to forecasts for capital or operating expenditures,[55] the Commission cannot agree that those kinds of adjustments can be considered a "penalty." For the Commission not to take available information into account, would, as the Board has previously stated:

> …fetter its statutory responsibility to fix just and reasonable rates and would ignore the authority it has to consider **all revenues and costs of the owner applicable to the year in which an application is filed**, or applicable to a subsequent year. As described above,

[54] Decision 2006-004, pages 3 and 4
[55] Decision 2006-004, page 6

> the Board and parties should be able to test the accuracy and reasonableness of the forecasts against prior year actual results, if available, and to take into account certain specific information of the types described above.[56] [emphasis added]

The Commission's views regarding the Viking Operating Centre will be discussed in Section 7.5 of this Decision.

4 MINIMUM FILING REQUIREMENTS

In Decision 2007-017[57], the EUB approved the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities. The Commission is considering the adoption of MFR for Alberta gas utilities, similar to those for electric utilities, recognizing that gas utilities currently use the Canadian Gas Association Uniform Classification of Accounts, Alberta Regulation 546/63. The Commission will initiate a consultation on these requirements.

The Commission considers that a MFR for gas utilities would improve efficiencies of proceedings and promote consistency of information. The Commission notes that throughout argument and reply from interested parties, recommendations were made with respect to information that should be filed in a GRA process to allow for better testing of the forecasts. The MFR may address the customer forecast area and review the methodology and information relied upon when forecasting customer growth, productivity and efficiency metrics, and other information required in support of capital forecasts. The MFR consultation may also be expanded to address other topics.

5 INFLATION

Noting the booming Alberta economy, and the significant inflationary increases this placed on operating and capital costs, AG identified the following inflation rates as having been incorporated into the applied for forecasts in this Application. AG engaged Dr. M. Percy to provide expert opinion on the subject of inflation.

Table 1. ATCO Gas Forecast Inflation Rates by Cost Category[58]

Cost Category	2007 (%)	2008 (%)	2009 (%)
Labour (Occupational)	4.25	4.50	7.50
Labour (Supervisory)	10.0	10.0	10.0
Contract Services	15.2	11.0	17.9
General Materials and Supplies	5.0	5.0	5.0

56 Ibid
57 Decision 2007-017 – EUB Proceeding Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities (Application 1468565) (Released:, March 6, 2007)
58 Application, page 8.0-1 Table 8.1

The UCA submitted evidence on inflation, which was prepared by Dr. C. Bruce, who recommended the following inflation ranges for 2008 and 2009 for the cost categories identified by AG:

Table 2. Inflation Rates Recommended by the UCA[59]

Cost Category	2008 (%)	2009 (%)
Labour (Occupational)	4.50	4.0 – 5.0
Labour (Supervisory)	4.5 – 5.0	4.5 – 5.0
Contract Services	4.0 – 6.0	4.0 – 6.0
General Materials and Supplies	3.5	3.5

The Commission provides its views on the appropriate inflation rate for each cost category in the sections that follow.

5.1 Occupational Labour

Commission Findings

It appears from their evidence that both Dr. Percy and Dr. Bruce considered that an inflation rate of 4.50% for 2008 for occupational labour was reasonable. Having reviewed all of the evidence in this regard, the Commission finds the 2008 forecast inflation rate of 4.50% for occupational labour to be reasonable. Therefore, the Commission approves AG's 2008 occupational labour forecast of 4.50%.

With respect to the 2009 forecast, AG indicated that wage catch-up was required in the occupational labour category, thus justifying a 7.50% inflation rate. The Commission considers that the determination of the 2009 forecast inflation rate in this category turns on whether wage catch-up is required. If the need for catch-up is substantiated by the evidence on the record, then the 7.50% inflation factor is likely to be reasonable. If not, the Commission considers that the occupational labour inflation rate forecast will likely fall into the 4.0% to 5.0% range as recommended by the UCA. The UCA's recommendation is based on the evidence of Dr. Bruce, based on his analysis of the occupational labour market in Alberta, including inflationary increases to ATCO Pipelines and the Alberta wage inflation index for the industrial aggregate.[60]

AG argued that it based its forecast on the increasing trend of external wage settlements. In response to UCA-AG-130(i) Attachment 1, AG provided an update to Table 8.3 of the Application, which further summarized the wage settlement data into appropriate year categories and overall time frame as shown below:

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59 UCA Argument, page 138
60 Dr. Bruce Evidence, page 6 of 21

Table 3. AG Update to External Wage Settlements

External Wage Settlements					
Company	Union	2006	2007	2008	2009
AltaGas	CEP 1947	3.25	3.25		
AltaLink	UUW	3.50	4.50	4.75	5.00
City of Calgary	CUPE 38	3.00	3.50	3.50	
City of Calgary1	CUPE 37	3.00	3.50	3.50	
City of Edmonton	CSU 52	3.00	4.00	5.00	
City of Edmonton	CUPE 30	3.00	4.00	5.00	
City of Grande Prairie	CUPE 787	3.70	4.25	4.00	
City of Lethbridge	IUOE 955	3.50	3.50	3.50	
City of Lethbridge	CUPE 70	3.20	3.30	3.50	
City of Red Deer	CUPE	5.00	3.00		
ENMAX	IBEW	6.00	4.50		
ENMAX	CUPE 38	5.00	4.50		
EPCOR	CEP	3.00	4.75	5.00	5.25
EPCOR	IBEW	3.00	4.75	5.00	5.25
EPCOR	CSU 52	3.00	4.75	5.00	5.25
Fortis	UUWA	4.50	4.50		
PetroCanada2	CEP	3.00	5.00	5.00	5.00
Suncor3	CEP	3.00	7.00	6.00	6.00
TransAlta	IBEW	4.50	4.25		
TransAlta	UUWA 100	4.00	4.00	4.00	4.00
1. For 2008 general wage increase was increased, outside of bargaining, from 3.5% to 5.5%. (added since original filing)					
2. For 2008 & 2009 general wage increase of 4.5% + additional 0.5% to recognize contribution in changes to operations.					
3. For 2007 general wage increase of 5.0% + additional 2.0% for oil sands supplement. For 2008 & 2009 general wage increase of 4.5% + additional 1.5% for oil sands supplement. (added since original filing)					
ATCO Pipelines	NGEA	3.00	3.25	5.00	4.75
ATCO Electric	CEWA	3.50	3.50	5.25	5.25

While AG argued that there was an upward trend in settlements, based on the information presented in the above table, the Commission is of the view that that upward trend alone would not support the 7.50% forecast by AG.

In response to CCA-AG-18(c), AG provided the following table to support the 7.50% inflation rate forecast in 2009 for occupational labour:

Table 4. Comparison of ATCO Gas Settlements with Construction Sector Council (CSL)[61]

Year	CSL Alberta Labour Income per Hour (%)	HypotheticalEmployee using CSL Labour Income -Dec. 31, 2004 at $20/hour	ATCO Gas Wage Settlement (%) Plant Unit	ATCO Gas Hypothetical Employee - Dec. 31, 2004 at $20/hour	Percentage Difference Based on Dollars (AG vs CSL) ($)
2005	7.00	21.40	3.50	20.70	-3.38
2006	6.20	22.73	3.00	21.32	-6.59
2007	6.20	24.14	4.25	22.23	-8.59
2008	6.40	25.68	4.50	23.23	-10.56
2009	5.10	26.99	7.50	24.97	-8.09

Having reviewed the above table, the Commission notes the assumption that both employee groups (CSL and AG) start with the same hourly wage, which results in the conclusion that the wage inflation proposed by AG is reasonable. However, if the starting wages were not equal, different conclusions could result from the analysis. The Commission is not aware of any evidence placed on the record indicating the actual starting wage rates in 2004, which would justify the conclusions drawn from this comparison. On this basis the Commission does not accept AG's forecast inflation rate for 2009.

AG noted that Dr. Bruce highlighted in his evidence that ATCO Pipelines and ATCO Electric reached settlements with their respective employee associations for amounts in the 4.50% to 5.25% range for 2008 and 2009. AG argued that the referenced adjustments were incomplete, as they only referred to the base increases. Many of the job classes within ATCO Pipelines that are similar to the job classes at ATCO Gas received a market adjustment of 4.0% or higher in addition to the 2008 base adjustment of 4.5%.[62]

However, the Commission accepts UCA's argument that without information on the wages and salaries of AG's staff relative to a comparator group, it is impossible to evaluate whether previous increases were below that comparator group. Further, without complete visibility into the structure of the comparator group, it is difficult for the Commission to rule without reservation that wage increases experienced by one group will be experienced by another.

During the hearing, the following statement was made by one of AG's witnesses:

> A. MR. ENGLER: And I hesitate to put this on the record, but there have been a few questions even by the Commission about what's the current status of things today. I can tell you that we have completed negotiations with our association. I can't give you any details. I can tell you there is catchup.[63]

The Commission understands that companies may choose not to reveal their planned wage increases for competitive or confidentiality reasons, and that these same considerations may

[61] Sourced from "Construction Looking Forward - Labour Requirements from 2007 to 2015"
[62] AG Argument, page 93, lines 18-22
[63] Transcript Volume 7, page 1469, lines 10-15

explain why AG's actual negotiated result was not discussed further at the hearing However, the Commission considers that information such as this would have been extremely helpful in rendering its decision on this matter, and notes that it has processes in place to receive such information on a confidential basis.

Based on the information provided, the Commission is of the view that AG has not demonstrated that a catch-up is required for the occupational labour category and as a result, AG's forecasted inflation rate of 7.50% is not accepted by the Commission.. Rather, based on the information presented in this proceeding, the Commission finds that the upper end of UCA's 2009 occupational labour inflation forecast of 5.0% is more reasonable which is based on the evidence of Dr. Bruce, based on his analysis of the supervisory labour market in Alberta, including wage increases to Alberta Government management employees and the Alberta wage inflation index for Professional, scientific, and technical services industrial aggregate.[64] Therefore the Commission directs AG to apply an occupational labour inflation rate of 5.0% in 2009 to all appropriate amounts in the Application and update all corresponding tables in the refiling.

5.2 Supervisory Labour

Commission Findings

AG forecasted a 10% inflation rate for Supervisory Labour for 2008 and 2009. The UCA provided evidence in support of a range of 4.5% to 5.0% for both years for the same category.

While AG argued that attraction and retention of employees has been difficult given the economic conditions, the witness for AG, Dr. Percy, indicated that there was less workforce mobility at supervisory levels than at occupational levels. Based on this information, the Commission considers that the 10% inflationary increase forecast for supervisory staff may be overstated.

While the UCA pointed to the fact that Alberta Government management employees will receive an increase of 4.80% in 2008, AG pointed out that this increase did not take into account pay grade adjustments and lump sum payments, which would have the effect of increasing the settlement above the 5.0% recommended by the UCA. However, no evidence was filed to demonstrate that these additional adjustments would result in the 10.0% increase sought by AG. Further, as indicated above in Section 4.1, without complete visibility into the comparator group, it is difficult for the Commission to find that wage increases experienced by one occupational group will necessarily be experienced by another.

AG filed the Association of Professional Engineers and Geologists of Alberta (APEGGA) Employer Salary Survey, which shows an actual average increase of 7.8% for 2007 in support of its 10.0% inflation rate. However, the UCA argued that engineers are only 20% of AG's supervisory labour complement. Noting this statistic, the Commission considers that the APEGGA Employer Salary Survey does not provide sufficient support to conclude that a 7.8% wage increase would be expected for t the other 80% of AG's supervisory complement. The Commission also notes that the 7.8% is well below AG's forecast inflation rate of 10.0%. As a result, the APEGGA Employer Salary Survey on its own would not provide support for the 10% inflation forecast proposed by AG.

[64] Dr. Bruce Evidence, page 9 of 21

In response to UCA-AG-128(c), AG provided the results of its review of the 2007 Mercer (MCTS) database comparing AG's non-executive, non-union (Supervisory) base pay and total cash to a group of utilities, pipelines, and midstream participants. AG indicated that it was 0.1% above the median for base pay, and 10% below the median on base pay plus short term incentives. This information demonstrates to the Commission that past wage increases for AG supervisory employees have kept pace in Alberta. However, in reviewing this evidence in light of Dr. Percy's statement[65] that the escalation of growth in Alberta started in 2003, and Dr. Bruce's evidence that the increase in annual weekly earnings peaked in 2005 at 5.21%, the Commission also finds that it cannot accept AG's proposed inflation rate of 10% for supervisory employees in both 2008 and 2009. In making this finding the Commission also relies on the evidence of Dr. Percy and Dr. Bruce that the inflationary pressures in the Alberta economy are decreasing. This suggests to the Commission that it is unlikely that AG will be required to increase its supervisory compensation by 10% in each of 2008 and 2009.

In the Commission view, the Conference Board of Canada's projected average salary increases in Alberta for 2008 of 5.2%, filed by AG,[66] provides an independent third party assessment of the likely 2008 experience.
Further, the Commission understands that AG's inflationary increases for 2008 and 2009 are net of any VPP payments. While the Commission will deal with VPP later in this Decision, the Commission notes that VPP is calculated as a percentage of salary. Further, the Commission understands that this amount could equal up to 5% of salary. Adding the maximum VPP amount to the UCA forecast range results in total salary increases of between 9.5% and 10.0%. for those employees eligible for the full amount.

Given the UCA's observation that management increases appear to be in line with occupational increases, and based on the findings above, the Commission directs AG in the refiling to apply a supervisory inflation rate of 4.5% in 2008 and 5.0% in 2009 to all appropriate labour categories in the refiling.

5.3 Contract Services

Commission Findings

In considering AG's forecast contractor inflation rates for 2008, the CG made a number of recommendations in its argument:

> In CG's submission ATCO Gas' contracting practices leave a number of unanswered questions. The result is customers are being asked to pay contractor cost increases significantly higher than those recommended by Dr. Bruce or the increases considered applicable by other utilities operating in the Province. ATCO Gas should be directed to review its contracting practices, including bid design to enable efficient price discovery among bidders.
>
> CG recommends ATCO Gas be directed to review its capital expenditure forecasts and apply the appropriate inflation increases to the appropriate cost components comprised of materials, labour, overhead and contractor costs. ATCO Gas should also be directed to use the actual 2007 supply dollars for purpose of determining the inflation dollars for 2008 by project.

[65] Transcript Volume 1, page 151, lines 12-17
[66] UCA-AG-128(i) Attachment

> CG does not object to ATCO Gas' forecast of second year increases for two year contracts subject to any adjustments needed to correct for duplication between the first and second year rates and for any allowances included in the second year rate for the unlikely event of requests for increases from contractors to complete the contracted work.
>
> CG recommends a contractor price increase in the same range as recommended by Dr. Bruce of 4% to 6% for all one year contracts involving distribution plant in 2008. Having regard to the downward trend noted by Dr. Bruce, CG recommends a contractor price increase of 5% for this category of contracts for 2008.
>
> Given the downward trend noted by Dr. Bruce, the contractor cost increases relative to construction of operating centers should be set at 5% for 2008.
>
> CG submits there is no merit in ATCO Gas' suggestion the contractor price reduction resulting from the entry of two new contractors for the mains replacement work should be retained by ATCO Gas' shareholders in 2008 and 2009. CG submits the contractor price change for this category of contracts should reflect the 8% price reduction obtained by ATCO Gas in 2008.
>
> With respect to 2009, CG notes Dr. Bruce's evidence that contractor increases should be in the 4% to 6% range. Based on this, the increases forecast by other Alberta utilities and the foregoing points with regards to 2008, CG recommends a 5% increase in contractor costs for 2009 on average for all contracts reflected in X170.[67]

Having reviewed the recommendations of the CG, the Commission makes the following general comments. While the CG makes some interesting observations regarding the contracting practices of AG, the Commission does not share all of the CG's concerns. The Commission notes that AG has indicated that it follows an industry standard process to secure fair, equitable and competitively priced quotes. The Commission considers that directing further process with respect to contracting practices at this time is not necessary.

The Commission accepts CG's submission that inflation forecasts should be consistently applied to the appropriate category or expenditure for which the inflation rate has been forecast. It is not clear to the Commission whether AG forecasts projects on a line by line basis; if this is not the practice, breaking out inflation factors for each specific line item for each project could result in significant amounts of additional work. The Commission considers that it would be more appropriate for AG to provide a discussion in its next GRA of how it applies inflation forecasts. Therefore the Commission directs AG in its next GRA to provide a discussion of how it applies inflation forecasts as noted above, and how these inflation forecasts are applied to projects with various time horizons. Further, to the extent that AG has double counted the second year increase for two-year contracts, the Commission directs AG in the refiling to remove these costs from the forecasts and clearly report these changes in the appropriate schedules.

The Commission notes that the CG recommended a contractor inflation rate of 5% for 2008, while the UCA recommended that the inflation rate fall within the 4%-6% range. The Commission rejects the UCA forecast inflation rates, given the evidence from BTY (Alberta)

[67] CG Argument, pages 123-124

Ltd.[68] that anticipated escalation rates for institutional projects would be 15.0% for 2008. On this basis, AG's proposed contractor inflation rate of 11% appears reasonable.

However, AG indicated that inflation forecasts were based on AG's actual experience for 2007, with the assumption that the pace of growth in 2006 and 2007 will continue in 2008 and 2009. The Commission notes that during the hearing it was acknowledged that the pace of growth in Alberta had decreased from previous levels[69] [70]. On this basis, the Commission considers that it would be appropriate to reduce AG's 2008 forecast level for contractor inflation to 10%. Therefore the Commission directs AG in the refiling to apply a contractor inflation rate of 10% to all appropriate forecasts.

Regarding 2009 contractor inflation rates, the Commission considers that evidence placed on the record of this proceeding suggests significant decreases in the 2009 contractor inflation rate as compared to AG's original forecast of 17.9%.

With respect to the issues surrounding the forecasting of contractor inflation rates in 2009, the Commission notes the following testimony from Dr. Bruce[71]:

> A. DR. BRUCE: So this is the issue we've been talking about, the difference between short run and long run competitive pricing. In the long run, in a competitive market, prices have to increase at the same rate as costs because if prices rise faster than costs, if firms are making profits, and that will attract more firms. That's what's meant by competition.
>
> To an economist, a competitive market is a market where it's easy to get in. Not easy in the sense that you and I could do it, but somebody with a few million dollars can do it. There's enough people like that. It's competitive.
>
> In the short run, it's possible that prices will rise faster than costs because it takes a while for competitors to mount an attack on you and bring prices back down. So the long-winded answer is prices and costs have to rise pretty much in line in a competitive market over the long run. The question is: Are we in -- how long is the long run? How long does it take before we're in the long run? It's how long it takes new firms to come in and compete prices back down again.
>
> He's saying we're in the short run. In the next year or so perhaps demand pressures will be sufficient that prices will be driven up faster than in costs and firms won't be able to come in and compete those prices down because it takes too long to enter the market. That's quite possible.
>
> So the issue is not whether he and I disagree on that point, it's how much pressure is it going to be. Are

68 CCA-AG-41(f) Attachment
69 Transcript Volume 1, page 151, lines 18-22
70 Transcript Volume 2, page 276, lines 15-20
71 Transcript Volume 2, page 282, starting at line 4

> the firms going to be able to increase prices 15 or 17 percent when costs are only going up 3 or 4 percent? I didn't think that the data showed that was happening. And he agreed, and that's when he modified his argument to 10 to 12 percent.
> So I think the issue is: Is 10 to 12 percent too much? We don't really have any good information on this. I'm sorry. We're not going to be very helpful to you. But what I can say, it seems to me fairly clear that costs are not likely to raise much more than about 5 percent. Cost of materials, cost of labour, in total. So if there's an increase in prices beyond that, it's because contractors are making very big profits. And if that's the case, I would have thought ATCO would be getting into this themselves in house

In light of Dr. Bruce's testimony that costs are only increasing by 3-4%, the Commission considers that for contractor inflation rates to reach AG's forecast of 17.9% there would have to be a shortage of contractors in 2009 that is equal or greater than what occurred in 2008. Based on the views expressed during the hearing from Dr. Bruce and Dr. Percy, the Commission understands that growth in the economy is expected to slowdown in 2009, which implies that a greater number of contractors will be available; therefore the inflationary pressures due to the lack of contractors will not materialize.

Further, the Commission notes Dr. Bruce's evidence that information on Specialty Trade Contractors suggests that the 2006-2007 trade labour wage inflation was approximately 6.71%.[72] Dr. Bruce also highlighted the following report:

> A review of a report entitled *Construction Labour Relations – An Alberta Association Wage Summary Construction – Alberta 2007-2011* suggests that trade occupations will experience an increase in wages of approximately four to six percent in 2008 and 2009 respectively. These percentages reflect increases for both journeyman and foremen.[73]

The Commission notes that AG indicated in its Application that the Construction Sector Council for Alberta forecasted labour income per hour percentage increase of 5.1% in 2009. Based on this information the Commission considers that the inflationary component of labour cost for contractor services will be significantly lower as compared to the past. Given the slow down in the economy, market pressures will not force contractor prices to rise above costs as experienced in the past.

The Commission cannot ignore the testimony of Dr. Percy, which based on new evidence; inflation for this category would be in the 10-12% range compared to the original 2009 forecast of 17.9%. The Commission considers that this is strong evidence that AG's forecast inflation rate will not be achieved.

Given that there is not expected to be an increasing shortage of available contractor services in 2009, market pressures are unlikely to force contractor price increases above cost increases. Therefore, the Commission is not satisfied that Dr. Percy's contractor inflation rate is likely to be

72 Dr Bruce Evidence, page 13
73 Dr. Bruce Evidence, page 12 of 21

experienced. The Commission is persuaded that the inflation forecast recommended by the UCA is more likely to be experienced, because it is consistent with historical and projected cost increases.

Further, the Commission notes the information supplied by CG respecting other utilities' contractor costs, such as FortisAlberta Inc.: 12.3% in 2006 and forecasts increases of 7.1% in 2007, 5.9% in 2008 and 5.5% in 2009 and EPCOR Distribution and Transmission cost increases of 6.5% in 2006, with forecast increases of 5.4% in 2007 and 4.0% in each of 2008 and 2009.[74] The Commission finds that this information provides support for the reasonableness of the UCA inflation forecast.

Based on these findings, the Commission approves a contractor inflation rate for 2009 of 5% and directs AG in the refiling to apply a contractor inflation rate of 5% to the appropriate contractor amounts for 2009.

5.4 General Materials and Supplies

Commission Findings

The Commission notes that in the past, the Consumer Price Index (CPI) has been used to determine the applicable inflation forecast for general materials and supplies. The Commission recognizes AG's argument that during periods of significant growth, the CPI may not be a reliable indicator of inflation for a utility's materials and supplies. However, given the expected slowdown in the rate of growth in the Alberta economy, predicted by both Dr. Percy and Dr. Bruce,[75] the Commission is of the view that CPI is a reasonable estimator in this case.

The Commission notes that the expert witness both considered that it was unlikely that inflation for this category would reach 5%. The Commission has reviewed the UCA materials and supplies inflation forecast of 3.5%, and finds this to be a reasonable estimator of inflation for 2008 and 2009. Therefore the Commission directs AG to apply general materials and supply inflation rate of 3.5% for 2008 and 2009 to the appropriate amounts in the refiling.

6 CUSTOMER GROWTH

The customer growth forecasts provided by AG for the 2008-2009 test period were used as part of its calculation of the related sales revenue, capital expenditures and operating expenses. A comparison of forecast and actual year end customer growth by North and South zones has been provided in Table 5 below:

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74 Written Evidence of Mr. Raj Retnanandan, page 24

75 Transcript Volume 1, page 151 lines 18-22, and Transcript Volume 2, page 276, lines 15-20

Table 5. ATCO Gas Summary of Year End Customer Growth by Zone[76]

	ATCO Gas North			ATCO Gas South		
Year	Forecast	Actual	Variance	Forecast	Actual	Variance
2002	9,030	12,396	3,366	10,965	12,553	1,588
2003	8,971	11,652	2,681	10,729	14,163	3,434
2004	9,038	12,738	3,700	10,662	13,842	3,180
2005	11,688	13,117	1,429	13,106	12,134	(972)
2006	11,922	15,081	3,159	12,763	15,198	2,435
2007	15,948	17,015	1,067	15,584	14,954	(630)
2008	16,674			15,972		
2009	17,535			16,324		

6.1 Reliability of Customer Growth Forecasts

The UCA was concerned that the customer growth forecasts provided by AG were not reliable or convincing evidence given the large changes in prior forecasts, or in comparison to actuals. The UCA commented these changes in prior forecasts could have impacts on growth related costs.

The UCA recommended that any potential adjustments to customer growth should be accompanied by corresponding adjustments to capital additions, return, taxes, depreciation and O&M.

The UCA proposed that AG provide reconciliations with any updated forecasts since AG did not provide any comparative analysis or explanations for changes in updates to prior forecasts.[77] The UCA was concerned that no information was provided showing why the forecast changed, how it changed, including any underlying support. Similar anomalies and inconsistencies existed for forecast and actual capital expenditures related to customer growth. The UCA recommended this area be addressed or future impacts would only grow for customers.

The UCA submitted that AG should be directed to provide side-by-side comparisons of all actual and forecast information by date with a full explanation of the identified anomalies and inconsistencies including any underlying supporting documentation in its refiling. The UCA stated that forecasting customer growth and related costs required a high degree of transparency to facilitate testing and evaluation of AG's forecast.

The CG commented that there have been significant differences in customer counts between forecasts and actuals. The CG argued that no supporting evidence relating forecast customer additions to housing starts was provided. The CG recommended that AG should forecast its residential customer additions using the best forecast information available for housing starts. The CG recommended that AG be directed to provide support for its forecast of residential customer additions with empirical data from the various sources it examined, including data on new housing permits and any other relevant economic data, as part of its next GRA.

The CG submitted that AG's present forecast method of using a three-year average of growth in all classes to spread the total customer growth forecast between the classes produced no change to the forecast number of customers in the high use rate class for the current application, and that

76 AG Rebuttal Evidence, Attachment 13, page 1 of 1
77 UCA Evidence, Attachment 3

this method has not produced accurate forecasts in the past, as shown in Table 7 of its evidence. The CG stated that AG's forecast method had implications for the demand revenue forecast for the high use rate class. The customer forecast was a significant component of the demand forecast for the high use rate class because the average highest normalized peak per customer was multiplied by the number of high use customers in the forecast month.

The CG recommended that AG be directed to refine its forecasting of high use customer additions to independently forecast such additions having regard to known developments in each community, in addition to using analytical methods to track historical growth patterns for high use customers. The CG highlighted that while AG had argued that a more detailed approach to forecasting high use billing demands would require additional manpower resources, AG had not quantified the cost impact.

AG disagreed with the UCA suggestion that AG's forecasts were inappropriate because they were not based on 2007 actual information. AG stated that it had provided an updated forecast for comparison purposes in its rebuttal evidence. In response to UCA's recommendation to increase AGs customer growth forecast based on calculating the average difference between AG's forecast of growth in previous years and what actually happened, AG stated that no causal relationship existed to support the adjustment as past growth does not influence what will occur in the future. AG explained that the 2007 actual customer growth had shown that the UCA recommendation was inaccurate.

In response to the UCA's concern over anomalies and inconsistencies, AG stated that it did not consider growth related year to year fluctuations to be anomalous or inconsistent. Therefore, the UCA's forecast should be rejected.

AG stated that the UCA had connected customer growth with capital expenditures growth and had accepted AG's forecast capital expenditure growth, but the UCA still advocated a 20% increase in AG's customer growth numbers for determining sales revenue. AG acknowledged that accurately forecasting customer growth in the recent past has been a challenge but AG's revenue forecasting history accuracy has been high over the past five years.[78]

AG disagreed with the UCA that the customer growth forecast should be increasing while the costs should be decreasing, as the UCA had ignored the related impact on AG costs. AG commented that the UCA would have AG adjust its revenue forecast for the additional growth but not increase its capital or operating expenditures. AG submitted that if the Commission decided to increase AG's customer growth forecast that AG be allowed to incorporate the impact on all components of its revenue requirement as part of the compliance filing.

AG stated that it has reviewed its forecasting practices to identify improvements that could be made. AG indicated the forecast of customer additions was developed for each community with input from various sources, including Canada Mortgage and Housing forecasts, Economic Development Edmonton forecasts and discussions with local housing authorities in smaller communities. Then AG explained that the information gathered was evaluated by its employees and management to determine the forecast for residential customer additions. AG added that it had relied on the knowledge and judgment of its experienced employees and management.

[78] AG Rebuttal Evidence, page 141, lines 16-22

AG disagreed that there was an issue with forecasting the customer growth for the high use rate group. AG indicated it had based its forecast growth on a three-year average for each customer class to spread the total customer growth forecast between the rate classes and that AG had demonstrated that the three-year average growth for high use customers should be zero.

AG disagreed with the CG's proposed change to its method of forecasting demand volumes. AG argued that even though the CG had stated that the forecast for relatively large high use customers should be developed based on discussions with those customers, the CG did not support the inclusion of the additional costs that would be incurred. AG stated that it did not believe more accurate demand forecasts would occur, but it would incur additional costs using the CG's proposed method. AG requested that if the Commission determined this change was needed, AG be allowed to amend its revenue requirement to include the extra cost.

Commission Findings

The Commission understands the implications and importance of maintaining a reasonable customer growth forecast. A review of Table 5 above suggests that forecasts for previous years may have been understated, however, the Commission notes that the 2007 combined North and South customer growth forecast had a variance of only +1.4% when compared to actuals.

Additionally, the Commission notes that AG's revenue forecasting accuracy for the past five years was in the range of 1.3% to -.2%.[79] As the calculation of the sales forecast is one of the major areas where customer growth forecasts are used, the Commission finds that concerns of potential understatement of customer growth as shown on Table 5 are partially offset by the revenue forecasting accuracy. The Commission finds forecast customer growth for the test years 2008 and 2009 to be reasonable when compared to the trends shown in Table 5 above. Seeing these findings, the Commission is of the view that the reconciliation and variance analysis proposed by the UCA is not necessary for the test period. Therefore the Commission is not seeking the information requested by the UCA on customer growth forecasts.

Regarding residential customer additions, the Commission notes that AG indicated that it gathered information for each community from various sources, including Canada Mortgage and Housing forecasts, Economic Development Edmonton forecasts and discussions with local housing authorities in smaller communities and relied on the experience of its employees to prepare its forecast.[80] The Commission is satisfied that AG has shown that the forecasts for customer additions were reasonable as AG applied its judgment and experience to the information gathered.

With respect to the high use rate group customer growth, the Commission has considered the information presented by the CG in Table 7 of its evidence in relation to the evidence submitted by AG. The Commission notes that the percentage of error displayed in Table 7 appears high for the high use customer group in comparison to the total forecast error for all classes combined. The Commission believes that the percentage is high because of the smaller relative size of the high use customer group as shown in Tables 7.2N and 7.2S.[81] Furthermore, a 1:1 correlation may not exist between high use customer growth and growth for other customer groups. Comparison of Table 7 in the CG's evidence across the years 2003 to 2006 also provides an indication that

[79] AG Rebuttal Evidence, page 141, lines 16-22
[80] AG Reply Argument, page 138, lines 15-19
[81] Application, Section 7 – Utility Revenue, page 7.0-8

the actual additions by each group have been difficult to forecast for all classes, not just the high use customer group. The Commission is satisfied that the overall method used by AG to allocate its customer growth forecast between the different classes has produced reasonable forecasts for the high use customer group.

Based on the evidence submitted by AG, the Commission finds that AG has shown that its forecasts for customer growth are reasonable and approves the forecast as filed for the purposes of determining the net revenue requirement.

In addition, the Commission has considered whether AG should be directed to provide the empirical data used to support its forecast of residential customer additions as part of its next GRA.

The Commission is of the view that the filing of the empirical data is not likely to assist the Commission in making a determination on the reasonableness of the forecast as judgment is applied to the data gathered. Furthermore, the Commission considers that the increase in workload and costs incurred by AG, arising from the forecasting of high use customer additions as suggested by the CG, may not produce significantly different forecasts. Also, the recommended analytical methods to track historical growth patterns for high use customers appears not to significantly differ from the historical analysis currently used by AG which includes all customer groups.

However, as noted previously, the Commission is initiating a consultation on MFR for gas utilities, which may address information requirements for customer growth forecasts.

7 RATE BASE

7.1 2008 Opening Balances

In its rebuttal evidence, AG updated the opening balances for 2008 Property Plant and Equipment (PP&E), accumulated depreciation, and Construction Work In Progress to reflect 2007 actual information. The impacts on the forecast revenue requirements are reductions of $2,696,000 for AGN and $3,487,000 for AGS for 2008 and $2,190,000 for AGN and $2,269,000 for AGS for 2009.

The Commission questioned the CG,[82] Calgary[83] and the UCA[84] with respect to the opening balance of PP&E as restated to include 2007 actual results. The Commission understood from these responses that parties were satisfied with the updates. In respect of the updates to the PP&E as they apply to IT and CC&B capital, the Commission will discuss these in Section 9 of the Decision. The Commission has reviewed the 2008 opening balances, and finds they are reasonable, with one condition. Subject to the Commission's findings in Section 9 with respect to IT and CC&B capital, the Commission approves the 2008 PP&E opening balances, and directs AG in the refiling to reflect these changes in its forecasts and revenue requirement calculations.

