ATCO Gas

2005-2007 General Rate Application
Phase I

January 27, 2006

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2006-004: ATCO Gas
2005-2007 General Rate Application
Phase I
Application No. 1400690

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Contents

List of Tables

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ATCO GAS **Decision 2006-004**
2005-2007 GENERAL RATE APPLICATION – PHASE I **Application No. 1400690**

1 OVERVIEW

1.1 General

By letter dated May 13, 2005, ATCO Gas (AG, ATCO, or the Company), a division of ATCO Gas and Pipelines Ltd., filed a Phase I 2005-2007 General Rate Application (GRA) for ATCO Gas North (AGN) and ATCO Gas South (AGS) (the Application). In the Overview of the GRA, AG indicated that the 2005 revenue shortfall was $18.5 million for the AGN and $0.2 million for AGS. The forecast AGS shortfall did not include costs in the amount of $9.4 million for 2005 for the Carbon storage facility. In the Application, AG requested an approval of 50% of the forecast shortfall for AGN, to be recovered from an across-the-board percentage increase to the existing AGN rates on an interim basis.

Notice of Hearing for the GRA was mailed to all interested parties on May 20, 2005 and published on May 26, 2005. The Public Notice indicated that the hearing would commence at the Board's offices in Edmonton on September 13, 2005.

The public hearing was convened in Edmonton, on September 13, 2005, before Board members Mr. B. T. McManus Q.C. (Chair), Mr. G. J. Miller, and Ms. L. Bayda. The hearing was completed on September 22, 2005.

Parties filed written argument and reply on October 14, 2005 and October 31, 2005, respectively. Accordingly, the Board considers that October 31, 2005, was the close of record for this proceeding.

Appendix 1 lists the parties who participated in the hearing.

1.2 GRA Application Timing and Updated Forecasts

In this section, the Board will deal with the timing of forecasts and when it is appropriate to consider updated actual results that were not available, or subsequent events that were not anticipated at the time forecasts were prepared.

Throughout the course of this proceeding, parties have provided their views regarding the timing for filing of a GRA, process scheduling and the use of forecast versus actual data. In particular, much discussion focused on the filing of actual data for the full year prior to a test year and the use of such information to compare with the forecasts prepared prior to such information becoming available. AG took the position that prospective ratemaking was premised on the use of forecasts and that the objective of a GRA proceeding was to test the reasonableness of such forecasts in light of the information available to management at the time they were prepared.[1]

[1] AG Argument, dated October 14, 2005, page 7

AG submitted that subsequently available actual results should not be allowed to be substituted for forecasts.

Interveners argued that the Board should be entitled to make use of the best information available up to the close of the hearing to determine revenue requirement for each test year and should not be bound to accept forecasts which are no more than projections based on less complete information.

Specifically, the issue involves the use of 2004 actual results and other material events that happened subsequent to the preparation of the forecasts contained in the Application. AG filed its Application on May 13, 2005 and included 2004 actual results. AG claimed that it did not have the use of the 2004 actual results when it prepared its 2005-2007 forecasts, since the forecasts were prepared some time in 2004. AG did not review its 2005-2007 forecasts prior to the Application filing date of May 13, 2005 to determine if any of its 2005-2007 forecasts should be updated to reflect material changes in circumstances that may have affected its forecasting criteria. AG proposed that its forecasts should be judged on their reasonableness using the criteria available on the day that each forecast was prepared and that no consideration should be given to updating the original forecasts for any changes in circumstances or criteria subsequent to the date of initial preparation of that forecast. AG argued:

> In Alberta, a regulatory trend has developed which tests a forecast against actual events that have occurred between the preparation of the application and the oral proceeding. Ostensibly, this information is used to further test whether the forecast was reasonable. Not only does this place the applicant in a difficult position of having to support the reasonability of its forecast on the basis of information it did not have at the time the forecast was developed, but practically, the result can be asymmetrical with adjustments in favour of customers through reductions in forecasts costs, or increases in expected revenues while adjustments that would increase forecast costs or reduce expected revenues being ignored.[2]

The Consumer Group (CG) stated:

> AG challenges what it describes as a "regulatory trend" in Alberta where initial forecasts are compared to actuals during the course of a particular proceeding. By definition, it is suggesting that the Board should ignore reality and approve a forecast which is patently in error. …
>
> In recommending that the Board not consider "actual events that have occurred between the preparation of the Application and the oral proceeding",[3] AG is inviting the Board to ignore its legislated obligations. For example, the *Public Utilities Board Act* provides the following instructions to the Board:
>
> 91(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility,
>
> (a) the Board may consider <u>all revenues and costs</u> of the owner that are in the Board's opinion applicable to a period consisting of:

[2] AG Argument, dated October 14, 2005, page 7

[3] AG Argument, page 7, lines 22 - 23

> (i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them …. [Emphasis added].
>
> Although it is obvious, the legislature was not telling the Board to only consider forecast revenues and costs. In fixing the fair return, the Board is given wide latitude and "… shall give due consideration to all those facts that, in the Board's opinion, are relevant."[4] [5]

The Board also notes Section 40(a)(i) of the *Gas Utilities Act*, RSA 2000 c. G-5 (GUA) parallels Section 91(1)(i) of the *Public Utilities Board Act*, RSA 2000 c. P-45 (PUB Act) in allowing the Board to consider all revenues and costs of an owner of a gas utility that are in the Board's opinion applicable to the whole of the fiscal year in which a proceeding is initiated. In addition, Section 91(1)(a)(ii) of the PUB Act and Section 40(a)(ii) of the GUA permits a consideration of revenues and costs applicable to a subsequent fiscal year.

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 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. This does not mean, however, that an applicant must wait until the year prior to the first test year has ended before it can file an application. The timing of a GRA application is within the control and discretion of the applicant. Rather, an applicant should be prepared to provide updated actual information whenever the processing of an application straddles the end of a fiscal year and the actual results become available prior to the close of the evidentiary portion of the proceeding. Further, partial

[4] PUB Act, Section 90(3)

[5] Reply of the Consumer Group dated October 31, 2005, pages 8-9

[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); 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).

year results may also be required when an application is processed over an extended period of time, provided the utility is offered the opportunity to put such partial results in the proper context and to describe the limitations applicable to partial actual information.

In addition, the Board will utilize updated information in respect of matters of the kind mentioned above (current interest rates, tax rates, status of projects etc.) in order to refine the forecasts in the Application.

The Board has recently considered the use of actual results that became available subsequent to the preparation of forecasts and prior to the close of the record in the proceeding. In Decision 2003-071, relating to the ATCO Electric 2003-2004 General Tariff Application, the Board stated:

> Clearly, the Board acknowledges that the GTA regulatory process ordinarily relies on forecasts of forward test years. The Board also considers that it ought to use reasonably up-to-date actual data in assessing both the ability of the applicant to prepare accurate forecasts as well as the implications of actual costs (and revenues) on the future test year periods. The Board considers this view to be consistent with its views in the previous Decisions noted particularly by FIRM. The Board acknowledges AE's concerns respecting the appropriate use of 2002 actuals and considers that the use of the data must be balanced and fair.
>
> The Board concludes that it is appropriate to utilize the 2002 actual data, in conjunction with AE's deviation explanations provided as in Exhibit 191, to assist in assessing the accuracy and reasonableness of the 2003 and 2004 forecasts.[7]

This view was similarly expressed in the AG Gas 2003/2004 GRA, where the Board commented on the 2003 and 2004 test year forecasts in light of 2002 actual results filed in of Exhibit 14-10 in that proceeding. The actual data for 2002 was not available at the time that the 2003 and 2004 forecasts were prepared and filed with the Board:

> …the Board also acknowledges the CG's comment that, if actual information provides insights as to the appropriateness of forecasting methods and assumptions used by the utility, those insights should be used to refine the Company's forecasting methods for the test years. Overall, the Board considers that examination of Exhibit 14-10 provided evidence that the 2002 forecast was prepared based on a reasonable assessment of known factors at the time, and agrees with AG that it is not possible to develop a forecast that takes account of every possible contingency.
>
> With respect to the issue of adjustment of test year forecasts in light of 2002 actual results, the Board agrees with interveners that test year forecasts should reflect the fact that actual 2002 data provides the most up to date information on the operations of the utility, and should be adjusted as necessary to recognize this principle. The Board considers that this principle in no way contravenes the concept of prospectivity, as evidenced in Decision U97065,[8] dated October 31, 1997, Decision E89091,[9] and Decision 2001-96,[10] where the Board concluded that forecasts were found to be deficient,

[7] Decision 2003-071, page 111
[8] Decision U97065
[9] Decision E89091
[10] Decision 2001-96

> as evidenced by actual information that became available during the course of the proceedings.
>
> While the Board will consider the applicability of this principle in other Sections of this Decision, the Board is aware of the need to balance positive and negative unforeseen circumstances. In this regard, the Board agrees with AG that focusing too heavily on prior year results could potentially overshadow unique circumstances in those years or changing circumstances in the test years.[11]

With respect to AG's concern of an asymmetrical result from the consideration of actual results or events that were not known at the time that the filed forecasts were prepared, the Board considers that it is up to the applicant to determine if it would like to update the forecasts it has provided in its application to reflect the updated information. If it chooses to do so, parties will be provided the opportunity to review and test such new information. If it chooses not to, the Board and parties may still make use of such information to assist in testing the accuracy and reasonableness of the application forecasts and the methodologies employed in making those forecasts.

In this Application, AG Gas identified a number of areas in Information Responses, Rebuttal and during cross-examination where more recent information suggests costs are expected to be higher than forecast. These included:

- Contractor costs for Mains Replacement ($1.7 million)[12];
- Contractor costs for MRRP ($3.1 million)[13];
- Fleet Fuel ($1.7 million in Operations and Maintenance and Capital)[14];
- Natural Gas for Compressors and Building usage ($2.9 million)[15];
- Capital costs related to flood damage in southern Alberta (greater than $500,000)[16];
- Implementation of the Tariff Billing Code ($ unknown)[17];
- Work Management ($3.7 million)[18];
- Job Redesign for Plant Employees ($1.3 million in operating costs over the test period)[19];
- General increases due to effects of Hurricane Katrina ($ unknown).[20]

Regarding reductions in forecasts expenditures, AG identified in BR-AG-4 that the proposal to relocate taps off the high pressure transmission lines would not be required in the 2006-2007 period.

Although it is within the control of the utility to amend its Application to adjust the applied for revenue requirement in light of events subsequent to the filing of its Application, AG chose not to do so in this instance. Instead, AG suggested that there was a balance of gives and takes in putting forward forecasts and that the Board should be prepared, as AG was, to work with the

[11] Decision 2003-072, pages 21 and 22
[12] BR-AG-3
[13] BR-AG-3
[14] Rebuttal, page 36
[15] Rebuttal, page 36
[16] Rebuttal, page 36
[17] BR-AG-15
[18] Transcript Volume 3, page 339
[19] BR-AG-19
[20] Rebuttal, page 36

forecasts submitted in the Application. Further, AG argued that the Board should accord deference to management's good faith judgement with respect to the operations of the utility.[21] AG's arguments with respect to a presumption of prudence with respect to forecasts are discussed in Section 4.1 of the Decision.

Views of the Board

As described above, the Board does not share AG's view that it should not reduce forecasts for capital or operating expenditures to take into account information that becomes available since the date the forecasts were prepared. The Board considers such a proposal would 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, 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.

Therefore, the Board will consider the forecasts submitted in the Application with the above principles in mind. The Board makes its determinations with respect to forecasts of capital expenditures and operating expenses in subsequent sections of this Decision.

2 RATE BASE

2.1 Rate Base Additions

AG forecast capital expenditures of $165.8 million, $159.1 million, and $158.8 million in 2005, 2006, and 2007 respectively. AG justified the quantum of the expenditures as required for the continued provision of safe, reliable, and economic service to existing customers and for the efficient extension of service to new customers, forecast at approximately 23,000 in each test year.

2.1.1 Historical Forecasting Accuracy (Capital)

Section 4.1 discusses the appropriateness of comparing forecasts with actual expenditures and whether or not an assessment of this nature can be useful in determining the reasonableness of forecast expenditures.

CG observed that in addition to exceeding growth related capital expenditures in 2003 and 2004, AG also exceeded discretionary expenditures such as Urban Mains Replacements ($1.5 and $6.6 million), Moveable Equipment ($7.7 and $5.4 million) and Information Technology ($2.2 and $7.7 million). The CG was concerned that the AG operating budgets and the GRA budgets were not the same, nor did they go through the same approval process. CG also noted that AG listed capital expenses that have increased since the application was filed as support for its original forecasts.

AG provided explanations for all significant deviations between forecast and actual expenditures for 2003[22] and 2004.[23] AG believed the results from 2003 and 2004 supported its position that its

[21] AG Argument, page 5, lines 3-4
[22] Application, Tab 8
[23] Information Workshop, IW-AG-02

forecasting methodology was accurate. The increase in capital expenditures in 2003 and 2004 relative to the forecast was to a significant extent due to customer growth greater than forecast. AG was required to undertake these capital expenditures by virtue of its franchise obligations.