[82] Transcript Volume 8, page 1652, starting at line 17
[83] Transcript Volume 8, page 1562, starting at line 3
[84] Transcript Volume 8, page 1738, starting at line 17

7.2 Capital Expenditure Forecast History

The UCA submitted that AG spending of higher than forecast amounts on capital expenditures in 2005-2007 should not be accepted as the basis for AG's forecast unit costs or forecast capital expenditures in 2008 and 2009. The UCA argued that the Commission should use 2007 actual base unit costs, inflated using rates recommended by the UCA's expert witness, Dr. Bruce, for meter stations, feeder mains, urban and rural distribution mains, services meters, regulators, urban mains replacements and meter relocation and replacement programs.

AG argued that the 2007 actual information was used as it deemed appropriate for each specific area and that it has consistently applied inflation factors throughout the Application.

Commission Findings

The Commission notes that in several categories AG capital expenditure was higher than forecast in 2005-2007. However, the Commission is cognizant of the fact that several factors outside of the control of AG were at play in Alberta during that time period, particularly in 2007. Because of this, using 2007 unit pricing across all categories may not lead to optimal forecasting for the test period. Therefore, the Commission will consider each area of AG's capital spending forecast to assess the reasonability of forecasts for 2008 and 2009.

7.3 Distribution Extensions

Distribution extensions consist of four main sub-categories of expenditure: Urban Main Extensions, Rural Main Extensions and Services, Urban Feeder Mains, and New Regulating and Meter Stations. These capital expenditures are required either to serve new customers added to the system or to acquire other systems through purchase or annexation. The capital expenditures required to serve system growth are driven by decisions made by municipalities and developers. The expenditures are required to enable AG to meet its franchise obligations as new developments attract new customers.

7.3.1 Distribution Services

The following table summarizes the costs forecast by AG and those proposed by UCA.

Table 6. Distribution Services

	2008 ($ Million)	2009 ($Million)
AG[1]	40.4	49.2
UCA[2]	37.6	41.4

[1] UCA Evidence, page 28
[2] AG Rebuttal Evidence, page 26

The UCA rebased the 2007 unit costs to actual costs and inflated the unit costs based on the inflation rate recommended by Dr. Bruce. The UCA pointed out that AG had forecast an increase of 31% in unit costs from 2006 to 2007, but actually experienced only a 21% increase. The UCA argued that given the problem in forecasting for 2007, AG may repeat the same error for the test period.

The UCA argued that although AG experienced an increase in contractor costs from 8% to 39% in 2007, there is no evidence that this trend will continue with increases of up to 30%. The UCA noted that AG secured the services of out-of-province contractors for urban mains replacement work, resulting in a 24% reduction in urban mains replacement, and should therefore be able to do the same for distribution services.

The UCA also noted that if AG applied UCA's forecast of customer growth to the distribution services, a higher than forecast costs for distribution services would have resulted. Although The UCA noted that AG has historically under-forecast customer growth, they have not revised its forecast costs for distribution services.

The CG argued that costs for distribution services vary by region as evidenced in the hearing[85] However, because AG did not provide support for its forecast costs by region, the CG argued that is it not possible to test the reasonableness of AG's forecast. Therefore, the CG argued that AG should be directed to provide support for cost increases by region so that these costs can be meaningfully compared with each region.

AG pointed out that the UCA was inconsistent in its argument that AG did not apply its customer growth forecast to distribution services, which would have resulted in increases of $5.5 million in 2008 and $1.1 million in 2009. Therefore, the UCA's argument for the number of services and its inflation assumptions are flawed and inconsistent with other parts of its argument and should therefore be rejected.

AG argued that the increases in 2007 were in part due to the fact that many two-year contracts were renewed that year. AG further argued that a similar increase can be expected in 2009 when these contracts are up for renewal again. AG noted that some of the highest contractor price increases at 39% were in the Edmonton Capital region.

AG also argued that the forecast increases are based on average contractor price inflation and are universally applied across all capital expenditure categories, not broken down by specific regions.

Commission Findings

The Commission notes that the differences between AG's forecasts and UCA's proposals in Table 6 above are due to the use of different inflation factors, not different volumes. In Section 5 of this Decision, the Commission provided its views with respect to appropriate inflation factors, and directed AG to apply the inflation factors to the appropriate categories. Therefore, the Commission considers that inflationary impacts will be appropriately dealt with in AG's refiling.

The Commission notes CG's recommendation that information should be provided by region to allow for better testing in the GRA process. As noted, previously the Commission is initiating a consultation on MFR for gas utilities, which may address whether information should be provided by region.

[85] Transcript Volume 2, page 316, line 3

7.3.2 Urban Mains Extensions

AG stated that the two key variables in forecasting urban mains extensions are the number of lots and the cost of installation per lot. The following tables summarize the amounts applied for by AG and those proposed by the UCA.

Table 7. Urban Mains Extensions

	2008 ($ Million)	2009 ($Million)
AG[1]	26.8	31.7
UCA[2]	28.9	31.4

[1] AG Rebuttal, page 22
[2] UCA Argument, pages 23-24

The UCA argued that because AG did not provide the ratio of services to lots installed or the extent to which the three year average was used or the 2006 unit costs it has not met the burden of proof to support its forecast of urban mains extensions expenditures. The UCA also argued for using the 2007 unit costs and adjusting them for the inflation factors provided by Dr. Bruce.

The UCA contended that AG would experience higher customer growth than forecast in 2008; therefore, the UCA proposed an increase in AG's forecast in 2008 and a reduction in 2009.

The UCA noted that in relation to contractor costs, AG secured the services of out-of-province contractors for urban mains replacement, resulting in a 24% reduction in urban mains replacement work, and should therefore be able to do the same for urban mains extensions.

The CG argued that AG did not provide the economic drivers behind the forecast number of lots and did not break down the costs by administrative area for meaningful comparison. Because these two elements are missing from AG's forecast for capital expenditures for urban mains extensions, the CG recommended that AG be directed to provide this information in future GRA filings.

AG pointed out that its forecasting methodology is supported by comparing its forecast costs for urban mains extensions for 2007 of $25.22 million and the actual costs incurred of $25.25 million.

AG explained that the unit pricing is based on a three year average, or on contractor pricing where that is known and that some pricing is calculated differently depending on whether the work will be completed by contractors or in-house staff. AG noted that the 2-year mains contract for Edmonton had an 18% price increase in 2007.

In response to the CG's recommendation for more information, AG noted that it provided historical details of work performed, lots forecast, and split of work between contractors and in-house crews, construction practices, inflation rates in responses to information request. Consequently, AG argued that providing more detailed information should be unnecessary.

AG disagreed with the UCA's customer growth forecast and noted that UCA's proposals would result in an increase in urban mains extensions.

Commission Findings

The Commission is of the view that the differences between AG's forecasts and UCA's proposals in Table 7 above are due to the use of different inflation factors. In Section 5 of this Decision, the Commission provided its findings with respect to appropriate inflation factors, and directed AG to apply the inflation factors to the appropriate categories. Therefore, the Commission considers that inflationary impacts on urban mains extensions will be appropriately dealt with in AG's refiling.

The Commission rejects the UCA's submission that 2007 unit costs for urban mains extensions should be used and adjusted for inflation because this method fails to consider the volatility of the costs of urban mains extensions and multi-year contractor pricing. However, the Commission accepts the UCA and CG submissions that the calculation behind the forecast for capital costs on urban mains extensions is unclear. The Commission notes that it is initiating a consultation on MFR for gas utilities, which may address the calculation used to forecast capital costs of urban mains extensions.

7.3.3 Rural Mains Extensions and Services

AG used a three-year average to forecast unit costs because of the small number of customers, and inherent volatility, involved. The following table summarizes the amounts applied for by the AG and those proposed by the UCA.

Table 8. Rural Mains Extensions and Services

	2008 ($ Million)	2009 ($Million)
AG[1]	13.4	15.1
UCA[2]	16.9	17.7

[1] Application, pages 2.1-6 to 2.1-7
[2] UCA Evidence, page 24

The UCA applied the 2007 actual unit costs with the inflation factor proposed by Dr. Bruce to the UCA's customer growth forecast to determine its proposed amounts. The inflation factors recommended by Dr. Bruce are 4.74% in 2008 and 4.85% for 2009. The UCA noted that the actual unit costs were higher than forecast in the North and lower than forecast in the South.

The CG argued that AG has not explained the significant variability in the cost for rural mains extensions and services from year to year. The CG recommended that AG be directed to provide more meaningful metrics to explain the unit costs for rural mains and services in its next GRA.

AG argued that in 2007 the inventory of lots constructed appeared to exceed the number of customers added, which consequently drove the unit cost higher than forecast in 2007. This trend is expected to reverse as more customers are added to these serviced lots in the test period.

AG argued that under the UCA's proposal lot inventory would need to increase faster than subdivisions are filled up and therefore the UCA's position was unreasonable.

Commission Findings

The Commission agrees with AG that the best method to address the volatility in unit pricing is to utilize three-year averaging. The Commission is not persuaded by UCA's argument that 2007 unit prices should be used.

The Commission is of the view that the difference between AG's forecast and the UCA's proposal in Table 8 above is due to the use of different inflation factors. In Section 5 of this Decision, the Commission provided its views with respect to appropriate inflation factors, and directed AG to apply the inflation factors to the appropriate categories. Therefore, the Commission considers that inflationary impacts will be appropriately dealt with in AG's refiling.

The Commission considers that AG has provided sufficient explanation for the variability in the unit costs for rural mains extensions and services. The Commission considers that CG has not demonstrated that overly detailed information will better assist the Commission in making a decision respecting ATCO's rate base. However, as noted previously, the Commission is initiating a consultation on MFR for gas utilities, which may address unit costs for rural mains extensions and services.

7.3.4 Urban Feeder Mains and Regulating Meter Stations

The following table summarizes the amounts applied for by the AG and the amounts proposed by UCA. Although AG continued to support the three-year average for calculating unit costs outside of the test period as directed in Decision 2006-004, because it is currently within the test period AG used more current information to forecast unit costs.

Table 9. Urban Feeder Mains

	2008 ($ Million)	2009 ($Million)
AG[1]	11.5	10
UCA[2]	7.0	7.4

[1] AG Rebuttal Evidence, page 24
[2] UCA Evidence, page 26

Table 10. New Regulating Meter Stations

	2008 ($ Million)	2009 ($Million)
AG[1]	1.3	1.45
UCA[2]	1.1	1.1

[1] AG Rebuttal Evidence, page 25
[2] UCA Evidence, page 27

The UCA noted that the 2007 urban feeder mains forecast was 42% higher than actuals. The UCA also noted that the 2008 and 2009 forecasts do not follow the three-year method requested by AG and approved by the EUB in Decision 2006-004. The UCA calculated unit costs for urban feeder mains using the three-year methodology. The forecast was then adjusted for growth factors and inflation rates recommended by Dr. Bruce.

The UCA also calculated the unit cost for new regulating meter stations using the three-year average, adjusted for inflation and growth factors, discussed above.

The UCA argued that AG cannot select a method of forecasting costs that will be to its advantage and then select another method when it is no longer to its advantage.

The CG argued that AG should use factors beyond the historical averages to forecast costs for urban feeder mains and regulating meter stations. The CG submitted that AG should be directed to regard the length and size of pipe as well as historical averages in its forecast for urban feeder mains and new regulating meter stations.

AG argued that many of the urban feeder mains projects forecast for 2007 did not materialize but were expected to occur in 2008. Because of this occurrence, AG increased its original forecast in the Application by $1.5 million in rebuttal evidence.[86] AG estimated that the actual costs for the test period for urban feeder mains to be $29 million. AG submitted that three quarters of these projects will proceed, and have therefore forecast $21 million.

AG argued that expenditures for new regulating meter stations doubled from 2005 to 2006 and then doubled again in 2007. AG argued that using an historical average does not address the exponential growth being experienced in the required numbers of new regulating meter stations.

Commission Findings

The Commission's findings in respect of appropriate inflation rates are discussed in Section 5 of this Decision. The Commission's findings in respect of customer forecasts are discussed in Section 6 of this Decision.

The Commission notes that the three-year method for forecasting costs in urban feeder mains and new regulating meter stations was requested by AG in its last GRA and subsequently approved by the EUB in Decision 2006-004. The Commission accepts that in the test year because of the exceptional growth experienced by AG, the rigorous application of the three-year method would have produced a patently incorrect forecast, such that in mid 2007, it was clear that a revised forecast using a three-year (2004-2006) average inflated to 2007 dollars would be less than the actual cost of work in progress.[87] Given this circumstance, the Commission considers that AG's forecasting for 2007 to be reasonable.

The Commission does not accept the amounts as proposed by the UCA to be a reasonable expectation of urban feeder mains. However, during the proceeding the Commission heard evidence that the overall Alberta economy was not experiencing the exponential increases as in the past, and even Dr Percy had modified his estimates of contractor inflation from 17.9% to 10-12% range. In light of the evidence presented, the Commission does not consider AG's increase of $1.5 million dollars to urban feeder mains to be reasonable. Therefore the Commission directs AG in the refiling to use its forecast of $19 million as originally filed.

The Commission also directs AG in its refiling to adjust the inflation factors used in the forecast for urban feeder mains and regulating stations using the rates of inflation approved by the Commission in Section 5.

[86] ATCO Gas Rebuttal Evidence, page 24
[87] UCA-AG-25(c)

The Commission is not persuaded by CG that the forecast for urban feeder mains would be made materially more reliable should additional factors like the length and size of pipe be included in the analysis. However, as noted, the Commission is initiating a consultation on MFR for gas utilities, which may address the information requirements provided with respect to forecasting these items.

7.4 Distribution Improvements

Distribution improvements provide for the improvement and replacement of AG's distribution system and capacity upgrading to serve increased load. Expenditures are categorized into Mains Replacements, Meter Relocation and Replacement Project (MRRP), Urban Main Relocations, Regulating Meter Station Improvements and Cathodic Protection Improvements. Forecasts are made based on estimates of specific projects. Unspecified expenditures are forecast based on historical levels of spending.

7.4.1 Urban Mains Replacement

Mains replacements are required to maintain a safe and reliable system. The facilities to be replaced are typically 60-year old steel pipe installations. AG forecast $12.1 million for 2008 and $19.3 million for 2009[88] for mains replacements.

The UCA supported the replacement of urban mains where the risks are unacceptable but had concerns respecting the forecast expenditures that AG proposed for urban mains replacement, which included:

- projects identified in the 2005-2007 GRA were delayed and/or cancelled,
- actual expenditures for 2005-2007 were well below applied-for amounts,
- significant reductions in scope (km) occurred for those projects that did proceed,
- efficiencies were discovered after the forecasts were filed (directional drilling, attraction of out-of-province contractors),
- forecast inflation of 17.7% and 17.5% exceeds the rates recommended by the witnesses for UCA, Dr. Bruce, and AG, Dr. Percy, and
- the forecasts appear to be based on preliminary information which was subjected to detailed engineering analysis, not economics, made before deciding on which projects truly represent risk to the public.

The UCA noted that actual capital expenditures for urban mains replacement were $17.5 million in 2005, $8.7 million in 2006 and $6.8 million in 2007. Having regard for its concerns and savings from AG's continued use of directional drilling and alignments with other utilities, the UCA proposed that urban mains replacement expenditures should be limited to $7.5 million ($6.0 million plus $1.5 million in delays in 2007) in 2008 and 2009. However, the UCA considered that if the adjustment to alignments is not ongoing, then $11 million to $12 million (average of the last three years) may be an appropriate level.

> CG submits there is no merit in ATCO Gas' suggestion the contractor price reduction resulting from the entry of two new contractors for the mains replacement work should be retained by ATCO Gas' shareholders in 2008 and 2009. CG submits the contractor price

[88] Exhibit 0143.01.ATCO GAS-11, AG Rebuttal Evidence, page 29 of 187

change for this category of contracts should reflect the 8% price reduction obtained by ATCO Gas in 2008.

AG stated that an important distinction to be made with regard to forecast and actual expenditures for urban mains replacement: replacement projects are executed when the level of risk presented by the continued operation of a particular pipe network is unacceptable, whereas forecasts of replacement projects are the areas where it is expected that the level of risk presented by the continued operation of particular pipe networks will be unacceptable. Consequently, if the risk in an area that was anticipated to increase does not arise, that area is not replaced but if an unplanned area has an unacceptable level of risk, that area is replaced immediately whether or not previously forecast in a GRA. AG therefore rejected the manner in which the UCA proposed to limit the forecast of expenditures for 2008 and 2009.

AG stated that since the filing of the IR responses it has captured an efficiency gain in urban mains replacement by attracting two out of province contractors to the Edmonton market, which resulted in a contractor price decrease in Edmonton. AG thus expected that it will be able to complete the 2008 work in the North for $8.3 million. AG argued that, as this efficiency improvement of $2.6 million was achieved inside the test period, it should be allowed to keep the benefits of the gain in accordance with regulatory principles upon which Alberta utilities are regulated. AG further argued that utility customers get the benefit of efficiency improvements when future years' forecast costs are based on the actual costs that include the improvement.

AG noted that no party suggested that the scope of urban mains replacement work should be reduced. AG submitted that a reduction in urban mains replacement costs as suggested by UCA would completely eliminate prospectivity from the regulatory process.

Commission Findings

The Commission finds that there was no issue with respect to the level of urban mains replacement work forecast by AG during 2008 and 2009. However, the Commission notes that the UCA's submission that there should be limitations on the forecast dollar amounts of expenditures in 2008 and 2009, depending on AG's ability to make an ongoing adjustment to alignments This submission was based on the UCA's concerns about delays and actual expenditures in urban mains replacement projects undertaken by AG during the 2005 to 2007 period. In this regard, the Commission accepts AG's explanation for the differences in the past between forecast and actual expenditures for urban mains replacement and will not limit AG's scope for forecasting urban mains replacement projects based on expenditure limits in the manner proposed by the UCA.

With respect to urban mains replacement in 2008, the Commission finds that the 8% price reduction due to the entry of two new contractors in Edmonton is not a productivity improvement as suggested by AG, and any cost reductions associated with this should be reflected in the costs for 2008 and 2009. Therefore the Commission directs AG in the refiling to appropriately reflect the 8% price reduction associated with the new contract pricing applicable to urban mains replacement and refile the corresponding schedules highlighting this change.

However, an issue of concern is the inflation factor used by AG to determine the amount of costs used in forecasting its urban mains replacement program. In regard to the inflation rates used by AG to determine its forecast costs of urban mains replacement for 2008 and 2009, the

Commission considers that AG should use those rates s approved by the Commissions on the appropriate rates of inflation as set out in Section 5. Accordingly, the Commission directs AG, in its refiling to adjust the inflation factors used in forecasting costs for urban mains replacement using the rates of inflation approved by the Commission in Section 5 of this Decision.

7.4.2 Valve and Vault Replacements

Valves are extremely important in emergency situations such as hit lines and when gas to buildings cannot be shut off at the customer valve during a fire. Valves are also used to isolate connected systems with feeds from different gas sources. A vault refers to a box containing valves. Replacement of valves is necessary because valves are subject to deterioration for many reasons including corrosion, damage or ineffectiveness due to water accumulations, freezing, and wear and tear. AG forecast $2.3 million in 2008 and $2.5 million in 2009 for valve and vault replacements.[89]

The UCA noted that AG used inflation rates of 8% in 2008 and 16.7% in 2009,[90] which it considered to be excessive. The UCA considered that an inflation factor of 5% would be more appropriate, based on inflation for services and meters and the recommendation of its witness, Dr. Bruce. Thus the UCA recommended that reductions of $0.404 million in 2008 and $0.762 million in 2009 should be made to AG’s forecast for valve and vault replacements.

AG submitted that the cost per valve varies considerably from one year to the next and replacement cost varies with the size of the valve replaced. AG noted that the actual costs in 2007 were $43,500/valve compared with the actual costs in 2006 of $46,000/valve. AG argued that forecast cost for valve replacements in 2008 and 2009 of $54,000/valve and $63,000/valve, respectively, continue to be appropriate considering the significant variability in unit cost per valve and the continued upward pressure on prices.

Commission Findings

The Commission finds that there is no issue with respect to the quantities involved with AG’s forecast of valve and vault replacements during 2008 and 2009 and therefore approves that part of AG’s program. However, the issue of concern to interveners is the costing of replacements with an acceptable rate of inflation. In this regard, the Commission considers that the rates of inflation used by AG to forecast costs for valve and vault replacements for 2008 and 2009 are those approved by the Commission on the appropriate rates of inflation as set out in Section 5. Accordingly, the Commission directs AG, in its refiling to adjust the inflation factors used in forecasting unit costs for valve and vault replacements using the rates of inflation approved by the Commission in Section 5 of this Decision.

7.4.3 Meter Relocation and Replacement Project

AG forecast costs of $41.2 million (14,643 units) in 2008 and $52.2 million (14,303 units) in for the Meter Relocation and Replacement Project (MRRP).[91] The MRRP mirrors the plans of 2006 and 2007.

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89 Exhibit 0093.00.ATCO GAS-11, Tables 2.1.5 and 2.1.6
90 Exhibit 0199.00.ATCO GAS-11
91 Exhibit 0093.00.ATCO GAS-11, Table 2.2.13 and Response to UCA-AG-29(a)

The CG was concerned with AG's over-forecast of meter relocations in 2005 (3.5%) and 2006 (5.6%). In addition, the CG was also concerned with the level of forecast MRRP program expenditures, driven by the increased number of moves and a higher unit cost per relocation, forecast for 2008 and 2009. The CG noted that contractors were forecast to complete between 63% and 69% of the meter moves[92] in the test period and that the contractor costs were significantly higher than similar costs of meter relocations forecast to be made by AG's employees. Therefore, the CG submitted the contractor portion of the MRRP should be reduced and the in-house portion increased. The CG suggested that if AG should become constrained by available labour, the number of meter moves for 2008 may have to be deferred to later years. In light of the over-forecasting of meter moves in the last GRA and to facilitate the reallocation of a greater portion of the moves to in-house labour, the CG recommended the MRRP forecast be reduced by 4.6% in both 2008 and 2009.

The UCA had concerns about AG's forecast for the MRRP, which included:

1. AG's failure to complete planned moves in 2006 and 2007 ostensibly because of increases in contractor rates and the overall capital spending limitations, has resulted in those units not completed now being rescheduled at significantly higher unit costs and in effect has cost customers an additional $1.2 million over 2006 and $2.0 million over 2007 costs,
2. the 2007 actual unit costs were 6.25% less for underground moves and 30% less for safety moves than AG's 2007 updated forecast,
3. the 2.5% adjustment for labour progression for AG's employees involved in the MRRP lacked support as AG did not provide information about the number of entrant level employees, the number of retiring employees nor the number of employees leaving the MRRP departments at mid-pay grades,
4. the use of 5% for inflation for materials and supplies appeared excessive,
5. the use of 15% for contractor inflation was not supported, and
6. the factor of 20% applied to contractor and in-house labor to account for the work being more spread out appeared to be an arbitrary assumption without supporting evidence.

Consequently, the UCA, based on assumed 10% of total costs for materials and supplies, calculated MRRP cost escalation for 2008 and 2009 as 4.68% and 4.85% respectively. The UCA considered that the actual costs per move in 2007 represented a reasonable base upon which to inflate MRRP in 2008 and 2009 and calculated costs for 2008 and 2009 as follows:

Table 11. Meter Relocation and Replacement Capital Costs[93]

	2007A ($)	2008F ($)	2009F ($)
Underground (per unit)	2,550	2,669	2,798
Safety (per unit)	737	771	809
Revised capital expenditures (millions)		38.5	39.5
Reduction in forecast costs (millions)		2.7	12.6

[92] Exhibit 0034.09.ATCO GAS-11, Response to UCA-AG-29(b), Attachment 1
[93] Exhibit 0102.02.UCA1-11, Evidence of the Office of the Utilities Consumer Advocate, page 34

The UCA noted cost savings related to two out-of-province contractors brought in by AG and considered that the data to support the 20% premium factor applied by AG to both contractor and in-house MRRP crews was insufficient. Consequently, the UCA recommended that the 20% factor should be reduced to no more than 10%. The UCA also recommended that the 2.5% wage adjustment factor was unjustified and should be rejected.

The UCA noted that AG confirmed that there are separate contracts for MRRP contractors and some of the MRRP contracts for 2008 have been received and the forecasts are expected to materialize.[94] The UCA submitted that, while there may be some support for the 2008 MRRP contract prices used by AG in 2008, that there is no support for its use of a 15% inflation rate in 2009 and that the rate should be 4.85%.

AG asserted that it was not trying to limit capital spending but that contractor resources were not able to complete work awarded to them; therefore, the CG and the UCA misunderstood reasons for not completing planned moves in 2006 and 2007. AG argued that the UCA was incorrect about unit prices in 2006 and 2007, noting that unit prices can vary from less than $1,000 for a simple move to over $5,000, depending on the amount of work required. AG stated that in 2007 a disproportionate amount of lower price work was completed but in 2006 the opposite had occurred, resulting in higher than forecast unit costs. AG expected the mix of work in 2008 and 2009 to revert to its historical average, with unit prices being confirmed by recent contractor prices.

AG argued that the UCA's opposition to the 2.5% included for labour progression was based on an incorrect assumption. AG submitted that the MRRP internal employee costs are appropriate because, while there are many employees at the top of their range, approximately 50% are early in their progression and receive progression adjustments to their wages at roughly 5% on a step basis; hence the wage inflation forecast included one-half of the 5% step rate, i.e., 2.5%.

AG argued that the UCA's concern regarding the cost forecast of MRRP was not based on fact, adding that the 2008 forecast costs are expected to materialize based on the 2008 contracts. AG submitted that the premium factor of 20% for the work to be performed on sites spread out across the province was based on AG's judgment, which, in view of subsequent contractor premiums obtained containing quotes in the range of 3% to 30%, appears reasonable. AG also argued that the 15% contractor price inflation factor for the work to be performed in 2009 was also reasonable considering the price increases seen in both of 2007 and 2008. In this regard AG submitted that there is nothing on the record to suggest that subsequent events will not support the MRRP forecasts and they should be approved as filed.

Commission Findings

The Commission notes that the Board conditionally supported the revised meter relocation and replacement plan proposed in AG's 2005-2007 GRA Phase I.[95] Given that the MRRP proposed by AG for 2008 and 2009 mirrors the previous plan the Commission accepts the implementation of the MRRP in the manner proposed by AG. The Commission also accepts AG's reasons for not completing the number of meter relocations previously approved by the Board. However, the Commission agrees with interveners that AG has not sufficiently demonstrated to the Commission's satisfaction that applying a 20% premium factor to MRRP because the work will

[94] Exhibit 0143.01.ATCO GAS-11, AG Rebuttal Evidence, page 33
[95] Decision 2006-004, ATCO Gas, 2005-2007 General Rate Application Phase I, pages 9 and 10

be performed on sites spread out across the province is appropriate. The Commission recognizes that labour constraints may be involved but expects AG to use its best efforts to utilize in-house labour in carrying out the MRRP and, in the absence of any otherwise conclusive evidence, will allow a midrange premium of 16.5% (midrange between the 3% and 30% received) as opposed to the 20% requested by AG and the 10% proposed by the UCA. Therefore, the Commission directs AG in the refiling to reduce the premium factor for the MRRP to 16.5% for the test years.

With respect to general rates of inflation used by AG to forecast costs for the MRRP for 2008 and 2009, the Commission considers that the rates are those approved by the Commission on the appropriate rates of inflation as set out in Section 5. Accordingly, the Commission directs AG, in its refiling to adjust the inflation factors used in forecasting unit costs for the MRRP using the rates of inflation approved by the Commission in Section 5 of this Decision. The inflation factors should be applied based on the forecast mix of contractors and in-house crews.

7.4.4 Commercial Below Ground Entries

AG initiated a four year project in 2007 to address the risks of underground straight in entries to commercial buildings and determine whether or not to install above ground shut-offs at approximately 1,700 commercial building sites. AG forecast costs of $5.6 million in 2008 and $6.0 million in 2009 for this project, based on a 2007 unit cost of $10,000 adjusted for inflation.[96]

The UCA submitted that AG did not provide any detailed cost information in support of the 2008 and 2009 expenditures and only limited actual information was provided for 2007 expenditures. The UCA noted that AG's unit costs for the project were based on judgment[97] instead of a detailed estimate. The UCA considered that given the forecast installation of 550 units in each of 2008 and 2009, AG should be able to achieve economies of scale. Therefore, lacking detailed cost estimates, the UCA recommended that an arbitrary 10% reduction should be applied to actual unit costs (adjusted base 2007 unit cost of $8,904 (actual $9,893 x 90%)) for reductions of $631,000 in 2008 and $671,000 in 2009.

AG argued that, as each site is unique, there is no practical way to generate a meaningful detailed estimate or economies of scale for all 1,700 sites, which are spread out across the province. AG submitted that the average actual cost of about $9,900 per unit that was incurred in 2007 would suggest that its forecast unit costs for 2008 and 2009 were reasonable.

Commission Findings

The Commission accepts AG's explanation that the uniqueness of the sites involved would make a detailed cost estimate impractical. In this regard the Commission finds that AG's method, using an average unit cost incurred in 2007 adjusted for inflation, for forecasting the project's costs for 2008 and 2009 reasonable under the circumstances. The Commission therefore rejects the UCA's recommendation of a reduction of 10% to the unit costs. However, the Commission considers that the rates of inflation used by AG are the rates approved by the Commission on the appropriate rates of inflation as set out in Section 5. Accordingly, the Commission directs AG, in its refiling to adjust the inflation factors used in forecasting unit costs for the Commercial Below Ground Entry Project using the rates of inflation approved by the Commission in Section 5 of this Decision.

[96] Exhibit 0093.00.ATCO GAS-11, Vol 2, Tab 2.1, BC 04, page 14 of 20
[97] Transcript Volume 4, page 795

7.5 New Operating Centres

AG proposed capital expenditures on four operating centres:

Table 12. Operating Centre Capital Costs

Operating Centre (OC)	2007	2008	2009	Total
	($ Millions)			
Viking[98]	0.2	3.3		3.5
North Edmonton[99]		8.5	16.3	24.8
Ft. McMurray[100]		4.6	1.5	6.1
Airdrie[101]		4.0	7.9	11.9
Total	0.2	20.4	25.7	46.3

In addition, AG proposed to re-open its Blue Flame Kitchen (BFK) facility in Calgary at a forecast cost of $1.0 million for renovations in the Calgary ATCO Centre in 2008.[102]

With respect to the Airdrie OC, Calgary was concerned that AG's determination of the parameters that made build-to-own more viable than leasing were assumptions made by AG without independent advice, which in turn caused its present value calculations to be doubtful. Calgary considered that in view of the Stores Block Decision AG was using property ownership to enhance its return in the long run. Calgary proposed that the net proceeds on a sale of property should be treated as a contribution against the cost of the new property or that those proceeds should be treated as miscellaneous revenue for the purpose of reducing the revenue requirement. Consequently, for the purposes of this Decision, Calgary submitted that any approval of proposed land and structures to be included in AG's rate base be conditioned upon the proceeds from the proposed disposition of assets be treated as a contribution towards the costs of new assets. Calgary considered that other options may be available in this regard but any determination would be subject to the Asset Disposition Rate Review proceeding.

Calgary recommended that the forecast capital expenditures to re-open the BFK facility in Calgary should not be approved. Calgary considered that the proposed re-opening of the facility was not based on a proper analysis and instead appeared to be an attempt to use space and make up for the denial of the cost allocation to ATCO Electric. Calgary also considered that its residents can be served from the Edmonton location.

The CG noted that Viking OC was originally forecast for 2005-2007 test year but its completion was deferred, causing cost increases of approximately $1.6 million. The CG questioned the reasons for the delay in construction and considered that if the postponement of the project was a result of higher capital expenditures in other areas, the explanation for postponing that expenditure into a future period was not reasonable. The CG submitted that AG has been imprudent with regard to completion of Viking and, in the absence of more persuasive reasons

98 Exhibit 0143.01.ATCO GAS-11, AG Rebuttal Evidence, page 37 of 187
99 Ibid, page 38 of 187
100 Ibid, page 40 of 187
101 Ibid, page 43 of 187
102 Exhibit 0093.00.ATCO GAS-11, page 4-2.27

justifying the delay, the capital costs of Viking should be reduced by $1.6 million, to the 2005-2007 GRA amounts.

The CG noted that AG received approval for its forecast 2005-2007 completion of Fort McMurray OC for $3.2 million in 2007,[103] notwithstanding the CG's submissions and recommendations to defer inclusion of the project in that test period. The CG submitted that AG was imprudent with respect to the Fort McMurray OC, particularly because AG tendered the project only as a modular project and not as a build in place project. The CG submitted that customers should not be required to absorb the costs from the last GRA and the increased inflation costs arising from a delay in completing construction. The CG considered that, to do otherwise, would be to create an incentive for utilities to delay projects in order to increase the final amount included in rate base, while earning a return on the uncompleted project between test periods. Therefore, the CG recommended that the addition to rate base for the Fort McMurray OC should be limited to the forecast amount approved in the last GRA.