As discussed in Section 4.1 of this Decision, the Board recognizes that during the past few years there has been a continual restructuring of the industry and of AG in particular. The Board considers that this provides a unique circumstance requiring consideration in keeping with the Views of the Board as expressed in Decision 2003-072,[24] and as further discussed in Sections 4.1 and 1.3 of this Decision.

These events contribute to the difficulty in relying on comparisons of prior forecasts to actual results as a tool in assessing the reasonableness of AG's forecasts in this proceeding. This is further aggravated by the fact that such comparisons are not available for AGN prior to 2003 due to the existence of a negotiated settlement with ratepayers.

Views of the Board

The following tables compare AG's (AGS and AGN combined) forecast capital expenditures to actuals for 2003 and 2004. Since capitalized administration charges were disallowed in the 2003/4 GRA, they have been removed from the forecast to actual comparison.

Table 1. AG 2003 Capital Forecast vs. Actual Expenditures ($000)[25]

	Forecast	Actual	Difference
Workover/Recompletions	$625	($28)	$653
Production/Storage Projects	$2,745	$2,115	$628
Distribution Extensions	$25,705	$28,749	($3,044)
Distribution Improvements	$21,260	$44,320	($23,060)
New Urban Service Lines	$15,280	$18,212	($2,932)
Service Line Replacements	$16,846	$2,977	$13,869
Meters & Regulators	$22,737	$9,344	$13,393
Regulator and Meter Install	$5,329	$6,113	($784)
Land & Structures	$10,009	$6,299	$3,710
Moveable Equipment	$8,863	$16,522	($7,659)
Communications Equipment	$1,053	$1,097	($44)
IT	$6,469	$8,654	($2,185)
TOTAL	$136,919	$144,374	($7,455)

24 Decision 2003-072
25 IW-AG-03, Attachment (c)

Table 2. AG 2004 Capital Forecast vs. Actual Expenditures ($000)[26]

	Forecast	Actual	Difference
Workover/Recompletions	$625	0	$625
Production/Storage Projects	$1,757	$1,715	$42
Distribution Extensions	$24,386	$31,347	($6,961)
Distribution Improvements	$25,312	$48,603	($23,291)
New Urban Service Lines	$15,738	$20,735	($4,997)
Service Line Replacements	$17,496	$3,241	$14,225
Meters & Regulators	$23,840	$10,499	$13,341
Regulator and Meter Install	$5,476	$6,008	($532)
Land & Structures	$7,086	$12,181	($5,095)
Moveable Equipment	$6,895	$12,269	($5,374)
Communications Equipment	$1,283	$1,455	($172)
IT	$2,476	$10,289	($7,813)
TOTAL	$132,370	$158,342	($25,972)

The tables show that overall, there does not appear to be a trend of over forecasting of discretionary capital expenditures. It can be seen that a large portion of the difference between forecast and actual expenditures is due to requirements of AG's franchise agreements. The Board notes CG's comments that it was "generally satisfied with growth related capital expenditures except as noted…"[27]

The following table compares capital expenditure forecasts to actuals from 2001-2004 for AGS. Again, there does not appear to be an historical trend of over forecasting expenditures. In fact, AGS has spent more on total capital expenditures than it forecast every year since 2002. The Board is satisfied that there is no clear evidence that AGS has been over forecasting capital expenditures.

Table 3. AGS 2001/04 Forecast & Actual Capital Expenditures[28]

	2001F	2001A	2002F	2002A	2003F	2003A	2004F	2004A
Capital Expenditures	$51,590	$44,720	$48,180	$53,150	$66,180	$69,990	$62,960	$68,080

The Board has some concerns regarding capital expenditures with respect to certain specific programs which will be discussed in subsequent sections of this Decision.

2.1.2 Meter Relocation and Replacement Project (MRRP)

The forecast expenditures for the revised MRRP for the test years were $29.963 million, $31.209 million and $31.286 million for 2005, 2006 and 2007 respectively.[29]

In the Application, AG submitted a revised plan for the MRRP from the plan approved in Decision 2004-036. The new MRRP plan focused almost exclusively on safety and the relocation of inside meters with underground entries. Meter sets with aboveground service entries were proposed to be relocated only where there were safety or accessibility concerns. In addition, AG

26 IW-AG-03, Attachment (d)
27 CG Argument, page 4
28 CG Argument, Attachment 1(A)
29 Application Volume 1, 2.1-43

proposed that customer requested moves should be done at no charge. AG stated that this would allow them to provide excellent customer service and be responsive to their customers.[30]

Views of the Board

The Board notes CG's recommendation that the Board should reject the revised MRRP plan because it increases costs to customers by 15.8%, 17.3% and 13.8% over the test period years. CG contended that AG did not provide analysis demonstrating that safety conditions have deteriorated sufficiently since the last MRRP plan was approved to warrant AG's changes.[31] The Board acknowledges the argument made by CG that AG has not demonstrated that safety conditions have deteriorated beyond those addressed in evidence by AG, the CG and Calgary which were adopted by the Board in Decision 2003-072.[32]

The Board also notes AG's argument that the MRRP would improve safety, efficiency, accessibility and would result in improved billing accuracy due to better meters and meter reading effectiveness.[33] AG responded that its concerns about safety have not changed since the compliance plan was approved.[34] The revised plan, AG argued, is different from the MRRP plan approved in Decision 2004-036 in that it defers relocating meters with aboveground service entries and focuses those resources on the primary safety concern, the need to relocate meters with underground entries.[35]

In Decision 2003-072, the Board stated that the program should focus on replacement of underground entries.[36] The Board directed AG in Decision 2003-072 that underground entries should be relocated/replaced over a 10 year period.[37] The Board notes the evidence presented by AG that there are significant safety concerns regarding inside meter sets with underground entries.[38] The Board notes that the new plan proposed by AG reduces that time frame significantly, and notes AG's contention that the new MRRP would improve safety for customers.

The Board also notes that the majority of the cost difference between the MRRP plan approved in Decision 2003-072 and the revised MRRP plan in this Application is due to increased costs attributable to the increase in the number of customer requested moves. Previously, customer requested moves were paid for by customers. AG would refund the customer 50% of these costs if MRRP crews came into their neighborhood to do planned work within two years of the meter move/replacement.[39] AG set that policy because it was inefficient to mobilize a crew to move one meter outside the program areas.[40]

The Board supports the revised MRRP plan proposed in the Application in that it prioritizes moves of meters with underground entries. However, the Board disagrees that customer requested moves should be performed at no charge to the customer. If customers outside of the

30 Application Volume 1, 2.1-42
31 CG Argument, page 6
32 CG Argument, page 6
33 Application Volume 1, 2.1-41
34 AG Argument, page 14
35 AG Argument, page 14
36 Decision 2003-072, page 81
37 Decision 2003-072, page 81
38 Application Volume 2, BC-04, page 13
39 Application Volume 2, BC-04, page 9
40 Application Volume 2, BC-04, page 9

area of planned moves desire to relocate their meters, then those customers should be required to pay for the moves. The Board considers that to do otherwise will not be cost effective and overly burdens customers who pick up the extra costs of the moves outside of the scheduled areas.

Consequently, the Board denies the amounts requested for customer requested meter moves outside the planned meter relocation areas and directs AG, in the Compliance filing, to reduce the forecast capital expenditures by the amounts of $5.3 million, $5.3 million and $4.7 million for 2005, 2006 and 2007 respectively. The Board directs AG to reflect the revised forecast costs to the MRRP plan in its Compliance filing.

2.1.3 Urban Mains Replacement (UMR)

2005 Opening Balance in Property Plant and Equipment (PPE)

AG reported capital costs for UMR of approximately $7.0 million in 2003 and $15.0 million in 2004.[41] In Decision 2003-072, the Board reduced the proposed 2004 capital expenditure to a level of $7.0 million in each year. AG actual expenditures were $8.1 million more than the Board awarded amount over that period (2003/2004).

CG argued that AG expended some $8.0 million in excess of the amount approved by the Board pending further discussion on the scope and goals of the program. CG's recommendation was that the Opening Balance of PPE for 2005 should be reduced by $8.1 million to reflect the fact that AG exceeded the expenditures approved by the Board for 2003 and 2004.[42] CG argued that AG had not demonstrated that those expenditures were urgently required for reasons of safety, system, or customer requirements and, therefore, AG did not meet its burden of proof to demonstrate that it replaced additional urban mains in 2003 and 2004 "on the basis of need."[43] CG proposed that if the Board found these expenditures to be prudent in the long term, they should be included in the closing balance of PPE at December 31, 2005.[44]

AG provided reasons for the over-expenditures, such as: three projects were coordinated with paving projects, two Black Diamond projects totaling $0.7 million were advanced from 2004 to 2003,[45] and the Crowchild Phase II project at a cost of $0.5 million was advanced from 2005 to 2003.

AG responded to the CG's submission that AG did not meet its burden of proof to establish that the "additional urban mains" replaced in 2003-2004 were done on the basis of need. Areas of concern were identified using the Demerit and ProLeak tools along with a further analysis using available information to determine the need for replacement, and the boundaries of the replacement area. The position of AG was that deteriorated mains must be replaced before the level of safety declines. AG argued that its program was consistent with Decision C90026, wherein the Board stated that "The Board expects that CWNG will replace pipe on the basis of need without waiting for a GRA."[46]

41 Decision 2003-072, page 47
42 CG Evidence, page 16
43 Rebuttal page 28, lines 22-23
44 Transcript, page 1090
45 BR-AG-4, 2003/2004 GRA, Piping Integrity Analysis, page 83
46 Rebuttal, page 25, lines 11-13

Views of the Board

In support of its UMR expenditures, AG provided Business Case 03-01, Analysis of Condition of Underground Pipe. The program described in the report has evolved over a number of years and has been examined by the Board in a number of previous applications. No detailed examination of BC 03-01 was conducted by parties. The Board reviewed the methods and selection criteria used to decide which mains should be replaced and is satisfied that the selection criteria are consistent with the criteria used in prior years and that they remain appropriate. In any case, due to the potential consequences of natural gas leaks, the Board retains its view that AG is expected to continually monitor its system and to effect any changes to its programs or replacement schedules necessary in the interests of safety or need. However, reliance on the above expectation is not sufficient by itself to support a determination of an appropriate PPE opening balance where, as was the case in this Application, there has been a significant over-expenditure when compared to existing Board approvals. The Board accepts AG's submission justifying this over-expenditure in the 2003-2004 time frame as shown in the evidence and reasons for the extra expenditures.[47] The Board considers this type of submission as being proper in providing adequate justification to show that its past decisions were prudent and in assisting the Board in determining the first test year's opening balances.

The Board accepts the AG's argument and evidence regarding the need for and level of the over-expenditures in 2003-2004 as compared with the forecast in the 2003-2004 GRA and considers that the over-expenditures were shown in evidence to be prudent. Therefore, the Board agrees that the over-expenditures for UMR in 2003-2004 were appropriate and shall be included in the 2005 opening balances in PPE.

2005-2007 UMR Forecast

AG forecast expenditure for UMR over the test period in the amounts of $19.0 million in 2005, and $15.0 million in each of 2006 and 2007. AG's evaluation and method for determination of replacement projects was based on the Demerit Point System, the ProLeak model and Engineering Analysis.[48]

CG argued that AG offered no adequate explanation or evidence as to the applicability of a program designed for bare mains as being appropriate for cathodic protected and coated and/or wrapped mains. AG had indicated that the original model has been appropriately adjusted, but offered no evidence as to what the adjustments had been, or how they were tested. Nor did it provide any analyses of AG's evaluation of the adjustments. CG argued that there can be no confidence that the modified Demerit Point System provides reasonable and accurate results.[49] CG did not take specific issue with the engineering assessments,[50] but did note the failure of AG to provide information as to how the Demerit System and the Pro Leak model are integrated with the Engineering Assessments.

CG noted AG's statement in response to CG-11(b) that the average leak repair cost in the mains replacement area was $7,900. CG observed that there was no cost benefit analysis contained in the entire Application showing that repairs would or would not be more cost effective than the

47 ATCO Gas Rebuttal Evidence Pages 27 – 28 and 53 - 59
48 Application TAB 2 BC03-01
49 Transcript Volume 7, pages 1087 - 1088
50 Transcript Volume 7, page 1088

proposed replacement program. Further, there was no supporting evidence that the leak frequency had changed from that considered in developing the expenditure levels in the last GRA.[51] CG submitted that based upon the record, the Board should continue to support its findings in the last GRA and allow approximately $7.0 million per year for this project for 2005 and 2006. The CG submitted that with some exceptions, like Rockyford, the UMR program could be carried out on a programmed basis at a level of $7.0 million per year until the next GRA.

AG suggested that the replacement of urban mains is a complicated and costly activity that is undertaken only after it has completed a thorough and complete analysis. ATCO Gas stated that the decision to replace is based on an engineering analysis of each area with a focus on the class of leaks occurring in an area.

AG pointed out that, unlike Bare Mains, UMR is not a “program”. ATCO Gas argued that it has been consistent in its methodology and forecasts for UMR and has forecast capital requirements over the test years. Once projects are identified based on risk tools using the Demerit Point System, ProLeak, and a detailed engineering analysis, detailed estimates for each project are provided closer to the actual construction period.

AG is currently replacing approximately 1% of its steel system on an annual basis.[52] Areas requiring replacement are determined based on a logical and progressive analysis. AG contended that replacements are undertaken in a cost effective and efficient manner.

AG argued that a full economic analysis of all related costs must include the probability and potential impact of a leak resulting in property damage, injuries, and fatalities.

Views of the Board

The Board notes CG’s recommendation that the UMR program expenditures should be held at the awarded level of the 2004 GRA. The Board also notes AG’s actual expenditures in 2004 were significantly higher than the 2004 award. In the preceding subsection, the Board concluded that AG adequately justified the over-expenditure in 2004. Therefore, on the basis of the 2004 required program and the evidence submitted in this Application, the Board does not agree that the CG recommended amount will be sufficient in the test years.

The Board also notes that the UMR program expenditures have escalated substantially from 2001 until 2004 and that the forecast for the test years indicates a significant increase above the levels of actual expenditures in 2004.

Table 4. Historical and Forecast UMR Expenditures ($000)[53]

	2001A	2002A	2003A	2004A	2005F
AGS	$1,530	$2,790	$4,890	$7,400	$9,690
AGN	N/A	N/A	$3,610	$6,210	$9,410
TOTAL	N/A	N/A	$8,500	$13,610	$19,100

AG submitted substantial evidence in BC-03[54] as justification for the extent of the UMR program for the test years. However, the Board finds that the quantum of evidence has not persuaded the

51 Transcript Volume-7, page 1086
52 Application, Volume 1, page 2.1-2
53 CG Evidence, Attachment 1 (A) & (B)

Board that the continued significant increases are justified. Therefore, the Board has determined that a reduction of 10% from the requested amount for UMR in each test year for each of the North and South zones would provide adequate funding to replace an appropriate amount of deteriorated underground mains while maintaining an appropriate level of safety.

Therefore, the Board directs AG in the Compliance filing to reduce the forecast capital expenditures for UMR by 10% in each test year for each of the North and South zones and to reflect this reduction in all of the associated schedules.

Notwithstanding the above reductions, the Board reminds AG that it has the responsibility to continually monitor its system using the tools it has to effect any changes to its programs or replacement schedules. The changes may be equally applicable to a reduction in the scope of annual expenditures as to increases in the program scope.

2.1.4 New Urban and Rural Extensions

AG requested $20.8 million, $21.4 million and $21.6 million for Urban and Rural Main Extensions for 2005, 2006 and 2007 respectively. While generally satisfied with AG's forecasts for growth-related capital expenditures,[55] the CG had concerns with three components of this area. Specifically, the CG was concerned about the per unit costs used for urban mains extensions in Red Deer, the unit costs used to forecast commercial mains extensions in Calgary and AG's decision to not include contributions in its forecasts for mains extensions.[56]

AG's per unit residential main extension forecast for Red Deer was determined by taking the average cost per lot for the three years preceding three years adjusting for inflation.[57] The CG contended that based on this methodology the forecast unit costs should be $430, $443 and $456 per lot for each test year respectively. These per unit costs would reduce the overall urban mains extensions forecast by $96,000, $102,000 and $107,000 for 2005, 2006 and 2007 respectively. In its Rebuttal Evidence, AG stated that it agreed with the CG's recommendation in this area.[58]

The second concern brought forth by the CG pertained to per unit costs used to forecast commercial urban main extensions in the City of Calgary. AG proposed taking the average of the three year, four and five year average unit costs for Calgary commercial extensions and adjusting that result for inflation.[59] AG argued that the unit costs of commercial extensions can vary significantly from project to project. According to AG, this volatility indicates that more statistical smoothing would yield a more accurate per unit forecast. The CG maintained that a simple three year average was sufficient to generate reasonable per unit forecasts and the CG suggested that the AG's approach appeared to be a selective modification to the three year average rule.[60]

The CG's third concern regarding urban and rural extensions was that AG did not forecast contributions. AG stated that according to its franchise agreements, AG is required to extend

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54 Application Volume 2, Tab 2.1, BC-03
55 CG Argument page 14
56 CG Argument, page 15
57 CG-AG-8(a)
58 AG Rebuttal Evidence, page 20
59 AG Rebuttal Evidence, page 20
60 CG Argument, page 15

mains to any lot that is serviced by municipal water and sewer without a customer contribution.[61] AG therefore only collects customer contributions for urban mains extensions for a small number of customers who do not have municipal water and sewer. The CG contended that since AG has collected contributions over the last 6 years,[62] AG should forecast those contributions using a simple three year average. AG stated that if the Board were to require AG to include contributions with its main extension forecasts, AG would also suggest the three year average approach.[63]

Views of the Board
Since both the CG and AG agreed with the per unit costs for Red Deer residential urban mains, the Board accepts that recommendation and orders AG to reduce its urban mains forecast in this area by $96,000, $102,000 and $107,000 for 2005, 2006 and 2007, respectively.

The Board has considered the suggestion by AG that, given the volatility in the Calgary commercial extension cost category, a more complex averaging technique would yield a more accurate per unit forecast cost. However, the Board agrees with CG that an exception to the three year average approach in this case is unnecessary. Therefore, the Board has determined that another reduction should be made to the Urban Mains Extensions forecast in the amount of $56,000, $55,000 and $54,000 in 2005, 2006, 2007, respectively.

In its Argument, AG indicated that in its 2003/2004 GRA, the Board had examined the issue of including contributions for Urban Mains Extensions with AG's forecasts. In Decision 2003-072, the Board accepted AG's submission that contributions have not been forecast for this category, since virtually all new customers in a municipal area are served by water and sewer.[64] Since it continues to be the case that the vast majority of new customers are served by water and sewer, the Board sees no reason to change its position regarding contributions at this time.

2.1.5 Other Replacement Projects

2.1.5.1 Urban Mains Relocations

AG forecast $545,000 in 2005, $585,000 in 2006 and $300,000 in 2007 for relocating distribution facilities in mobile home parks.

CG argued[65] that consistent with the forecasting method for mains extensions, the forecast mobile home park relocations should be based on the three year average adjusted for inflation. From 2002-2004, the actual expenditures averaged $403,000. CG recommended that the forecast of costs for mobile park mains relocations should be $411,000, $419,000 and $428,000 for the three test years, 2005 – 2007 based upon the three year average method adjusted for inflation in each year.

AG indicated[66] that the amounts were based on the forecast activity in each business unit. In its Rebuttal Evidence[67], AG provided an analysis of historical GRA forecast and actual amounts as well as the forecast amounts in this Application.

[61] AG Argument, page 18
[62] CG Evidence, page 12
[63] Argument, page 19
[64] Decision 2003-072, page 38
[65] CG Argument, page 16
[66] Transcript Volume 1, page 87

Views of the Board
The Board agrees with CG that the evidence does not support AG's forecast. The Board accepts CG's argument that the forecasting method for mains extensions is also appropriate for urban mains relocations and therefore accepts the CG suggested amounts of $411,000, $419,000 and $428,000 for the 2005-2007 test years respectively as being a more reasonable forecast. Therefore, the Board directs AG in the Compliance filing to revise its forecast expenditure in the test years to these amounts.

2.1.5.2 Measurement Instrumentation

AG forecast expenditures for the purchase of new and replacement meters and instruments in the amounts of $11.7 million, $15.8 and $14.6 million for 2005, 2006 and 2007 respectively. Included in these expenditure forecasts, AG proposed a new program commencing in 2006 to replace obsolete mechanical modules with electronic modules on rotary meters at a forecast annual cost of $3.6 million in each of 2006 and 2007. These costs include $0.6 million in each year for conversion kits and $0.6 million for the build up of working inventory.[68]

CG recommended that the program to replace obsolete mechanical modules be deferred until AG demonstrated that the replacement of the mechanical modules was the most efficient and economic option. CG noted that AG had purchased only 31 modules in 2002 and 2003 as compared with the 1700 modules for 2006 as proposed in the Business Case. CG also noted that AG had not experienced any catastrophic failures with the mechanical units in the past.[69] In addition, CG argued that the Business Case did not show the full year impacts for the conversion kits or the 25% extra modules acquired for rolling stock. The capital carrying costs were forecast to increase from $362,000 in Year 1 to $2,341,000 in Year 6 ($2.517 million if the conversion kits and rolling stock were included). The carrying costs of the project would decline thereafter as the electronic modules were depreciated. Although AG had not provided a NPV analysis, CG argued that the costs of replacing the mechanical modules far outweighed the best-case benefits.

CG submitted that AG did not justify replacing the mechanical modules on rotary meters on either a cost-benefit/net present value basis or on the basis of obsolescence and, accordingly, CG submitted that the $3.6 million of forecast capital expenditures in each of 2006 and 2007 should be denied until AG can present a more convincing business case.

AG noted that there should have been an adjustment of $2.3 million in 2004 due to an incorrect allocation of meters between North and South. AG reversed the incorrect allocation in 2005 as shown in Table 2 of the Rebuttal Evidence.[70] The CG accepted the adjustment, but noted that reversing the incorrect allocation in 2005 may affect the 2004 closing and 2005 opening balances for AGN and AGS as well as related accounting entries. The Board agrees that the $2.3 million incorrect allocation in 2004 should be reversed, and directs AG in the Compliance filing to confirm that the correcting entries have been effected and that the 2005 opening balances for AGN and AGS are correct.

[67] Rebuttal, page 21
[68] Rebuttal, page 33
[69] Transcript Volume 1, page 97
[70] Rebuttal, page 34

AG noted that a disadvantage of using the mechanical modules was a risk of parts availability and re-certification and re-calibration costs. These risks were not quantified beyond stating that one manufacturer has phased out making replacement parts for older models. AG argued that it has an obligation to keep measurement equipment and instrumentation working as accurately and efficiently as possible. As technology changes and improves, AG must determine the best time to replace old equipment to ensure that it can be properly maintained, remain accurate and improve reliability.

AG explained that $600,000 of the $3.6 million for conversion kits was a continuation of upgrades of measurement that has been ongoing since 2004.[71] This expenditure was not in the business case for module replacement because it is a separate program. In addition there has also been an ongoing replacement of obsolete instruments that was started in 2003 with a $430,000 expenditure, and continued in 2004 with an expenditure in the order of $1 million. The ongoing replacement will be completed in 2006, with expenditures in the order of $2 million in each of 2005 and 2006. These costs were included in the total meter replacement costs.

AG noted that CG inferred that AG provided only anecdotal evidence that mechanical modules would not pass a sampling process.[72] AG replied that it presented evidence and that based on the expertise and knowledge of AG, there had been enough failures to know that a sample would not pass.[73]

Views of the Board

The Board notes that AG filed the Business Case related to the Mechanical Module Replacement program with its Rebuttal evidence. Since this is a new program for which the total capital expenditures are substantial, the Board reminds AG that it expects Business Cases for such programs to be filed along with the Application.

Notwithstanding the late filing of the Business Case, the Board is of the view that sufficient time was provided for evaluation. Based upon the projections in the Business Case, the Board is of the view that the Mechanical Module Replacement project has merit from a financial and operating perspective. Therefore, the Board approves the initiation of the Mechanical Module Replacement program projected to commence in 2006 and approves the forecast capital expenditures for 2006 and 2007 as per the Application.

2.1.5.3 Moveable Equipment

AG forecast capital expenditures in the amounts of $9.4 million, $8.5 million and $7.7 million for 2005, 2006 and 2007 respectively for additional and replacement vehicles. AG manages a fleet of 960 vehicles [74] and replaces vehicles according to the following guidelines:[75]

GVW[76] less than 17,500 lbs	200,000 km (150,000 km pre-1999)
GVW over 17,500 lbs	300,000 km
Highway Tractors	500,000 km

71 Rebuttal Evidence, page 33
72 CG Argument page 18
73 Transcript Volume 1, page 94
74 Application, page 2.1-55
75 Application, page 2.2-57
76 GVW means Gross Vehicle Weight

Based on these criteria, AG targets replacements of smaller vehicles at 10 years (7-8 years pre-1999). AG proposed to add 39, 38 and 12 new vehicles and to replace 133, 120 and 100 vehicles in each of 2005, 2006 and 2007 respectively.[77]

CG noted its concern related to the acquisition of new vehicles required for growth.[78] CG argued that growth was driven by number of employees, assuming constant productivity, and would not be materially different than growth in customers or capital expenditures. The CG was concerned that AG required 960 vehicles for 1742 employees[79] for a ratio of 1.82 employees per vehicle and encouraged the Board to carefully scrutinize new vehicle additions based on maintaining productivity levels. The CG submitted that no more than 25 new vehicles should be added to meet growth in the test years. Based on the AG forecast additions of 39, 38 and 12 new vehicles in the test years,[80] new vehicle additions should be reduced by 14 in 2005 and 13 in 2006. At an average cost of $57,000 per vehicle,[81] the reduction in new vehicles would translate to reductions of $798,000 in 2005 and $741,000 in 2006. No changes to additions were determined in 2007 because AG did not segregate additions from replacements.[82]

CG also noted that AG introduced new evidence on fleet vintage in the form of Appendix 2. AG noted that there had been an increase in fleet units beginning in about 1994 and that these units were now 10 years old and would require replacement in the test period. CG considered that AG's comments about extending the life of units and the reductions due to the merger in 1999 were largely irrelevant because most of the units thus affected should be out of the system by now.