The CG considered that AG's forecast timeline regarding the construction schedule for the Airdrie OC appears to have insufficient flexibility to absorb delays impacting various steps in the project and the delays AG had already incurred make completion by the end of 2009 exceedingly unlikely. Therefore, the CG submitted the capital expenditures related to the Airdrie OC should be removed for the test period.

The CG agreed with Calgary that expansion of BFK in Calgary was unnecessary and therefore any capital costs involved should be disallowed.

The UCA noted that AG originally forecast the Viking OC to be in service in 2006 at a cost of $1.2 million. With the Viking OC, the UCA was concerned that AG made an unrealistic cost estimate, which missed some $750,000 in costs, no updated business case following the unsuccessful tender in September 2007 and the failure to proceed because of construction inflation despite the Board's approval in 2006. Accordingly, the UCA submitted that the cost of the new Viking OC should be reduced by $210,000, representing the return, taxes and depreciation on the $1.2 million included in rate base in 2006 and 2007, on the grounds that the Viking OC was prematurely included in the 2006 rate base.

The UCA noted that the price of the North Edmonton OC had increased primarily due to inflationary increases. UCA also noted that the detailed cost estimate prepared by BTY (Alberta) Ltd. in April 2008 for the North Edmonton OC was based on the original design using the same inflation estimates of 18% for 2008 and 15% for 2009, as were provided to AG in January 2008. The UCA also noted that its witness, Dr. Bruce, placed the non-residential building price inflation at 5.5% to 6.5%, annualized by the fourth quarter of 2007, and that AG's witness, Dr. Percy, had reduced his estimate of contractor inflation for 2009 to 10%-12%. Therefore, the UCA submitted that the inflation rate used to cost the North Edmonton OC was overstated by about 12% in 2008 and 9% in 2009 and the revised cost should be reduced by about $2.5 million, based on Dr. Bruce's recommendations.

The UCA had reservations that the first phase of the Fort McMurray OC may not be completed during 2008 because of the delays in commissioning the operating centres in Red Deer, Viking,

[103] Decision 2006-004 – ATCO Gas 2005-2007 General Rate Application (Released: January 27, 2006), pages 23-24

Fort McMurray and North Edmonton. Notwithstanding its concerns, the UCA did not oppose the inclusion of the Ft. McMurray OC in rate base.

The UCA noted that the Airdrie OC was expected to be tendered in December 2008, construction to commence in spring and completion by December 2009, which prompted completion concerns that were similar to those it had for the Ft. McMurray OC. As the UCA did not oppose the inclusion of the Ft. McMurray OC in rate base, the UCA considered that one of the two new operating centres should be deferred one year. The UCA therefore submitted that on the basis of probabilities given the delays incurred with other operating centres, the Airdrie OC should not be included in rate base until 2010. However, if approved for inclusion in rate base in 2009, the UCA submitted that the costs of the Airdrie OC should be reduced by $1.2 million to adjust for the excessive inflation rate used by AG.

AG submitted that evidence provided by interveners did not factually reflect the timing and cost estimates for the operating centres.

AG asserted that construction of the Viking OC was not previously delayed as a result of capital expenditures in other areas but was delayed because of the following:

- Community Concerns and Cost Escalation
  The Village of Irma and the Town of Tofield expressed concerns about the move and numerous meetings with the Mayor and Council of Irma in particular were required to resolve these concerns.
- Land Availability
  In early 2007 an agreement was reached with the Town of Viking and Beaver County with an expectation of site readiness by Spring 2007 but the Town and County could not deliver the site for physical construction access (site grading and road access) for a further six months to September 2007.
- Initial Tender
  Construction was tendered in September 2007 but as very high bids were received a decision was made to delay and rebid the project in January, 2008. The rebid resulted in a savings of almost a million dollars versus the September 2007 bids. Proceeding in the earlier timeframe would thus have resulted in the higher costs.

AG argued that interveners based their assertions of imprudence on hindsight, which is not relevant. AG submitted that the test for inclusion of the $3.5 million in 2008 should be whether or not it had been prudent in the decisions it made on this project, based on the best information available at the time of those decisions. Referencing Decision 2000-1,[104] AG contended that any evaluation of imprudence should be based on whether or not the decisions reflected good judgment and discretion and were reasonable in the circumstances which were known, or reasonably should have been known, when the decisions were made.

AG argued that the UCA was incorrect with its contention that costs were missed in the Viking OC estimate. AG stated that its estimate was based on a total dollar per square foot basis, and when compared to costs for its operating centres in Red Deer and Sherwood Park, the Viking OC estimate was reasonable.

[104] Decision 2000-1 – ESBI Alberta Ltd., 1999/2000 General Rate application, Phase 1 and Phase II (Application 990005, File Nos. 1803-1 and 1803-3) (February 2, 2000), page 46

With respect to the adjustment proposed by UCA, AG stated that the delay in construction had resulted in it being unable to achieve labor cost savings of $150,000/year, utilities and maintenance savings of $31,000/year, and meeting room rental costs of $2,300/year. AG noted that the impact of these direct costs was to reduce the UCA's recommended disallowance of $210,000 to a maximum of $27,000, which excluded significant intangible costs.

AG noted that construction of the Viking OC had begun and completion was scheduled in 2008. AG thus submitted that no disallowance for the Viking OC was warranted and that the forecast costs for the Viking OC should be approved as requested.

AG submitted that the BTY (Alberta) Ltd. estimate for the North Edmonton OC did not include an inflation component as it was a current year estimate and thus there was no basis for a reduction for an inflation factor. AG noted that the land for the North Edmonton OC had been purchased and construction was scheduled from October 2008 to October 2009. AG believed that it provided the information required for assessing the reasonableness of the forecast and submitted that forecast costs for the North Edmonton OC be approved as requested.

AG confirmed that the land for the Airdrie OC had been purchased and stated that a contract would be tendered in December 2008 enabling construction to begin in the spring of 2009 and completed by December 2009. AG opposed the recommendations by the CG and the UCA that forecast costs for the Airdrie OC not be included in rate base for the test period and submitted that the costs should be approved as requested.

AG further stated that it had relied on BTY (Alberta) Ltd.'s cost estimate which included a softening cost escalation to 15% for the remaining year. AG noted that the rate was also supported by Alberta Infrastructure building cost escalation rates. AG submitted that no evidentiary support had been provided by the UCA for its inflation assumption.

AG disagreed with Calgary's perspective on the Airdrie OC with regard to building ownership versus leasing. While AG acknowledged that it had not sought advice from a consultant on the Airdrie OC present value calculations, it noted that it administered numerous leases and also had the benefit of consultant recommendations on other projects. AG rejected Calgary's recommendation of using proceeds of sale to reduce cost as being confiscatory and contrary to law and cited the Stores block decision in support.

AG stated that the Ft. McMurray OC was tendered in 2007 as a modular project but that no bids were received. AG noted that when the project was subsequently re-tendered to accommodate conventional construction options, a contract was awarded and construction was scheduled for completion in early 2009. AG also stated that construction was not delayed due to higher costs, other capital expenditure requirements or increased earnings. AG also noted that cost estimates for the Ft. McMurray OC included an inflation factor and a location factor to reflect that costs in Ft. McMurray were higher than in central Alberta. Therefore, AG submitted that costs for the Ft. McMurray OC should be approved as requested.

AG submitted that the BFK remained an important part of its on-going communication efforts with customers to disseminate safety and conservation messages and gauging customer satisfaction. AG explained that the drivers for the re-introduction of the BFK in Calgary were the increased customer growth in Alberta, space restrictions in the Edmonton area, and the provision of additional benefits to customers and communities in the South service area. AG noted that communication with its customers had become increasingly more complex and difficult in the ever evolving high-tech world. AG stated that the BFK, notwithstanding its perception of providing services for cooking and food preparation, was used to promote the safe and efficient uses of energy and was a highly effective resource that would assist AG to meet its obligations as a gas distribution utility in Alberta. AG stated that the ATCO Center in Calgary was selected because it was centrally located, had accessible parking and transit service and was a place where customers would expect to find utility services.

Commission Findings

The Commission is cognizant of the economic realities that could have constrained construction projects in Alberta and therefore accepts AG's explanation for the delays incurred in completing operating centre projects, which were otherwise approved in AG's last GRA, and its reasons for increases in cost estimates.

In addition, the Commission has considered the evidence placed on the record by AG and the interveners regarding the prudency of AG's decisions in allocating previously approved amounts in its capital expenditure program. In particular, the Commission notes the evidence of one of Calgary's witnesses, who, when asked whether Calgary had any concerns regarding capital expenditures made by AG between 2005 and 2007, stated, in part:

> But other than in the IT and ITBS area, which we outlined in our evidence, where it appeared that they were forecasting certain things as expenses in capital or vice versa, Calgary has no real concerns with respect to what transpired these last three years because of, as I say, the caveat that, in actual fact, it looks like, in order to provide service, ATCO had to spend at least that much money in their -- into rate base.[emphasis added]
>
> So it's not like customers are paying for something, a phantom rate base, if I can use that term. The rate base was there. It just wasn't a piece of rate base was anticipated in the last decision.[105]

After a review of the record, the Commission concludes that AG's decisions in regard to these matters were prudent and therefore will allow the Viking, North Edmonton, Ft. McMurray and Airdrie operating centres to be included in rate base in for 2008 and 2009 in accordance with the construction schedules proposed and updated in this GRA proceeding.

With respect to the amount of costs to be included in rate base for the four operating centres, the Commission notes that it approved inflation rates for the test period in Section 5 of this Decision. The Commission's approval of the final amount of costs forecast for each project is subject to the adjustment of the amounts to the approved inflation rates. Accordingly, the Commission directs AG in the refiling to adjust the inflation factors used in forecasting costs for the Viking, North Edmonton, Ft. McMurray and Airdrie operating centres using the rates of inflation approved by the Commission in Section 5 of this Decision. Given that the North Edmonton OC is a current

[105] Transcript Volume 8, page 1563

project for 2008, the Commission agrees with AG that there will be no adjustment for inflation in 2008.

Having regard for the Stores Block Decision and the Asset Disposition Rate Review Proceeding, the Commission is of the view that commenting on Calgary's recommendations concerning the use of net proceeds from a sale of assets by AG would not be appropriate at the present time. The Commission will consider such issues in the Asset Disposition Rate Review Proceeding.

With respect to the re-opening of the BFK in Calgary, the Commission considers that AG has not demonstrated to the Commission's satisfaction that the facility in Calgary is warranted. AG has not shown how direct communication with customers will be established or the amount of customer traffic that it expects will use the facility in any given year, particularly if communication with customers has trended more to the electronic format (the high-tech world). The Commission is not convinced that the service cannot be provided through the Edmonton office.

Further, the Commission notes that the BFK in Edmonton was considered to be a "legacy" service.[106] The Commission views that this legacy service was related to AG's former involvement in the retail gas business. Given the responsibilities of retailers and their ability to offer product differentiation to customers the Commission does not consider that additional BFK resources should be approved in this Application. The Commission accepts the submissions of the interveners that the facility is not needed at the present time and denies inclusion of capital costs in revenue requirement for the BFK facility in Calgary.

If AG wants to reopen this issue, the Commission considers that AG should address the reasons it used for originally closing the facility in Calgary, and how circumstances have changed which would justify these costs being included in future revenue requirements.

7.6 Automated Meter Reading

AG proposed two projects involving Automated Meter Reading (AMR). One project, beginning in 2008, involves the eventual replacement of 3500 AMR devices, all of which have been discontinued by the manufacturer and have been unsupported by the vendor for over two years. The total replacement cost of new AMR devices was estimated to be $2.9 million. For this purpose AG forecast costs of $540,000 in 2008 and $560,000 in 2009. The second project involves installation of AMR devices for load research purposes on approximately 5,400 Rate 1 non-residential sites (Rate 1 sample) at an estimated cost of $5 million.

With respect to replacing 3500 existing AMRs, Calgary noted that AG gave no indication that the forecast of $500,000 per year was based upon failures of the existing devices and that a safety issue was not involved. Calgary suggested AG should wait until the equipment starts to fail before initiating the project.

Based on AG's statement that the percentage of customers that are read using AMR in the North is 7.8% and in the South is 8.4%,[107] Calgary recommended that the inclusion of $5 million for AMR devices for load research in the rate base for 2009 not be approved. Calgary considered that AG had more than enough AMR devices in service that could be used for load research.

[106] Decision 2006-004, page 70
[107] Exhibit 0211.00.ATCO GAS-11, response to an undertaking

The CG supported the need to assess diversity among Rate 1 customers but was concerned that the $5 million projected cost was not cost effective in the near term for the purposes of analyzing load research because the AMR devices would be scattered. The CG therefore submitted that the proposed expenditure of $5 million for the project should be denied for purposes of this proceeding.

The CG also recommended that AG should be directed to propose an approach to load research where the cost was consistent with the relatively small proportion of non residential customers within Rate 1 who were apparently the main target of the load research as part of its refiling.

The UCA did not support including the $5 million for load research meters in AG's rate base. The UCA contended that AG was not using an appropriate process to conduct its load research and that its method of using annual average consumption as the variable was incorrect to statistically estimate the daily or hourly demands that were used to plan the system. Consequently, the UCA submitted that AG provided no reliable evidence to support for the size of its load research program and thus the actual number of meters needed for accurate load research. The UCA recommended that request for the load research meters should be rejected.

AG noted that Calgary was the only intervener to oppose the AMR replacement project. AG also noted that most of the hourly AMR devices (2300 of 3500) are used for billing high use customers, which requires hourly billing information. AG thus submitted that its intention was to replace the AMR devices before they fail and avoid a situation that could impede its ability to properly bill customers.

AG stated that the load research was proposed in direct response to the Board's direction in Decision 2007-026, which stated:

> In particular, ATCO Gas is directed to include in its next Phase I application a program designed to collect a representative sample of diversity measurements across the North and South distribution systems. The results of this program, if approved by the Board in the next Phase I proceeding, will be provided in the next Phase II proceeding.[108]

AG disagreed that it had enough AMR devices in use to conduct the load research as directed by the Board. AG argued that, with the exception of the residential sample, the existing AMR devices on low use customers provide monthly meter readings only and were not capable of providing the hourly data necessary to respond to the direction.

With respect to the use of AMR devices for load research, AG noted that, while the Rate 1 sample would provide other additional information for load forecasting and load settlement, its primary purpose was for use in the estimation of the hourly peak by rate group for cost allocation, not the calculation of annual consumption. AG argued that the proposed number of AMR devices in the Rate 1 sample would result in a cost allocation between rate classes that was more reflective of actual system use.

[108] Decision 2007-026 – ATCO Gas, 2003-2004 General Rate Application Phase II, Cost of Service Study Methodology and Rate Design and 2005-2007 General Rate Application Phase II (Application 1475249) (April 26, 2007), Direction 14

AG stated that it determined the sample size of 5,400 sites in order to estimate hourly consumption within a bound of +/- 10%. AG further stated that a reduction in the sample size would be accompanied by an increase in the error and thereby result in questionable conclusions regarding each rate group's contribution to the hourly peak.

AG submitted that data obtained could also be used within the Daily Forecasting and Settlement System, which could enhance forecasting and settlement accuracy. AG considered that the longer term benefits of proceeding with the project warrant the costs that were required to establish the sample.

Commission Findings

The Commission recognizes that the replacement of the existing AMR devices in question will occur over a number of years and will replace the ones which are no longer manufactured or vendor supported. The Commission accepts the reasons provided by AG that the project is warranted and therefore approves the project's forecast costs of $540,000 for 2008 and $560,000 for 2009.

The Commission accepts the submissions of interveners with the forecast of $5 million for the Rate 1 sample proposed by AG for its load research program and the method by which AG is conducting the load research. The Commission finds that AG has not demonstrated that the project will achieve the intended results in a cost effective manner and notes that AG also expressed uncertainty about the project in its Application as follows:

> ATCO Gas would note that in the Phase II proceeding it indicated that there is no guarantee that the information obtained from this additional sample will result in an improvement in the cost allocation methodologies currently being used. Given the significant cost associated with undertaking this project and the uncertain outcome, ATCO Gas is seeking approval of the cost of establishing this sample before it undertakes the work. ATCO Gas therefore does not anticipate that the results of the sampling will be available for the next Phase II proceeding.[109]

Accordingly, the Commission denies the costs, estimated to be $5 million, for the Rate 1 sample for purposes of this Application. The Commission directs AG in the refiling to remove the costs associated with this project.

7.7 Replacement of Non-Gas Sales Information System

The Non-Gas Sales Information System (NGSIS) is used to track the addition of new services onto AG's distribution and to bill for non-distribution tariff items. AG proposed to replace the NGSIS, which was built in 1983, because changes to AG's business have outpaced that system's capabilities and it has a number of operational deficiencies.

Calgary, referencing Board Direction 49 from Decision 2006-004, argued that the NGSIS replacement project business case did not include basic elements required for the project to be given the Commission's approval, namely information concerning benefit quantification or payback period. Also, without identification of the economics, Calgary submitted that potential

[109] Exhibit 0093.00.ATCO GAS-11, Vol 1, Tab 1.0, Outstanding Board Directions, Directions 14 and 16, page 2 of 2

savings would not be tracked and realized. Consequently, Calgary recommended that the NGSIS project should not be approved until the business case is completed.

The CG agreed with Calgary's recommendations.

The UCA considered that AG had sought to minimize the risks associated with potential development costs by building a significant contingency budget into the overall NGSIS project budget. More particularly, the UCA noted that AG included a 30% contingency allocation ($1,155,608) for the ATCO I-Tek budget for 2008 and 2009 and another $1,000,000 in 2008 as a contingency (250% of the non-contingency costs) for its portion. The UCA submitted that the use of contingencies for custom development activities was neither supported by actual business requirements or project development estimating techniques nor otherwise explained nor justified. Accordingly, the UCA recommended that the project budget should be reduced by the proposed contingencies in 2008 and 2009. The UCA further recommended that the NGSIS business case should be updated to include a revised forecast of costs for the balance of 2008 and a forecast of costs and activities in 2009, which were supported by realistic and quantifiable estimates.

AG argued that the overall project estimate was based on high level requirements and business processes and the contingency aspects take into consideration that specific areas require further scoping during the detailed design phase, such as invoice formats, contract billing specifications, reports, graphical user interface for new screens and work orders. AG stated that once the requirements were determined in the detail design phase the budget would be adjusted accordingly, which would decrease the overall contingency. AG noted that implementation of the project was now forecast for mid 2009.

Commission Findings

The Commission recognizes that in some instances a complete justification in the level of detail required by the Commission may not have been available when the Application was filed. However, the Commission is concerned with the level of contingencies attached by AG to the NGSIS replacement project in relation to the overall project costs. Further, the Commission finds that the project's business case lacks certain of the basic elements required[110] to appropriately detail costs and economic benefits of the project. Accordingly, while the Commission considers that the NGSIS replacement project has merit, the Commission considers that the amounts identified in the business case as contingent costs, aggregating $2,155,608, lack the necessary detail to allow their approval and denies those amounts for inclusion in the project's costs for 2008 and 2009.

Therefore the Commission directs AG in the refiling to remove the contingency costs of $2,155,608 from the NGSIS project. The Commission considers that the onus is on AG to demonstrate that costs are reasonable and any additional costs incurred by AG, which would have otherwise been included as part of the contingent costs, for the project in excess of the remaining amounts will be subject to review at AG's next GRA.

[110] Refer to Decision 2000-9, Canadian Western Natural Gas Company Limited, 1997 Return on Common Equity and Capital Structure, and 1998 General Rate application (March 2, 2000), Direction 16, and Decision 2001-96, ATCO Gas South, 2001/2002 General Rate Application Phase 1 (December 12, 2001), page 29

7.8 Other Rate Base Items

Subject to the appropriate rate of inflation to be used in forecasting all additions to rate base, the Commission accepts AG's forecast of the quantities of additions to rate base in 2008 and 2009 that are not an issue of concern or not specifically discussed in this Decision. Where applicable, the Commission directs AG in the refiling to apply the rate of inflation for 2008 and 2009 as approved in Section 5 of this Decision to such additions.

8 CAPITAL STRUCTURE

AG indicated that it planned to issue the following long term debt during the forecast period with 30-year debenture issues at a coupon rate of 7.00%.

Table 13. ATCO Gas Forecast Debenture Issues[111]

	2008 ($000's)	2009 ($000's)
ATCO Gas (North)	89,800	56,000
ATCO Gas (South)	40,800	16,400
	130,600	72,400

AG indicated that on an annual basis, CU Inc. surveys a number of its financial advisors to determine a forecast of financing rates. In preparation for this rate application, the forecast was updated as of 19 July 2007. Due to the current volatility of the market, AG used the average long Canada bond rate for 2008 and 2009 of 5.00% and applied a spread of 200 basis points to determine its forecast debenture rate of 7.00%.

The UCA, CG and Calgary considered that the forecast debenture rate was overstated, and made the following recommendations:

Table 14. Debenture Rates Proposed by UCA, CG and Calgary[112]

	2008 (%)	2009 (%)
UCA	5.66	6.03
CG	5.60	5.60
Calgary	6.25	6.25

AG also indicated that it planned to issue nine-year preferred shares at a preferred dividend of 6.00% during the test period in the following amounts:

111 Application, page 3.2.3
112 UCA Argument, page 50; CG Argument, page 30; Calgary Argument, page 13

Table 15. ATCO Gas Forecast Preferred Share Issue[113]

	2009 ($000's)
ATCO Gas North	18,700
ATCO Gas South	20,100
	38,800

The CG considered that the preferred dividend rate of 6.00% was overstated and should be reduced to 5.35%.

8.1 Long Term Debt Financing

Commission Findings

The Commission notes that in Attachment 20 of AG's rebuttal evidence, AG updated the 2007 forecast debenture rate of 6.00% with the embedded debenture rate of 5.62% approved in U2008-56. The Commission accepts this update.

In its reply argument, AG averaged the spread between its debenture yields and Government of Canada long term bonds, from June 2007 to April 2008, and then used this average to estimate the spread for the remainder of 2008. According to this calculation, the spread would increase to 250 basis points, which supports AG's forecast of a 200 basis points spread. However, the Commission does not accept this type of extrapolation of averages, given the volatility of the spreads from June 2007 to April 2008. Further, the Commission is not convinced that the spreads will widen to 200 basis points as suggested by AG.

The Commission accepts AG's submission that the point in time basis spread utilized by UCA and Calgary does not take into account the trend of increasing spreads over long Canada bonds. However, the Commission is of the view that there is insufficient evidence on the record to determine quantitatively what the increase in the spread should be to account for this fact.

While the UCA and Calgary added a spread to certain bond rate values to arrive at their recommendations for 2008 and 2009, the Commission considers that this methodology is better suited to determining debenture rates that are one year out. For 2008 debenture rates, the Commission finds the methodology used by the CG reasonable.

Based on the previous bond yields from July 2007 to April 2008, which ranged from 5.5% to 5.6%, the CG recommended that the debenture yield be set no higher than 5.6%. Given the actual bond yields, it is reasonable for the Commission to expect that future bond rates in the very near term will closely match past yields. On this basis the Commission accepts CG's 2008 debenture recommendation of 5.6%.

The Commission notes that the methodology employed by the UCA resulted in a 2008 debenture rate of 5.66%, which is very close to the CG recommendation. Therefore the Commission directs AG in the refiling to use a 2008 debenture rate of 5.62% in determining the 2008 long term debt rate.

113 Application, page 3.2-4

With respect to the 2009 debenture rate, the Commission notes that AG, the UCA, and Calgary each used different values for the long bond rate to which their individual basis spread was added. In reviewing the bond rate forecasts, the Commission notes that in rebuttal evidence AE indicated that the 30-year long Canada bond rate had decreased over recent months, the Commission considers that this brings into question the 5.00% base rate AG used to arrive at a 7.00% debenture rate for 2009. However, AG provided a forecast from the Royal Bank of Canada,[114] which indicated that, the long Canada bond rate would reach 4.70%, which AG indicated was not far off the 5.00%. The Commission considers that AG issues debentures throughout the year, therefore the Commission is not satisfied that the 4.70% forecast by AG is reasonable, given that it is a point estimate for the final quarter of 2009.

The Commission notes that the UCA has proposed to average the four quarterly forecasts from the Royal Bank of Canada to arrive at a 2009 average of 4.48%. Given AG evidence that it issues debentures throughout the year, the Commission finds that UCA's approach in determining the long Canada bond rate of 4.48% to be reasonable.

With respect to the appropriate spread to add to this rate, the Commission notes that AG proposed 200 basis points while the UCA proposed 155 basis points. Given the Commission's view that a widening of the spreads must be taken into account, the Commission considers that due to the volatility of the markets a reasonable approach would be to find the middle ground between the AG and UCA forecasts. Therefore the Commission considers that a reasonable basis spread would be 177.5 basis points.

Based on the above findings, the Commission concludes that an appropriate 2009 debenture rate would be 4.48% plus 1.77% to equal 6.25%. Therefore the Commission directs AG in the refiling to use a 2009 debenture rate of 6.25%.

8.2 Earnings on Rate Base vs Mid Year Book

In its evidence, Calgary raised a concern with AG's use of short term debt to finance part of its operations while collecting long term rates or equity returns on that debt. Calgary indicated that this was part of the problem of using the mid-year convention for capital structure. ATCO Gas addressed these concerns in its rebuttal evidence, and Calgary did not raise these issues again in argument.

However, in argument, the CG noted that due to the timing differences associated with the earnings on rate base common equity and mid year book value common equity, AG was able to achieve excess earnings, as indicated in the table below:

[114] AG Rebuttal Evidence, Attachment 2

Table 16. CG Forecast of Excess Earnings[115]

	AGN		AGS		Corporate Utility	
	2008	2009	2008	2009	2008	2009
	($000)					
Long term debt interest included in return calculation	25,045	29,042	23,795	25,661	48,840	54,703
Preferred dividend included in return calculation	1,889	2,454	1,466	2,072	3,355	4,526
Sub total	26,934	31,496	25,261	27,733	52,195	59,229
Long term interest corporate-utility	23,443	28,677	22,881	24,942	46,324	53,619
Preferred dividend corporate-utility	1,849	1,943	1,442	1,543	3,291	3,486
Short term interest corporate-utility	693	12	247	149	940	161
Amortization of issue costs corporate-utility	168	162	163	162	331	324
Sub total	26,153	30,794	24,733	26,796	50,886	57,590
Corporate gain/(loss)	781	702	528	937	1,309	1,639

CG submitted that AG should be directed to reflect a reduction in working capital to recognize the excess earnings resulting from timing differences on long term financing and any other sources of capital not presently recognized for regulatory purposes.

Alternatively, CG submitted that if the AUC considers the matter requires further examination in the context of the upcoming Generic Cost of Capital proceedings, the Commission should direct the matter be addressed by AG as part of the initial filings in that proceeding. In any event, the final determination of revenue requirement and, conceivably, working capital for 2008 and 2009 must take into consideration the excess earnings resulting from timing of long term financing and other sources of capital, such as construction hold backs that may not be recognized by AG for regulatory purposes.

Commission Findings

The Commission finds that the CG recommendations were not raised in evidence and not fully tested in this proceeding. Further, the Commission notes that the mid-year convention is the current accepted standard for determining rate base and capital structure values. The Commission is of the view that isolating only certain transactions without addressing the entire mid-year convention methodology would be inappropriate, particularly since these issues were not fully canvassed during this process.

The Commission considers that the use of the mid-year convention is best dealt with in the Generic Cost of Capital proceeding (Application 1578571, Proceeding ID 85), which is currently underway. If parties in the Generic Cost of Capital proceeding consider that the mid-year convention is an issue that needs to be reviewed as part of the generic process which would address all Alberta utilities, this issue should be raised in that forum.

Based on the foregoing, the Commission will not issue any directions to AG with respect to the mid-year convention for rate base and capital structures.

115 CG Argument, page 35

9 OPERATING EXPENSES

In the Application AG forecast total operating and maintenance (O&M) expenses of $282.649 million and $307.003 million for 2008 and 2009, respectively. The forecast developed by AG incorporated inflation rates, increases in salaries and wages, employee additions, expenses for new projects, system growth, customer additions and other factors to arrive at the amounts submitted. During the course of the hearing AG updated and adjusted certain items. The following sections will consider and address specific aspects of the O&M expenses.

9.1 Productivity

Productivity issues were introduced by the interveners in this proceeding for the purpose of considering adjustments to the future years' revenue requirements. Interveners sought to apply productivity measures in two ways: first, to apply a productivity factor to test year estimates; second, to develop metrics to measure or test the reasonableness of the forecasts on an overall/high level basis by comparing to historical values and trends. This Section of the Decision will deal with each aspect separately.

9.1.1 Productivity Factor

The UCA argued that productivity should be included in the AG forecast, but was not. The UCA submitted that past efficiencies had not been captured by the prospective rate making process due to consecutive GRAs submitted by AG.

The UCA considered that certain metrics demonstrated that distribution operation and maintenance (O&M) expense per customer, customer service O&M expense per customer and meter reading O&M expense per customer were all increasing faster than the inflation rate it had recommended. The UCA also considered that the kilometre (km) of main per full time equivalent (FTE) and customers per FTE both exceeded inflation and indicated that these parameters were much higher in the North as compared to the South. Further, theses metrics showed declining productivity.

The UCA argued that AG's municipal index cost efficiency performance index (CEPI) was not relevant as there was no similarity between expenses and revenues. The UCA considered that North to South comparisons were more relevant than any comparisons to outside agencies.

AG submitted that it had included efficiencies from previous test years and the application of a productivity factor would be over and above what was already included in the forecast. AG also believed that it would also not be in keeping with the prospective rate making model.

AG argued that the change in CEPI and having the lowest utility delivery charge demonstrated AG was performing effectively compared others.

AG claimed that the gap, in percent, between North and South for distribution O&M per km and distribution O&M per customer as noted by the UCA were less in 2009 than in 2004. AG also pointed out that more FTEs in the North lowered the North's customers per FTE and km per FTE.

In respect of meter reading AG argued that gains in meter reading would be hard to maintain due to meter reading being mostly labour intensive.

On an overall basis, AG argued that safety, reliability and responsiveness must be given consideration when considering cost reductions.

Commission Findings

Based on the information filed, the Commission is not comfortable with AG's use of the CEPI and the comparison of municipal spending to that of AG. The spending of the municipalities is influenced by many different factors not present in AG's business.

The Commission accepts AG's submissions that past productivity gains are reflected in recent actual expenditures (to the shareholders' benefit when achieved during test years) and accepts that such gains are factored into the next test years. This is accomplished by using the most recent actual expenses as a starting point for the forecasts and forecasting expected actual costs and growth. Use of this approach automatically includes expected productivity improvements. The Commission rejects the UCA's submission that it is necessary to impose an additional overall productivity factor against the forecast. Nevertheless the Commission will examine the evidence as it pertains to efficiency metrics to determine whether or not the forecast needs to be adjusted.

In addition, the Commission has evaluated the evidence pertaining to inflation rates that might be used to affect the forecast when they are applied to previous years' actual expenditures.

The Commission notes that the UCA's data for comparing parameters between North and South, such as distribution O&M per km, was out by one year. While this fact does not change the UCA's claim that efficiency is decreasing, the Commission considers that a better observation would be that North and South expenses per unit appear to be diverging, i.e., the North is becoming more costly by comparison. On a similar note, while AG stated the gap, in percentage terms, between North and South for distribution O&M per km had narrowed between 2004 and 2009, the Commission notes the gap has widened since 2006.

The Commission considers that depending on how comparisons are presented it is possible to draw a number of conclusions about the relative efficiency of the North and South operations. Generally, however, various metrics show that the North does have higher unit expenses than the South. While the Commission accepts that there are likely to be differences between various efficiency metrics in the North and South, it is not satisfied that it has a sufficient understanding of the reasons for the differences. Therefore, the Commission directs AG in its next GRA to provide empirical data that will provide the Commission with a better understanding of the differences in unit costs between the North and South and the reasons for those differences.

9.1.2 Metrics

The CG argued that metrics were needed to provide greater transparency when reviewing a GRA and would provide an enhancement to regulatory efficiency and effectiveness. The CG considered that the Commission should set up a collaborative process with stakeholders to develop metrics that assist in understanding unit costs.

The UCA argued that utility metrics would be useful and referred to Decisions 2005-019[116] and 2007-071,[117] wherein the Board had embraced the notion of developing metrics. The UCA argued that one collaborative process was all that was necessary and the AUC Policy section should lead the focus group in an effort to develop the metrics.

AG considered that the collaborative process suggested by the UCA would be an abdication of management's responsibility. AG also pointed out that the cost of resources to participate in a collaborative process and develop metrics had not been included in the forecasts. Further, the comparison of North to South by the UCA and its claim that the North was less efficient than the South was a pitfall of relying on metrics. Focusing on cost alone can negatively impact service quality and level.

Commission Findings

As noted in the preceding comments on productivity factors, the Commission understands the pitfalls of relying on metrics and that caution must be taken when reviewing productivity parameters. Even so, the EUB concluded there is a benefit to productivity metrics as stated in Decision 2007-071:

> In particular the Board believes that productivity metrics can be useful in assessing forecasts and as stated in Decision 2005-019 are "useful indicators of trends in output levels and corresponding costs and can provide an indication of the range of reasonableness for forecast costs." The Board considers that the availability of appropriate productivity metrics at the time of reviewing an application would facilitate and enhance the testing of certain aspects of the applied-for revenue requirements. However, as noted in Decision 2005-019, and readily apparent in this proceeding, there is considerable disagreement over the appropriate productivity metrics to be used. It also appears that an application's interrogatory and hearing processes do not lend themselves easily to resolving this conflict.
>
> In furtherance of the Board's view respecting the possible use of productivity metrics as an additional tool for testing the reasonableness of a utility's applied-for revenue requirement, the Board directs AE to consult with all of its stakeholders and possibly other Alberta utility companies to determine appropriate productivity metrics to be included in AE's next GTA.
>
> To be clear, the Board expects AE to include in its next GTA a separate section that addresses productivity issues. This section should contain information as generally described in the passage quoted from Decision 2006-054 cited above. The Board emphasizes that AE should not consider the inclusion of a productivity section in its next GTA as a substitute for sufficient budget and actual detail presented on a basis that is consistent and comparable. The latter information is still required.
>
> Further, the Board directs AE in the Refiling to provide the Board with a process and schedule that would enable AE to comply with this direction. The Board urges AE to keep Board staff advised of its progress respecting the determination of appropriate

[116] Decision 2005-019 – AltaLink Management Ltd. and TransAlta Utilities Corporation 2004-2007 General Tariff Application (Application 1336421) (Released March 12, 2005)

[117] Decision 2007-071 – ATCO Electric Ltd. 2007-2008 General Tariff Application – Phase I (Application 1485740) (Released September 22, 2007), page 15

> productivity metrics and to seek staff input if AE considers that such input and assistance would facilitate the process.

As noted previously, the Commission is initiating a consultation on MFR for gas utilities, which may address the use of productivity and efficiency metrics.

Consequently, it will be beneficial to have the AUC's Regulatory Policy Division lead a consultative process with AG and interested stakeholders to develop productivity metrics for AG that would be included in the next GRA. The identification of metrics that will be useful in the evaluation of GRA forecasts would be best determined in conjunction with what should constitute the MFR.

9.2 Level of Wages and Salaries for 2007

A review of wages and salaries is of importance in order to appreciate how the forecast for the test year(s) relates to the base year. In this Application the base year is 2007 and the Commission will consider the reasonableness of the 2007 wage and salary levels before any inflation factors are applied.

The UCA argued that the AUC should reject the suggestion that AG's Occupational and Supervisory staff were being compensated below market, given that AG did not submit an independent salary study to justify its position, therefore, AG had not met its burden of proof. The UCA submitted that the norm was to support the salary levels in a GRA with a non-confidential study.

AG argued that it had been prudent using data generated independently by the Conference Board of Canada, Mercer, Towers Perrin and the Association of Professional Engineers, Geologists and Geophysicists of Alberta. AG considered the sources of information were sufficient and did not commission an independent review but rather based its Application on review of observations and assessments in other rate applications.

Commission Findings

The Commission approves AG's salaries and wages in so far as it establishes the 2007 base to which an inflation factor is applied to determine the labour component of the test years' forecast. The Commission approved inflation rates in Section 5.

The Commission is satisfied with AG's explanation of its analysis and its use of the information from various sources in support of the salary levels for this GRA. Although, an independent analysis is more the norm in these cases the company decides the manner in which to present its case and the methods it employs to meet its burden of proof. Therefore the Commission will not direct AG to have a study prepared for the next GRA.

9.3 Pension

The CG raised the following issues in argument with respect to pension expense:

1. The mid-year amount included in Necessary Working Capital for AGN was stated to be \$2.710 million in 2009. However based on CCA-AG-3(a) it appears the correct amount should be \$2.541 million. The CG recommended that this difference be corrected in the refiling.

2. The CG noted AG's proposal to shorten the amortization period to four years to collect the balance of the deferred pension amount. Noting the myriad of factors that affect the performance of pension plans, the CG recommended that it would be prudent to await the outcome of the 2009 actuarial study before changing the amortization period. Thereby decreasing the amortization amount by $0.89 million in 2008 and 2009.
3. The CG did not agree with AG's assertion that the pension surplus related to both the Defined Benefit (DB) and Defined Contribution (DC) pension plans. Further, a reduction in the funding excess in the DB plan was attributed to transfers to money purchase component (i.e. to fund employer's share in the DC plan). The CG recommended that AG be directed to address the appropriateness of this issue at the next GRA.

AG agreed with the CG's recommendation that the mid-year amount included in Necessary Working Capital needed to be corrected, and committed to do so in the refiling.

AG noted that issue with the amortization period was only raised by the CG in argument. AG considered it was inappropriate to bring this issue forward in argument, where it could not be fully tested. However, out of caution, AG indicated that, if the amortization period was not adjusted and the 2009 actuarial study confirmed that the surplus funding will be depleted by 2011, customers would see the annual amortization expense increase by $1.9 million per year in 2010 rather than the current proposed increase of $0.9 million in 2008. Further, AG was directed by the EUB in Decision 2006-100[118] to propose changes to the amortization period in future GRA applications, if necessary, to achieve the goal of collecting the Deferred Pension Asset amount by the time the contribution holiday ends. AG submitted that its proposal was in compliance with that direction.

With respect to addressing the appropriateness of using pension surplus to fund the employer's portion of the DC plan AG stated:

> This would result in ATCO Gas and customers being required to commence partial funding of the pension plan sooner than under the current arrangement while delaying full funding past when it would be required under the current arrangement. This proposal would also result in a further escalation of the amortization period for the deferred pension asset. ATCO Gas submits that this is not a desirable outcome and that it is preferable to continue to use the surplus to address the funding requirements of both the DC and DP portions of the pension plan.[119]

Commission Findings

The Commission notes AG's commitment to correct the mid-year amount included in Necessary Working Capital associated with pension expense. The Commission considers this to be a clerical error, and agrees that the amounts should be corrected. On this basis the Commission directs AG in the refiling to apply the correct amount in Necessary Working Capital for 2009.

With respect to the amortization period, the Commission considers that it is appropriate to adjust the amortization period over which the pension asset is being drawn down. AG's recommendation results in a consistent approach over the remaining life as estimated by Mercer

[118] Decision 2006-100 – ATCO Utilities 2005-2007 Common Matters Application (Application 1407946) (Released: October 11, 2006)
[119] AG Reply Argument, pages 72-73

Human Resource Consulting. Further, if the 2009 actuarial study results in changes to the life of the asset, those changes can be dealt with in the next GRA. On this basis, the Commission will not require AG to adjust the amortization period as recommended by the CG.

Regarding the use of pension surplus, regardless of whether the company obligations are to DB or DC pension members, the costs of such programs are collected from customers in rates. In this regard, the Commission views the surplus as one large amount for rate making purposes rather than a distinct amount associated with one plan. On this basis the Commission finds that no further explanation regarding the use of surplus funds is required.

9.4 Full Time Equivalents/Manpower

The UCA argued that AG's evidence was not persuasive in support of the addition of seven new engineers in 2008. The UCA submitted that the additional engineers should be spread out with four being hired in 2008 and three being hired in 2009. Also, the UCA added that the hiring of ten new clerical positions should be uniformly spread out over the two test years, rather than eight in 2008 and two in 2009. The UCA reasoned that clerical positions were tied to growth of customers, employees and clerks per AG metrics.

The UCA considered that based on an increase in outside meter sets from MRRP the meter readers should be reduced by one FTE in 2008 and two FTEs in 2009 and by one additional FTE for the low use AMR project. As a result, the UCA submitted that reductions of $50,000 and $150,000 for the 2008 and 2009 test years respectively should be made.

In regards to the BFK staff additions, the UCA submitted that the BFK FTEs should be reduced by 1.7 (those related to ATCO Electric) in each test year, which would result in a total reduction of $116,000 and $123,000 in 2008 and 2009, respectively.

The CG submitted that there should be an improvement in the number of customers per clerical FTE, which based on AG metrics, would result in a reduction of 3.5 clerical FTEs in 2008. Such a reduction would be keeping in line with FTEs for past years.

The CG were not satisfied with AG's explanation of improvements in productivity for Distribution Operator Service (DOS) and suggested that AG should be directed to provide a further explanation.

The CG observed that the metrics of km of main/Distribution Operator Field (DOF) had decreased over the period 2003 to 2009, but considered that the data may not be reliable. The CG submitted that AG should be directed to provide explanations that support the forecast main kms and DOF metrics.

The CG argued that as a result of the MRRP project for which productivity improvements were expected, the meter reader FTE additions should be reduced by one in both 2008 and 2009. Also, future GRAs should include meter reading metrics (meters/FTE).

The CG recommended that the service level for BFK should remain at the level approved in AG's last GRA, i.e. increased staff and transfer of 1.7 FTEs from AE should be disallowed. The CG also agreed with Calgary that that there was no evidence that existing service through internet, telephone and newspapers was insufficient for BFK to address the Alberta marketplace.

It also appeared to the CG that advertising and other direct costs were in other accounts and related administrative and management overhead allocations were not identified.

AG submitted that its capital program had increased over 2007 amounts and in conjunction with other operational aspects, explained the requirement for seven additional engineers in 2008. Capital expenditures increased from an average of $190 million during the 2005 to 2007 period to a forecast level of approximately $265 million during the test period.

With respect to the UCA's use of AG's metrics relative to clerical positions, AG argued that the Commission should ignore the argument put forward by the UCA as AG had not been able to test the analysis. The CG's position that clerical additions should be reduced by 3.5 FTEs to restore the 2008 clerical FTE metric was considered by AG to be micro-managing.

With respect to meter readers, AG argued that it had included the benefits of the MRRP, but required additional readers for a number of reasons. AG stated that it had to forecast meter reader growth rates slightly higher (3.5%) than average forecast customer growth rate (3.3% per year over the two test years) as it worked towards continual improvements in achieving meter reading metrics related to worker injury reduction, inside and outside meter reading success percentages, and long term estimates.

AG claimed that the 1.7 BFK FTEs were justified based on customer growth and demands for information. In order to maintain service offerings and levels for the BFK AG required the additional 1.7 FTE positions. The customer growth in AG's service territory from 2005 to 2007 was near record levels and as such AG has been required to add professional staff, field and service personnel and meter readers to continue to provide safe and reliable natural gas service to all customers in Alberta. AG considered that the BFK was no different. Existing staff could not continue to meet the growing needs of the customer base for the services it provided. This growth in customers and continued demands for information and service required AG to increase the number of positions for the BFK. AG stated that, as shown in AUC-AG-15(c), there was relatively no growth in FTE's from 2005 to 2007 thus confirming the need for the additional 1.7 FTE's to be added to the BFK to address continuing service levels from existing customers and customer growth.

Commission Findings

The Commission accepts AG's submission that the addition of seven engineers is to deal mostly with new capital projects, which are notably on the increase. The Commission also is aware that a reduction in engineers related to capital will not directly influence the revenue requirement as capital programs are not formulated using FTEs and as such, reducing the FTEs will have little impact on the revenue requirement. Also, any O&M work to be performed by the additional engineers is understood to be only a part of their activities of which some justification will be related to growth. Based on the foregoing the Commission will not alter the forecast based on the number of engineers to be hired by AG.

However, the Commission accepts the submissions of the UCA and CG to reduce clerical FTEs in 2008 by three (per UCA's recommendation) to be more in line with customer growth. The Commission considers the customer per clerical FTE metric is a reasonable measure on which to pace the additions. Therefore the Commission directs AG in the refiling to adjust the O&M expense for 2008 and 2009 such that the addition of clerks is equal to five in each test year.

The Commission is satisfied that the metrics for the addition of DOFs or DOSs indicate the additions are reasonable. Therefore no adjustments are necessary.

The Commission is not convinced the productivity improvements as a result of the MRRP have been included in the test period. AG stated in reply argument that "These improvements are generated when ATCO Gas adjusts meter routes after the MRRP work is completed in areas."[120] This statement does not specifically state the improvements are included. The Commission accepts the submissions of the UCA and the CG to reduce the number of additional meter readers by one in 2008 and two in 2009 (per the UCA recommendation) to allow for improvements from MRRP. Therefore the Commission directs AG in the refiling to reduce the O&M for meter reading, Account 712, as noted by the UCA as $50,000 in 2008 and $150,000 in 2009.

The Commission understands AG's position that the BFK provides an important contact point and is part of the on-going communication efforts with AG's customers to disseminate safety and conservation messages to its customers. The Commission accepts that in respect of BFK, there is growth in the number of customers; however, it does not appear that telephone calls have increased since 2005. Only the internet contact has increased significantly. The Commission is of the view that the lack of increase in personal contact does not support the addition of the 1.7 FTEs. The Commission concludes that the increases to O&M included in the test years by AG are not warranted. Therefore the Commission directs AG in the refiling to adjust the O&M forecast for 2008 and 2009 to equal the budget levels of 2007, adjusted for inflation only, i.e. $800,000 (2007) which included 12 full and part time positions. To be clear, the Commission is not addressing the specific number of BFK staff to be included, nor the location where the staff will be employed. The Commission is only stipulating the maximum amount that can be included in the revenue requirement for the test years.

In a related matter the Commission notes that the BFK does not report to a department under the President of AG, but rather to a Vice President outside AG. This organizational arrangement raises a concern as to the BFK's relationship to other parts of the ATCO organization. The Commission directs AG in the refiling to address this concern demonstrating to the Commission that the BFK's duties are not performed for the benefit of affiliated companies. If they are, then the Commission expects that AG should be able to show revenue for any work done for others.

9.5 Variable Pay Program

In the previous GRA decision the EUB approved only that portion (50%) of the Variable Pay Program (VPP) that was applicable to the operational targets and had not allowed the inclusion of the financial targets in the VPP. Also a deferred account was established to reconcile any difference between forecast and actual payouts. It was approved on the basis of 15 employees. In this GRA AG has included $2,166,000 in 2008 and $2,418,000 in 2009 which was based on paying out 50% of the maximum. Additionally, the plan was to cover 396 employees in 2008 and 404 employees in 2009.

The UCA asked that the AUC direct AG to ensure all expenses that were related to an earnings target be excluded from the test years revenue requirement when submitting a compliance filing.

[120] AG Reply Argument, page 82, lines 24-25

The UCA argued that the VPP Deferred account should only relate to the 13 individuals that were in the VPP program approved in Decision 2006-004. The UCA recommended that the positions added in 2006 and 2007 should be excluded. The UCA also recommended that the 2007 closing balance should be revised from a shortfall of $164,000 to a surplus of $186,000 with corresponding adjustments of approximately $175,000 per year to total O&M and capital in 2008 and 2009.

The CG considered that Cost Efficiency metrics for VPP should produce a degree of operational savings and therefore recommended approving a reduction equal to 10% of the value of the VPP in each test year ($217,000 and $242,000).

The CG also recommended that the Commission should direct AG to address, in its next GRA, why payments were under control of the parent company.

With respect to the treatment of number of positions in the deferral account and expense adjustment, the CG agreed with the UCA.

AG made note of the Commission's audit and compliance group VPP audit and that no non-compliance was reported. AG confirmed that the VPP amounts related to operational metrics are paid even if the approved ROE for AG was not achieved. AG noted that it had provided the details of the approval process in its rebuttal evidence.

AG argued that the CG's recommendation of a reduction of 10% was first mentioned in argument and should be ignored. AG considered it was an attempt to inappropriately implement a productivity factor.

AG submitted that the program had been expanded to attract and retain employees. It also considered that the VPP Deferral account was approved without limitations and therefore including additional staff in 2006 and 2007 was not retroactive rate making. AG also requested that the deferral account be continued.

Commission Findings

The first issue the Commission will address is the matter of what is included in the revenue requirement attributed to the VPP. The Commission is satisfied with AG's assurance that only operational targets are used to establish the amounts to be paid out under the VPP; earnings targets are not included. The Commission understands that the UCA subsequently accepted the clarification established by the Commission that earnings targets are not included.

Second, the Commission will not require AG to further explain the participation of the parent company staff and how the VPP is approved for pay out. The Commission considers that the management of the VPP program is a management responsibility, and AG has provided a sufficient explanation.

The Commission does not accept the CG's recommendation to apply a reduction in revenue requirement for productivity based on VPP operational targets. Expected productivity improvement is inherent in the forecast used to establish revenue requirement in the test years.

The Commission considers that one of the major issues related to the VPP is the management of the deferral account. Decision 2006-004 approved the revenue requirement based on 15 non-officer employees and a deferral account to ensure the VPP amount approved was reconciled to the amount paid out. The Commission clarifies that only the difference between the basis for the revenue requirement, which was 15 employees, and the actual amount paid out to the 15 employees was to be reconciled.

The Commission notes that AG has added 19 additional employees in 2006 and 22 additional employees in 2007. Although not explicit, reconciling for additional staff in the VPP was not intended by Decision 2006-004. While it is up to the company to decide who it will include in the program, the revenue requirement was based on 15 employees, no more. The Commission accepts the UCA and the CG submissions that the deferral account balance should be based on the original number of employees and although only 13 were paid out in 2005 at least 15 were paid out in 2006 and 2007. The Commission finds it is appropriate to arrive at the closing balance for 2007, the opening balance of the VPP deferral account for 2008, based on the average pay out to 15 supervisory employees in both 2006 and 2007. The Commission considers the 2007 closing balance to be a credit of $178,000 rather than a debit of $164,000, as shown in the following table:

Table 17. Calculation of 2007 VPP Deferred Closing Balance

	Deferred VPP Costs Supervisory/Professional ($000)		
ATCO Gas	2005[1]	2006	2007
Opening Balance		(93)	(139)
Expense - O&M	(98)	(101)	(105)
Expense - Capital	(37)	(38)	(39)
Payments – O&M[2]	30	61	73
Payments - Capital	12	32	32
Closing Balance	(93)	(139)	(178)
Number of Participants	13	15	15

[1] Source: UCA-AG-78(c) Attachment

[2] 2006 payment per participant = (182+98)/34 and 2007 payment per participant = (181+79)/37

On this basis, the Commission directs AG in the refiling to confirm the calculations above, and make the necessary adjustment to the forecast revenue requirement to reflect these amounts.

The VPP deferral account was established to reconcile revenue requirement for the test years in order to eliminate concerns regarding changes to the utility's expenses that are in management's control and could result in a benefit to the company that was not intended by the Commission's decision. The Commission finds no reason to change the previous GRA's findings and consequently, the Commission approves the continued use of the deferral account for 2008 and 2009 based on the revenue requirement and maximum number of participants as filed in the Application.

9.6 Sales and Transportation Promotions

AG included expenses for advertising in Account 701 related to the recruitment of employees in the amounts of $775,000 in 2008 and $780,000 in 2009. Also included are expenses for Volunteer recognition in the amounts of $105,000 in 2008 and $150,000 in 2009. As presented in the regulation for the uniform classification of accounts, Account 701 is used for Advertising related to Distribution Sales Promotion – Operating.

Commission Findings

In response to AUC-AG-14, AG quoted from the uniform classification of accounts for Account 701 as saying "…this account….which is designed to promote or retain the use of the utility service." The Commission understands the account is to be used to promote distribution service, not for recruitment of employees or recognition programs. The expenses are clearly a human resource expense and therefore should be recorded as a supplies expense in association with that activity in Account 721 - Administration expense. The Commission directs AG to forecast, and account for actual expenditures for, the above named amounts in Account 721 in the refiling and in future GRAs.

9.7 Corporate Aircraft Expenses

AG included a forecast of expenses for the use of two corporate aircraft in the amounts of $1,104,000 and $1,175,000 for 2008 and 2009, respectively. The issues raised involved the allocation of fixed charges from the Office of the Chairman (OOC), the cost of using the aircraft and the suitability of the type of aircraft.

The UCA submitted that the Application showed that the major user of the aircraft was the Office of the Chairman (OOC) at 55.44%, but none of the aircraft fixed costs were allocated to the OOC. The UCA noted that in Decision 2007-071 the EUB directed ATCO Electric to reduce the fixed costs by allocating a share to the OOC.

The UCA argued that the commercial airfare between Calgary and Edmonton represented the Fair Market Value (FMV) for corporate aircraft travel between the cities. The UCA analysis of these costs showed that a 63% decrease in the AG's expense would equal commercial airfare costs. The UCA considered that AG's comparison to charter costs was flawed as it did not include AG's fixed costs.

The UCA recommended a reduction of $817,000 in 2008 and $873,000 in 2009 to reflect allocation of fixed costs ($348,000 for 2008 and $375,000 for 2009) and FMV of airfare between Calgary and Edmonton ($469,000 for 2008 and $498,000 for 2009). In addition, the UCA suggested that the Commission should include a direction that aircraft cost reductions may not be allocated back to AG through Head Office allocations.

The CG submitted that there was no new evidence from AG to cause a deviation from Decision 2007-071 with respect to fixed costs and their allocation. The CG recommended that the revenue requirement be reduced by $359,000 in 2008 and $385,000 in 2009 to reduce fixed cost allocation.

The CG noted that the Citation X cannot land in a majority of landing strips in the AG territory and submitted that AG had admitted the Citation X was not needed for AG to run its utility operations.[121] The CG argued that the costs of Citation X, a long-range aircraft capable of overseas travel, should be replaced by those of the Citation V, similar to that provided in Decision 2007-071. The recommendation would result in a reduction of $324,000 in 2008 and $279,000 in 2009.[122]

The CG suggested that the Commission should direct removal of costs of all non-utility operations from the ATCO corporate pool prior to the operation of the PriceWaterhouseCoopers (PWC) allocation formula for allocating costs to the regulated utilities.

AG submitted that it was allocated a portion of the fixed costs for the aircraft based on a long standing allocation formula and that variable costs were based on usage. Further, the costs for services incurred by ATCO Ltd. were provided at no profit or return and AG benefited from economies of scale. AG submitted that the Citation X was needed by ATCO Ltd. to mange its group of companies.

AG claimed it had compared its variable costs to charter costs and had found them similar and therefore the UCA's recommended reductions should be disregarded. AG argued that the UCA's comparison to commercial flights was flawed as it included fixed costs. The decisions to use the corporate aircraft were based on comparisons to variable costs as fixed costs were unchanged with use.

AG considered that the availability of corporate aircraft to senior executives provided significant flexibility and time savings.

Commission Findings

The Commission has reviewed Decision 2007-071 which stated the following in respect of the corporate aircraft:

> Based on the evidence before it, the Board has a number of concerns with respect to the prudency of aircraft costs passed down to AE. The greatest of these concerns is the fact that fixed costs are not allocated to the Office of the Chairman (OCC), ….[123]

And:

> In addition, the Board notes that, for the forecast period, total aircraft charges allocated to the OOC represent 31% and 32% of the total charges in 2007 and 2008 respectively, yet the OOC is forecast to use 60% of the aircraft hours in both 2007 and 2008, as shown by the forecast hours in response to BR-AE-53(e).[124]

And further:

> The Board considers that the method for allocating aircraft costs to AE is flawed for the following reasons:
>
> - fixed costs are not allocated to the OOC,

[121] AG Argument, page 41
[122] Based on Exhibit 0200.01.ATCO GAS-11
[123] Decision 2007-071, page 119
[124] Ibid, page 120

> - the OOC has the highest usage of the aircraft, yet does not receive a proportionate allocation of fixed costs.
>
> As a result of the flawed methodology, inappropriate amounts of aircraft costs are being passed on to AE's customers. Therefore, the Board concludes that AE must reduce the forecast aircraft costs in order to achieve just and reasonable rates.[125]

And finally:

> The make-up of the corporate aircraft fleet was also provided, which included a Citation X aircraft. The Citation X is a long range aircraft capable of overseas travel and can only land at 3 or 4 of the 36 service point airports in the AE service territory.[208] The Board has trouble accepting that the costs of such an aircraft would be a prudent investment by a regulated utility with operations only in Alberta. It is not clear to the Board what additional benefits flow to AE's consumers as a result of the Citation X aircraft as compared to a Citation V. On this basis, the Board considers that the forecast amount for corporate aircraft costs allocated to AE is too high.
>
> Based on these two additional findings, the Board considers that it would be appropriate to further reduce AE's forecast aircraft costs. The Board directs AE in the Refiling to further reduce aircraft costs by substituting the costs associated with the Citation X for 2007 and 2008 with the costs for the Citation V.[126]
>
> 208 Transcript Volume 6, page 789

The Commission considers that Decision 2007-071 was reasonable in that the OOC (ATCO Ltd.) should be allocated some of the fixed costs which it must retain (i.e. no reallocation) based on its significant use. Thus the Commission accepts the UCA's calculation of the reduction related to fixed costs and directs AG in the refiling to reduce its aircraft expenses by $348,000 for 2008 and $375,000 for 2009.

Also the Commission is satisfied that the utility does not need a Citation X for its Alberta business. A Citation V is more than adequate and is be able to make any necessary trips to business destinations outside Alberta when required. Accordingly, the Commission directs AG to further reduce the revenue requirement associated with aircraft costs by $324,000 in 2008 and $279,000 in 2009.

When considering the UCA's recommendation to reduce AG's expenses based on FMV of airfare between Calgary and Edmonton, the Commission accepts AG's position that it makes decisions based on the variable cost. The UCA's calculations do not take into account that fixed costs are just that, fixed, nor do they take into consideration the effect of reduced use should AG use the commercial option. Also the calculation unrealistically assumes that the cost and value of each trip is weighted equally in respect of employee time management, urgency of trip, time of day, etc. Therefore the Commission is not making an adjustment, as presented, related to FMV of travel between Calgary and Edmonton.

With respect to the merits of revisiting the allocation formula established several years ago by PWC, the Commission will address this issue in Section 9.8 that follows.

125 Ibid, page 121
126 Ibid, page 122

9.8 Head Office Expenses

The Head Office expenses allocated to AG are forecast to be $7,600,000 and $8,756,000[127] in 2008 and 2009, respectively, and can be categorized into four areas as shown on Table 18 below:

Table 18. Head Office Expense Increases Categorized

	2008 ($000)	2009 ($000)
Percentage Allocation	(651)	-
Inflation	454	567
Non Inflation	1,704	(50)
Vancouver Olympics	43	639
Total	1,550	1,156

The UCA provided an analysis of the Head Office expenses in its evidence.[128] The UCA observed that the Head Office expenses increase by $1.6 million (26%) and an additional $1.2 million (15%) in 2008 and 2009, respectively. Increases were primarily due to increases in the following functions in Head Office shown in Table 19 below:

Table 19. Increase in Head Office Cost Functions

	2008 (%)	2009 (%)
Corporate Office – Supplies	27	49
Corporate Secretary	35	8
Finance & Controller	49	8
Human Resources	44	7
Corporate Communications	68	8

The UCA considered that AG had not properly quantified the reasons for cost increases and noted that in many cases, the requested business plans had not been provided. Without proper justification the UCA submitted the increases should be limited to inflation.

The UCA submitted that it had difficulty extracting meaningful information from AG as it related to Head Office expenses, such as for "electronic board books for directors". The UCA noted that only in cross-examination, when asked if AG would file a business case, did AG reveal its share of the cost of electronic board books, which was $13,000. The UCA noted that AG claimed that costs related to electronic board books were an explanation for cost increases of $584,000 in 2008 and an additional $784,000 in 2009,[129] indicating in an IR response and rebuttal evidence that business cases for electronic board books would be prepared, implying the costs were material. Had the UCA known the costs of electronic board books were that small, it would not have pursued the issue.

[127] Exhibit 0093.00.ATCO GAS-11, Application Volume 2, Tab 4.4, and AUC-AG-20
[128] Exhibit 0102.02.UCA1-11, pages 82-83
[129] Exhibit 0102.02.UCA1-11, page 83

In reply, the UCA stated that it did not agree with AG's position regarding a "Package of Costs" as noted below:

> As long as the benefits received by being part of the ATCO Group of companies exceed the allocated costs, the specific nature of the costs should not be determinative.[130]

The UCA acknowledged that a proceeding was under way related to ATCO Electric Ltd. regarding a stand alone study.

The UCA stated:

> As the Commission is aware, Sec. 91(1)(a) of the Public Utilities Act authorizes it to consider … all revenue and costs of the owner ….

The UCA noted that AG provided the components of the 2008 increase in Corporate Office-Supplies & Corporate Secretary costs in a table in its Rebuttal Evidence as shown below:[131]

Table 20. Corporate Office Supplies &Corporate Secretary Increase

	($000's)
Performance Project	213
Directors' Fees and Expenses	202
Real Estate Management	71
Staff Additions	53
Records Management Program and Electronic Board Books	41
Other Miscellaneous Costs	36
Change in Allocation Percentage	(220)
Total Non Inflationary Increase	396

The UCA argued that there was no evidence demonstrating that the costs of travel and the level of travel for directors was just and reasonable. Absent any study or report in support of the need for the increase to Compensation for Directors[132] the UCA argued there was no evidence demonstrating that the increases were needed.

The UCA argued that AG had failed to provide the business case for the records management project as requested. While it may be a reasonable project, with no quantification of the costs or benefits of the project, the UCA submitted that there was no way to assess the merits of the project.

With respect to the costs related to the development and/or improvement of existing real estate, sale or purchase of real estate, and lease transactions, the UCA expected that AG would have had similar costs as AG had owned and leased property in the past. Given that, the UCA would expect to see a compensating reduction elsewhere in the AG forecasts, the UCA stated that it had not found such a reduction and submitted the proposed costs should be excluded.

130 AG Argument, page 45
131 Rebuttal Evidence, page 86
132 Exhibit 0143.01.ATCO GAS-11, page 87

The UCA considered AG's response in rebuttal to be confusing. First AG stated:

> The real estate services being performed by ATCO Corporate Services are not replacing the services being performed within ATCO Gas so it is not appropriate to expect to see a reduction in these costs for ATCO Gas.[133]

Then only two lines later AG stated:

> This group provides in house expertise that reduces the need for ATCO Gas to rely on external consultants in this field.[134]

The UCA argued that either the Head Office cost for real estate service was replacing costs incurred by AG or it was not; there was no evidence of reductions in external consulting costs. It did not appear that AG had demonstrated the claimed savings from the corporate real estate services group.

In respect of the Finance & Controller expenses, the UCA submitted that the planning, education and implementation of IFRS were one time costs. There was no evidence that these costs would continue after implementation.

The UCA submitted that AG could not quantify the costs or benefits of centralized cash management, nor had they produced the requested business case. The UCA considered that a project of this nature should be done on the basis of a positive payback. However, AG indicated that benefits would be in short term interest, which was a non-utility item. As a result, the UCA argued that the costs of the project should also be treated as non utility and all the costs should be excluded from revenue requirement.

The UCA stated that the following table[135] provided in AG's Rebuttal Evidence contained new evidence:

Table 21. Finance & Controller Initiatives

2008	($000's)
IFRS Project	100
Depreciation Related to Additional Workspaces	78
Cash Management Initiative	42
Amortization of System Software	29
Higher Audit Fees Related to Financial Instruments	18
Other Miscellaneous Costs	9
Change in Allocation Percentage	(65)
Total Non Inflationary Increase	211

The UCA argued that no justification was provided with respect to these costs, only an indication of what the forecast costs were.

133 Ibid
134 Ibid
135 Exhibit 0143.01.ATCO GAS-11, page 88

The UCA noted that Human Resources expenses increased by $148,000 (44%) in 2008 and an additional $36,000 (7%) in 2009.[136] The UCA expected that recruitment, succession planning, performance management, training and development programs, employee service awards, compensation, pension administration and benefit administration were included as direct costs of AG in the past, as it was AG's responsibility to recruit employees, manage performance, train employees, and administer pensions and benefits in prior years. Therefore, if these functions were now part of Head Office, there should be a corresponding reduction in internal AG expenses. The UCA noted there was no business case produced to justify the increase. As such, the UCA recommended that increases in the forecasts should be reduced to the inflation factors as recommended by Dr. Bruce.

Corporate Communications costs increased by $327,000 (68%) in 2008 and an additional $61,000 (8%) in 2009.[137] AG indicated it could not quantify each initiative but did provide a description of the additional effort. In Decision 2006-004 (page 68), the EUB ruled that costs for customer education and public safety programs be reduced; the UCA considered that these expenditures were similar to the costs eliminated in 2006. Also, increases in the forecasts should be reduced to the inflation factors as recommended by Dr. Bruce.

The UCA noted that AG had included expenses related to the 2010 Vancouver Olympics of $43,000 in 2008 and $639,000 in 2009.[138] Based on a long history of Commission decisions, all costs of the Vancouver Olympic program should be disallowed.

The UCA argued that the allocation methodology developed in 2000 and used to apportion Head Office expenses was flawed, and noted that AG used revenues, total assets and capital expenditures[139] in allocating Head Office expenses. The UCA considered that this resulted in double counting as capital expenditures were included in total assets. As such it gives a heavier weight to capital intensive businesses such as utilities, and benefits service organizations that do not have large capital requirements. The UCA recommended that the Commission should order AG to remove capital expenditures from the allocation methodology.