The CG submitted that AG did not meet its burden of proof to demonstrate that it will require 133, 120 and 100 replacement vehicles in the test period. CG submitted that in the absence of adequate proof, vehicle replacements should be limited to 100 units per test year. This translated to reductions of 33 and 20 units in 2005 and 2006 or $1.39 million and $1.14 million respectively.

CG remained concerned over the average unit price utilized by AG to develop its forecast transportation equipment expenditures. CG noted that it was forced to rely on what AG chose to provide and analyzed the mix of transportation units provided in CG-AG-17.

CG did not detect a material shift in the mix of vehicles from 2005 through 2007 and accordingly, maintained its position that AG did not support the average cost of $68,800 per vehicle in 2007 as determined from the information provided in CG-AG-17(a). Accordingly, CG submitted that the $57,000 average for 2005 and 2006 ($44,100 in 2003 and $55,400 in 2004) as noted in its evidence, should be utilized to determine 2007 vehicle expenditures with a resulting $1,321,600 reduction ({68,800 – 57,000} x 112).

[77] Rebuttal Evidence, page 35
[78] CG Evidence, page 24
[79] Application, page 4.1-2
[80] Rebuttal, page 35, line 17
[81] CG Evidence, page 24
[82] Application, page 2.1-57

AG argued that it “determines the need for additional vehicles based on its business requirements primarily driven by growth in employees and not on a formula as suggested by the CG.”[83] AG also criticized CG’s suggestion that the number of additional vehicles should be related to growth and that CG’s determination of cost per vehicle was overly theoretical by using an average cost per vehicle.

AG argued that the logic of the CG was flawed in three respects. First, as indicated by AG,[84] vehicle additions were related to a number of factors, primarily its business requirements and number of employees requiring access to transportation in the performance of their responsibilities. Vehicle additions were not directly related to either customer additions or capital additions, as suggested by the CG. Second, AG forecast vehicle additions on a case by case basis to determine specific requirements. There was a significant range in the cost of individual vehicles due to the variability in size and rig-up. AG argued that it was completely inappropriate of the CG to apply a fleet average cost to determine a requirement in revenue requirements.[85] Third, the vintage of the fleet is influenced by the new vehicles purchased for monthly meter reading which, if disallowed from opening balance, would tend to make the overall fleet older, increasing the need for replacements.

AG was also concerned with the CG’s approach to expenditures for replacement vehicles. AG provided substantial evidence in its Application,[86] responses to Information Requests,[87] and Rebuttal.[88] AG reiterated that the forecast expenditures for replacement vehicles were based on specific assessments and analysis[89] rather than a general formula approach. AG argued that CG did not provide any evidence that the vehicles identified for replacement were not required.

Views of the Board

The Board accepts AG’s justification that the number of new vehicles required for customer growth is related to the mix of new employees requiring access to transportation in the performance of their responsibilities. Therefore, the Board accepts AG’s forecast of the number of vehicles required for growth. In addition, AG’s method for forecasting the cost of additional vehicles using projected specific requirements for each vehicle will provide a more accurate estimate for new vehicles, as compared with using a fleet average cost to forecast the cost of additional vehicles for growth. Therefore, the Board accepts AG’s forecast of cost for new vehicles required for growth.

Regarding the forecast number of replacement vehicles for each test year, the Board considers that AG’s method of determining the replacement requirements based upon specific assessments appears to account for the variations in circumstances for each vehicle service application, rather than using a general formula approach. This method will likely result in a more accurate forecast of replacement requirements. Therefore, the Board accepts AG’s forecast of replacement vehicles along with the forecasted average cost for new vehicles in each year.

[83] Rebuttal, page 35
[84] Rebuttal, page 35, lines 4-17
[85] Rebuttal, page 35, lines 35-40
[86] Application, Volume 1, Section 2.1.3.9
[87] CG-AG-17
[88] Rebuttal, pages 34-35 and Appendix 2
[89] AG Argument, page 20, line 20

2.1.5.4 Pipeline Replacement Projects

AG forecast capital annual expenditures in the North of $5 million in each of 2006 and 2007 for the relocation of distribution facilities (distribution mains and regulating meter stations) required as a result of the relocation of taps off high pressure transmission systems.

CG objected to this forecast expenditure noting there was neither a business case, nor an estimate for this $10 million expenditure. CG argued that AG seemed to be taking the position in Rebuttal Evidence that these amounts have now become “unspecified expenditures” for projects that have a likelihood of proceeding.[90] The CG stated “It is therefore impossible to assess either the need for, the quantum of costs or the timing of these capital expenditures” and “Had this case been tested in this proceeding based on the evidence provided, the CG considers there is little doubt that these projects would not have been approved.”[91]

AG indicated that the plans for the replacement project were preliminary and that it no longer forecast the $5 million level of expenditure. However, AG was maintaining its capital forecasts as presented in the Application.[92] AG argued that the Board must be cognizant of the inappropriateness of using hindsight to test a forecast as well as the issue of asymmetry when analyzing new, post-forecast evidence. AG claimed that the test of what is forecast to be “used or required to be used” as part of forecast rate base is based on facts existing at the date of the forecast, not facts that become available after the Application has been submitted. AG identified other significant changes to its capital expenditures forecast as a result of more recent information.

In addition, AG noted that Decision U96002 specifically contradicts the CG’s position:

> The Board agrees with the submission of Centra that it is not required to prove that each individual capital expenditure item will occur as forecast. The Board also agrees with the submission of Centra that Centra’s actual capital expenditures are not required, or even expected, to be identical to those approved by the Board for a test year. The Board agrees with the position of Centra that it must build to fit the need rather than the forecast. [93]

AG therefore continued to consider that the inclusion of this cost would result in rates that were just and reasonable and that the Board should approve the inclusion of the forecast amounts in rate base.

Views of the Board

The Board does not share AG’s view that forecasts should be weighed for reasonableness only on the basis of the facts available on the date when the forecast was prepared. In Decision 2003-100,[94] the Board considered the revenue requirement forecast of ATCO Pipelines which included an amount in respect of the Bretona Loop project. At the time of the forecast the project was expected to proceed. Subsequent events lead to the conclusion that expenditures by ATCO Pipelines would not be required as an alternative had been identified. ATCO Pipelines submitted that its overall forecast of capital expenditures was reasonable and prudent, and that approval of these forecast expenditures should not be affected by its decision not to proceed with

[90] Rebuttal, page 36
[91] CG Evidence, page 25
[92] BR-AG-4
[93] Decision U96002, pages 23-24
[94] Decision 2003-100, ATCO Pipelines 2003/2004 General Rate Application Phase I, December 2, 2003

the Bretona Loop. In denying the inclusion of the capital expenditures for the Bretona Loop project, the Board stated at page 18 of Decision 2003-100:

> The Board has considered ATCO Pipelines' argument that in accordance with prospective ratemaking principles, the cancelled Bretona Loop project should remain in rate base. However, the Board agrees with Calgary's position and considers that inclusion of the Bretona Loop would distort the forecast and would not meet the statutory rate base tests, when clearly the loop would not be installed and neither the capital cost nor any other associated cost would be related to a facility that was used or required to be used….
>
> The Board considers that it is the responsibility of the utility to thoroughly demonstrate to its customers and to the Board that projects and expenditures are both prudent and used or required to be used. Should the Board find that these tests are not met, the Board will disallow all, or a portion of, the project from rate base.

Later, at page 96 of Decision 2003-100, the Board stated:

> ATCO Pipelines argued that altering forecasts used in the preparation of a regulatory filing may damage the prospective nature of the rate-making process. However, as all parties are aware, the time lapse between the filing of any original evidence and the time of the subsequent hearing can be several months during which time certain costs or parameters can change markedly. In the past, the Board has taken into account current or updated information on actual costs in cases where the updated information is materially different from the forecast information presented in the Application. In the Board's view, this practice is supported, in part, by Section 91 of the *Public Utilities Board Act* and is consistent with the approach it took most recently in relation to the ATCO Electric Ltd. 2003-2004 GTA in Decision 2003-071[95] and the ATCO Gas 2003-2004 GRA in Decision 2003-072.[96]

The Board finds the foregoing reasoning equally applicable in the present circumstances in respect of the forecast capital expenditures of $5 million in each of 2006 and 2007 for the relocation of distribution facilities. The Board understands that forecasts must be prepared well in advance of the close of record. However, should there be a change in circumstances subsequent to the preparation of the original forecast that materially impacts the rationale supporting any significant aspect of the applied for revenue requirement, the Board must take that information into account in determining if the subject expenditure continues to be required in respect of facilities that are used or required to be used to provide service to the public, and in determining if the applied for revenue requirement will result in just and reasonable rates.

In this Application, the Board finds that the justification for the tentative relocation program of taps off high pressure transmission systems is inadequate. By its own admission, AG no longer expected this project to be required. However, AG requested the Board to permit the funding for this program to remain in capital additions as an offset for probable projects that were identified after the original forecast date[97] and which would be additional to the original forecast. In Argument, AG listed a number of areas where information subsequent to the preparation of the

[95] Decision 2003-071, ATCO Electric Ltd., 2003-2004 General Tariff Application, Rate Case Deferrals Application, 2001 Deferral Application (October 2, 2003), pages 110-111
[96] Decision 2003-072, ATCO Gas, 2003-2004 General Rate Application, Phase I (October 1, 2003), pages 20-22
[97] AG Argument, page 12

original forecast suggested projects in addition to the original forecast, for which funds were not provided in the Application.

The Board does not accept the justification that funds should remain in capital additions where AG has admitted that the project for which the funds were identified will not likely proceed. The Board has stated its views regarding updated forecasts in Section 1.2 above. Therefore, the Board directs AG in the Compliance filing, to reduce its forecast of capital additions in the North by $5 million in 2006 and $5 million in 2007 and to reflect this change in all schedules that are affected, including corresponding reductions to the operating and maintenance forecasts.

2.1.5.5 Fort McKay Project

The Fort McKay distribution project was proposed to serve residential development near Fort McKay. Specifically, Athabascan Resource Company (ARC) approached AG to estimate the cost of providing service to 500 homes in the first year with future growth to a maximum of 1200 lots. A Business Case in support of the project was included in the Application.

CG commented that the provincial and federal governments had not yet completed land transfer agreements necessary to commence the project.[98] CG stated that AG was not aware of who owns the property, nor was AG aware of whether there may be additional land claims affecting the land involved in the project.[99] An October 7, 2004 letter from ARC indicated that an agreement between the Fort McKay First Nation and CNRL had not been completed. AG also acknowledged that until the agreement was completed, the exact schedule and details of the project would be unknown.[100]

In addition to unresolved land transfer issues, CG argued that AG also advised that the negotiations amongst ARC, the Fort McKay First Nation and an investor remain unresolved at the time of the proceeding and the project was put on hold.[101] Even if these negotiations were to be resolved during the test period, the CG submitted that there was no evidence to indicate whether Fort McKay, ARC or the investor has the financial and/or managerial ability to complete the project.[102]

The CG submitted that it appears highly unlikely that the land and investor issues will be resolved so as to allow the Fort McKay project to commence during the current test periods.

CG argued that AG had not demonstrated there was even a reasonable likelihood the Fort McKay project would proceed in the test years, and therefore recommended that the forecast costs and contributions associated with the Fort McKay project should be removed in totality from AG's revenue requirement.

As ownership of the land has not yet been settled, AG acknowledged that it did not have a franchise agreement with respect to this project. Moreover, if the project was on reserve land, there would be the possibility of other distribution companies providing service to the project area.[103]

[98] Exhibit 02-015-005, CG.AG-58(h)
[99] Transcript Volume 1, page 145; line 8
[100] Exhibit 02-001-001, Vol.2, Tab 2.1, BC 01-01, page 13 of 17 & T146; L17, V.1
[101] Exhibit 02-015-005, CG.AG-58(i)
[102] Transcript Volume 1, page 149, line 18
[103] Exhibit 02-001-001, Volume 2, Tab 2.1, BC 01-01, page 7 of 17

AG argued that CG's suggestion, that the forecast costs and contributions associated with this project should be removed from the revenue requirement on the basis of considerable post-forecast evidence, should be rejected. AG considered that this issue was identical to the issues discussed with respect to the Pipeline Relocation[104] project. AG restated the same objections to the hindsight review CG conducted with respect to the Fort McKay Project.