The CG argued that forecast increases in administration expense (Account 721) should be limited to no more than the historical relationship between the enterprise growth rate and the administrative expense growth rate.[140] The CG noted that in Rebuttal, AG identified certain updates to IT and CC&B placeholders to reflect fair market value rates resulting from the Collaborative Benchmarking process. The revised administrative expense amounts resulting from the updates were $53.529 million in 2008 and $62.918 million in 2009. Based on the revised forecasts the CG evaluated the reduction in administrative expense to be $1.6 million in 2008 ($53.5 million - $45.8 million *1.134) and $4.0 million ($62.9 million -$45.8*1.134*1.134) in 2009.

[136] Exhibit 0102.02.UCA1-11, page 87
[137] Exhibit 0102.02.UCA1-11, page 87
[138] UCA-AG-97(g)(ii)
[139] UCA-AG-96(b)
[140] Exhibit 0101.02.PICA-11, p. 30, CG Evidence: "…no more than 13.4% (1.4 historic differential between administration growth and enterprise growth times 9.6% average growth rate in enterprise during test period) in each of 2008 and 2009…"

The CG submitted that AG's proposed increase in 2007 administrative costs on a retroactive basis for use in calculating the historical administrative cost increases reflected in Table 6 of the CG's evidence[141] should be rejected.

The CG argued that any increase greater than the historical relationship between growth in administrative expense and enterprise growth was an indication of loss of productivity of administrative expenses as compared with the last few years.

The CG submitted that if administrative expenses were considered to serve the enterprise and if, after making allowance for enterprise growth including inflationary increases inherent in the calculations, administrative expenses were growing disproportionately; the AUC needed to impose some cost discipline on the overall growth in administrative expenses.

The CG recommended the ceiling on administrative expense be set at $51.9 million in 2008 and $58.9 million in 2009. In the event the AUC considers this ceiling level should be raised to accommodate exceptional items, such as the introduction of IFRS (scope change) or market driven items, such as the extension of VPP to supervisory employees and head office rent, it should only do so after giving due regard to the 13.4% per year increase already reflected in the ceiling. Moreover, any IT and CC&B governance rate changes resulting from the Evergreen proceedings should be subject to the above overall ceilings on administrative expense for 2008 and 2009.

The CG argued that since AG did not outsource products and services received from ATCO/CU, it would be difficult for the Commission and interveners to gauge whether these services were really necessary and, if so, whether they were fairly priced. Noting that AG stated it reviews the products and services received from ATCO/CU to see if they cost less than the cost of providing these services from within AG, the CG submitted there was no independent, external evidence to support these assertions. Also, it was not clear the degree to which AG was able to negotiate costs with ATCO/CU or how hard a bargaining position AG took or may be able to take with Corporate Office as the sole supplier. Therefore, the CG recommended that the Commission provide a similar direction to AG as that provided to ATCO Electric Ltd. in Decision 2007-071 wherein the Board stated:

> Noting FIRM's calculated increase of these affiliate costs over a five year period, the Board considers that AE should provide evidence in its next GTA that demonstrates services received from head office are necessary and appropriately priced. Therefore, the Board directs AE, in its next GTA, to provide such evidence with respect to head office costs.[142]

In respect of Olympic expenses, the CG questioned the reasonableness of customers paying $0.6 million in costs for alleged benefits that were nebulous and indeterminate. The CG considered that based on the 1988 Winter Olympic involvement, it appeared the primary beneficiaries were ATCO's non-utility operations. The CG submitted that in fairness, all Alberta utilities should play by the same rules. That is, costs related to corporate positioning should not be funded by customers.

141 Ibid, page 27
142 Decision 2007-071, page 94

AG argued that the provision of the services by ATCO Corporate allowed AG to receive these services at a fraction of the cost if AG were to provide them on a stand alone basis. These functions or services were not duplications of services already provided within AG.

AG argued that it was not appropriate to isolate certain costs allocated to AG by ATCO Corporate and debate whether that specific item was, strictly speaking, required to operate a natural gas distribution utility. AG submitted that as long as the benefits received by being part of the ATCO Group of companies exceeded the allocated costs, the specific nature of the costs should not be determinative. AG viewed the benefits of such an arrangement were self evident and that there was no need to undertake a stand alone study.

AG claimed that the additional work and new initiatives being performed by the various departments within ATCO Corporate required a total of 22 new positions that were added with the vast majority (20) being added in 2007.

AG submitted that the non inflation related increase in Corporate Services expenses were the costs of the performance benchmarking project, increases in Directors' fees and expenses as well as costs for the IFRS project. With respect to the performance benchmarking project, ATCO had retained the services of a consulting company to look at and benchmark its operating costs and performance. This initiative was driving a cost increase of $213,000 for AG in 2008. Increases in Directors fees and expenses were the result of increases to annual retainers and committee attendance fees, which increased to maintain competitive compensation levels and to reflect changes in roles and responsibilities of Directors. Directors travel costs resulted in an increase of $202,000 in 2008. The IFRS project was an ATCO project looking at the requirements for planning, education and implementation of IFRS which resulted in an increase of $100,000 to AG's expenses in 2008.

AG submitted that it was clear from the table (Table 20 above) that the cost increases for the records management program and the electronic board books were immaterial.

AG submitted that there was no level of justification that was satisfactory to the UCA. In some instances, the UCA chose to ignore the justification when it was provided. AG submitted that the positions of the UCA regarding the suggested level of detail necessary to justify costs were unreasonable.

AG also argued that no changes were required to the corporate cost allocation methodology. AG indicated that capital expenditures were an important factor in assessing how corporate costs should be allocated since capital expenditure programs generally require a significant amount of head office involvement.

AG stated that it had included costs associated with the Vancouver Olympics project as part of the package of costs associated with the services provided by ATCO Corporate. The value of the Winter Olympics to customers was that it enhanced and facilitated communication with employees, future employees and customers as well as promoting that the organization was a good corporate citizen, which was important in attracting and retaining a quality workforce. All Canadians, including Albertans, share in Canada's Winter Olympics. AG claimed that its participation in the Vancouver Olympics project was an appropriate business expense and therefore should be approved as requested.

AG was concerned with the CG's metric used to revise the Administrative O&M (Account 721), which included Head Office expense, as the metric did not take into account all drivers of administrative costs. AG adjusted the CG calculations to reflect the appropriate administrative costs for 2007 and submitted that if the intent in the CG's calculation was to get an accurate picture of the average growth rate over the last three years, this adjustment was required. AG submitted that this metric and the resulting ceiling on administrative expense was arbitrary and would result in AG being unable to recover its prudently incurred costs. As such, the CG's recommendation should be dismissed by the Commission.

Commission Findings

The Commission has noted the comments of AG with respect to what has been referred to as a "package of costs" or a "package of services" when discussing the Head Office costs. The Commission does not endorse the concept that such "packages" should not or can not be reviewed by examining the various components that comprise the package. Nor does the Commission agree with the premise that corporate costs are to be accepted and approved as a package. To do so would prevent examination of individual cost elements and whether customers of utility services should be required to pay for them through regulated rates. Accordingly, the Commission makes its findings herein subsequent to it having reviewed the various items that constitute the Head Office Expenses, and provides direction as necessary.

The Commission accepts the submissions of the UCA that AG has provided minimal support for the increases in Head Office expenses. Further, any discussion provided offers little, if any, justification.

With respect to the Corporate Office-Supplies & Corporate Secretary expenses the Commission does not accept nor is it apparent that such increases are required in the face of evidence presented. The Commission agrees with the UCA that the management of AG's real estate was being done by AG and therefore a saving should result if the activity was transferred to Head Office; this saving has not been identified. If Head Office were performing the activity, an inflationary increase is all that is warranted. The Commission directs AG to restate the expenses in the refiling using the approved inflation rates since 2007 only.

The IFRS project, which comes under the expenses for Finance & Controller, was considered by the UCA to be a one-time project and the $100,000 expense should be restricted to 2008. AG indicated that the project involved looking at the requirements for planning, education and implementation. For further discussion of the IFRS project refer to Section 14.2 of this Decision.

Also under Finance and Controller expenses is $42,000 in 2008 and $45,000 in 2009 for a cash management project. The Commission finds that there was no business case and no benefits for customers presented. The Commission does not approve these specific amounts to be included in revenue requirement.

The Commission considers that AG has not satisfactorily explained the increase in expenses for human resources at the Head Office level or why they need to be included in Head Office. The Commission notes that AG has not identified any benefits as a result of these changes. The Commission is not persuaded on the evidence that such an increase is justified. The expense increase of $148,000 and an additional $36,000 for 2008 and 2009, respectively, are not approved as part of the test years' revenue requirement.

The increase in Corporate Communications expense has been explained, in part, to assist in recruiting and retaining employees, increase investor relations, promoting the ATCO Group and for internal communications. The Commission considers that the significant increase in expenses for these types of activities has not been persuasively explained, and in fact, seem to have some of the same justification given for the additional expenses being proposed in account 701 (Advertising) for employee recruitment and community business development. The Commission finds that the increases and necessity at the Head Office level are not adequately explained and nor are the benefits to AG. Consequently the Commission will not allow the increases of $327,000 and an additional $61,000 in 2008 and 2009, respectively, to be included in the test years' revenue requirement.

Both the CG and the UCA argued against the inclusion of expenses for the 2010 Winter Olympics. The Commission considers that the expenses for the 2010 Winter Olympics to be no different than Donations and Sponsorships that have been consistently denied in previous decisions. Accordingly, the Commission directs AG to remove the expenses related to the 2010 Winter Olympics, forecast as $43,000 in 2008 and $639,000 in 2009.

The Commission has not allowed certain increases in Head Office expenses, but for clarity, the existing expenses and those permitted can be increased over those in 2007 on the basis of inflation. The inflation factor to be used was discussed in Section 5 of this Decision. Therefore the Commission directs AG in the refiling to apply the approved inflation factor to re-estimate the test year expenses for Head Office. Further, based on the following table, the Commission directs AG in the refiling to reduce its Head Office expenses by the amount indicated. The Commission also considers that these reductions should not be reallocated to the utility.

Table 22. Head Office Expense Deductions

	2008 ($)	2009 ($)
Inflation	To be adjusted	To be adjusted
Cash Management	42,000	45,000
Human Resources	148,000	184,000
Corporate Communications	327,000	388,000
Winter Olympics	43,000	639,000

AG argued that no changes were required to the allocation methodology used by Head Office to recover its expenses from the various affiliates. The UCA recommended both the removal of capital expenditures from the allocation of Head Office Costs and that the Commission direct AG to have the PWC study redone for its next GRA.

In Decision 2008-100[143] the Commission directed ATCO Electric or the ATCO Utilities to propose a timeframe for reviewing the corporate cost allocation methodology by February 27, 2009. Given that a process has been established to deal with this issue, the Commission directs AG to participate in the allocation study.

[143] Decision 2008-100 – ATCO Electric Ltd. Stand Alone Study (Application 1562230 Proceeding ID. 18) (Released October 21, 2008)

9.9 Meter Reading

AG forecasts spending $17.3 million and $19.3[144] million in operating expenses in 2008 and 2009 for meter reading and bill delivery. These expenses are contained in Account 712.

AG also provided the following metrics:[145]

Table 23. Meter Reader Position Metrics

	2002	2003	2004	2005	2006	2007 YTD Aug
Average monthly long term estimates	613	652	260	168	61	21
Inside read percentage	59	60	53	52	59	58
Outside read percentage	94	87	91	92	94	93
Injuries (medical aid & lost time)	25	54	40	39	39	19

The UCA argued that there was no evidence in the Application for the need to improve service levels and as Table 23 above indicates the number of long term estimates (LTE) had decreased dramatically before the increase was requested. The UCA considered that the only reason to justify the increases was customer growth.

The UCA considered the following table eliminated the impact of customer growth on meter reading costs:[146]

Table 24. Meter Reading – Cost per Customer (by UCA)

	2005 Actual	2006 Actual	2007 Forecast	2008 Forecast	2009 Forecast
Cost per Customer – North	$16.40	$17.50	$18.56	$19.65	$21.27
Cost per Customer – South	$11.96	$12.06	$12.73	$13.71	$14.78
Increase (North)		6.66%	6.06%	5.87%	8.28%
Increase (South)		0.80%	5.59%	7.63%	7.86%

The UCA argued that the expenses related to 3 additional supervisory staff in 2007 and 2 additional clerks in 2009 would, as noted by AG, “increase the overall meter reading cost per customer above inflation in 2008 and 2009.”[147] The UCA considered that the addition of incremental meter reading staff must be justified by new customers. The UCA submitted that there was no evidence that “AMR [automatic meter readers] battery replacements, AMR trouble calls, corporate postage costs and special meter reads” were increasing at all, let alone faster than inflation or constituted a material portion of meter reading costs. Thus the maximum increase in per customer cost should be no more than the UCA recommend inflation rate. This change would

144 Application, Table 4.2.21, page 4.2-29; UCA-AG-41(j) (k)
145 Application, Table 4.1.9
146 Exhibit 0102.02.UCA1-11, UCA Evidence, page 63
147 Exhibit 0143.01.ATCO GAS-11, Rebuttal Evidence, page 95

result in reductions in meter reading costs of $597,000 and $1,201,000 in 2008 and 2009[148] respectively.

The UCA noted that there were significant differences between the cost per customer in the North and South with costs in the North being higher than the South. The UCA considered that given meter reading costs per customer averaged 43% more in the North than in the South, AG should be directed to reconcile the reasons for these significant differences in its next GRA and discuss what AG was doing to minimize the cost differences, including exploring joint meter reading with FortisAlberta Inc.

The UCA observed that AG and the four largest distribution companies spend $42,870 million[149] annually on meter reading, and considered that this significant investment created an opportunity for synergy and savings. The UCA was concerned that there had not been any detailed business case prepared to fully evaluate the costs and potential benefits of joint meter reading. The UCA recommended that the AUC Policy branch convene a study into meter reading in Alberta. The objective would be to develop a detailed business case for joint meter reading and to develop an industry wide guideline for meter reading.

The CG considered that as a result of the MRRP which was to provide benefits related to meter reading as meters were moved from inside to outside, there should be a reduction to meter reader FTEs by one in both 2008 and 2009.

The CG also recommended that future GRAs should include meter reading metrics, such as meters per FTE.

AG submitted that as it adds more customers, it needs to add more meter readers to read the meters. And as AG adds more meter readers, it needs to add supervisors and clerks to support the meter readers in their duties.

AG submitted that meter reading positions included growth for supervisory and clerical staff were required to ensure that the field employees had all the proper training, uniforms, etc. Without the proper supervision and support for new employees, the accuracy of the meter reads they acquire and the personal safety of the employees might be at risk.

AG stated it continued to recognize productivity improvements in meter reading as below grade inside meter sets were moved outside. These improvements were generated when AG adjusted meter routes after the MRRP work was completed in areas.

AG submitted that expenses, which were higher than average inflation rates, were for supply costs, specifically fuel for vehicles. AG explained that in order to accurately calculate the meter reading costs on a per customer basis, costs for activities such as AMR battery exchanges, AMR trouble calls, and special meter reads must be deducted from the total cost of meter reading in order to truly understand the cost differences of manual meter reading from year to year.

AG argued that the UCA was incorrect in its assessment of the meter reading metrics as they had ignored the meter reader safety metric.

[148] Exhibit 0102.02.UCA1-11, UCA Evidence, pages 99-100
[149] Exhibit 0102.02.UCA1-11, page 98

AG indicated that the differences between North and South, although unquantifiable, were due to colder winters with more snow, lower population density and a larger geographic area in the North that contribute to higher costs. In the South, communities were larger and closer together whereas in the North, communities on average, were smaller and located further apart. Travel times to the communities and walk times to read the meters were longer in the North. Winter weather conditions made the differences even more extreme. AG argued that meter reading in the North simply cost more to complete than the South and there were no productivity improvements that could be implemented to somehow make the costs equal.

AG submitted that the UCA had made no recommendations to change the forecast meter reading costs due to North/South differences in this Application.

Commission Findings

The Commission accepts AG's submission that as customers are added it will be necessary to add more meter readers, subject to any productivity improvements that may arise. Also from time to time it may be necessary to add supervisory and support staff. The Commission also accepts that the MRRP will result in productivity improvements as each stage is completed.

Based on the above the Commission would expect to see a balance between productivity improvements and growth in new positions (or FTEs) during the test years. However, the balance is not readily apparent, and in fact the Application seems to present quite the opposite. For example the increase in meter reading expenses from 2008 to 2009 is about 11.6%. If the customer growth of 3.3%, as submitted by AG, is accounted for, that leaves an increase of 8.3%, well above both AG's occupational labour inflation factor of 7.5%. The Commission notes that it has set the inflation rate for occupational labour at 5% for 2009 in Section 5 of this Decision.

The Commission accepts the UCA argument that it is reasonable to expect the rate of growth in meter reading expenses, to be more consistent with the rate of customer growth. The Commission accepts the method applied by the UCA to determine an adjustment to each of the test years that results in the following reductions to meter reading and bill delivery expenses included in Account 712.

Table 25. Reductions to Meter Reading Expenses per UCA

	2008 ($000)	2009 ($000)
North	304.86	677.40
South	292.02	524.08
Total	596.88	1,201.48

Therefore, the Commission directs AG in the refiling to include the above reductions to meter reading and bill delivery expenses, Account 712.

The Commission notes the CG's recommendation to reduce the meter reading FTEs by one in each test year. The Commission considers that it will not be necessary to include such a reduction in addition to the above reduction ordered by the Commission. The above noted reduction includes the effect of the recommended FTE reduction thereby making it redundant.

The Commission shares the concern of the UCA with respect to the significant difference between North and South meter reading expenses. Developing metrics as recommended by the CG may assist the Commission in appreciating the difference and whether there is little ability to close the gap as suggested by AG.

The Commission understands that the Government of Alberta has recently issued a white paper on meter reading. Given this initiative, the Commission will not direct AG to undertake any further studies at this time. The Commission recognizes that it is more appropriate to deal with the issue of meter reading in a generic setting rather than address it on a single utility basis.

9.10 Transmission Operating Expense

AG has revised the method of estimating the Peak Billing Demand (PBD) which it provides to ATCO Pipelines (AP) 12 months in advance. Based on a reduction to the 2009 PBD, the CG recommended a 2009 reduction for AGS of approximately $1.8 million (from $26.253 million) and $1.7 million (from $37.826 million) for AGN.

In its rebuttal evidence AG had requested a one time adjustment for the transmission charges from AP, but confirmed in its argument that it was no longer seeking the adjustment. This was as a consequence of AG having submitted a separate application to deal with the impact of adjustment in demand rates approved in Decision 2007-073.[150] The AUC approved the adjustment when it issued Order U2008-264[151] approving Rider T.

The CG argued that, since the previous PBD method was to simply aggregate the peak demands for all downstream service lines, there would be no diversity considerations on the upstream distribution mains and feeder mains that ultimately interconnect to the transmission service point or tap. Further, this simple aggregation approach would have tended to overstate the peak demand at the transmission service point that AG utilizes to determine the PBD.

The CG noted for the South zone for each of 2008 and 2009, there was a reduction of 61 TJ in the PBD estimate as a result of moving from the previous method to the new method. Further, it would appear this 61 TJ reduction arose from the use of gate meter data as 73.6% of the AGS forecast was attributable to the use of that data. The remaining portion of the forecast (e.g. 26.4% for AGS) was estimated using the previous method.

The CG submitted that AG had historically over-estimated the PBD on the basis of the previous design based method and the gate meter data from 2005 onward clearly showed the extent of this prior over-estimation.

The CG also observed that AG was not required to provide the 2009 test year PBD estimate to AP until the end of 2008.

Given use of gate meter data for 73.6% of the PBD estimate causes a reduction of 61 TJ relative to the previous design method; the CG submitted it was reasonable to extrapolate this result to all of the transmission service points and estimate a 83 TJ reduction for the AGS PBD estimate

[150] Decision 2007-073 – ATCO Pipelines Application for Realignment of Rates (Application 1510692) (Released October 9, 2007)

[151] Order U2008-264 – ATCO Gas - Rider T (Application 1578601, Proceeding ID. 84) (Released: August 7, 2008)

(61 TJ/0.736 = 83 TJ). Using a forecast 2009 AP rate of $1.827/GJ, [152] the 83 TJ reduction in the AGS PBD would translate into a 2009 transmission charge reduction of $1.8 million (83,000 x 1.827 x 12 months). The CG recommended the reduction in transmission charges should be applicable to AGS in 2009.

Similarly, the CG argued that a reduction in the AGN transmission charges should also be estimated. AGN's estimates were based on gate meter data for 59.2% of the forecast PBD and resulted in a reduction of 36 TJ. Extrapolating this reduction to all transmission service points would result in a 61 TJ reduction (36 TJ/0.592 = 61 TJ). Using a forecast 2009 AP rate of $2.258/GJ, the 61 TJ reduction in the AGN PBD would translate into a 2009 transmission charge reduction of $1.7 million (61,000 x 2.258 x 12 months). The CG recommended the reduction in transmission charges should be applicable to AGN in 2009.

AG argued that there were a number of problems with the CG's recommendations. The first problem was that the reduction was an aggregate reduction, but AG did not contract for aggregate capacity. AG stated that it contracts for capacity at every point it receives service. AG noted that the taps without gate meters were the smaller taps and served smaller groups of customers. These smaller groups of customers had less diversity. AG considered a reduction of 119 TJ/day [sic] could not be applied "off the top."

The second problem according to AG was that even though using gate meter data had generally caused the forecast of the peak load requirements of a system to go down, it was not universally so. AG claimed that in some cases the peak load requirement had gone up.

AG's third issue with the CG's recommendation was that it would potentially expose the customers on smaller systems without gate meter information to the risk of outages as a result of AG adopting a PBD that was too low.

Commission Findings

The Commission appreciates AG's claim that the CG's recommendation might be problematic. The Commission also notes that the use of the new meters has produced a reduction in the forecast of the PBD. However, the Commission is not persuaded that it should completely ignore the CG's proposal. The Commission can accept that the PBD based on metered data indicates the existence of some diversity, which had not previously been accounted for. Therefore the Commission considers there is merit in the CG's argument that the PBD should be lowered to account for an overstatement of the PBD attributable to the non gate station portion of the PBD.

However, it is the Commission's view that it should be cautious when directing such a change and therefore will direct a change of 50% of the CG's recommendation. The Commission will be interested in AG's review of the PBDs at its next GRA.

While the Commission accepts the notion that there should be a reduction directionally in line with the CG's recommendation, it does not accept the CG's calculation of the adjustment. Using the South as the example, the South's 2009 PBD of 1202 TJ/day is the 61 TJ reduction attributed to the use of gate station meters. On that basis, of the 83 TJ adjustment calculated by the CG, 61 TJ is already included and an adjustment for the remainder would be equal to 22 TJ/day (83 - 61 = 22) Accordingly, applying 50% to the <u>additional</u> adjustment results in a reduction of

[152] Exhibit 0093.00.ATCO GAS-11, Application, page 4.2-12

11 TJ/day making the approved PBD for the South in 2009 equal to 1191 TJ/day. As a result, the revenue requirement in the South for the 2009 Transmission Operating expense will be reduced by $241,164 (11 x 1.827 x 12 months). Therefore, the Commission directs AG in the refiling to make the foregoing reduction to the South's 2009 Transmission Operating expense.

Similarly, the calculation for the North is also necessarily adjusted. Of the 61 TJ/day adjustment calculated by the CG, 36 TJ is already included leaving 25 TJ as the remaining adjustment of which the Commission will apply 50% or 12.5 TJ/day. The resulting PBD for 2009 in the North will be 1385 TJ/day (rounded) and the adjustment to the Transmission Operating expense will equal $338,700 (12.5 x 2.258 x 12). Therefore the Commission directs AG in the refiling to make the foregoing reduction to the North's 2009 Transmission Operating expense.

9.11 Reserve Accounts, Self Insurance & Other

9.11.1 Litigation Related to Late Penalty Charges

In the Application, AG advised that it was involved in a legal claim related to late payment charges. While AG did not anticipate any payments to settle this claim, it indicated in CAL-AG-45(e) Supplemental that $160,000 in costs was charged to the Reserve for Injuries and Damages (RID) in 2007, and that there was a possibility for payments to the claimant. AG considered that since customers received the benefit of late payment charges as an offset to revenue requirements, it was appropriate that the litigation costs and the cost of any potential payments be charged against the reserve for injuries and damages for future recovery from customers.

Commission Findings

The Commission considers that it would be inappropriate to make a ruling on this matter until it is aware of all the details including any costs that may arise as a result of the litigation. On this basis, the Commission notes that the litigation is still ongoing and may have one of several outcomes. Therefore the Commission directs AG that any costs, legal fees or other payments be maintained as a separate item in the RID, pending conclusion of the case, and determination by the Commission.

9.11.2 Hearing Cost Reserve Account and Costs in Excess of Scale

AG indicated in the Application that legal and consulting costs in excess of the Scale of Costs were not included in the forecast years.

The CG noted that during the course of the hearing, AG indicated that it credited costs in excess of scale back to the reserve account. The CG considered that costs in excess of scale should not be included in any utility regulatory account and that AG's practice made it difficult to test the forecast. The CG recommended that AG's costs in excess of scale should be removed from the utility regulatory accounts and treated as a non-utility item.

Commission Findings

The Commission notes that Table 4.2.26 of the Application provides total legal and consulting fees, costs in excess of scale, and remaining legal and consulting fees, for the period from 2005 through to the 2009 forecast. It is not clear to the Commission how this information makes it difficult to test AG's forecast as recommended by the CG. Further, the Commission notes in the

O&M comparison by account code, listed as Section 4.02 Attachment of the Application that Account 722 which primarily includes legal and consulting expenses shows an amount that would correspond to the remaining legal and consulting fees. The Commission rejects the CG's recommendations regarding legal and consulting fees.

10 INFORMATION TECHNOLOGY COSTS

AG requested the following approvals in this GRA proceeding:

- Approve the capital related fixed and variable volumes contained in the January 1, 2008 opening PP&E balances for IT and CC&B costs in the GRA refiling. This requires approval of fixed and variable volumes for 2005 to 2007 which ATCO submits should be the actual volumes for those years.
- Approve the 2008 and 2009 IT and CC&B fixed and variable volumes for both O&M and Capital.
- Approve price placeholders for 2008 and 2009 for both O&M and Capital.

The Commission considers that the following summary provides context for these matters.

The ATCO Utilities and interveners established a Collaborative Process Committee (CPC) that was sanctioned and monitored by the EUB. The CPC engaged the services of Compass Management Consulting Limited and UtiliPoint International, Inc. (Benchmarker) to benchmark pricing for Information Technology (IT) and Customer Care and Billing (CC&B) provided by an unregulated affiliate ATCO I-Tek[153] to the ATCO Utilities for the 2003-2007 periods. The Benchmarker was requested to benchmark these services to the fair market value (FMV) of these services. The Benchmarker was also requested to provide recommendations as to an objective process for determining the FMV of these services for periods subsequent to 2007.

By letter dated February 21, 2008, the Benchmarker's Price Benchmark report was submitted to the Commission[154] (Benchmarker's Report). There are a number of proceedings currently before the Commission dealing with the results of the Benchmarker's Report. The Benchmarker's Report is the subject of the ATCO Utilities 2003-2007 Benchmarking & I-Tek Placeholders True Up – ID 32 (Benchmark & True Up)[155] proceeding. Also, the ATCO Utilities Evergreen proceeding Application 1577426 - ID 77 (Evergreen Phase 1[156]) deals with IT and CC&B pricing for 2008-2009 while a future Evergreen Phase 2 proceeding will deal with pricing issues for 2010 and beyond. Rate applications for each ATCO Utility (this Application for AG) will continue to utilize placeholders for IT and CC&B costs until the placeholders are finalized.

The UCA believed it was important to ensure AG and customers were receiving fair value for services from AG's affiliate as compared to the open market. The UCA contended that AG's detailed IT volume information was unreasonable and excessive and preferred to look at an overall IT operating budget.

153 ATCO I-Tek Inc. (I-Tek) and ATCO I-Tek Business Services Ltd. (ITBS)
154 See EPS Proceeding ID 32 for the full report
155 For additional details see Application No. 1509540, which lead to Order U2007-111, approving the commencement of benchmarking activities, and also contains the Terms of Reference which provide a history of this process.
156 The Evergreen Phase 1 process will also include Governance Costs and Cessation of CIS Royalty Payments

The UCA argued that using the Gartner 2006-2007 IT Spending and Staffing Report (Gartner Report) as an overall benchmark, indicated an annual IT operating budget should be 2.1% of revenue for utility industry companies. This indicated $10.3 million for 2008 and $11.4 million for 2009 for AG, compared with AG's forecasts of $14.1 million (which equals 2.9%) in 2008 and $18.1 million (which equals 3.3%) in 2009, resulting in variances of $3.8 million and $6.7 million for 2008 and 2009 respectively.

The UCA proposed a four-year plan to reduce the current AG operating budget variances, first by 25% for 2008 (a reduction of $0.95 million), followed by 50% for 2009 (a reduction of $3.35 million).

Calgary had no issues with AG's 2008 and 2009 CC&B (ITBS) capital cost forecasts.[157]

Calgary noted the five-year average AG IT rates were 6.1% above the fair market value (FMV) estimated by the Benchmarker in the Benchmarker's Report and in 2007 were 22% above the benchmarked FMV. Calgary estimated that a 2% difference amounted to $1 million.

Calgary expressed general concern with the 2008-2009 variable items filed in the Application, and submitted that AG had not disclosed the underlying drivers of variable items that were required by the Benchmarker in order to estimate a FMV for the variable amounts in 2003-2007. Calgary argued that in order to provide some type of estimate of FMV for the variable amounts the Benchmarker had to have obtained the underlying cost drivers; it was Calgary's position that in order to test the 2008-2009 variable items the same type of information was required for the years 2007 – 2009.

Calgary was also concerned with a discrepancy in the number of Distributed Applications between the Benchmarker's Report and AG's Rebuttal Evidence. Calgary noted that Distributed Applications doubled on a percentage basis from 20% to over 40% of the I-Tek O&M costs. Calgary also considered that due to a lack of volume information associated with these amounts, there was reduced transparency in this expense category.

Calgary submitted that none of the AG IT business cases or Statements of Work (SOWs) filed in this proceeding provided the information to allow the Commission and Calgary to determine if the requested IT fixed volume and variable dollar forecasts were reasonable. Calgary noted that this information was provided in the past two AG GRA's and the EUB ordered ATCO Pipelines to provide this information in Decision 2003-100.[158]

As a result Calgary argued that all variable items must remain unapproved until the Commission and interveners obtained and had a reasonable opportunity to test the volumes associated with the variable amounts. Calgary requested that the Commission order AG to provide the 2007 to 2009 capital and O&M underlying unit volumes (the price drivers) for the variable dollars in the same manner that they were provided in the ATCO Benchmarker's Report.

[157] Calgary's Argument, page 12
[158] Decision 2003-100 – ATCO Pipelines 2003/2004 General Rate Application – Phase I (Application 1292783) (Released December 2, 2003)

Calgary anticipated that once the volumes were provided that they would be found to be excessive by approximately 10% and therefore the Commission should order AG to reduce the O&M and capital volumes for IT and CC&B in such a way that the placeholder costs were reduced by 10% for IT (I-Tek) and 7% for CC&B (ITBS). Calgary considered that once the volumes had been properly tested and approved (preferably in the 2008-2009 GRA Compliance Process) then there would be volumes to utilize in the Evergreen proceeding.

Calgary considered that the AG amendments to the existing placeholders were unnecessary as they were simply placeholders. Once the amounts and processes were assessed for specific compliance with the Code of Conduct then the placeholders could be relieved of their existing duty and replaced by amounts based on benchmark results and amounts allowable via the Code of Conduct. Calgary submitted that in situations where the I-Tek price was less than the FMV determined by the Benchmarker, the actual I-Tek price should be used. For the purposes of this GRA, Calgary considered the issue was whether the proposed placeholders were appropriate and whether there was appropriate information to determine the approvals sought.

Calgary pointed out that AG had forecast no benefits in the business case associated with the increased functionality for Service Initiation (SI) and Non-Gas Billing (NGB), the Non Gas Sales Information System (NGSIS) replacement. Calgary maintained that the issue with SI and NGB projects was whether or not the business case complied with Board Direction 49 from Decision 2006-004. Calgary argued that AG had provided no evidence that it had met Board Direction 49 and therefore the project costs should be excluded from the placeholders.

Calgary further submitted that the prudence of the final cost of the Daily Forecast Settlement System (DFSS) was not known and therefore it was inappropriate to include it in rate base.

AG argued that it had provided detailed fixed and variable volumes in sufficient detail for the Commission to review and approve.

AG claimed that it had pointed out in both its Rebuttal Evidence and during cross examination that there were serious flaws with the Gartner Report based approach suggested by the UCA. AG noted that in its Rebuttal Evidence it had highlighted that the Gartner Report itself cautioned parties against using the Report’s findings instead of relying on the decisions of company management.

AG submitted that implementation of the SI and NGB projects were delayed to mid 2009. AG also noted that the higher operating costs arose as a result of the new applications in comparison to the existing NGSIS legacy application. AG explained during cross examination that the forecast operating costs would be greater because the functionality of the new systems would be significantly greater than the existing applications. Further the business case for SI and NGB discussed the deficiencies of the existing NGSIS, the alternatives considered and the revenue requirement impact of the selected option. As noted in Rebuttal Evidence, the existing system was in excess of 20 years old and was not meeting AG’s business requirements.

AG submitted that the Commission should consider the following in its assessment of IT and CC&B volumes for which ATCO Gas was seeking approval for:

1. ATCO Gas has provided a significant amount of detail regarding its IT and ITBS volumes; greater than any other utility in Alberta has been required to provide.
2. The EUB, the predecessor of the AUC, has reviewed and previously approved similar volume information, including fixed and variable volumes, in prior proceedings.
3. The most significant component of variable volumes is Distributed Applications. Relative to the benchmarking period, the most significant changes in this Application are the implementation of IRIS, NGSIS and the continuing implementation of Work Management. ATCO Gas has provided significant support for each of these projects included business cases.
4. In this proceeding, ATCO Gas is seeking approval of IT and ITBS volumes. Price related issues will be determined in the Evergreen proceeding.[159]

AG submitted that over a five-year period, the determination by the Benchmarker was that ATCO I-Tek actual charges were within 6.1% of FMV for IT Services and within 0.2% for ITBS. AG also noted that the actual charges were less than the reductions to placeholder amounts directed by the EUB which were 7.5% for IT services and 11.1% for ITBS.[160]

AG stated it had determined forecast activity for CC&B by using actual service account and call centre activity as the basis of its forecast. The customer growth factor used elsewhere in the Application was then applied to determine forecast activity in the test period.

AG noted that Calgary's suggestion was that in situations where the I-Tek price was less than the FMV determined by the Benchmarker, the actual I-Tek price should be used. AG argued that this approach suggested by Calgary would result in a cost less than and inconsistent with the overall FMV determined by the Benchmarker. Calgary's suggestion was that the FMV determined by the Benchmarker only applied in some situations by suggesting that where the I-Tek price was less than the FMV determined by the Benchmarker, the actual I-Tek price should be used in the determination of placeholder amounts.

Calgary's approach would utilize actual I-Tek pricing where it was less than the FMV for a service. This approach was incorrect because it was inconsistent with the second objective in the Benchmark, namely the opinion of overall FMV since the FMV price, not the actual I-Tek price, was used by the Benchmarker to determine the FMV for the Master Service Agreement (MSAs) as a whole. AG submitted that the approach used in the calculation of placeholder amounts needed to be consistent with the approach used in the calculation of overall FMV in the Benchmark. AG advocated the FMV rates determined by the Benchmarker should be used as the basis for determining placeholder amounts which would be consistent with the approach in the Benchmark.

AG noted that the EUB had previously approved the inclusion of costs related to the DFSS in AG's 2007 revenue requirement when it was anticipated that Retailer Service would be implemented in the year 2007. That implementation date was delayed and the EUB approved the continued capitalization of testing costs and AFUDC for the system until Retailer Service was implemented. AG claimed that the change in costs for the DFSS from previous forecasts related

[159] AG Reply Argument, page 103
[160] AG Reply Argument, page 89

for the most part to the capitalization of testing costs, AFUDC and inflation. AG submitted that the Commission should approve the inclusion of the DFSS in rate base commencing in the year 2008.

Commission Findings

The Commission notes that some confusion arose in the proceeding in regard to the definitions of various terms. In this Decision the Commission uses the following definitions:

- Fixed volume items: are those that are specified as a billable unit. Total cost for fixed items is the product of volume and price.
- Variable items: are those that are specified in terms of dollars and may reflect a number of transactions related to various activities.

The Commission also notes that the use by AG of the term "variable volume" created concern and some confusion amongst the parties. In order to provide clarity and a common understanding of this component of IT and CC&B costs, in this Decision, the Commission uses the defined term "variable item" except when summarizing AG's views.

The following two tables set out the proceedings where ATCO Gas proposes (or the Commission has decided*) determinations should be made for certain Capital and O&M items.

Table 26. Determinations of Capital and PP&E Items

Year	Capital (Includes Fixed[1] and Variable[2] Items for IT and CC&B)		
Item:	Fixed Volumes	Variable Items & Prices	Opening PP&E Balances
2003	Actuals Approved in 2005-039[3]*	Benchmark & True up	Benchmark & True up – (Use Actuals)
2004	Actuals Approved in 2005-039*	Benchmark & True up	Benchmark & True up – (Use Actuals)
2005	Use Actuals- (as determined in this Decision)*	Benchmark & True up	Benchmark & True up – (Use Actuals)
2006	Use Actuals (as determined in this Decision)*	Benchmark & True up	Benchmark & True up – (Use Actuals)
2007	Use Actuals (as determined in this Decision)*	Benchmark & True up	Benchmark & True up – (Use Actuals)
2008	Use Forecasts (as determined in this Decision)*	Approve as Placeholders in GRA and Finalize in Evergreen Phase 1 (as determined in this Decision)*	Finalize after Benchmark & True up (as determined in this Decision)*
2009	Forecasts (as determined in this Decision)*	Approve as Placeholders in GRA and Finalize in Evergreen Phase 1 (as determined in this Decision)*	Finalize after Evergreen (as determined in this Decision)*
2010+	Evergreen Phase 2		

* Items determined by the Commission either in this Decision or a prior Decision or letter

[1] Fixed volume items are those that are specified as a billable unit. Total cost for fixed items is the product of volume and price.

[2] Variable items are those that are specified in terms of dollars and may reflect a number of transactions related to various activities.

[3] Decision 2005-039 – ATCO Gas 2003/2004 GRA – Impact of the Retail Transfer and ITBS Volume Forecast (Application No. 1355457) Released May 3, 2005

Table 27. Determination of O&M Items

Year	O&M (Includes Fixed and Variable Items for IT and CC&B)	
Item:	Fixed Volumes	Variable Items & Prices
2003	Actuals Approved in 2005-039*	Benchmark & True up – (Use Actuals)
2004	Actuals Approved in 2005-039*	Benchmark & True up – (Use Actuals)
2005	Forecast Approved in 2006-004*	Benchmark & True up – (Use Actuals)
2006	Forecast Approved in 2006-004*	Benchmark & True up – (Use Actuals)
2007	Forecast Approved in 2006-004*	Benchmark & True up – (Use Actuals)
2008	Forecasts- (as determined in this Decision)*	Approve as Placeholders in GRA and Finalize in Evergreen Phase 1 (as determined in this Decision)*
2009	Forecasts (as determined in this Decision)*	Approve as Placeholders in GRA and Finalize in Evergreen Phase 1 (as determined in this Decision)*
2010+	Evergreen Phase 2	

* Items determined by the Commission either in this Decision (See Commission Findings) or a prior Decision or letter

The Commission has indicated by letter dated October 24, 2008[161] that all costs and volumes related to variable items for 2008-2009 will be determined in the Evergreen Phase 1 proceeding.

The Commission has also indicated in the October 24, 2008 letter, that the Benchmark and True up proceeding will examine whether there is any need to adjust the Benchmarker's findings to address the principles contained in ATCO's Code of Conduct. The Commission considers that adjustments (if any) for Code of Conduct related issues that arise in that proceeding would likely also impact IT and CC&B costs for 2008 onwards. Accordingly, for efficiency, the Commission will deal with any implications for 2008-2009 after the determinations are made in that proceeding.

As the Commission has indicated above, it will deal with variable items and the implications of ATCO's Code of Conduct in other proceedings. Given this approach and the timing of those proceedings, the Commission notes that the final 2008 opening capital balances will likely not be approved in the Benchmark and True up proceeding before AG makes the refiling ordered in this Decision. Accordingly, the Commission approves a placeholder for the opening 2008 capital balances later in this section.

The Commission has been asked to approve the 2008 and 2009 forecast volumes for the fixed items for capital and O&M for both IT and CC&B.

In regard to the IT O&M the Commission notes that Calgary provided an analysis in its evidence and ultimately did not recommend any adjustments to the forecast for the fixed volumes. However, Calgary did make recommendations with respect to "Financials Appl Host & Storage" and "Adabas-IMS License" which were shown as dollar amounts in the fixed volume section of Attachment 2 to CAL-AG-12(a). Calgary recommended that the "Financials Appl Host & Storage" belonged in the variable section, and the "Adabas-IMS License" should be denied outright.

First, the Commission agrees with Calgary that both the "Financials Appl Host & Storage" item and the "Adabas-IMS License" item are IT variable items as they are both expressed in dollars.

[161] Letter from 2003-2007 Benchmarking and I-Tek Placeholders True Up Application No. 1562012 Proceeding ID. 32 and Evergreen Application, Application No. 1577426 Proceeding ID. 77

Consequently, the Commission directs AG to include both items with the variable items to be evaluated during the Evergreen Phase 1 proceeding. The Commission will consider Calgary's recommendation to disallow the "Adabas-IMS License" in that proceeding.

In its review of the reasonableness of the remaining IT O&M forecast fixed volumes the Commission compared the previous GRA forecasts to the actual quantities for the years 2003 to 2007 and noted that AG's forecasts tended to be on the high side more often than on the low side. The Commission also found the comparison challenging due to the many variations. For example, when comparing the 2007 forecast volumes to 2007 actual volumes, the Commission notes that a line by line comparison was difficult as not all cost categories could be found in both spreadsheets. However, the Commission did not consider the deviations between forecast and actuals to be significant enough to warrant any adjustment. During its review, the Commission found Calgary's evidence, which provided tables summarizing the fixed and variable items since 2005, was of assistance, and concurs with Calgary that the estimated fixed volumes for 2008 and 2009 do not require adjustment. Accordingly, the Commission approves the remaining IT O&M forecast fixed volumes for 2008 and 2009.

The Commission also examined the forecast O&M fixed volumes for CC&B and notes that AG explained that it had used customer growth to project the volumes for 2008 and 2009. In its evidence Calgary did not recommend any adjustments to the fixed volumes. The Commission is satisfied that the estimates for the fixed volumes are reasonable given they track customer growth. Accordingly, the Commission approves the CC&B fixed volume forecast for O&M for 2008 and 2009.

The UCA has recommended a four-year plan to reduce the IT O&M using the Gartner Report as the guide. Calgary also recommended a reduction to the forecast that was based on the expectation that the total dollars would be too high. Like the UCA the Commission observes a significant year-over-year increase since 2006 in the forecast of O&M IT expenses. Since 2006 the year-over-year increases were forecast to be 18.3%, 17.6% and 22.7%, which the Commission considers is much greater than the growth of the business. The Commission would expect a combination of customer growth and inflation, in the order of 8% to 12% would have been behind the forecast increases.

However, the Commission recognizes that, in part, the forecast increases will be affected by the outcome of both the Benchmark & True-up and Evergreen proceedings, and based on AG's updated information provided in its rebuttal evidence the forecast expenditures will likely be reduced. Under the circumstances, the Commission considers Calgary and the UCA's recommendations based on total IT costs to be at best premature as the final forecasts for 2008 and 2009 are as yet unknown. The caution in the Gartner Report to rely on the decisions of company management may reduce the weight given the Gartner Report in future proceedings when the IT and O&M spending trends are available.

Accordingly, the Commission would expect any such recommendations based on total IT costs to be raised in the Evergreen proceeding where 2008-2009 total IT costs will be tested.

In respect to fixed capital volumes for 2008 and 2009 the Commission notes that it has been asked to approve both IT and CC&B amounts. With respect to CC&B, the Commission notes that Calgary had no issue with the capital cost forecast. The Commission also notes that both Table 6B and Table 11 in Calgary's evidence provided the forecast of combined dollar amounts for both fixed and variable items from 2003 to 2006 and compared these amounts to total actual dollars. While the tables show periods of over and under forecasting, the Commission recognizes that it is on a combined basis, and that the pricing associated with fixed and variable items is currently under review. Therefore the Commission considers that it cannot rely on this analysis in making its determinations regarding the fixed volumes.

The Commission observes that the significant reason for the fluctuations in the IT capital forecast is tied to the Work Management Replacement, and the NGSIS replacement. The Work Management Project is expected to be completed in 2008 and a substantial portion of the NGSIS replacement is forecast in 2009 (originally forecast in 2008). AG is replacing the aging NGSIS with the SI and NGB systems as the legacy system is difficult to maintain. The DFSS project is also expected to come to a close in 2008.

The Commission is not convinced that it should deny the capital costs of these projects, or any portion of them, as Calgary has recommended. Given that these are capital projects, and will be reviewed for prudence when AG applies to have the actual costs included in rate base, the Commission will approve the forecasts as filed for the fixed volumes for both IT and CC&B for 2008 and 2009,

The estimated fixed volumes for IT and CC&B are approved for 2008 and 2009 to be used together with the pricing which is to be approved in the Evergreen proceeding. In addition the Commission also approves, as a placeholder for 2008, the 2008 opening capital balances as originally filed in the Application. The Commission directs AG in the refiling to reflect these values as approved.

Calgary's recommendation to exclude the DFSS capital cost from rate base is not accepted. The Commission notes that the DFSS had previously been approved in principle. AG's request to include the forecast amounts in the 2008 rate base for the purpose of determining a revenue requirement is granted. However, the Commission will, as noted above, review the final rate base amount for prudence when it is requested to be placed in rate base.

Final approval of the actual IT and CC&B fixed volumes for capital for 2005, 2006 and 2007 was also requested. Upon review the Commission finds that the actual fixed volumes related to the capital costs for both IT and CC&B are reasonable and, in addition, interveners did not recommend any adjustment to the actual values. As a result of its review, the Commission approves as final the actual fixed capital volumes for 2005, 2006 and 2007 to be used together with the pricing which is to be approved in the Benchmark & True Up proceeding. The Commission considers that all other matters relating to the 2003-2007 period should be dealt with in the Benchmark & True Up proceeding.

11 DEPRECIATION

A comparison of forecast depreciation and amortization expense by North and South zones has been provided in the table below:

Table 28. ATCO Gas Summary of Depreciation and Amortization Expense by Zone[162]

	2007 Forecast ($000)	2008 GRA ($000)	2009 GRA ($000)
AG North	44,304	49,278	55,296
AG South	40,441	44,247	48,603
AG Total	84,745	93,525	103,899

AG's most recent full depreciation study was internally prepared for its 2005-2007 GRA (2005 depreciation study) using historical data to the end of 2003. For the current Application, AG retained Gannett Fleming to prepare a technical update to its 2005 depreciation study. The technical update adjusted annual depreciation rates for changes associated with plant activity to the end of 2006, but it did not comment on previously approved depreciation parameters, which included average service life, net salvage percentage estimates, or grouping procedures.[163]

AG explained that its fixed assets were depreciated or amortized using one of four methods of calculation, which included:

1. Study Assets
2. Unit of Production
3. Contract Life
4. Straight Line Fixed Rate

Commission Findings

Having reviewed the depreciation and amortization expense amounts forecast for 2008 and 2009, and the methodology used to produce these amounts, the Commission finds that it is consistent with the previous methodology, and the results are reasonable. Also, the Commission notes that parties did not object to the quantum of the increases in depreciation expense or the overall methodology applied by AG. On this basis, the Commission finds that the depreciation and amortization expense is reasonable for the 2008-2009 test period. Therefore, the Commission accepts the 2008 – 2009 forecasts as filed, with the exception of the specific areas raised by interested parties which are individually addressed below.

Due to the significant amount of capital expenditures that have either occurred or are forecast in the test years, the Commission directs AG in its next GRA to file a full depreciation study which must include updates for capital activity as well as recommendations regarding the appropriate depreciation parameters.

11.1 Leasehold Improvements Methodology

AG currently uses the contract life depreciation method only for the area of leasehold improvements. In its Application, AG proposed the implementation of an annual reserve

[162] Application, Section 5.0 – Depreciation, page 5.1.1, Table 5.1.1
[163] Application, Tab 9.0 – Board Comments, page 9.0-30

amortization process for leasehold improvements to complement its current practice, which would be similar to the method used for its Study assets. AG indicated this proposed change was requested to address the situation where leasehold improvements were retired prior to the term being used for depreciation purposes.

The UCA submitted that the new methodology proposed by AG to provide for unrecovered costs at the end of leaseholds was not required as a simple method was already in use, which was based on a maximum five-year remaining life recovery. The UCA indicated the unrecovered cost was small and it could be addressed in AG's next depreciation study. The UCA submitted that a simple adjustment was all that was required, not an additional administrative process, such as the proposed reserve amortization. The UCA submitted that a more appropriate and consistent methodology, similar to the one used for Study assets, was required to calculate the amortization of leasehold improvement costs.

The UCA stated that there was confusion regarding AG's current methodology as the definition in AG's Rebuttal evidence differed from the information in the depreciation section of the Application. The UCA recommended that AG be directed to clarify the method it follows, given the multiple definitions.

AG confirmed that leasehold improvements were depreciated over the remaining contract term of the existing lease plus one renewal period, if specified in the contract, and not for a period shorter than five years.

Contrary to the UCA's view, AG stated that once it moved out of a leased facility or replaced a leasehold improvement with another leasehold expenditure, AG retired that leasehold improvement and did not depreciate it further. This meant that AG was unable to recover the remaining costs associated with these retirements through its normal depreciation practice. AG stated that the alternate method recommended by the UCA would lengthen the period of recovery for these costs, and that the method proposed by the UCA did not address the recovery of removal costs or the un-recovered costs on AG's balance sheet.

AG's request for establishment of an annual reserve amortization process for leasehold improvements, similar to that used for Study assets, was similar to those approved for FortisAlberta and ENMAX. AG stated that another alternative treatment of netting leasehold improvement retirements against new leasehold costs would understate depreciation expense.

AG's current method of amortizing a leasehold improvement over the original life of the lease plus one renewal period, regardless of when the expenditure occurred, was different than the UCA proposed method, used for general asset expenditures such as tools and work equipment, which amortized these costs occurring in the same year over the expected life of those assets.

AG committed to review its leasehold improvement practices at its next GRA so only the addition of the reserve amortization process had been proposed in the Application. AG stated that its proposal would address historical issues related to retirement of leasehold improvements and would result in depreciation expense increases of $159,000 in the North and $176,000 in the South for each of the test years.

Commission Findings

The Commission considers that the method proposed by the UCA will lengthen the period of recovery for leasehold improvements cost and could introduce intergenerational inequities where an asset is consumed in providing utility service to one group, but then paid for by a different group in following years. While the dollars involved may be small, the Commission does not see a need to change the entire process for the amortization of leasehold improvements.

The Commission finds that AG's proposal to add the reserve amortization process to the existing methodology efficiently addresses the situation raised by AG, where leasehold improvements were retired prior to the term being used for depreciation purposes. This procedure is already in use for AG's Study assets. The Commission notes that while the UCA proposed an alternative method, it did not address the original reason for the topic being raised in the Application.

The Commission rejects the UCA request that AG be directed to clarify the method it follows for leasehold improvements. AG confirmed that leasehold improvements were currently depreciated over the remaining contract term of the existing lease plus one renewal period, if specified in the contract, and not for a period shorter than five years.

In its rebuttal evidence, AG committed to review alternative methods for depreciating its leasehold improvement costs[164] and this information will be filed as part of its next GRA. Therefore, the Commission directs AG in its next GRA to provide the referenced study as indicated in rebuttal evidence.

11.2 Customer Information System Life for Amortization Use

The UCA suggested that AG had not complied with EUB Direction 42 from Decision 2006-004 to complete and file a life study for CIS that justified its final retirement date. UCA recommended that AG be directed to complete this for the next GRA.

The UCA stated the determination of an asset's life and net salvage determined the appropriate depreciation expense to use, not that the study should be used to determine when AG should retire CIS, as AG suggested. The UCA commented that the current amortization period was too short, and the amortization periods for CIS assets have not been updated since its inception.

The UCA proposed that 2014 was a reasonable retirement date for CIS as it represented an amortization period of 15 years for the earliest CIS placements. Enhancements to the CIS assets and other CIS software should use one-half or a 7-year amortization period.

The UCA explained that the use of amortization accounting for assets should not cause concerns over an amortization period that resulted in assets not being fully depreciated at the end of their physical life. Amortization accounting did not guarantee that assets would be fully depreciated at the end of the amortization period. For assets placed after the initial year of placement, the life used for the amortization period would amortize the related assets to the original placement past the end of the amortization period of the original placement, even in some cases for CIS enhancements which had a life of one half of the original life.

164 AG Rebuttal Evidence, page 128, lines 19 – 23

Calgary stated that AG's CIS Life Study should have examined alternatives for its replacement as well as an examination of the life of the existing system. Calgary submitted that the CIS Life Study was not properly undertaken.

AG responded to UCA's recommendation to extend the amortization period used for CIS and enhancements beyond the current 2014. While the UCA claims this would be reasonable, AG demonstrated that based on current approved amortization rates CIS and enhancement costs to the end of 2009 will be recovered by 2014 because enhancements are being amortized over five years, or half of the original assets life.

AG disagreed with continuously updating depreciation rates for software expenditures, and instead recommended amortizing enhancement expenditures over half the estimated remaining life of the software. AG stated that this would extend the period of time over which the total costs of the system are recovered.

AG recommended that no changes related to CIS were required for the above reasons.

Commission Findings

The Commission has reviewed AG's response to Direction 42 from Decision 2006-004 and agrees with the UCA that the response provided in the Application did not fully provide the requested information. Direction 42 had requested the following:

> The Board agrees with AG that the life span of the AG CIS is not likely extended by the enhancements forecast in the GRA. Accordingly, the Board agrees that the recommended life span of the AG CIS until 2010 is reasonable. However, the Board requires that AG have a strategy to maximize the useful life of CIS and, therefore, directs AG at its next GRA, to complete and file a life study for AG CIS justifying the final retirement date of the AG CIS.

AGs response included the following study assessment summary:[165]

> The application health check evaluation methodology proposed by Gartner (Research Publication) has resulted in an overall score of 39 for ATCO CIS. This indicates the application is performing well but requires enhancements in isolated areas. Based on the strong application performance rating and ATCO Gas' future business requirements that can be reasonably foreseen, ATCO CIS will be able to meet ATCO Gas' needs for the foreseeable future.

While the Board had directed that the provided study should confirm the appropriate final retirement date of CIS, in the preface to the supplied study AG indicated that the amortization period chosen for CIS of 2010 was reasonable but that the system will be used beyond that date.

AG indicated, in UCA-AG-104(l) Supplemental that "ATCO Gas does not plan on replacing ATCO CIS in the next five years." As this response was provided on March 12, 2008, at a minimum the addition of five years to 2008 would extend the final retirement date out to 2013, instead of the year 2010 which is currently being used in the Application. The Commission notes that AG has included enhancements for CIS in the current test years, and also that the supplied

[165] Application, Tab 1 – Board Direction 42 Attachment, page 14 of 14

study in response to Direction 42 indicates that with enhancements, the CIS system could be used for the foreseeable future.

The Commission is not revising the retirement date for use with CIS amortization as recommended by the UCA, as the date that would be selected would apply to the unamortized portion of the assets remaining during the test years. The remaining three years of amortization for the original asset could be amortized over an additional number of years that would be selected at the present time, but due to the seemingly open nature of the retirement date for the CIS system, there is a strong likelihood that the retirement date would be revised again in the future.

However, the Commission directs AG in its next GRA to fully comply with Direction 42 from Decision 2006-004 and provide its best estimate of the retirement date for the CIS system, and to clearly identify the assumptions and rationale for the selected date. As indicated by the study provided in this Application, future enhancements may be required if the life of the CIS system extends beyond its original retirement date. The information provided regarding the retirement date would be helpful to the Commission in determining an amortization period for those future enhancements. To the extent that AG has any preliminary information on alternatives to CIS, the Commission directs AG in its next GRA to file the information, including any available preliminary cost information.

11.3 Production Abandonment Costs

Production abandonment costs relate to AG's obligation to properly abandon production properties which were used to provide utility service. Costs mainly relate to the two following areas: environmental remediation of well and other production sites; and correction of problems with previously abandoned properties, such as leaks causing gas migration to the surface. A production abandonment deferral account was established in the prior GRA through Decision 2006-004, and an annual expense amount was included in the revenue requirement forecast for these costs, as noted below:

Table 29. AG Forecast Production and Abandonment Costs[166]

	2007	2008	2009
ATCO Gas North	100,000	350,000	350,000
ATCO Gas South	250,000	700,000	700,000
Total	350,000	1,050,000	1,050,000

In addition to the above forecast amounts for 2008 and 2009, AG is seeking a one-time recovery of $551,000 related to the balance of the 2007 AGN production abandonment deferral account.

The UCA clarified that it agreed that continued recovery in rates of costs related to assets which have been physically retired from service after retirement were appropriate for production properties. This recovery, related to unrecovered production abandonment costs, was not a guarantee though, and AG should justify these costs in each GRA before the Commission.

Calgary submitted that based on the uncertainty surrounding assets in rate base which were not providing service, it would be inappropriate to include the abandonment costs in revenue

[166] Application, Section 5.0 – Depreciation, Attachment 7 – Production Abandonment Deferral Account Schedule

requirement at this time. Calgary recommended the amounts should either be considered as placeholders, or be continued in a deferral account pending further disposition when a better understanding of the Stores Block decision was known. There was an $83.9 million shortfall between the required reserve and the actual reserve, but based on the Stores Block decision, the amortization of this shortfall shouldn't be included as part of depreciation rates, which would then be collected as part of the 2008 and 2009 revenue requirement. Calgary submitted that as the Calgary Stores Block Decision may apply to over and under collections, the depreciation expense should exclude the amounts related to amortization of the reserve deficiency for production abandonment costs.

The CG submitted that to the extent customers may no longer participate in the future value of production and storage assets in AGS resulting from the Court of Appeal decisions, then customers should also no longer be responsible for current capital forecast costs and expenditures for production and storage in the South. The CG recommended that AG be directed to ensure the working partner credit for the abandonment costs was appropriately reflected in the deferral account and be demonstrated in AG's refiling.

AG stated that these increased expenditures were required to remediate the surface impacts and correct issues related to prior well abandonments. AG confirmed these costs related to assets that were fully consumed in providing utility service, and recommended the annual expenses and the one time adjustment be approved.

Commission Findings

The Commission has not yet rendered a decision in the Utility Asset Disposition Rate Review proceeding (EPS Proceeding ID 20), and the courts have not provided any further guidance regarding the Calgary Stores Block decision.

Consequently, as with the Carbon Storage matters discussed elsewhere in this decision, the Commission considers that the *status quo* should be maintained, in this case, pending resolution of the above noted proceedings. Therefore, AG is directed to account for these abandonment costs using the current deferral account treatment. On this basis the Commission approves AG's forecast production and abandonment costs.

Additionally, the Commission agrees with the CG regarding the need to confirm whether the working partner's credit identified in IR AUC-AG-29 has been applied against the $551,000 one time shortfall shown in 2008. Therefore, the Commission directs AG in the refiling to ensure and demonstrate that the working partners' 25% credit is appropriately reflected in the abandonment deferral account.

12 INCOME TAXES

In principle, a utility is allowed to collect in any year, the forecast income taxes that would be payable on the allowed return. While AG is not a taxpaying entity, as it is a division of AGPL which is a taxable corporation, for regulatory purposes AG is deemed to be a taxpayer. The income taxes included in AG's revenue requirement would only be the same as its actual portion of income taxes paid by AGPL for the test year if AG's forecast allowed return was identical to the actual income recorded in AG's accounts. As income taxes are not ordinarily treated as deferral amounts for regulatory purposes there is certain forecast risk for the amounts included in the revenue requirement.

AG generally uses the flow-through method to calculate income tax expense for revenue requirement purposes. Under this method, AG would calculate the least amount of income taxes that would be expected to be payable on the income forecast for the test years concerned. Forecast income taxes are determined in accordance with the income tax legislation as it existed at the particular time of the filing of the Application. Revenue recognition and deductions claimed for income tax purposes in a year can differ from the related amounts used for accounting purposes. In respect of forecasts for test years, where announcements of changes to income tax rates and tax laws by government may have the substantive effect of enactment, the changes normally are used in the forecasted income tax calculation.

AG, consistent with prior GRA applications, departs from the full use of the flow-through method by deferring income taxes related to the recognition of income tax timing differences associated with regulatory deferral accounts. Deferral accounts include deferred hearing costs, North production abandonment costs, ATCO CIS royalties and the reserve for injuries and damages.

12.1 Implementation of all Rate Changes Arising from Federal/Alberta Budgets

CG submitted that changes proposed in the March 19, 2007 Federal Budget, as well as the October 30, 2007 Federal Budget Update, should be incorporated in the determinations of AG's 2008 and 2009 revenue requirements.

Calgary similarly recommended that as the income tax rates included in the federal budget have now been implemented the amended rates should be used in the final compliance filing to determine income tax expense.

AG stated that it had updated its 2008 and 2009 revenue requirement to include the rates in the Federal budgets.

Commission Findings

In the case of an income tax expense forecast, the income tax rates are not forecast and there is no expectation that a utility will attempt to anticipate what changes government may make to income tax rates or policies in the test period for a GRA. However, the Commission is of the opinion that, where there is evidence that a change in income tax rates will occur before a final decision for a GRA is issued, the income tax expense included in revenue requirement should be updated to reflect the change in any refiling made by the utility for compliance purposes. The Commission also considers that the use of updated income tax information is in the overall public interest as it results in a more accurate revenue requirement, without causing undue benefit or harm to the regulated utility. The Commission acknowledges that AG has included the appropriate revisions to rate changes affecting forecast income tax expense set out in Federal budgets for the purposes of updating its 2008 and 2009 revenue requirements. However, for greater certainty, the Commission directs AG in the refiling to use the Federal budgeted rates to determine income tax expense in its 2008-2009 GRA.

12.2 Use of a Deferral Account for Income Taxes

The CG submitted that a regulatory deferral account should also be established to account for income tax rate changes that may occur during a test year, as the changes are beyond the control of management and can result in significant amounts. The CG considered that, as AG cannot forecast government intentions or future policy in respect of changes in income tax rates, to the extent such future government policies may impact the computation of test year revenue requirements, deferral account treatment is a fair method for both customers and shareholders. The CG noted that deferral account treatment for income tax rate changes was approved for AG's affiliate, ATCO Electric Ltd.

The CG argued that over the six-year period 2002-2007, the excess of actual over forecast tax deductions for non-recurring or unexpected items has amounted to approximately $42.50 million. Given the admitted difficulty in forecasting similar tax deductions and considering there may be a potential for a significant or material "other" temporary differences in the 2008-2009 test years, or beyond, the CG submitted that AG should be directed to include in the income tax deferral account any such amounts greater than $250,000. The CG considered that this treatment would serve as a reasonable safeguard against unwarranted windfalls that AG may incur.

AG disagreed that a deferral account for income taxes should be used for regulatory purposes, as there is not a significant degree of volatility or uncertainty involved. AG noted that it had already incorporated the change to income tax rates in the update to its 2008 and 2009 revenue requirements.

AG submitted that the amounts that may arise as a result of non-recurring or unexpected deductions that may occur during the test years would not be material. AG also argued that forecasting such deductions based on prior year trending was inappropriate as the deductions in question were unique and, consequently, using deferral account treatment would not be reasonable.

Commission Findings

The Commission is aware that deferral accounts have been approved for ATCO Pipelines[167] and ATCO Electric,[168] affiliates of AG, to provide for changes in income tax rates as they may subsequently apply to the forecast made for a test year. In light of the concerns outlined below in Section 12.4, in particular, the differing tax treatment of the ATCO regulated utilities, the Commission will defer consideration of this issue until the process noted below has been concluded.

12.3 Capitalized Expenses Deducted in a Year for Income Tax Purposes (Rainbow Type Expenses)

Capital repair costs refer to expenditures that AG would include in its rate base but which, for income tax purposes, would be fully deductible as an expense in the year incurred. Expenditures of this nature have been referred to as Rainbow[169] type expenses. The tax case referred to four principle factors that would suggest that repair costs concerned would be expenses deductible in

[167] Decision 2003-100 – ATCO Pipelines, 2003/2004 General Rate application, Phase 1, page 112
[168] Decision 2007-071 – ATCO Electric Ltd. 2007-2007 General tariff Application – Phase 1, September 22, 2007, page 87
[169] Refer to Rainbow Pipeline Company, Ltd. v. Her Majesty the Queen, 99 DTC 1081, Tax Court of Canada

the year incurred as opposed to being capital outlays:

1. the repair would be recurring events,
2. a major repair was not involved,
3. the cost of any one repair or all of the repairs taken together would not be substantial in relation to book value, annual expenses or annual profits, and
4. a repair cost viewed alone, or together with others, did not bring into existence an enduring asset.

The CG submitted that AG's practice of expensing capital repair costs for income tax purposes does not appear consistent with AG's own capitalization policy and is also not in the best interests of customers who, as consequence, unnecessarily pay for 100% of these costs up front. The CG argued that if expensed capital repair costs are material in amount large swings in O&M expenses will result, making comparability more difficult.