Views of the Board
The Board finds that AG has not met the burden of proof that the Fort MacKay project will proceed in the test years. Therefore, the Board denies the inclusion of the forecast amount of $1.029 million in 2005 capital additions for this project, and directs AG in the Compliance filing, to reduce this amount from its forecast of capital additions in the North for 2005. The Board directs AG to reflect this change in all schedules that are affected, including any forecast revenue from projected sales to customers and corresponding reductions to the operating and maintenance forecasts.

2.1.5.6 Brooks Operating Centre

AG proposed to build a new operating centre in Brooks and forecast a capital cost of $982,000. Land was purchased in 2004 for $160,000, with construction scheduled to begin in April 2005 with occupancy in October 2005.[105]

CG argued that the costs associated with the Brooks Operating Centre should not be included in rate base for the test years. CG contended that AG failed to demonstrate that AG's request was the lowest cost option. CG further suggested that, if the project is approved, it should be deferred at least one year as the construction schedule appeared unrealistic.

AG argued that the Brooks Operating Centre was not justified based on a strict cost/benefit analysis, but rather on the other issues as described throughout the Business Case. Based on the present value calculation and the availability of suitable land/facilities, the only feasible option was to build a new operating centre.

AG pointed out that the schedule included 19 days in December to rectify deficiencies.[106] During cross examination, Mr. Schmidt confirmed that construction had commenced and that occupancy was forecast in the first two weeks of December.[107]

Views of the Board
The Board accepts AG's rationale and Business Case as appropriate justification for the need to build a new operating center in Brooks on the land it acquired for the building. In addition, the Board accepts AG's expectation that the new Brooks Operating Center will be occupied prior to end of 2005. Therefore, it is appropriate to include the project costs into the capital additions for 2005.

[104] Application, page 2.1-27
[105] Application Volume 1, page 2.1-48
[106] BR-AG-60(a) Attachment 1
[107] Transcript, Volume 1, page 157

The Board notes that AG proposed to move the remaining undepreciated capital cost of the vacated facility into non-utility accounts effective on October 1, 2005[108] and that AG's intention is to dispose of the facility.[109] The Board also notes AG's view that the disposition of the Brooks facility would be outside the ordinary course of business and that, accordingly, AG intends to submit an application for disposition.[110] The Board agrees that the disposition of the Brooks facility falls outside of the ordinary course of business and, therefore, expects AG to apply, in due course, for sale of the Brooks facility and disposition of proceeds. However, in the interim, AG's accounting treatment of the Undepreciated Capital Cost (UCC) and Capital Cost Allowance (CCA) in this Application is not to be interpreted as having received any specific or implied approval. The Board notes Mr. Beckett's reference[111] to the appeal before the Supreme Court of Canada of the Board's decision[112] with respect to the Calgary Stores Block. The Board will deal with the appropriate accounting treatment of the proceeds of sale upon receipt of an application for sale and disposition of proceeds for the Brooks facility.

Therefore, until the Board deals with an application for the disposition of the vacated Brooks facility, the Board directs AG to treat the remaining UCC and CCA as regulated assets held for future disposition, but not included in the current rate base upon which a return would be included in the revenue requirements for the test years. The issue of whether or not any return is applicable to these assets held for future disposition will also be determined subsequent to the decision of the Supreme Court of Canada.

2.1.5.7 Fort McMurray Operating Centre

AG forecast an amount of $3.2 million for 2007 to renovate and convert the existing Fort McMurray Operating Centre to four bays and a warehouse and to construct a new 9,000 square foot office facility adjacent to the existing building.

The CG considered that the expansion of the Fort McMurray Operating Centre was excessive and a scaled down version would be more appropriate. CG considered that AG, ATCO Electric (AE) and ATCO Pipelines (AP) should share facilities to the greatest extent possible. The CG considered that at maximum a 4,500 square foot facility was appropriate, given that a significant number of employees were only at the facility for a short time during the day.[113]

The CG also considered that the project should be delayed at least one year. The CG noted that AG had in the past been overly aggressive in the completion of service centres. Further, Fort McMurray had severe labour shortages and this could only add to scheduling difficulties. AG argued that CG did not provide any evidence to demonstrate that the scaled down version would be more appropriate or even a feasible alternative.

Views of the Board

The Board accepts AG's rationale and Business Case as appropriate justification for the need to renovate the existing building and to construct a new operating center in Fort McMurray. The Board also finds the construction estimates to be reasonable. Accordingly, the Board approves

[108] BR-AG-8
[109] Transcript Volume 4, page 543, line 22
[110] Transcript Volume 4, page 544, lines 3-7
[111] Transcript Volume 4, page 544, lines 15-19
[112] Decision 2002-37
[113] Transcript Volume 1, page 166

the inclusion of $3.2 million in 2007 as a reasonable estimate of the cost for the facility defined in the Business Case.

2.1.5.8 Meter Shop, Electronics, Instrumentation and Distribution Centre (MEID) Relocation

AG forecast an amount of $2.5 million for the relocation of the MEID functions into a new facility to be completed by December 15, 2005.[114]

The CG considered that the project should be delayed at least one year as the new Measurement Canada rules would not be implemented until at least 2007.

AG[115] argued that it identified all of the drivers behind the requirement for a new facility. The change in Measurement Canada rules was only a minor consideration.

Views of the Board

The Board accepts AG's rationale and Business Case as appropriate justification for the need to relocate the MEID functions into a new building at a new location, and that the relocation effective date prior to the end of 2005 is reasonable. The Board considers that the need for the facility was justified despite the possible delay in the release of the new Measurement Canada rules. The Board also accepts the forecast expenses associated with the relocation to be reasonable.

Therefore, the Board approves the inclusion of $3.5 million in 2005 as a reasonable estimate of the cost for the facility defined in the Business Case.

2.1.6 Information Technology Capital Projects

AG forecast IT capital project expenditures totaling $7,828,000 in 2005, $4,175,000 in 2006 and $5,760,000 in 2007.[116] The IT capital projects identified included a mix of ongoing projects and new projects, all of which are being performed by ATCO I-Tek under contract.

2.1.6.1 IT Capital Project Volumes

Business cases were provided in respect of each forecast IT Capital project to support the forecasted expenditures. Business cases did not expressly identify ATCO I-Tek service volumes. AG, however, requested approval of IT capital project volumes[117] and further requested that the forecast amounts be considered as placeholders[118] until the ongoing benchmarking process for IT unit pricing was complete, at which time the placeholders could be replaced.

Calgary argued that AG had not provided the required I-Tek volume information in the Application related to capital items. Therefore Calgary examined the forecasted IT budget in total (capital and operating expenses) which it used as a test for volumes.

[114] Application Volume 1, pages 2.1-53
[115] Application, Tab 2, Business Case 10
[116] Ex 02-001, Application Volume 1, p. 2.2-11, Table 2.2.31
[117] AG Rebuttal Evidence, page 45, lines 21-24
[118] AG Reply Argument, page 26 lines 2-4

Calgary noted that AG outsourced its IT projects to I-Tek under the terms of the I-Tek IT MSA Renewal Agreement for the AG Group.[119] Calgary also noted that AG acknowledged it omitted to provide volumes.[120]

In Rebuttal Evidence, AG agreed (pages 45 & 46) that as a general principle, on a go forward basis, quotations on IT related capital projects would provide more information on volumes, but highlighted the difficulty in forecasting volumes in business cases for IT capital projects.

Views of the Board

The Board notes the difficulties, for both the Board and interveners, of trying to assess the reasonableness of forecast IT capital projects absent sufficient information such as the I-Tek volumes for IT capital projects. Therefore, the Board directs AG to provide in the Compliance filing, the 2005 actual I-Tek volumes for IT capital projects and an estimate of the 2006 I-Tek volumes for IT capital projects for each IT capital project. The Board also directs AG to suggest a process for consideration of I-Tek volumes for 2007 IT capital projects in the Compliance filing. Accordingly, the Board will defer further consideration of IT capital project volumes until the Compliance filing.

2.1.6.2 Reasonableness of Forecasts for IT Projects - Overview

The Board will now consider the reasonableness of the requested placeholder amounts for the IT capital projects.

Calgary submitted its version of the IT budget (capital and operating expenses) using the definition in the Gartner 2001 IT Spending and Staffing Survey.[121]

Calgary used the Gartner-defined IT budget and metrics from the 2001 and 2004 Gartner IT Spending and Staffing Surveys. Calgary concluded that the most conservative indicator showed that the AG IT budget was high.[122]

Calgary recommended that IT capital budgets must be compared to the costs for what AG considers to be their peer utilities to show whether AG's IT strategies and budgets are competitive. During cross-examination, AG accepted that at least two other organizations produced IT spending analysis reports in 2004 by industry, those being Forrester Research and Meta Group.[123] Calgary argued that any major variance from whatever metrics AG chooses to use should be supported by a detailed explanation, including potential costs or benefits.[124]

Calgary argued that there were no benefit realization plans associated with any of the projects.[125] Nor had AG provided an overall report on the benefits associated with its IT capital investments.[126] Calgary recommended that the Board adopt its evidence with respect to tracking the benefits of IT Projects, and requested that the Board direct AG to produce a Benefits Realization Plan for major IT projects, providing an annual report showing the magnitude of the

119 Exhibit 02-001-003, Application, Volume 4, Tab 6.2 (10-1), and dated January 1, 2005
120 Exhibit 02-027, AG Rebuttal, pages 45-46
121 Exhibit 10-012-001, BR-CAL-4 Attachment 1
122 Exhibit 10-012, page 11 through13, BR-CAL-4
123 Transcript, Volume 3, pages 313-314
124 Exhibit 10-008-001, page 3, lines 24-28
125 Calgary Evidence, page 11, Q20
126 Exhibit 10-008-001, page 11, Q20

previous year's benefits and total benefits to-date. If the benefits were below expectation, the Annual Benefits Realization report would include the action plan to improve the benefits capture.

AG criticized Calgary's development of the IT budget. AG stated that Calgary attempted to adjust the table for estimated costs of operating the CIS system, which would be an inappropriate adjustment because the cost of operating the CIS system was not the responsibility of AG and was not billed directly to AG. Since the cost associated with operating the CIS system was not even available to AG, any adjustment, as well as being inappropriate, was also highly speculative.[127]

AG also argued that the Gartner report cautions organizations not to use their IT metrics as the basis for making decisions impacting the amount they spend on IT because of the following deficiencies that were inherent in the metrics:

a) Potential inaccuracy of data
b) Lack of compatibility between companies
c) Use of Garner IT metrics alone do not measure IT effectiveness

AG argued that Calgary had incorrectly applied the Gartner definitions. Business process outsourcing does not fit the definitions listed on page 11 of the Gartner 2001 Spending and Staffing Survey results.[128] The definitions shown on page 11 cover typical IT spending areas like hardware and software. If these items were specifically outsourced then they would and should be included in the Gartner survey.

AG indicated that it completes post implementation reviews 12 months after the completion of an IT project.[129] However, during cross-examination, AG indicated that these post implementation reviews "mostly" compared costs rather than benefits.[130]

In response to an IR on the Work Management (WM) project, AG stated that it had not yet developed a benefits realization plan. AG committed to providing an update on the benefits received from the rollout of the full CAD/WM in the next GRA.[131]

AG argued that benefit realization plans are tools for management control. They are a retrospective analysis of a project – in a word, hindsight.

Views of the Board

The Board considers that the development of Benefit Realization Plans would be helpful in two scenarios. Such plans would be relevant to any discussion of over-expenditures of IT capital projects where AG seeks to include the amount of the over-expenditure in the Property, Plant and Equipment opening balances of a future test year. Benefit Realization Plans would also be a useful tool for the Board and parties when considering future IT capital projects, as they may provide assistance in assessing the degree to which AG is able to accurately identify IT needs, match forecasted project costs, meet deadlines and achieve project objectives. In this regard the

[127] Exhibit 02-027, page 49, lines 6-10
[128] BR-CAL-04 Attachment 1
[129] Ex 02-027, p.49, lines 17-18
[130] Transcript, Volume 3, p.318, line 25 to p.319, line 7
[131] Ex 02-015-002, CAL-AG-29(f)

Board notes that that the Business Case supporting the WM project, attached to BR-12, included an October 2000 report which forecasted an annual savings in labor of 80 person-years per year.