The CG argued that, while AG stated it was relying on previous studies indicating AG's capital repair projects do not enhance the service potential of these assets, there appears to be no such studies on the record. The CG thus submitted that no reliance can be made on studies that may or may not exist or reviews which may have been undertaken but are not on the record to test. Therefore, the CG recommended that, as part of its next GRA, AG should be directed to provide a comprehensive assessment of all capital repair projects in excess of $100,000, and capitalized in accordance with generally accepted accounting principles, to determine what expenses may be eligible for deduction in the year incurred for income tax determination purposes. The CG submitted that the study should be provided as part of AG's next GRA. The CG also recommended that the Commission approve deferral account treatment for Rainbow-eligible capital repairs, similar to that approved for AE.

AG submitted that it has studied these types of expenditures before and the results of those previous studies have shown that these repair costs do not meet the criteria for capitalization. AG further submitted that its O&M costs are audited regularly by both internal and external auditors who have never indicated any that capital costs have been incorrectly charged to O&M.

Commission Findings

In light of the concerns outlined below in Section 12.4, the Commission will defer consideration of the issues raised by CG until the process noted below has been concluded.

12.4 Income Tax Reassessments and Other Matters

In 2006, AGPL pursued cost reductions through the deductibility, for income tax purposes, of certain costs which were charged directly to capital projects. These cost reductions were pursued through a real time audit with the CRA and with the CRA Appeals Division. Ultimately, AG's portion of the amounts recovered through reassessments was approximately $8.6 million ($4.5 million regarding AGN and $4.1 million regarding AGS)[170] in income taxes in respect of the years 1999-2006.

The CG submitted that to the extent costs deducted in obtaining the prior years' income tax recoveries were still in rate base, customers would be paying the booked amount of depreciation

[170] Exhibit 0034.05.ATCO GAS-11, CCA-AG-11(t), Attachment

without corresponding capital cost allowance (CCA) to shelter future taxes expense due to the reduction in undepreciated capital cost (UCC), thereby creating a further inequity for customers. CG recommended that:

(i) AG be directed to refund the income tax refund it received or, alternatively,
(ii) AG be directed to restore the UCC to the level it was prior to recovering the prior years' income taxes.

Calgary submitted that the income tax refunds represent approximately 2% of additional return since common equity for 2007 was forecast on a mid-year basis to be $228 million for AGN and $220 million for AGS. However, the rates for 2007 were not designed on the basis that these additional deductions were available. Calgary noted that that as a result of these additional deductions the UCC carried forward for income tax deduction purposes by AG would be lower than it otherwise would have been if these amounts had not been deducted. Calgary argued that if AG was allowed to keep this windfall then customers would be harmed in future years by having less CCA available.

Calgary proposed that, in order to avoid retroactivity, a deemed UCC schedule for regulatory purposes should be used to reflect balances that would exist if the deductions had not been made. In that way customers would not be double penalized and AG would benefit from the time value of the deductions.

The UCA submitted that income tax recoveries of $10.3 million ($8.6 million for 2006 and prior years and $1.7 million for 2007) belong to customers and should be refunded to customers over the 2008-2009 test period or, alternatively, the UCC balances should be reinstated to include the amounts allowed by the CRA as deductions in prior years for the benefit of customers in the future. The UCA argued that as a result of AG's deduction of costs that it otherwise included in UCC, customers would be charged an additional $3.1 million over the ten-year period from 2008 to 2017.[171]

AG submitted that recommendations of the interveners represented retrospective rate making and would effectively remove its incentive to seek cost reductions as the proposals result in the entire benefit being provided to customers. AG considered that share owners would be penalized for seeking efficiency gains as the entire benefits of the additional tax deductions would be provided to customers but would see share owners absorbing the costs incurred to ascertain the benefits. AG countered UCA's expected income tax expense increase over the ten-year period and calculated that, on a present value basis, the grossed-up value of deducting the capitalized amounts in the future would provide net benefits to customers of $15,481 over the ten-year period from 2008 to 2017.[172]

AG further submitted that requiring the income tax recoveries to be credited to customers would provide to customers the benefits of a past gain or refund in future rates, which is clearly a breach of the well established principle against retrospective ratemaking (i.e., it would be contrary to principle as set out in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4. AG submitted that the Commission has no power to refund a past gain to customers in a future period in any event. AG considered that acceptance of the intervener

[171] Exhibit 0102.00.UCA1-11, UCA Evidence, Table 2, page 113
[172] Exhibit 0143.00.ATCO GAS-11, AG Rebuttal Evidence, page 133

proposals would send a strong message to AG's share owners not to pursue further cost reduction initiatives. AG stated that the EUB upheld the principle that the risk and benefit of tax changes after rates have been set for a test period was to be borne by utility shareholders.

Commission Findings

The Commission has concluded that it is not in a position to determine the proper regulatory treatment of the effects of the 2006 income tax reassessment, the proposed deferral accounts for income taxes and AG's treatment of Rainbow type expenses.

The Commission acknowledges that AGPL pursued the tax deductions that resulted in the reassessment but cannot agree that a company availing itself of a permitted tax deduction that it qualified for in the past but had not pursued, are attributable to a productivity gain. The Commission understands AG's argument that a failure to allow shareholders to keep the gains realized by the reassessment would mean that the Company would be discouraged from seeking further "cost reduction initiatives" in the future. The Commission also recognizes that issues regarding retrospective rate making arise when considering the options the Commission might have in dealing with the effects of the reassessment. In considering these questions, the Commission became aware of past regulatory proceedings dealing with the tax deduction at issue here. In addition, it became evident to the Commission that more fundamental regulatory principles were engaged.

Therefore the Commission invites parties to make further submissions on the regulatory treatment that can and should be accorded to the cost increases/reductions occasioned by income tax reassessments, deferral accounts for income taxes, and, AG's treatment of Rainbow type expenses. In making these submissions, parties are invited to address all factors they consider relevant to the treatment of income tax cost increases/reductions and invites comment on the following matters specifically:

1. Are issues, facts or circumstances raised in the records of EUB applications and decisions (from 1999 to 2006)[173] on the subject of the income tax deductions which were the subject of the AGPL income tax reassessment, relevant to the Commission's consideration of the issues raised by the reassessment in this proceeding and if so, how are they relevant?
2. Should the Commission consider past EUB decisions relating to AG (North or South) regarding these deductions in making its determination in this proceeding? If the EUB did not address the issue of the potential for these deductions, is it fair for the Commission to do so now?
3. If the EUB had given a direction to AG to pursue these income tax deductions, would parties consider that such a direction would have amounted to micro-management of the utility?
4. Considering that a company in a competitive environment would be incented by market forces to seek all eligible deductions to make itself more competitive, does it fall to the regulator, when no competitive market forces are present, to step into the shoes of a competitive market and direct the utility to apply for specific tax deductions?
5. Did AG have an obligation to notify the EUB of its intention to apply for reassessment to the CRA given the timing of that application?

[173] For example EUB Decision 2001-96 ATCO GAS South GRA 2001-2002 and EUB Decision 2003-72 ATCO Gas 2003-2005 GRA

6. Is it open to the Commission to consider whether it was imprudent of AG to not take these deductions when they were first identified? If so, based on the prudency test enunciated in the DGA Decision and upheld by the Alberta Court of Appeal, did AG act imprudently in not seeking the tax deductions when they were first identified?
7. Is the treatment of these income tax deductions by the other ATCO regulated utilities relevant and, if so, how? Also, given the use of deferral accounts for income taxes by AE and AP, for consistency should AG be directed to establish same?
8. Is the Commission limited in the range of options available to it by application of legal principles dealing with retrospectivity or retroactive rate making, or any other legal principles? If so, please describe the limitations with reference to applicable case law and how the case law supports the position being taken.
9. Is AG's current treatment of Rainbow type expenses sufficient for the test years?

As a result, the Commission requests that parties file argument following the deadlines set out below:

Argument for all parties:	December 4, 2008
Reply Argument:	December 14, 2008.

Consequently, the forecast income tax expense amounts for 2008 and 2009 (as amended by the Commission's Direction in Section 12.1) will be considered placeholders until the Commission has made its findings with respect to the income tax reassessment.

13 UTILITY REVENUE

AG prepared its throughput forecasts for the various rate classes using a multiple regression model approach, with separate models developed for each zone (North and South). The results from the models were supported by additional information provided in the Application which included 12-month rolling average customer graphs, vintage analysis, an average trend analysis, and results from an annual customer energy conservation survey.

Vintage analysis is a method used to support trends in GJ per site by observing the effects of efficiency improvements, or other site changes, on consumption, while average trend analysis was used to identify trends in GJ use per customer.

AG has proposed to change the methodology for calculating revenue by basing the throughput and revenue forecasts for the test years on the ten-year average temperatures ending in 2006, rather than the 20-year average used in previous applications.

13.1 Weather Normalization

The normalization calculation used by AG was based on the linear regression of sales/customer to temperature (on a restricted basis). AG's methodology was reviewed in detail in its 2003-2004 GRA.[174]

[174] AG Rebuttal Evidence, page 159, lines 16-21

For normalization purposes, AG prepares a regression calculation each year based on the previous year's actual monthly sales/customer to temperature, for each rate class that has a commodity charge. The temperature coefficient (line slope) from this regression is applied to the deviation between the actual temperature and the normal temperature for each month, which is then, in turn, applied to the actual day sales/customer for each month to produce a normal day sales/customer.[175]

13.1.1 Number of Weather Stations Used for Normalization

The UCA was concerned with AG's use of only two weather stations for normalizations: Calgary International Airport, and Edmonton Municipal Airport. The Daily Forecasting and Settlement System (DFSS), which was used for estimating the consumption of gas on a daily basis, used six weather stations: Edmonton, Grande Prairie, Fort McMurray, Red Deer, Calgary and Lethbridge. The UCA recommended that since AG used six weather stations to assist retail marketers in balancing the system, then AG should at least use that same number of stations for weather normalization. The UCA commented that AG may have used six weather stations for DFSS due to the microclimates faced.

The UCA recommended that AG be directed to provide an analysis of expanding the number of weather stations used for weather normalization, including any analysis of the transitional impact when temperature is near the heating base.

The UCA was also concerned with the choice of weather stations used. The UCA stated that AG's use of the Edmonton Municipal Airport resulted in AG's claim that $37 million of revenue was unrecovered over the last ten years. The UCA stated that if the Edmonton International Airport had been used, AG would have refunded $28 million to customers. The UCA commented that the approach AG had used was not appropriate as too much uncertainly existed for both AG and customers if the numbers could swing by $64 million due to which weather station was selected for use.

The UCA recommended that AG should be directed to examine the bias associated with using the Edmonton Municipal Airport weather station vs. the Edmonton International Airport, and that AG's weather deferral account should be rejected unless AG enhanced its proposal.

AG stated that in the 2005-2007 GRA the Board found that use of six temperature zones to forecast throughput would not significantly improve forecast precision.[176] AG stated that six different weather stations were used for the DFSS to forecast individual customer sites for load settlement purposes. AG explained that it did not prepare its throughput forecast on an individual customer basis, and if the throughput forecast was prepared at an individual customer level, it would have an insignificant effect.

While AG indicated it could use additional weather zones for temperature forecasting and normalization, and that it would probably have little impact on the normalized throughput, significant work would be needed to restate historical information used in the regression models, vintage analysis, and a12-month rolling data. Throughput forecasts would become more complex with the development of regression models by class and by temperature zone, and additional

[175] Application, Section 7.10 – Weather Deferral Account Mechanism, page 7.0-47, lines 18-23
[176] AG 2005-2007 GRA, Tab 1.0 – Outstanding Board Directions, No. 69 from Decision 2003-72

resources would be required. AG indicated it could provide its next GRA forecast using the additional temperature zones and defer any incremental costs until the next GRA.

AG submitted that having the current forecast based on two weather zones should not be seen as a reason to delay implementing the weather deferral account as the impact of using the additional temperature zones was not expected to be significant.

AG responded to the UCA's concern with the use of a single weather station for a large metropolitan area. The AG analysis[177] showed that there was no significant impact on AG's forecasting or normalization methodologies if the Edmonton International Airport, instead of the Edmonton Municipal Airport, had been used for North residential customers.

AG stated that it would be difficult to split customers within a community to use different temperature zones for the same community and that changes would be required with how data from CIS was provided for load research information.

Commission Findings

The Commission has considered the information provided by the UCA and AG, including the response to Direction 69 from Decision 2003-72 which studied the impact of increasing the number of weather stations from two to six. The Commission notes that the information requested by the UCA regarding a study of the use of six weather stations had been prepared in response to Direction 69 from Decision 2003-072.[178] While this study was prepared in 2005, the Commission notes that it was based on the analysis of twenty years of data for the additional stations being studied, and it showed that the impacts of moving to six weather stations from two were insignificant at that time.

While AG indicated, that costs would be higher if six weather stations were used for weather normalization, the Commission considers that some of the work required to use six weather stations has already been done as demonstrated in the analysis from AG's response to Direction 69 from Decision 2003-072. Additionally, the Commission considers that AG's proposed use of a 10-year temperature methodology instead of the previously used 20-year average should reduce the amount of additional work required by AG in comparison to the analysis prepared for Direction 69. AG has indicated that it currently uses six weather stations for the DFSS for load settlement purposes, and that it could provide its next GRA forecast using the additional temperature zones.

The Commission finds that the use of six weather stations would provide a higher level of precision given AG's sizable service territory, and would increase transparency for AG's proposed weather deferral account. Based on this finding, the Commission directs AG to use six weather stations for its next GRA and to fully identify its methodology and any incremental costs related to preparing its forecast using the six weather stations. The Commission also directs AG to fully explain the circumstances of any incremental costs that may be identified given that six weather stations were used for the response prepared to Direction 69 from Decision 2003-072. For this Application, the Commission accepts AG's use of two weather stations for weather normalization for the test years.

[177] Information Response UCA-AG-111(b)
[178] Decision 2003-072 – ATCO Gas 2003/2004 General Rate Application – Phase I (Application 1275466) (Released: October 1, 2003)

Regarding the use of the Edmonton Municipal Airport vs. the Edmonton International Airport for a weather station, the Commission notes this information has been provided by AG in information response UCA-AG-111(b) in this proceeding. The Commission finds that the information indicates that there was no significant impact on AG's forecasting or normalization if the Edmonton International Airport had been used instead of the Edmonton Municipal Airport. Therefore, the Commission rejects the UCA's request for AG to examine the bias associated with using the Edmonton Municipal Airport weather station rather than the Edmonton International Airport.

13.1.2 Regression Analysis Methodology

<u>Potential Problems with Regression Models for Normalizing Revenue and Vintage Analysis</u>

The UCA was concerned with the structure of the formulas used in AG's regression models for adjusting revenue for abnormal weather (weather normalization process). The UCA noted that customers could be using gas for heating while the weather zone station was above the heating range and vice versa. The UCA indicated this hockey stick effect was not modeled in AG's multiple regression models. The UCA stated that if AG had used the wrong formulas in its regression models, then AG also used the wrong formulas for creating the normalized revenue shown on the various tables in its Application. The UCA submitted that AG should be directed to study the UCA regression model issues and revise its normalization process.

The UCA was concerned with the conclusions from AG's vintage analysis that the average consumption per customer was declining. This impact was shown using a trend variable in the models. The UCA considered that the normalized consumption per customer should reflect the decline from year to year, but this did not occur for most vintages between 1992 and 1993. The UCA stated that AG selected a poor form for the multiple regression analysis formulas, which should have included a spline function to address the hockey stick effect.

AG responded to the UCA's concern regarding the throughput forecast and the regression models. AG stated that it used multiple regression models to develop most of its throughput forecast. The EUB had approved AG's previous two GRA throughput forecasts which were based on multiple regression models. Any significant changes to the 2005-2007 GRA models were identified in this proceeding and no party took issue with the changes or demonstrated that the throughput forecasts were not reasonable.

AG tested the use of restricted temperatures in the regression model and use of the balance point temperature as a variable in place of the summer variable to capture the effect that warmer temperatures approaching the balance point could have on consumption, but the results indicated a higher mean absolute error.

AG had updated its throughput forecast for the impact of 2007 actuals on its sales/customer forecasts, incorporating a full year of 2007 actual usage and temperatures into the regression models. AG also incorporated the impact of an additional day due to leap year as proposed by the CG. As such, AG recommended that the throughput forecasts be approved for the forecast period.

AG indicated that the UCA's concern with the vintage analysis did not indicate that the regression models were inappropriate, as the vintage analysis was not created by AG's regression models. AG considered that the UCA's concern was related to a one year anomaly, which was not indicative of anything.

Temperature Coefficient and Ten-Year Average Temperature Forecasting Methodology

The CG expressed concern with AG's only using a temperature coefficient when calculating the weather deviation between actual and normal temperatures instead of incorporating the various independent variables that are used in the sales/customer forecasting models. The CG stated that the temperature coefficient used to determine the revenue impact of warmer than normal or colder than normal temperatures may not only isolate the effects of temperature on consumption volume, but may also include the effects of conservation or other effects.

The CG supported AG's use of 10-year average degree days to determine normal temperatures instead of the 20-year average currently in use. The CG stated the 10-year average provided greater relative symmetry and accuracy in forecasting of temperatures for normalization purposes.

In response to the CGs concern, AG indicated that the normalization methodology addressed both changes to the actual number of customers being served and changes in GJ/customer by using the actual GJ/customer and then normalizing it, rather than normalizing on the basis of forecast GJ/customer. With respect to the temperature coefficient AG stated its normalization methodology was based on a linear regression of sales/customer on restricted temperature using the latest 12 months of data for the different customer classes. Restricted temperatures made an adjustment whenever the temperatures were at or above the balance point, and therefore additional summer variables were not required in the normalization regression. The use of the latest 12-month period in the normalization regression and by determining the effects of deviations in temperatures using actual and not forecast throughput meant that AG was normalizing at the current conservation levels and that the CG's recommended trend or other variables were not required.

AG stated that no party indicated concern regarding use of a 10-year average temperature forecasting methodology instead of the currently used 20-year average.

Commission Findings

The Commission has considered the concerns raised by the UCA and the CG regarding the regression models used by AG. These models have been the subject of review at the previous two GRAs. Further, significant changes that were made to these models in the 2005-2007 GRA were identified by AG, and interveners in this proceeding did not raise concerns about these changes. The Commission notes that AG has used these regression models to prepare its throughput forecast for the test years. The Commission finds that the regression models have been applied in this Application in a manner consistent with previous applications, and that the results are reasonable. Therefore, on this basis, the Commission approves the throughput forecasts for the test period.

However, the Commission will not direct AG to study the UCA and CG regression model issues and revise its normalization process, as this will not resolve the differences in opinion regarding the regression model methodology. Instead, the Commission directs AG to arrange for a technical meeting to be held with interested parties before AG finalizes its next GRA so that the parties can either agree on one approach or, at least, develop a better understanding of the approach that would be used in the upcoming GRA. In this way, proposed changes that might be brought forward in that proceeding will have the opportunity of being fully understood and examined. The Commission also directs that the information shared and discussed at this technical meeting shall be included in its entirety in the application for the upcoming GRA.

The Commission acknowledges that no party has objected to AGs used of a 10-year temperature methodology instead of the previously used 20-year average. The Commission finds that the 10-year average will provide greater relative symmetry and accuracy in forecasting of temperatures for normalization purposes. Given the improved accuracy that will result, the Commission approves AG's use of the 10-year average temperature forecasting methodology.

13.2 Weather Deferral Account

AG requested a weather deferral account to offset revenue risk of temperatures being different than those forecast, to allow for recovery of its costs, and to earn the return approved in rate design. AG indicated that while almost 100% of its costs were of a fixed nature, approximately 44% of its revenue was recovered through a variable charge. AG stated that temperature forecasting for a future year could not be reasonably forecast with accuracy, and that the deviation in weather had a significant impact on return.[179]

AG proposed to commence use of a deferral account, effective January 1, 2008, in each of the North and the South rate zones to account for the impact on delivery revenue differences between the actual degree days and the forecast (normal) degree days used in the determination of the approved revenue forecast. The normal temperatures that would be used for the deferral account would be those used to develop the approved revenue forecast for that year. AG proposed that a 12-month rider would be required when either the North or the South weather deferral revenue accounts exceeded $7 million dollars at April 30th of each year, which would represent about a +/- 10% variation in the normalized weather forecast.

If the Commission approves the weather deferral account mechanism, AG would file a mock rider application to demonstrate the proposed process for the determination of any future riders related to the deferral account.

13.2.1 Impact on Business Risk

The UCA and Calgary stated that implementing the Weather Deferral Account would impact AG's risk. Since the issues of business risk and capital structure are being dealt with in a separate proceeding, Calgary recommended that AG's Weather Deferral Account proposal should not be addressed at this time. CG stated that weather risk should be carried by AG shareholders instead of customers as AG could diversify this risk away.

AG stated that while matters that related to the capital structure and utility risk would be determined in a future proceeding, there was no reason to deny the use of a Weather Deferral Account in order to study its impact on AG's utility risk, because there was no risk impact. AG stated that the future proceeding would not be able to determine the appropriateness of the requested deferral account.

[179] Application, Section 7.0 – Utility Revenue, pages 45–49

Commission Findings

The Commission notes that the proposed weather deferral account addresses factors with significant impacts which are beyond the control of AG and therefore not within the ability of the utility to accurately forecast. As such, the proposed weather deferral account meets the criteria previously established by the EUB for the creation of deferral accounts.[180]

The Commission finds AG's request for the proposed weather deferral account is reasonable given the that the current rate structure does not match the way that AGs costs are incurred, where almost 100% of AG's costs are of a fixed nature but approximately 44% of its revenue is recovered through a variable charge.

The Commission notes that the UCA, Calgary and the CG each suggested that AG's business risk would be impacted if a weather deferral account was approved. The Commission also notes that the 2009 Generic Cost of Capital proceeding (EPS Proceeding ID 85) is currently underway and will deal with the impacts of the different factors on each utilities return and capital structure. The Commission had determined in Decision 2008-051 that the 2009 Generic Cost of Capital proceeding would deal with AG's proposed increase to its 2008 equity ratio as part of a module to the generic proceeding.[181] For this reason, any potential impact of a weather deferral account on AG's business risk for 2008 and 2009 will be addressed as part of the 2009 Generic Cost of Capital proceeding.

For the above reasons, the Commission approves the weather deferral account proposed by AG, with an implementation date of January 1, 2008.

13.2.2 Impact on Rate Stability

Calgary commented that the weather deferral account proposed in the Application would not fully decouple consumption from the revenue of a utility, and that although decoupling was not a new concept, it could be considered as part of a Phase II proceeding.

The CG expressed concerns that recovery of the weather deferral account balance, when it exceeded $7 million, over a 12-month period could cause rate stability concerns. Noting the possibility of changes to rate design, the CG stated that a higher recovery of costs through fixed charges may be unacceptable to some customer groups. As such, AG's proposed weather deferral account should be rejected.

AG submitted that significant changes to its rate structure would be required to manage the effects of temperature if a weather normalization mechanism were not used. These changes could result in greater impacts on customers than an occasional weather deferral account rider.

AG suggested that the use of a deferral account could ensure there was equality in the number of degree days that were above or below the forecast over time, which would result in fair and symmetrical treatment for customers and the utility. AG confirmed that its proposed weather deferral account would not fully decouple consumption from revenue.

[180] Decision 2003-100, pages 115–116
[181] Decision 2008-051 – Generic Cost of Capital – Preliminary Questions Proceeding (Application 1561663 Proceeding ID. 15) (Released: June 18, 2008)

AG stated that without a weather deferral account, the only way to manage the effect of temperature deviations would be to move to a full fixed charge for the low use rate group. AG submitted that use of a weather deferral account provided an opportunity to earn the return approved in rate design, and ensured customers only paid the revenue requirement approved in AG's rates.

Commission Findings

After examining the weather deferral account proposal, the Commission is of the view that the thresholds which have been proposed by AG minimize the number of potential riders required while balancing the rate impacts within a 12-month period, and that use of the weather deferral account will replace the need for potential rate design changes that may have undesirable impacts on certain low use rate groups. Further, given the threshold limit as proposed by AG for collection or refund of accumulated amounts, the Commission considers that the collection should not be onerous on customers. However, if an extreme condition were to occur, resulting in two weather deferral account riders being applied simultaneously, the Commission considers that it may have to review the collection period, threshold amounts, or other details associated with the forecasting of normal weather.

The Commission notes that AG's current rate structure does not match its cost causality as previously indicated. However, given the potential for rate stability and equality of treatment between the customers the Commission approves AG's proposed weather deferral account as an alternative to moving to a full fixed charge rate structure for the low use rate group to manage the effects of temperature on AG's revenue.

13.3 Commercial Throughput

The Commission has reviewed the commercial throughput forecast for 2008 - 2009. The Commission notes that the commercial throughput forecasts for 2008 are 57,305 TJ and 46,987 TJ for the North and South zones respectively, and for 2009 are 58,297 TJ and 47,684 TJ for the North and South zones respectively, and the Commission finds these forecasts to be reasonable. On this basis, the Commission accepts the 2008 -2009 commercial throughput forecasts as filed, with the exception of the specific areas raised by interested parties which are individually addressed below.

13.3.1 High Use Customer Conservation Adjustment

The CG noted that AG had accepted its recommendation to update the average consumption per customer to incorporate the effect of the leap year in 2008, resulting in additional revenues of approximately $.7 million[182] for 2008. AG also accepted the recommendation to revise its demand forecasts for all high use customers impacted by the introduction of the high use rate, approved in Decision 2007-059,[183] and had reflected this increase for the test year revenue. However, for 2009 AG assumed that the increase in demands experienced in 2008 would be reduced by a 50% conservation adjustment, resulting in 2009 forecast revenues increasing by $1.1 million for the North and by $1.3 million for the South.

182 CG Evidence, page 30, lines 24–28
183 Decision 2007-059 – ATCO Gas 2005-2007 General Rate Application Phase II Compliance Filing to Decision 2007-026 (Application 1513143) (Released: July 31, 2007)

Regarding the 50% conservation adjustment, the CG agreed that a 30% adjustment would be reasonable for customers with contract demands higher than billing demands, as customers would potentially adjust their contract demands as early as August 2008. However, the CG disagreed that AG's use of the additional 20% conservation factor could be justified by former rate 13 customers seeking out efficiency measures due to the change in the rate structure and the cost of natural gas in the marketplace. The CG recommended that the 50% conservation adjustment factor used by AG to determine additional high use revenues for 2009 be reduced to 30% in the refiling.

AG stated that the CG's analysis of the 20% was inappropriate, and the resulting conclusions should not be relied upon. Also, there were changes in the number of customers in the high use rate group (formerly Rate 3 and 13) and as customers moved between the high and low use rate groups, this would mask the impact of conservation measures that were occurring. AG suggested that as former Rate 13 customers were based on contract demand this group would be incented to seek out efficiency because of the change in rate structure and due to the high cost of natural gas in the market place. AG recommended that the conservation factor of the additional 20% was reasonable (being approximately $0.9 million of demand on total revenues of $30 million).

Commission Findings

The Commission notes that the CG's membership includes the Public Institutional Consumers of Alberta, and that this group is likely impacted by the conservation adjustment. Based on the CG's position, the Commission finds that a 30% adjustment for customers having contract demands higher than billing demands is reasonable. The Commission considers that the 30% factor is a significant downward adjustment for a forecast period of only one year, particularly given the forecasting uncertainty related to the new high use rate group.

Regarding the justification provided by AG for the additional 20% conservation adjustment, the Commission considers that the impact of natural gas costs in the marketplace would more likely be on consumption than peak use over the short term. Thus customers would be more likely to adjust their consumption in reaction to the market price of natural gas, rather than revise their demand commitment which had a longer term impact. On this basis, the Commission accepts the 30% conservation factor.

The Commission accepts AG's proposal to revise its high use customer demand revenue forecast for 2008 for the impacts related to the introduction of the high use rate. The Commission notes that the CG supported these revisions. Therefore, the Commission directs AG in the refiling to reflect these estimated increases of $2.1 million for the North and $2.6 million for the South. Further, the Commission directs AG in the refiling to reflect the related impacts for its 2009 high use customer demand revenue forecast, incorporating a 30% conservation factor.

The Commission also directs AG, in its next GRA, to provide a schedule in the format of the CG's Table 8 – High Use Demand Forecast[184] to assist with review of demand forecast accuracy for high use customers. The schedule should include forecasts and actuals for the years 2007 through 2009, plus forecasts for the GRA test years.

[184] CG Evidence, page 34, Table 8

13.4 Irrigation Throughput

AG's Irrigation throughput forecast was based on multiple regression modeling. The 10-year (1986-2006) average precipitation levels from May to October were used in the model to calculate forecasts for 2007 to 2009.[185] AG provides irrigation service only in the South zone.

13.4.1 Negative Throughputs for Irrigation Forecast Model During Out of Season Months

The CG expressed concern with AG's irrigation forecast model which used 10 years of historical throughput and precipitation levels to forecast annual throughputs which were then distributed to the 12 months of the year. The CG stated that a number of the irrigation throughput months were negative because the historical records used were billing records, which reflected corrections for over-billing in prior months.

The CG stated that the irrigation season, which occurred from April to October, should be reflected in the irrigation throughput for those months, but AG used historical billing month data to distribute the forecast annual irrigation throughput to the 12 months of the year. The CG expressed concern with AG's recording of over-billed irrigation throughput for in season months and then applying billing corrections in out of season months.[186] CG submitted that AG should be directed to investigate and correct this problem, and then report the outcome at its next GRA.

The CG stated that AG used actual monthly throughput data to forecast demand amounts in subsequent Phase II proceedings. The current practice of over billing throughput for in season months and correcting these amounts in off season months caused an over statement of irrigation peak month throughput for purposes of demand determination. The CG recommended that the monthly billing throughput record should be adjusted in AG's refiling by pro-rating the billing corrections to actual consumption months.

AG expressed concern that the CG only raised the issue of the monthly distribution of the irrigation throughput for the first time in their argument. AG commented that while over billing in the final month due to uncertainty regarding when an irrigation customer was coming off the system was possible, it didn't overbill throughput in the summer months which was later corrected in the off season months, as suggested by the CG. AG stated that the negative amounts from the off season months likely had nothing to do with consumption for the peak months of July and August.

AG indicated another cause could be differences between the estimated unbilled revenue and the actual amount of revenue billed in the following month. Irrigation customer usage declined as the fall months approached which made estimating of unbilled amounts more difficult.

AG suggested that pro-rating the negative forecast consumption amounts across the positive consumption months would not be appropriate as AG developed its peak billing demand forecast for cost allocation purposes in the Phase II process using historical actual, not forecast amounts.

AG disagreed with the CGs recommendation that AG be directed to investigate this matter, as AG could only remove the irrigation customers from the system once instructed by the retailer serving those customers. AG indicated it had limited ability to change the requirement for billing

185 Application, Tab 7.1 – Multiple Regression Models, page 7.1.2-61, lines 4-6
186 CG Argument, page 111, Monthly Irrigation Throughput

adjustments and reversal of unbilled revenues due to the uncertainty related to usage by those customers.

Commission Findings

The Commission considers that negative irrigation throughput during out of season months may be an indication that some portion of the positive irrigation throughput related to the in season months could be artificially high. AG indicated that it had not investigated the specific causes for the negative adjustment amounts, and that multiple causes were possible.[187]

The Commission directs AG in its next GRA to investigate the cause or causes for the negative irrigation throughput amounts, and report the findings to the Commission. As these annually reoccurring negative adjustment amounts are not large but could impact Phase II irrigation cost allocations if related to a peak month, the Commission directs AG to recommend a cost effective solution to address this issue.

The Commission will not require AG to pro-rate the negative throughput amounts in the irrigation monthly throughput of the refiling, as recommended by the CG. The Commission finds that an adjustment should not be made without confirmation of the reason for these negative amounts, otherwise future corrections to the proposed adjustment might be required.

14 OTHER MATTERS

14.1 Single Revenue Requirement

AG requested approval to move to one revenue requirement with separate North and South rate zones. AG indicated that it had filed separate revenue requirements for the North and South zones in this Application. The first use of one revenue requirement by AG would occur at the time of its next Phase I GRA.

The UCA argued that the Commission should reject AG's one revenue requirement because there were a number of inconsistencies in AG's current cost allocation methodology which required greater transparency and that sufficient support for one revenue requirement had not been provided.

The ASBG/PGA was concerned that the proposed single revenue requirement process would not provide any benefits to existing AGN and AGS customers. The North and South zones have substantial cost differences that need to be addressed with the direct assignment of costs as was currently done with a number of the accounts. The weighted customer methodology does not recognize the cost differentials between the North and the South, further, ATCO Pipelines, maintains North and South zones in alignment with the AG zones. On this basis, the single revenue requirement should not be approved.

Calgary noted that in rate design and cost allocation accounting, it was better to directly charge items rather than allocating. Further it would be counter productive to combine costs so that they could then be segregated again to determine costs for ratemaking purposes. Given that AGN and AGS were not integrated, and there were significant cost differences between the two systems,

[187] Transcript Volume 3, pages 616–617, lines 19-23 and lines 3-8 respectively

the two systems should continue to have separate revenue requirements to assist in and to ensure that the rates resulting reflect the costs incurred to the best extent possible.