The Board would expect that a Benefit Realization Plan would provide an assessment with respect to the realization of this key objective to realize a labor savings of 80 person-years per year. The Board notes that AG committed to providing an update on the benefits received from the rollout of the full WM. Therefore the Board directs AG, at the time of its next rate application, to provide a Benefits Realization report and plan for the remaining program showing where the projected benefits have accrued.

2.1.6.3 Examination of AG IT Project Business Cases

Calgary argued that several IT project business cases did not justify the expenditures forecast in the GRA. Calgary argued that a much more complete business case should have been provided for the Oracle Financials (Legacy System Replacements), DGIS, Provincial Graphics Upgrade, Khalix Budgeting, FMS, and Oracle Budgeting projects. Calgary recommended that the Board direct AG to prepare future business cases based on a Total Cost of Ownership (TCO) methodology showing the project alternatives, capital costs, operating costs, and benefits over the life of the IT project. Further, Calgary recommended that an appropriate hurdle rate such as payback period, return on investment (ROI), or internal rate of return (IRR) must be established to ensure a reasonable comparison of discretionary IT and non-IT projects.[132]

AG argued that complete IT business cases were submitted which included the economics and rationale for each chosen alternative. AG argued that a business case does not choose solutions solely on the basis of payback or on a Net Present Value analysis. AG used business cases to develop recommended courses of action in order to resolve specific business issues.[133] AG also argued that not all projects can be measured on economic benefits alone. AG stated that projects are completed for many reasons. Examples were:

- Requirements to meet government and regulatory directions (i.e. deregulation)
- Mandatory replacement as the technology is old and no longer supported
- Operational efficiencies
- Improved Safety
- Reduce risk caused by older technology which is a critical issue that must be considered when recommending a solution to the identified business issue.[134]

Views of the Board

The Board has addressed its general concerns with the quality and completeness of the business cases in Section 10.1 of this Decision. However, the Board does not accept Calgary's proposal to alter the business cases to include a TCO study. The Board considers that AG's existing business case structure, when completed, provides adequate information upon which to determine the need for, and reasonable cost of, the selected alternative.

[132] Exhibit 10-008-001, page 13
[133] Exhibit 02-027, page 50, lines 2-8
[134] Exhibit 02-027, page .50, lines 13-21

2.1.6.4 IT Technology Architecture Strategy

AG outlined its IT Technology Architecture Strategy which called for the movement of all legacy applications off the mainframe computer by the end of 2007. From 2005 to 2007 there would be an overlap for the CAD/ADVICE legacy mainframe application and the replacement WM distributed application. CAD/ADVICE is an extremely large complex integrated mainframe application built on old technology which is not modular and therefore, cannot be shut down until all of WWM has been implemented in the fourth quarter of 2007. AG advised that there would be a significant decrease in mainframe processing costs in 2008 when CAD/ADVICE is retired.[135]

Calgary attempted to clarify the IT Technology Architecture Strategy with respect to the legacy Customer Information System (CIS), which has a depreciation base[136] of $50 million, net rate base[137] of $13.4 million, and estimated annual operating costs[138] of $11.5 million. AG confirmed it has not initiated a review of the life of AG-CIS.[139] Calgary found that the approach taken by AG concerning IT technology architecture was of no assistance in trying to test and understand the reasonableness and prudence of the requested IT projects filed in the Application.

Calgary questioned the ability of AG to move its legacy applications off the mainframe by 2007 without replacing its CIS application. Therefore, Calgary requested that the Board direct AG to provide a complete and proper business case for the movement of each legacy application off the mainframe. Calgary did not wish to see, and submitted that in future GRAs, the Board should not accept, a backward looking formalization of decisions taken in this regard. [140]

Views of the Board
The Board shares the concerns of Calgary that AG's strategy and implementation plan to migrate all of its legacy systems from the current CAD/WM to the WM System were not clear. The Board directs AG in the Compliance filing to clarify its migration strategy including plans with respect to the CIS application.

2.1.6.5 Business Case – Oracle Financials (Legacy Applications Replacement)

The Oracle Financials project is to replace certain legacy applications such as Financial Gas System, Material Management System, Accounts Payable System and Order Processing System.

Calgary stated its concerns with respect to AG's evidence supporting the Oracle Financials system, which included:

- The requested IT capital and forecast depreciation could not be determined from Appendix 4 as they have been rolled into a row called "rate base";
- The rate base included the capitalization of user fees for the engineering and accounting staff that support the capital work of the company;[141]
- The rate base did not appear to be reduced by accumulated depreciation;
- The benefits were not described in BC 20, but summarized as part of the GRA;[142]

135 Exhibit 02-001, Application Volume 1, p.4.3-45, line 31 to page 4.3-46, line 9
136 Exhibit 02-015-002, CAL-AG-21(a) Attachment 1
137 Exhibit 02-015-002, CAL-AG-21(a) Attachment 1, 2007 net rate base of $5.871 + $7.585 = $13.356 million
138 Exhibit 02-015-002, CAL-AG-30(b) Attachment 1, 2002 Actuals of $11.5 million
139 Exhibit 02-015-002, CAL-AG-21(d)
140 Exhibit 02-001, Application Volume 1, p.2.1-80, line 8 through 11
141 Exhibit 02-015-001, BR-AG-13(a)

- Not all of the identified benefits were included in Appendix 4 of the business case;[143]
- The potential benefit of replacing all legacy applications with distributed applications was not mentioned;
- Other potential productivity benefits associated with the deficiencies identified in Appendix 2 of BC 20 were not quantified; and
- All the benefits were not itemized in Appendix 4 or elsewhere, which means AG will not easily track the realization of the benefits.

Given that the Oracle Financials applications are already in production, Calgary recommended that AG produce an updated Oracle Financials business case for the next GRA which would include all the expected benefits along with a benefits realization report on the benefits achieved to-date.

CG submitted that there was sufficient uncertainty as to what was included in the prices charged by I-Tek for Oracle Financials and therefore, recommended that the monthly fee for licensing should be excluded from any placeholder until the existing benchmarking process is complete and a final determination of market price is made.

AG argued that there was no duplication of charges for Oracle Financial licensing as submitted by CG. AG was given the option of paying higher monthly licensing and maintenance fees, or paying a one time fee of $1,249,000 (Section 2.1 Table 1) and paying lower ongoing monthly licensing and maintenance fees (Section 2.1 Table 2). The evidence was clear that AG selected the lower cost option for licensing fees, which included the capitalization of a one time fee of $1,249,000.

AG submitted that the business case for Oracle Financials justified the costs included in the revenue requirement. AG advised that it would submit the benefits, both tangible and intangible, that were achieved from the implementation of Oracle Financials at the next GRA, if the Board views that as necessary.

Views of the Board

While the Board is sympathetic with the concerns raised by Calgary with respect to the Oracle Financial system business case, the Board accepts AG's position that Oracle Financials, Oracle Budgeting, Khalix Budgeting and DGIS replaced outdated technology and were necessary to improve efficiency. In the business cases, the Provincial Graphics project shows annual savings of $217,000, including improved safety benefits, and the Fleet Management project shows $88,000 annual savings, including business process improvements. Therefore the Board is satisfied that AG has supported the proposal for Oracle Financials and approves the expenditures forecast by AG in the test periods with respect to Oracle Financials.

2.1.6.6 Business Case – CAD/WM Project

The CAD/WM project was originally requested in the 2001-02 GRA to replace the Computer Aided Dispatch (CAD) system installed in 1991. Estimated cost savings resulting from the project were at least $5.6 million.[144]

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[142] Exhibit 02-001, Application Volume 1, pp.2.1-75 to 2.1-80
[143] Exhibit 02-015-002, CAL-AG-26(k) and Transcript p.332, lines 5-7
[144] Exhibit 02-001, Application Volume 1, page 2.1-82, lines 25-28

The CAD/WM was broken into two phases. Phase I of the project replaced the field terminals, the proprietary radio system, and the dispatch software and was implemented late in 2004 at a final cost of $5.6 million. Phase I was also extended to the AG agencies in 2004-05.

Phase II of the project was to replace the mainframe database and scheduling application.

Views of the Board

The Board notes that the forecast cost estimates for CAD/WM have increased significantly over the last three GRAs.[145] Including the most recent I-Tek CAD/WM Phase II estimate, costs have increased from $2.2 million in the 2001-02 GRA to $13.5 million in this 2005-07 GRA. The Board has prepared the following tables showing the increases in estimates from the original forecast provided in the 2001-2002 GRA.

Table 5. Comparison of CAD/WM Forecasts

AG Application	Original Forecast	Increase from Original Forecast	% Increase from Original
2001-02 GRA Original	$ 2.2 million	$ 0.0 million	0 %
2003-04 GRA	$ 7.6 million[146]	$ 0.0 million	245 %
2005-07 GRA Application	$ 9.8 million[147]	$ 7.6 million	352 %
2005-07 GRA Update Increase from Application not requested by AG	$13.5 million[148]	$ 11.3 million	613 %

Table 6 shows the CAD/WM actual expenditures for 2003 and 2004 plus the forecast capital expenditures for the test years.[149]

Table 6. CAD/WM Actual Expenditures for 2003 and 2004 ($000)

CAD/WM	2003	2004	Subtotal	2005	2006	2007	Total
Capital							
- WMS SW[1] - Phase I	$5,024	$168	$5,192				$5,192
- WMS HW[2]		$1,577	$1,577				$1,577
- Phase II – Stage 1				$2,777			$2,777
- Phase II – Stage 2					$3,076	$319	$3,395
- Phase II – Stage 3						$3,184	$3,184
- WMS Enhance HW				$37	$273	$282	$592
- WMS Enhance SW				$607	$541	$817	$1,965
Total	$5,024	$1,745	$6,769	$3,421	$3,890	$4,602	$18,682

1. SW – Software
2. HW - Hardware

AG provided the Business Case for WM in its response to BR-AG 12, along with the reasons for the substantial increase in costs for WM Phase II[150]. In that response, AG advised that in the original evaluation of the Phase II, an external vendor proposed that the existing CAD

145 Ex 02-015-001, BR-AG-12, pages 1-5 and BR-AG-12(d) Attachment 2, page 6
146 BR-AG-12(a) P 2 of 9
147 BR-AG-12(b) P3 of 9
148 BR-AG-12(b) P5 of 9
149 CAL-AG-19(a) Attachment 1
150 BR-AG-12(b) P3-5 of 12

mainframe system could be ported into the new operating environment, and provided an estimate to AG in the amount of $2.3 million. Subsequently, upon further evaluation, that vendor advised AG that its former concept of porting the existing CAD into the new environment was not feasible and as a consequence, revised its original estimate to a substantially higher estimated cost for the Phase II, and include other conditions to the proposed contract. AG determined that the revised cost and the revised conditions were not acceptable and as a consequence, contracted ATCO I-Tek to build the project. ATCO I-Tek submitted an estimate for Phase II that was below the revised estimate provided by the original vendor. At this point, AG reviewed the project economics and determined that the project was still feasible based on the premise that, should the existing CAD system fail, a reversion to a manual system would cost an estimated annual amount of $5.6 million in operating costs.

The Board notes that Calgary identified several concerns with the justification for the CAD/WM project. In addition, Calgary noted that AG had confirmed that the CAD/WM Phase II was a technology conversion from mainframe technology to distributed technology.[151] Further, AG confirmed that it has not been to the marketplace since 2000/2001 to see if WM application packages are available although AG stated that the eight people that did respond to the original RFP were being contacted all the way along.[152] Calgary submitted that this approach was not acceptable, and recommended that the Board direct AG to issue a new RFP for the WM application packages, recognizing that the application packages have been and currently are available in the marketplace since 2000/2001.

Calgary submitted there were several items in evidence that must be considered in evaluating whether the amounts forecast in addition to the original estimates for the CAD/WM Phase II are acceptable, such as:

- I-Tek prepared all the estimates for Phase II, which have increased over 600 percent from their original estimate;
- Phase II of CAD/WM is simply a technology conversion from a mainframe application to a distributed application platform;
- Phase II, Stage 1 has recently slipped from an estimated cost of $2,777,000 and a target completion date in 2005 to an estimated cost of $4,855,000 and a target completion date in 2006;[153]
- AG agreed that other distribution utilities have similar needs in terms of a CAD/WM system and that the original RFP for packages was in 2000/2001;[154]
- Calgary also filed an analysis which purported to show that the costs of Phase II over 10 years would exceed the cost of remaining on the old existing mainframe system.[155]

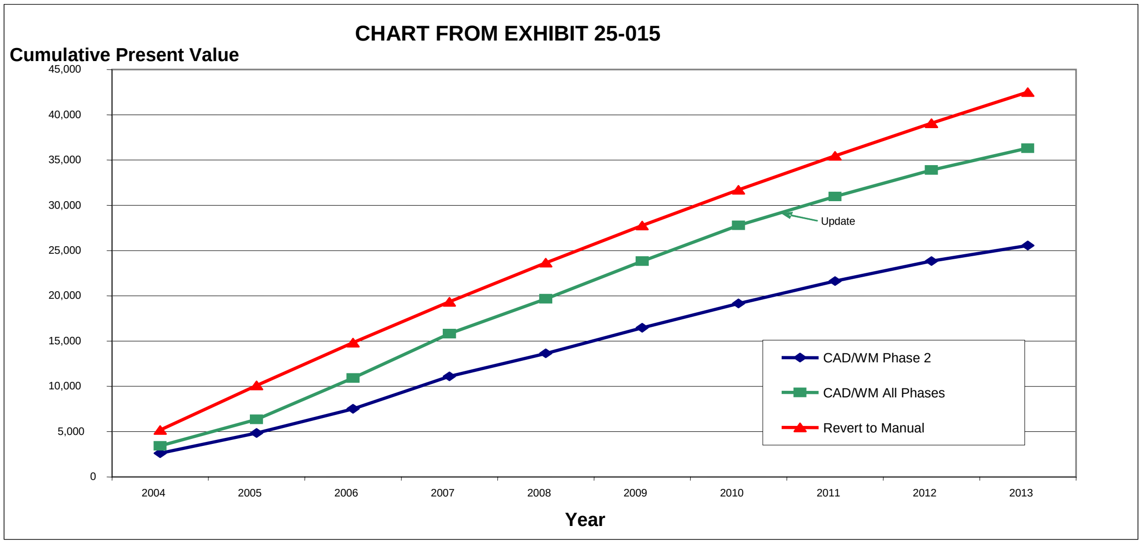
Based on these considerations, it was Calgary’s recommendation that all CAD/WM Phase II costs be disallowed in this Application. Should AG choose to proceed with and present CAD/WM Phase II in the next GRA, Calgary recommended the Board require AG to file a CAD/WM business case that detailed all associated IT and non-IT capital, all IT and non-IT operating costs, and all expected IT and non-IT benefits along with a Benefits Realization Plan and report on projected benefits and benefits achieved to-date.

151 Transcript Volume 3, page 338, lines 8-20
152 Transcript Volume 4, page 557, line 1 to p.558, line 6
153 Exhibit 02-015-001, BR-AG-12, pages 3-5
154 Transcript Volume 4, page 557, lines 7-19
155 Calgary Argument, page 22

The Board notes AG's argument that Calgary's analysis which showed the cost of Phase II over 10 years to exceed the cost of remaining on the old existing mainframe system, was flawed for the following reasons:

1. Calgary assumed the old existing mainframe will have no additional costs associated with it besides current levels of O&M inflated on a yearly basis, and
2. Calgary assumed the old existing mainframe CAD application will remain functional until 2013.

AG provided the following chart showing the cumulative present value of expenditures comparing the cost of reverting to manual operations versus the costs utilizing CAD/WM Phases I and II:



The Board notes that the Business Case supporting the WM project, attached to BR-12, included an October 2000 report which forecast an annual savings in labor of 80 person-years per year. AG has not updated that forecast, nor has it shown where any part of those savings is reflected in the expenditures to date. Accordingly, the savings in labor have an appearance of being theoretical only, which raises concerns about the credibility of the savings demonstrated in the above graph.

The Board is concerned with the record of extensive escalation in scope and cost for the entire WM project. Although the Board agrees that AG should progress with its migration toward the new distributed system, it considers that AG has not adequately justified in this proceeding the escalation in total costs to complete Phase II of WM. The Board considers that the forecast placeholder amount of $9.8 million to complete the project is excessive. The Board directs AG to reduce its placeholder forecast by 20% to the amount of $7.8 for the total Phase II project. The 20% reduction shall be applicable to the items listed above in each stage in each test year.

As directed in Section 2.1.6.1, AG is required to include in the Compliance filing, 2005 and 2006 development volumes applicable to this project and all other IT capital projects. AG is also required to suggest a methodology for determining 2007 volumes. The Compliance process will afford parties the opportunity to review the filed volumes as a cost driver for the CAD/WM Phase II project. The Board's 20% reduction to the placeholder amount reflects the Board's determination that there has been insufficient evidence provided to the Board to justify the setting of a placeholder at the forecast amount. The Board notes that I-Tek advised AG[156] that the project might require an additional investment of approximately $3.7 million over and above the amounts included in the filed forecasts. The Board's rationale for reducing the placeholder reflects the Board's view that the evidence before it is insufficient to justify the level of the requested placeholder. Obviously this indicates that amounts in excess of the reduced placeholder would require additional support that has not previously been provided to the Board, before the Board would consent in some future proceeding to recovering additional amounts from ratepayers.

2.1.6.7 Customer Care & Billing (ITBS) Capital

AG forecast $180,000 in 2005, $120,000 in 2006, and $120,000 in 2007 in capital costs associated with acceptance testing of AG-CIS system changes.[157]

Calgary noted that AG did not file the ITBS labour hours and rates for the ITBS Benchmarking process associated with the requested ITBS capital forecasts. Calgary was unable to reconcile the sums associated with I-Tek and ITBS capital in Tab 6.1 Affiliate Transactions to the IT capital in Table 2.2.31 or the IT asset continuity schedule in CAL-AG-19. Calgary recommended that AG provide reconciliation in the Compliance filing.

AG argued that the level of detail requested by Calgary was not realistic to expect in a capital forecast and therefore submitted that Calgary's request be rejected.

AG submitted that Table 2.2.31 contained the capital forecast for information technology projects. This would include both payments made to I-Tek and ITBS as well as direct costs such as labour and other expenses for AG employees working full time on these projects. Therefore, this table would not coincide with the I-Tek and ITBS capital shown in Tab 6.1 Affiliate Transactions. AG was at a loss as to what benefit this reconciliation would provide in relation to testing the prudence of the AG CIS enhancement expenditures or the testing of the I-Tek and ITBS volumes requested in this Application.

Views of the Board

The Board requires clarity of the record showing the distinction between capital and direct expenses forecast for the I-Tek and ITBS services captured within the forecast capital costs associated with acceptance testing of AG-CIS system changes. Therefore, the Board directs AG to provide in the Compliance filing reconciliations associated with I-Tek and ITBS capital in Tab 6.1 Affiliate Transactions to the IT capital in Table 2.2.31 or the IT asset continuity schedule in CAL-AG-19.

2.1.6.8 AG I-Tek - Infrastructure

AG included IT infrastructure project expenditures of $367,000, $300,000, and $300,000 for 2005, 2006 and 2007, respectively. In addition, AG included infrastructure expenditures in the amount of $615,000 for the implementation of Oracle Financials in 2004.

[156] BR-AG-12(b) P5
[157] Exhibit 02-015-002, CAL-AG-18

CG stated that AG I-Tek was charged with providing services, but did not have the tools to do the job. In describing the foregoing, the AG witness indicated that AG was paying for the tools that I-Tek uses to provide security services for AG's IT systems.[158] If this was the case, CG wondered why I-Tek was chosen to do this work. Given that portions of the MSA specifically indicate that I-Tek is responsible for security administration, one would expect that I-Tek would have and maintain the tools to provide the service.

Infrastructure spending also included the purchase and implementation of middleware and portal solutions. In reviewing the Infrastructure Business Case, no business benefits or savings were quantified. The only benefits were the claim of efficiencies and a claim that AG will experience lower prices for these products as a result of the volume purchasing power available to AG. CG argued that the lack of quantified business benefits seriously undermined AG's claim that it needed these products.

CG submitted that customers should not be required to pay for costs that are I-Tek responsibilities or that have not been properly justified. As such, the CG recommended that all infrastructure costs be excluded from rate base until the existing benchmarking process is complete and a final determination of market price is made. The CG considered this to be another example of AG not meeting its burden of proof as expressed at numerous other places.

AG submitted that I-Tek fulfills their contractual obligations by supporting and maintaining the existing infrastructure, which includes security for AG. For example, I-Tek maintains and upgrades the various components used for the wide area network (WAN). This includes wiring, fiber optics, switches and routers, etc. These necessary maintenance activities, software and hardware upgrades to the WAN were included within the fees. Similarly I-Tek completed the maintenance and upgrades to the existing security systems within the AG computing environment. This again included upgrades to hardware and software to the security systems. In addition, there were the security and administration activities that the Consumer Group quotes from the MSA.

The infrastructure project encompassed new technology and services being introduced not previously covered by existing fees. As stated in the business case filed with the GRA, three areas were included; enhanced security, portal and middleware. There was no duplication with existing AG I-Tek infrastructure services.[159]

Views of the Board

The Board notes that AG entered into a new MSA with ATCO I-Tek in January 2005. The Board notes that there is no list of the specific tools required by ATCO I-Tek to complete the contract. The Board accepts the position of AG in this specific instance that these services are in respect of new technology and services that are not covered by existing fees. Accordingly, the Board approves of the requested expenditures.

In this Section 2.1.6, the Board has approved certain amounts as placeholders for the IT capital projects. In the Compliance filing the Board will consider AG's request to approve volume forecasts in respect of these IT projects. Approved volumes will then be multiplied by benchmarked IT service unit prices upon the completion of the ongoing benchmarking process to

[158] Transcript, page 194, line 8
[159] Transcript page 197, line 17-19

determine the final IT capital project revenue requirement. At this time the Board considers it appropriate to make two observations with respect to the finalization of IT capital costs.

First, the Board is concerned with instances where IT actual spending has exceeded forecast and approved capital project costs. The initial phase of the WM Project is a case in point. Although the Board has approved 2005 test year opening balances which include over expenditures in respect of this project, this approval should not be taken as an indication that the Board will continue to approve over expenditures without a comprehensive prudence review. The Board reminds AG that it is at risk for such over expenditures, unless it is able to satisfy the Board that such expenditures were appropriate. The Board remains concerned both with the potential for incremental creeping costs and with the transparency of these costs to the Board and interveners, particularly when these costs are associated with services provided by an affiliate. Continued over expenditure will influence the Board's perception on the reasonableness of initial expenditure forecasts, and accordingly the fundamental support for the cost/benefit analyses of requested projects.

Second, the Board continues to struggle with the problems in the benchmarking exercise for replacing placeholders. The Board is aware of a variety of reasons why the benchmarking process has taken the time that it has, but remains concerned that the interests of all parties, utilities and ratepayers alike, are not well served when the finalization of placeholders are held in abeyance for several years, in some cases, following the completion of the applicable test years. The Board again encourages parties to expedite their efforts at completing the benchmarking processes in order to finalize all outstanding placeholders. The Board would also encourage the exploration of future alternatives to the current benchmarking exercise with respect to future test years, aimed at avoiding the lengthy delays experienced to date.

2.2 Opening Balances of PPE, Accumulated Depreciation, Contributions and CCA

In Decision 2003-072, the Board determined that a reasonable forecast for the 2004 UMR was $7.092 million and that this amount would provide sufficient funds for the replacement of the deteriorated mains. The Board also stated that the onus remained with AG to determine the appropriate levels of safety and reliability in its provision of economical service. Since UMR was an area that could impact public safety, in that decision, the Board stated that it was prepared to re-evaluate the issue in the future.

In 2003 and 2004, AG exceeded the $7.092 million capital expenditures approved by the Board for Urban Mains Replacements by a cumulative amount of $8.1 million for both years.

In addition, in Decision 2003-072, the Board denied AG's request for monthly meter reading. However, AG continued to read meters on a monthly basis at its own expense. To continue with monthly meter reading, AG required the use of vehicles and other equipment.

Views of the Board

The Board notes CG's argument that the 2005 opening balance of PPE should be reduced by $8.1 million to reflect the fact that AG exceeded the $7 million capital expenditures approved by the Board for Urban Mains Replacements in 2003 and 2004 and that, as a consequence, the Board should require AG to adjust accumulated depreciation and CCA accordingly in its Compliance filing.

The Board also notes CG's concern related to inclusion of 40 vehicles purchased in 2003 and 2004 at a cost of $1,151,000 to facilitate monthly meter reading.[160] CG argued that it saw no compelling reasons for the Board to deviate from Decisions 2003-072, 2004-036 and 2004-047 that approved bi-monthly meter reading. CG recommended that the 2005 opening balance of PPE should be reduced by $1,151,000.

The Board notes that AG determined, on the basis of its engineering analysis,[161] that it was necessary to replace certain deteriorated mains to maintain the level of safety and, as the consequence of the quantum of mains replaced, the total expenditures for the 2003 and 2004 test years exceeded the awarded amount by $8.1 million. The Board has reviewed the evidence[162] provided by AG regarding the condition of mains that were replaced in 2003 and 2004 and finds that this evidence supported of the replacement level for 2003 and 2004. The Board views the expenditure amount of $8.1 million above the forecast amount awarded in the 2003-2004 GRA was prudent in view of the evidence presented to show that the deterioration of the replaced pipe was in fact a serious concern. Therefore, the Board agrees that the amount of $8.1 million was appropriate and therefore, is appropriately recorded in 2003 and 2004 PPE capital additions.