Edmonton concluded that there was no information on the record to continue to justify two revenue requirements. Information in the proceeding supported the transition to one revenue requirement, but the final decision could only be affirmed in the context of a full discussion of Phase II ratemaking policy. On this basis AG's proposed transition to one revenue requirement should be approved given that no party provided evidence or argument that suggested costs would increase or customers would be harmed. However, to fully satisfy Edmonton that the rate zones should be merged, Edmonton recommended that AG should be directed to address the specific question of why each and every line item in the study should be first allocated or assigned between North and South by comprehensively addressing the issue of whether a North or South location directly and unambiguously causes cost differences and whether there was a valid ratemaking rationale to reflect the difference in rates. Edmonton considered that a single revenue requirement may lead to a single rate zone, simpler and easier to understand rates that treat urban and rural customers the same on both sides of the North-South boundary. These outcomes would improve fairness for customers as a whole.

CCA and PICA considered that the use of one revenue requirement should result in administrative costs savings rising from maintaining separate records for North and South, CCA and PICA did not object to AG's one revenue requirement proposal, and noted that the proposal appeared to recognize the need to maintain differences in cost causation between North and South for key items. The details of how these cost causation differences are to be reflected for North and South should be examined as part of a Phase II proceeding.

Commission Findings

The Commission is prepared to accept Phase I evidence in AG's next GRA based on a single revenue requirement. However, the Commission recognizes that it will still be necessary to identify and file costs separately for the North and South as part of the Phase II filing in the next GRA. For Phase II purposes, and also for the Phase I purpose of assessing the reasonableness of capital forecasts in the next GRA, the Commission will require that the capital costs (including capitalized labour) of the North and South systems be maintained separately. AG indicated that this was its intention. The systems are different in that they operate at different pressures. In addition, they are not operationally integrated.

For O&M costs, AG proposed that it would allocate costs between North and South based on a weighted customer allocation model developed by AG. Based on the information filed by AG, the Commission is not satisfied that the AG weighted customer allocation model is robust enough to capture the differences in costs between the North and South for rate making purposes. There are many factors in addition to customer numbers that affect operating and maintenance costs and the Commission wants to ensure that those cost differences are recognized for Phase II purposes. In order for the Commission to allow AG to bring the operating and maintenance costs of AG together in one set of books for its next Phase I application, the Commission will require that AG first satisfy the Commission that it has established a cost allocation method capable of capturing costs causal to the North and South systems. The Commission is aware that widely accepted activity based costing approaches and techniques for operating and maintenance costs that would capture costs causal to the North and South systems are available. AG may propose a process and timing for the filing of its proposed operating and maintenance cost allocation method for review by the Commission.

The Commission notes that cost of service revenues are also currently tracked on a North-South basis and that this information will continue to be available for Phase II purposes.

14.2 International Financial Reporting Standards

The Canadian Institute of Chartered Accountants (CICA) announced in January 2006 its intention to replace Canadian Generally Accepted Accounting Principles (GAAP) with International Financial Reporting Standards (IFRS) for all publicly accountable enterprises effective January 1, 2011.[188] AG explained in its Application that it required additional resources as early as 2008 to plan, educate, and implement the transition to IFRS. AG stated the significance of the project required head office management and monitoring.

Finance & Controller costs in the Application includes $100,000 in 2008 and in 2009 due to the increased volume of work and required staff associated with IFRS.[189]

14.2.1 Information and Details Related to IFRS Implementation

The UCA stated that AG's response to IR UCA-AG-97(f) to quantify the costs of implementing IFRS did not provide the requested information. The UCA indicated that AG only quantified the cost of IFRS implementation in their rebuttal evidence which did not allow testing of the information.

The UCA submitted that while AG has provided a summary of its reporting dates for IFRS, much of the work would already be done in advance of the reporting dates provided by AG to be ready for the transition. The UCA recommended the 2008 cost of $100,000 should be removed for this reason.

The UCA submitted that the planning, education and implementation of IFRS were one time costs and that there was no evidence these incremental costs would continue after implementation. The UCA also recommended that costs for IFRS beyond the implementation of the project should be disallowed as AG has not supported the need for ongoing IFRS costs.

The UCA stated that without a project plan with milestones and dates, there was no way to validate the costs. The UCA submitted that these costs, if approved, should only be included in this GRA and then AG should be directed to provide a complete project plan for IFRS implementation as part of its next GRA.

CG confirmed that at the hearing AG had identified that its share of head office costs to converge to IFRS in 2011 was forecast to be about $100,000 in 2008 and 2009, and that AG would communicate its convergence plans to interveners following completion.

AG responded to UCA's proposal, that ATCO Corporate Services cost increases should be disallowed because sufficient justification had not been provided, by restating that ATCO initiated the IFRS project to look at the requirements for planning, education and implementation, and had included costs in 2008 of $100,000.

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188 Application, Tab 9.0-4, Board Comments 6
189 AG Rebuttal Evidence, page 88

At the hearing AG provided information regarding IFRS reporting dates. At the end of 2008 in AG's management discussion and analysis it must inform shareholders of the plan to move to IFRS. The quantified impact of going to IFRS was required to be disclosed in the corporate management discussion and analysis for 2009. The year 2010 will be based on IFRS as it becomes the comparison year for reporting in IFRS when it starts on January 1, 2011.

Commission Findings

The Commission notes that AG has included in its Application under the Finance & Controllers costs the amount of $100,000 for 2008 and for 2009. The Commission recognizes that the transition from GAAP to IFRS as announced by the CICA is a significant project with potential material impacts. For this reason, the Commission finds that the costs included by AG to plan, educate and implement the required changes are reasonable. The Commission does not accept the suggestion from the UCA that the funds requested by AG should be removed as much of the work would have been done and costs already incurred in advance of AG's reporting dates. Given the scope of the project, some areas of work such as planning may have commenced in 2006 but it is not reasonable to expect that later steps such as education or implementation would have already occurred. The Commission accepts AGs IFRS costs in the test years as filed.

The Commission agrees with the UCA that it is difficult to validate the IFRS project costs given its size and multi-year timing. The Commission notes that AG has indicated that it will be providing information on its IFRS plan in its management discussion and analysis at the end of 2008, and that the quantified impact of the IFRS plan will be disclosed in its management discussion and analysis at the end of 2009. Therefore the Commission will not direct AG to provide the detailed project plan information requested by the UCA.

14.2.2 Involvement of Interested Parties

The CG stated that based on its review of the comments from the Commission's IFRS initiative, the IFRS convergence project will have numerous impacts on customers.

The CG submitted that customer review and consultation was needed in advance of AG finalizing and communicating its compliance proposals in its 2009 financial statements as part of the Management Discussion and Analysis. The CG recommended AG be directed to provide customers with the same information that it would provide the Commission in response to the Commissions IFRS initiative letter dated May 23, 2008. The CG also recommended a process be established where customers were able to provide feedback to the proposals advanced by AG for its compliance with IFRS, especially where these proposals involved accounting and regulatory changes that had potentially significant impacts on customer rates.

AG stated that IFRS sets out standards to which all companies must comply, and that there are few options as the CG seemed to suggest. While AG recognized that some impact clarification of the standards would occur between the ATCO companies and their auditors, AG was opposed to intervenors being involved in this process. AG recommended as an alternative that customer representatives can participate in the IFRS collaborative process being led by the AUC.

Commission Findings

The Commission agrees with the CG that customers may be impacted by the implementation of IFRS. The Commission has established an IFRS collaborative process which includes both customer representatives and utilities. The Commission established this process to facilitate an open and consistent approach which allows for review and consultation with interested parties.

The Commission notes that the CG has requested access to AG's response to the Commission's IFRS initiative letter dated May 23, 2008, and that the CG recommended a process which allowed customers to provide feedback on AG's proposals for its compliance with IFRS. The Commission finds that the most appropriate and effective method for customer involvement is through participation in the existing AUC IFRS collaborative process. In this way, interested parties have input into the process for all utilities, not just AG, and participation allows registered parties to have access to information placed on the record by all participating parties, including information received from AG.

14.3 Code of Conduct

Inter-affiliate code of conduct audits[190] which covered the 2006 business cycle were conducted in the second half of 2007, with audit planning and fieldwork occurring from June through November 2007. During 2007, audits were done on five utilities, including AG.

The audit work focused on testing each utility's implementation and adherence to the measures in its Compliance Plan (Plan). The measures in each utility's Plan are the preventive and detective controls used to help assure the utility, the Commission, and other stakeholders that the utility is complying with the spirit and intent of its Code.

14.3.1 Role of EUB Audit Report Regarding Code of Conduct Compliance

Calgary expressed concern that the inter-affiliate code of conduct audit report (the audit report) issued by the EUB appeared to not follow Generally Accepted Audit Standards (GAAS) in the reporting on the results of the audit. Calgary indicated the audit report was qualified by the statement that compliance audits could not determine whether the audited utility had been fully compliant with the Code, and that the report acknowledged that there were code interpretational issues yet to be worked out. Calgary stated that the normal audit level of assurance could not be given that the inter-affiliate code of conduct had been followed.

Calgary objected to AGs claim that the EUB audit confirmed all of the inter-affiliate transactions including those with I-Tek and ITBS as the audit report only stated that AG had demonstrated compliance. Calgary indicated that the scope of the audit report work was for 2006 only and should not be relied upon for the years 2003 – 2007 or for the test years 2008 and 2009.

Calgary stated that the AUC did not follow its findings in Decision 2003-040[191] to include intervenors in audit consultations, and Calgary recommended that the Commission address Calgary's concerns due to the significant dollars involved with IT and CC&B transactions to confirm that the Code will deliver the directions and findings from Decision 2003-040.

AG stated that the EUB audit and compliance group adhered to AUC Rule 006, *Rules on Regulatory Audits* regarding the use of generally accepted auditing standards (GAAS) of the Canadian Institute of Chartered Accountants and the professional standards of the Institute of

[190] Regulatory Audit Report #2008-001, issued March 11, 2008

[191] Decision 2003-040 – ATCO Group Affiliate Transactions and Code of Conduct Proceeding Part B: Code of Conduct (Application 1237673) (Released May 22, 2003)

Internal Auditors. AG commented that following GAAS means that the EUB auditors used a representative sample of the affiliate transactions, rather than examining all the transactions, to form the basis of their opinion. The audit standards followed by the EUB were no different than those which Price Waterhouse would use to form an opinion on AG's financial statements as AG's third party auditors.

AG commented that Calgary's concern regarding the three interpretational issues were industry issues which affected multiple utilities, and these issues were thoroughly documented in the EUB audit report. AG stated that the issues had not been significant enough to qualify the audit opinion, and that AG was working with the AUC to address them.

AG disagreed with Calgary's suggestion that the EUB did not follow its findings from Decision 2003-040 to include interveners in the audit consultations. AG stated that the EUB had the option to choose whether to include the utility and other interested parties in audit consultations, and the fact that Calgary, nor other interveners, were included was at the discretion of the EUB for such matters.

Commission Findings

The Commission notes that regulatory audits are conducted by the AUC audit group in accordance with AUC Rule 006, *Rules on Regulatory Audits.* Section 9 of Rule 006 states that the Audit and Compliance Group (the audit group) adheres to the generally accepted auditing standards of the Canadian Institute of Chartered Accountants and the professional standards of the Institute of Internal Auditors.

Regarding Calgary's suggestion that the audit report didn't confirm that a utility was *fully* compliant, the Commission finds that appropriate procedures were followed when EUB auditors used a representative sample of the affiliate transactions, rather than examining all the transactions, to form the basis of their opinion. The Commission finds the use of sampling in the compliance audit for selection and review of affiliate transactions to be appropriate, rather than examination of every single transaction. This process is part of the normal audit procedures under GAAS and used in most audits for reasons of efficiency and control of costs. In addition, it is important to recognize that the actual conduct of an audit, even if it is conducted by examining every single transaction, is not the principal compliance tool employed by the Commission. Instead of actually auditing every affiliate transaction, the Commission sets rules and expects companies to comply. The potential that an audit may be performed creates a further incentive to comply, or put another way, mutes potential incentives to not comply.

Regarding the interpretational issues identified in the audit report and raised by Calgary, the Commission is of the view that these were industry issues which were not long standing or material enough to qualify the audit opinions. The Commission finds that it is reasonable to expect that utilities might interpret areas of the Code slightly differently as the utilities themselves have organizational differences. The Commission expects that as more experience is gained with the Code, and as the AUC Audit and Compliance Group works with the utilities on Code related matters, differences in interpretation will align to a more common understanding.

The Commission considers that the audit report, which covered the 2006 business cycle, concluded that AG had demonstrated compliance for 2006 with its Code. Since the audit report is associated with the period of time examined by the audit and while it demonstrated compliance at that time, the audit report does not specifically indicate that AG was in compliance before the period examined, or is in compliance after the period examined. The Commission notes however that the outcome of the audit was that AG followed the spirit and intent of the Code, It is also important to note that the Code was only approved in early 2005, and that compliance audits are generally not performed on a yearly basis. For this reason, the utilities are required to prepare compliance reports which are monitored by the Commission for potential issues. While AG has complied with the Code as demonstrated with examination of the 2006 business cycle, continued compliance reporting by AG and monitoring by the Commission, including periodic audits, remains the most suitable means to demonstrate compliance for future years.

The Commission was surprised that Calgary would suggest that it did not follow its own finding in Decision 2003-040:

> The Board agrees that the ability of the Board to audit compliance is necessary in order to ensure affiliate related costs and revenues incorporated by the utility into its revenue requirement are appropriate and that Utility customers are adequately protected. The Board may exercise this right pursuant to its existing legislative powers. The Board does not agree that interested parties should have a general right to audit compliance with the Code by the Utility. Rather, interested parties are free to make application to the Board demonstrating why they believe a compliance audit is appropriate at any given time.
>
> Should the Board, either pursuant to its own initiative or pursuant to a third party application, consider the necessity of directing an audit, the Board would expect to seek input relevant to the circumstances existing at the time, from the Utility and interested parties as to the terms of such an audit, who would conduct the audit, the audit process, who would have access to the audit results, how the results of the audit would be used and the costs of the audit.[192]

The Commission maintains the responsibility to perform compliance audits to provide assurance that the Code is followed, rather than interested parties performing individual audits. As identified in the above quotation, interested parties may make application to the Commission when they feel an audit is required, and at that point the Commission would seek their input on the appropriate terms for the audit to be able to address the concern that the raised. The Commission is not aware of any such applications being made by interested parties. The Commission has not, under its own initiative or in response to an identified issue, requested that an audit be prepared. Rather, the audits were performed by the Audit and Compliance Group in accordance with Rule 006, auditing utilities for different areas based on a risk assessment which considers a number of criteria.

14.3.2 Affiliate Transaction Transfer Price and Compliance with Affiliate Code of Conduct

Calgary raised a number of concerns related to the use and determination of fair market value and the appropriate transfer price for affiliate transactions to confirm compliance with the Code. A benchmarking process was underway at the time of the audit and the results were not available to the audit group for examination. Issues of transparency of information and use of the results from the benchmarking study were also raised by Calgary related to the IT and CC&B area of affiliate transactions. AG explained why it disagreed with the concerns raised by Calgary.

[192] Decision 2003-040, page 111

Commission Findings

The Commission considers that these issues would more appropriately be dealt with in the ATCO Utilities 2003-2007 Benchmarking and I-Tek Placeholders True-Up proceeding (EPS Application ID 32), which is currently underway.

For this reason, the Commission will not issue any findings or directions to AG in this decision on the above issues raised by Calgary related to an appropriate transfer price for IT and CC&B affiliate transactions, and compliance with requirements of the Code.

14.4 Carbon Storage Matters

AG indicated the following in its Application with respect to Carbon storage matters:

> ATCO Gas also notes that Decision 2007-005 made final Order U2005-133. Three leave to appeal applications have been filed in respect of that Order, that Decision and Decision 2005-063. ATCO Gas maintains that the Carbon storage assets and business are not required to carry out its gas distribution service. ATCO Gas does not voluntarily apply for any costs, return or revenue associated with Carbon. It has included those costs, return and revenue only under compulsion of the Board's final Order U2005-133 as directed in Decision 2007-005. The authority to implement it has been challenged before the Courts.[193]

The Commission notes that in Interim Order U2005-133[194] (made final in Decision 2007-005[195]) and in Decision 2006-004,[196] it provided directions to AG in relation to Carbon Storage, such that carbon storage facilities and associated producing properties would continue to be part of rate base, and all operating expenses, working capital, depreciation, taxes, return and other related costs would continue to be included in revenue requirement. Associated production and storage riders and charges would also continue in place.

Order U2008-213[197] suspended Rate Rider "G", Rider "H", Rider "I" and the Carbon Production and Storage Charge effective July 1, 2008.

The appeals referenced by AG above have been granted[198] since the filing of the Application and the Commission notes that there are currently proceedings underway which will take into account the directions of the Court of Appeal.

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193 AG Application at page 1.0-6

194 Order U2005-133 – ATCO Gas South 2005/2006 Carbon Storage Plan Interim Order (Application 1357130) (Released: March 23, 2005)

195 Decision 2007-005 –ATCO Gas South Carbon Facilities - Part 1 Module - Jurisdiction (2005/2006 Carbon Storage Plan) (Application 1357130) (Released:February 5, 2007)

196 Decision 2006-004 starting at page 91

197 Order U2008-213 – ATCO Gas Suspension of Riders and Rates (Application 15747333, ID. 61) (Released: June 20, 2008)

198 *ATCO Gas & Pipelines Ltd. v. Alberta (Energy and Utilities Board),* 2008 ABCA 200

15 REFILING

The Commission directs AG to provide its Refiling to the Commission and all parties on or before January 5, 2009. Further, the Commission directs AG in its Refiling, to provide a summary that sets out a detailed reconciliation of its requested revenue requirement for 2008 and 2009 in its Application to the revenue requirement resulting from the Commission's determinations in this Decision.

16 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

ATCO Gas shall refile its 2008-2009 General Rate Application to reflect the findings, conclusions and directions in this Decision by January 5, 2009.

Dated in Calgary, Alberta on November 13, 2008.

ALBERTA UTILITIES COMMISSION

(original signed by)

Willie Grieve
Chair

(original signed by)

Bill Lyttle
Commissioner

(original signed by)

N. Allen Maydonik, Q.C.
Commissioner

APPENDIX 1 – HEARING PARTICIPANTS

(return to text)

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
ATCO Gas (AG or ATCO) L. Smith K. Drozdowski	M. Percy D. Wilson G. Feltham D. Belsheim D. Kong J. Engler B. Dolan G. Schmidt B. Bale
Office of the Utilities Consumer Advocate (UCA) A. Bryan	C. Bruce B. Shymanski J. Laskoski R. Bell B. Bruggeman D. Gray M. Lively H. Vander Veen
City of Edmonton (Edmonton) C. Pooli	
Consumer Group (CG) Consumers' Coalition of Alberta (CCA) J. Wachowich Public Institutional Consumers of Alberta (PICA) N. McKenzie Alberta Sugar Beet Growers Association and Potato Growers of Alberta (ASBGA/PGA) H. Unryn	A. Merani R. Retnanandan J. Jodoin
First Nations J. Graves	
The City of Calgary (Calgary) D. Evanchuk	H. Johnson G. Matwichuk J. Stephens
Rate 13 Group L. Manning	

Alberta Utilities Commission Commission Panel W. Grieve, Chair B. Lyttle, Commissioner N. A. Maydonik, Q.C., Commissioner Commission Staff G. Bentivegna (Commission Counsel) V. Slawinski (Commission Counsel) C. Burt D. Weir R. Armstrong D. Cherniwchan K. Schultz	

APPENDIX 2 – SUMMARY OF COMMISSION DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

materials and supplies inflation forecast of 3.5%, and finds this to be a reasonable estimator of inflation for 2008 and 2009. Therefore the Commission directs AG to apply general materials and supply inflation rate of 3.5% for 2008 and 2009 to the appropriate amounts in the refiling. 26

7. The Commission questioned the CG, Calgary and the UCA with respect to the opening balance of PP&E as restated to include 2007 actual results. The Commission understood from these responses that parties were satisfied with the updates. In respect of the updates to the PP&E as they apply to IT and CC&B capital, the Commission will discuss these in Section 9 of the Decision. The Commission has reviewed the 2008 opening balances, and finds they are reasonable, with one condition. Subject to the Commission's findings in Section 9 with respect to IT and CC&B capital, the Commission approves the 2008 PP&E opening balances, and directs AG in the refiling to reflect these changes in its forecasts and revenue requirement calculations. 30
8. The Commission is of the view that the difference between AG's forecast and the UCA's proposal in Table 8 above is due to the use of different inflation factors. In Section 5 of this Decision, the Commission provided its views with respect to appropriate inflation factors, and directed AG to apply the inflation factors to the appropriate categories. Therefore, the Commission considers that inflationary impacts will be appropriately dealt with in AG's refiling. 35
9. The Commission does not accept the amounts as proposed by the UCA to be a reasonable expectation of urban feeder mains. However, during the proceeding the Commission heard evidence that the overall Alberta economy was not experiencing the exponential increases as in the past, and even Dr Percy had modified his estimates of contractor inflation from 17.9% to 10-12% range. In light of the evidence presented, the Commission does not consider AG's increase of $1.5 million dollars to urban feeder mains to be reasonable. Therefore the Commission directs AG in the refiling to use its forecast of $19 million as originally filed. ..36
10. The Commission also directs AG in its refiling to adjust the inflation factors used in the forecast for urban feeder mains and regulating stations using the rates of inflation approved by the Commission in Section 5. 36
11. With respect to urban mains replacement in 2008, the Commission finds that the 8% price reduction due to the entry of two new contractors in Edmonton is not a productivity improvement as suggested by AG, and any cost reductions associated with this should be reflected in the costs for 2008 and 2009. Therefore the Commission directs AG in the refiling to appropriately reflect the 8% price reduction associated with the new contract pricing applicable to urban mains replacement and refile the corresponding schedules highlighting this change. 38
12. However, an issue of concern is the inflation factor used by AG to determine the amount of costs used in forecasting its urban mains replacement program. In regard to the inflation rates used by AG to determine its forecast costs of urban mains replacement for 2008 and 2009, the Commission considers that AG should use those rates s approved by the Commissions on the appropriate rates of inflation as set out in Section 5. Accordingly, the Commission directs AG, in its refiling to adjust the inflation factors used in forecasting costs for urban mains replacement using the rates of inflation approved by the Commission in Section 5 of this Decision. 38
13. The Commission finds that there is no issue with respect to the quantities involved with AG's forecast of valve and vault replacements during 2008 and 2009 and therefore approves that

18. Accordingly, the Commission denies the costs, estimated to be $5 million, for the Rate 1 sample for purposes of this Application. The Commission directs AG in the refiling to remove the costs associated with this project. 50

19. Therefore the Commission directs AG in the refiling to remove the contingency costs of $2,155,608 from the NGSIS project. The Commission considers that the onus is on AG to demonstrate that costs are reasonable and any additional costs incurred by AG, which would have otherwise been included as part of the contingent costs, for the project in excess of the remaining amounts will be subject to review at AG's next GRA. 51

20. Subject to the appropriate rate of inflation to be used in forecasting all additions to rate base, the Commission accepts AG's forecast of the quantities of additions to rate base in 2008 and 2009 that are not an issue of concern or not specifically discussed in this Decision. Where applicable, the Commission directs AG in the refiling to apply the rate of inflation for 2008 and 2009 as approved in Section 5 of this Decision to such additions. 52

21. The Commission notes that the methodology employed by the UCA resulted in a 2008 debenture rate of 5.66%, which is very close to the CG recommendation. Therefore the Commission directs AG in the refiling to use a 2008 debenture rate of 5.62% in determining the 2008 long term debt rate. 53

22. Based on the above findings, the Commission concludes that an appropriate 2009 debenture rate would be 4.48% plus 1.77% to equal 6.25%. Therefore the Commission directs AG in the refiling to use a 2009 debenture rate of 6.25%. 54

23. The Commission considers that depending on how comparisons are presented it is possible to draw a number of conclusions about the relative efficiency of the North and South operations. Generally, however, various metrics show that the North does have higher unit expenses than the South. While the Commission accepts that there are likely to be differences between various efficiency metrics in the North and South, it is not satisfied that it has a sufficient understanding of the reasons for the differences. Therefore, the Commission directs AG in its next GRA to provide empirical data that will provide the Commission with a better understanding of the differences in unit costs between the North and South and the reasons for those differences. 57

24. The Commission notes AG's commitment to correct the mid-year amount included in Necessary Working Capital associated with pension expense. The Commission considers this to be a clerical error, and agrees that the amounts should be corrected. On this basis the Commission directs AG in the refiling to apply the correct amount in Necessary Working Capital for 2009..60

25. However, the Commission accepts the submissions of the UCA and CG to reduce clerical FTEs in 2008 by three (per UCA's recommendation) to be more in line with customer growth. The Commission considers the customer per clerical FTE metric is a reasonable measure on which to pace the additions. Therefore the Commission directs AG in the refiling to adjust the O&M expense for 2008 and 2009 such that the addition of clerks is equal to five in each test year. 62

26. The Commission is not convinced the productivity improvements as a result of the MRRP have been included in the test period. AG stated in reply argument that "These improvements are generated when ATCO Gas adjusts meter routes after the MRRP work is completed in areas." This statement does not specifically state the improvements are included. The Commission accepts the submissions of the UCA and the CG to reduce the number of

40. The Commission considers that it would be inappropriate to make a ruling on this matter until it is aware of all the details including any costs that may arise as a result of the litigation. On this basis, the Commission notes that the litigation is still ongoing and may have one of several outcomes. Therefore the Commission directs AG that any costs, legal fees or other payments be maintained as a separate item in the RID, pending conclusion of the case, and determination by the Commission. 82

41. First, the Commission agrees with Calgary that both the “Financials Appl Host & Storage” item and the “Adabas-IMS License”item are IT variable items as they are both expressed in dollars. Consequently, the Commission directs AG to include both items with the variable items to be evaluated during the Evergreen Phase 1 proceeding. The Commission will consider Calgary’s recommendation to disallow the “Adabas-IMS License” in that proceeding. 88

42. The estimated fixed volumes for IT and CC&B are approved for 2008 and 2009 to be used together with the pricing which is to be approved in the Evergreen proceeding. In addition the Commission also approves, as a placeholder for 2008, the 2008 opening capital balances as originally filed in the Application. The Commission directs AG in the refiling to reflect these values as approved. 90

43. Calgary’s recommendation to exclude the DFSS capital cost from rate base is not accepted. The Commission notes that the DFSS had previously been approved in principle. AG’s request to include the forecast amounts in the 2008 rate base for the purpose of determining a revenue requirement is granted. However, the Commission will, as noted above, review the final rate base amount for prudence when it is requested to be placed in rate base. 90

44. Due to the significant amount of capital expenditures that have either occurred or are forecast in the test years, the Commission directs AG in its next GRA to file a full depreciation study which must include updates for capital activity as well as recommendations regarding the appropriate depreciation parameters. 91

45. In its rebuttal evidence, AG committed to review alternative methods for depreciating its leasehold improvement costs and this information will be filed as part of its next GRA. Therefore, the Commission directs AG in its next GRA to provide the referenced study as indicated in rebuttal evidence. 93

46. However, the Commission directs AG in its next GRA to fully comply with Direction 42 from Decision 2006-004 and provide its best estimate of the retirement date for the CIS system, and to clearly identify the assumptions and rationale for the selected date. As indicated by the study provided in this Application, future enhancements may be required if the life of the CIS system extends beyond its original retirement date. The information provided regarding the retirement date would be helpful to the Commission in determining an amortization period for those future enhancements. To the extent that AG has any preliminary information on alternatives to CIS, the Commission directs AG in its next GRA to file the information, including any available preliminary cost information. 95

47. Additionally, the Commission agrees with the CG regarding the need to confirm whether the working partner’s credit identified in IR AUC-AG-29 has been applied against the $551,000 one time shortfall shown in 2008. Therefore, the Commission directs AG in the refiling to ensure and demonstrate that the working partners’ 25% credit is appropriately reflected in the abandonment deferral account. 96

48. In the case of an income tax expense forecast, the income tax rates are not forecast and there is no expectation that a utility will attempt to anticipate what changes government may make

APPENDIX 3 – COMMISSION RULING ON UCA MOTION

(return to text)

Appendix 3 -
Commission Ruling on

(consists of 5 pages)

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MR. MAYDONIK: Thank you.
MR. SMITH: Thank you.
THE CHAIR: Here's what we're going to do. We're going to proceed with Dr. Percy after lunch and then when we -- but before we proceed with him, we're going to tell you what we've decided on what we've heard this morning.
MR. SMITH: Thank you, sir.
THE CHAIR: Okay. Thank you.
MR. BENTIVEGNA: Sorry, Mr. Chair, what time were you adjourning to?
THE CHAIR: Just a minute. I had it in my notes. 2:00. Just like I said this morning.
(Proceedings Adjourned at 12:38 P.M.)

PROCEEDINGS ADJOURNED TO 2 P.M.

THE CHAIR: All right. Welcome back. We're going to give our ruling on the UCA's application and Calgary's proposal.

First, the Commission acknowledges, of course, that the objective here is to make sure that the process is as fair as possible to everyone in the circumstances.

We've considered the submissions and we

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recognize that, especially in the case of the small intervenors, dealing with extensive evidence that's filed this close to the beginning of the hearing, it's difficult for them to deal with it. And we acknowledge that a great deal of material was filed.

We also recognize that the record of the proceeding is such that the oral hearing can begin, subject to what follows here.

Counsel for ATCO Gas did admit that some of their rebuttal evidence is not properly rebuttal and has proposed to withdraw the Towers Perrin compensation review, which is attachment 3 and 4 of the ATCO rebuttal evidence, and also to remove all references to the Towers Perrin compensation review in the rebuttal evidence and in Dr. Percy's evidence.

So the Commission, in order to deal with that and the complaints about that evidence, and lessen the amount of material that intervenors need to deal with in the process for the hearing itself, the Commission will grant the ATCO application to withdraw the Towers Perrin compensation review and all references it to it on the record.

The Commission has also considered whether there's other evidence that falls into that category, and the Commission considers that the IT and ITBS governance costs, evidence page 100, line 26 to page 102, line 4, inclusive, and attachment 22 should be removed from the record of this proceeding, and we'll deal with it as part of the forthcoming ATCO evergreen proceeding.

So with this evidence no longer needing to be dealt with in this proceeding, the Commission will adjourn after Dr. Percy and allow -- you know, see how late we have to sit to do that today, and allow Friday -- we'll adjourn Friday, not sit Friday, to allow intervenors an opportunity to draft information requests on the ATCO rebuttal evidence, other than the evidence that we've removed from this record. ATCO will then seat its witnesses on Monday and have until Wednesday, end of day, to answer the information requests.

I don't know how long the intervenors will need for the information requests, but I think with the evidence that's been removed, they may be able to have them done by the send of Friday, which gives you the weekend, or perhaps Monday, when they come back, but I would encourage toes IRs to come in no longer than Monday and those interrogatory responses or the IR responses no later than end of Wednesday.

If there's a problem -- if you find that there's a problem with those dates, you can come back to the Commission and ask.

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Now, if the intervenors determine that they need, by the end of the hearing, or sometime during the hearing, that they just absolutely need to file additional evidence, that they could consider proper evidence, then they can certainly apply to the Commission to do so.

I would add that it wouldn't be a very good idea to file evidence with the Commission, put it on the record, and on the EPS system, without first applying at this point. It's much simpler to deal with it if you haven't already filed it.

So considering all of the arguments this morning and the different positions of parties and the situations they find themselves in, we consider this to be fair in the circumstances, and we would like to call Dr. Percy now, unless there are some questions.

Okay. Dr. Percy.

MR. SMITH: Thank you, sir. And I think I heard you, that the ATCO main panel should expect to be ready to go Monday morning at the scheduled hour, and we will do our best to turn around IR responses as we might receive them; IRs that is.

THE CHAIR: Yes.

MR. SMITH: And file them by whenever we can on Wednesday, and we will be able to keep you appraised of our ability to meet that deadline along the way.

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THE CHAIR: Great.
MR. SMITH: Thank you.
THE CHAIR: Thank you.
MR. SMITH: Mr. Chairman and members, it is my privilege to introduce to you Dr. Michael Percy, who is the dean of the University of Alberta School of Business.
He had been asked for an opinion - that is an expert opinion - on inflation in connection with certain aspects of the ATCO Gas application.
What I would ask, sir, is if we might first have him sworn, and then I would propose to have Dr. Percy describe to you why he would consider himself authoritative in respect of the matters which he's addressed in his evidence.
THE CHAIR: Okay.
MR. SMITH: Thank you.
M. PERCY (For ATCO Gas), sworn, examination in chief by Mr. Smith:
Q. Now, Dr. Percy, if you would, your curriculum vitae has been filed. Could you, without going through it line by line, would you just give the Board -- sorry, the Commission and intervenors, a sense of why you should be considered authoritative in connection with the matters in your evidence?