The Board also notes AG's argument that the cost of the vehicles used to continue its monthly meter reading service should be included in the opening balance of PPE in 2005 since these vehicles were partially depreciated and were used to provide a service prior to 2005 and for the continuation of this service into 2005. The Board agrees that the PPE balances include extra vehicles that were used to provide the monthly meter reading service and therefore, the 2005 opening balance PPE includes the UCC of the extra vehicles. The Board agrees that the company has funded the depreciation associated with the use of the vehicles during the 2003-2004 period. The Board views that the adjustments to the change to the PPE records to reverse the accumulated depreciation other associated accounting reversals for the 2003 and 2004 would produce an immaterial change to the revenue requirements. Therefore, no adjustment to the opening balance to PPE for extra vehicles will be required.

2.3 Working Capital

2.3.1 Lead Lag Study

AG provided a Lead/Lag study[163] and a comparison to the results from the previous Lead/Lag study prepared for the 2003/2004 GRA.[164] There were no objections or proposed alternatives to the AG Lead/Lag study.

The Board has reviewed the Lead/Lag study and is satisfied that the Lead/Lag study has been prepared in an appropriate manner. Accordingly, the Board accepts the use of the Lead/Lag study to determine working capital requirements for the test year period.

[160] CG Evidence, page 23
[161] AG Argument, page 16
[162] Rebuttal Evidence, pages 27-28, and 53-59
[163] Application, Volume 2, Tab 2.2
[164] Application, Volume 1, page 2.6-2

2.3.2 Salt Cavern Peaking Working Gas

In the Salt Cavern Peaking Working Gas Deferral Account Decision,[165] the Board dealt with a request by ATCO Pipelines for approval to assume responsibility for providing Salt Cavern Peaking Working Gas and the establishment of a Peaking Working Gas Deferral Account for the operation of the Salt Cavern Storage facility in the AGN service area to be effective April 1, 2005. The Salt Cavern Working Gas had historically been acquired by AG and its predecessors. The Board approved ATCO Pipelines as the party to manage the acquisition and sale of Salt Cavern working gas. In that Decision, which issued after the close of the hearing in this proceeding, the Board set out its findings with respect to the manner in which ATCO Pipelines should account for Necessary Working Capital (NWC) for the peaking gas.

The responsibility for the Salt Cavern Peaking Working Gas transferred from AG to ATCO Pipelines on April 1, 2005. The transfer of the NWC responsibility also took place on that date. The CG submitted that NWC should be calculated using a monthly convention rather than a mid-year convention so that issues such as the transfer of storage gas can be accounted for more effectively.

AG stated that it calculated the NWC related to the Salt Cavern Peaking Working Gas by doing a pro-ration of the months this gas was held by AG versus ATCO Pipelines. On this basis, AG reflected 3/12ths of the mid year balance as part of the 2005 NWC. AG considered using the mid-year rate base convention for its share of the working capital; however ATCO Pipelines used a pro-rationing approach. Given the pro-ration approach utilized by ATCO Pipelines, AG determined its working capital requirement in a similar fashion to ensure that the end result was equivalent to the mid-year convention. AG indicated[166] that adjustments to the revenue requirement forecast may be required depending upon the Board's disposition of the ATCO Pipelines' application with respect to this matter.

Views of the Board

The Board notes that the Salt Cavern peaking gas is in the AGN working capital for the first 3 months of 2005 and then is transferred to ATCO Pipelines. The Board considers that the NWC calculation for the Salt Cavern Peaking Working Gas should be treated consistently for AG for 2005 with the treatment that was determined for ATCO Pipelines in Decision 2005-119.

While AG and ATCO Pipelines recommended that the necessary working capital be recognized on a monthly basis for the Salt Cavern Peaking Gas for 2005, the Board determined that the mid-year convention should be maintained. The Board notes the following excerpt from the Salt Cavern Peaking Working Gas Deferral Account Decision:

> The established mid-year method is to determine NWC separately for AP and AG. The NWC for each would be determined by dividing the sum of the January 1 opening balance and the December 31 closing balance by 2, to get their respective mid-year NWC. The Board directs that the NWC for Cavern Storage Gas should be determined on an actual basis rather than on a forecast basis.
>
> Therefore, to retain consistency with the previously approved methods, the Board directs AP to revise its method of calculating the amount of revenue requirement for the NWC to reflect a mid-year balance using zero as the opening balance as of January 1, 2005 and

[165] Decision 2005-119, issued November 1, 2005
[166] Application Overview, page 1.0-5

> the full year actual cost of gas in storage at year end (December 31, 2005) to obtain a mid-year amount to establish the NWC.
>
> The Board continues to be concerned with the appropriateness of using the mid-year convention versus a monthly averaging methodology in respect of expenditures that are consistently more seasonal in nature as opposed to random or evenly spread throughout the year. ATCO Pipelines is directed to address the continued appropriateness of using the mid-year convention in respect of all the accounts for which it applies in its next GRA. ATCO Pipelines is further directed to supply an analysis that would consider the merits/detriments of making changes to the mid-year convention on an across the board basis versus on an account by account basis.[167]

To maintain consistency between these two decisions, the Board directs AG to revise its method of calculating NWC to reflect a mid-year balance using the actual cost of gas in storage opening balance as of January 1, 2005 and zero at year end (December 31, 2005) for ATCO Pipelines to obtain a mid-year amount to establish the NWC. The Board considers by allowing both AG and ATCO Pipelines the mid-year calculation to determine the NWC requirement for Salt Cavern Peaking Gas, there will not be a double-counting of the NWC requirements. AG is also directed to provide its revised calculation of the NWC for the Salt Cavern Peaking Gas for 2005 and to update its Compliance filing to reflect this amount.

3 COST OF CAPITAL AND CAPITAL STRUCTURE

3.1 New Debt Issue

AG forecast the following long term debt issues during the test period:

Table 7. AG Forecast Long Term Debt Issues 2005-2007

	2005	2006	2007
AG North	$30 million	$17 million	$25 million
AG South			$12 million

In the Application, AG stated that these issues will be 30 year debentures at a coupon rate of 6.50%.[168] This forecast rate was based on projections from financial advisors and the consensus forecast for Government of Canada 10 year bonds. The 6.50% forecast debenture rate was determined as follows:

Table 8. AG Forecast Debenture Rate[169]

	January 2005 Consensus Forecast (%)
Canada 10 Year Bonds	5.00%
Spread 10/30 Year Canada Bonds	0.50%
Forecast 30 Year Canada Bonds	5.50%
Premium Over 30 Year Canada for A (high) Debenture	1.00%
Forecast Debenture Rate	6.50%

[167] Decision 2005-119, pages 5-6
[168] AG 2005-2007 GRA Volume 1, page 3.2-5
[169] AG 2005-2007 GRA Volume 1, page 3.2-5

The August 2005 Consensus Forecast, provided by AG in Exhibit 25-012, listed the forecast Canada 10 year bond at 4.20% for November 2005 and at 4.60% for August 2006. CG suggested that AG should use the most current consensus forecast to determine its forecast debenture rate. CG noted AG's argument that the Board should consider the original consensus forecast, because it represented the best information available at the time AG's forecast was prepared[170] and AG's contention that considering an updated forecast would constitute hindsight. CG responded that a forecast should not be based on evidence that was proven incorrect.[171] CG noted the Board's practice with respect to cost of capital matters had been to use the most up to date and accurate information available to the Board in its deliberations.[172]

CG also challenged AG's use of a 30 year bond rate as the basis for its debenture forecast. AG replied that it is generally accepted that the term of the financing should match the life of the asset being financed as much as possible.[173] CG indicated that AG issued debt with 10, 15 and 30 year maturities in 2004 and for this reason CG recommended that the forecast debenture rate should be based on a 15 year term. AG conceded that it did not always issue 30 year maturity debentures, but asserted that many factors determine the best maturity for a debt issue, such as market receptivity, interest rate trends, pricing anomalies, maturity schedules, bond rating considerations and long term growth prospects. AG argued that these complexities caused CU Inc., on behalf of AG, to rely on the expertise of its Underwriters.[174] AG stated that CG did not provide any support for how they determined the average of 15 years[175] and AG therefore argued that this recommendation should be dismissed.

Views of the Board

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. The Board considers that the forecast debenture rate should be based on the updated Canada bond yield information. With respect to 2007, in the Board's view, the forecast for 2006 is also the best available forecast for 2007. The Table below applies AG's debenture forecast methodology to the updated consensus forecast information presented in Exhibit 25-012.

Table 9. Forecast Debenture Rate (Updated Consensus Forecast Ex. 25-012)

	November 2005 Forecast (%)	August 2006 Forecast (%)
10 Year Canada Bond Yield	(Nov. 2005) 4.20%	(Aug. 2006) 4.60%
Spread 10/30 Year Long Canada Bonds[177]	0.34%	0.34%
Premium over Long Canada's for A (High) Debenture[178]	1.00%	1.00%
Forecast Debenture Rate	5.54%	5.94%

170 AG Argument, page 25
171 CG Reply, page 28
172 CG Reply, page 28
173 AG 2005-2007 GRA, Volume 1, page 3.2-4
174 AG 2005-2007 GRA, page 3.2-5
175 AG Reply, page 46
176 AG Argument, page 25
177 Based on average of 10/30 Canada Bond Spreads presented in Exhibit 25-005
178 Application, page 3.2-6

With regard to the issue of the appropriate forecast debt term, the Board agrees with AG that the maturity of the debt should in general be matched with the life of the asset being financed. This reaffirms the position taken by the Board in 2003-072.[179] In that Decision, the Board also acknowledged that a utility which finances its long term assets with short term debt would be considered materially more risky than one which finances its long term assets with long term debt.[180] The Board recognizes the concerns of CG that sometimes AG issues debt with maturities of less than 30 years. The Board also acknowledges that the debenture rates in those cases may be lower than the forecast debt rate. However, the Board reiterates its position from Decision 2003-072 that:

> There are many factors that help to determine the appropriate term of debt, and that it would be difficult for the Board to provide direction to the utility with regard to this matter. Based on this consideration, the Board is also of the view that it is logical and fair that the utility should be in control of its financing plan, and in turn should be allowed to determine the appropriate term of debt for new debt issues.[181]

The Board agrees with AG that 30 years is the appropriate maturity upon which to base the long term debt rate forecast.

The Board directs AG, in its Compliance filing to use a forecast cost of new issue debt of 5.54% for 2005 and 5.94% for 2006 and 2007.

3.2 Review of Consistency with Decision 2004-052

In Decision 2004-052[182] (the GCC Decision) the Board established a formula to calculate a Generic return on equity (ROE) which applied to the equity capital employed by the utilities that participated in that proceeding. The GCC Decision established an annual adjustment mechanism which provided for a recalculation of the ROE each calendar year utilizing a formula established in the Decision. The GCC for 2005 was determined in Order U2004-423 to be 9.50%. On November 22, 2005, the Board in Order U2005-410, set the generic rate of return on equity for 2006 at 8.93%.

AG stated that the company was prepared to follow the Board's guidance with respect to the GCC, but wanted to ensure that all utilities subject to the GCC were treated the same. However, AG also argued that since the 2006 GCC rate had not been determined before the end of the evidentiary portion of this GRA proceeding, the 2005 GCC rate should apply to 2005, 2006 and 2007.[183]

Views of the Board

The Board notes the concern of AG with regards to application of the GCC Decision. In the GCC Decision, the Board stated:

> With respect to current or future applications by an Applicant to establish a revenue requirement for 2005 or later years, the Board shall apply the common ROE for that year resulting from the adjustment mechanism approved in this Decision and shall apply the

[179] Decision 2003-072, page 147
[180] Decision 2003-072, page 147
[181] Decision 2003-072, page 147
[182] Decision 2004-052, Generic Cost of Capital, July 2, 2004
[183] AG Argument , page 26

> capital structure as set out in this Decision for such Applicant, unless the Applicant can demonstrate to the satisfaction of the Board that there has been a material change in business risk that warrants a change to the capital structure set out in this Decision.[184]

The Board considers that the generic ROE determined in accordance with the GCC Decision should apply with respect to each year of the test period in the Application. The Board considers that in the case of an application with multiple test years, the Board will approve an ROE for each test year equal to the ROE determined in accordance with the GCC Decision when the approved ROE for the test year is known prior to the date the decision is released. When the generic ROE is unknown with respect to a test year as at the date of decision, the Board will establish a placeholder equal to the last ROE established by the Board. The placeholder will then be replaced by the applicable ROE once it is subsequently determined by the Board. This is the case for the 2007 test year in this Application.

The Board considers that this is consistent with the objectives of the GCC Decision of improving regulatory efficiency, ensuring greater consistency between utilities, and greater certainty and predictability of utility returns. Accordingly, the Board finds that the ROE for 2005 is 9.5%. The ROE for the 2006 test year is 8.93%. The ROE for the 2007 test year will be a placeholder set at 8.93% which will be treated as a deferral account to be reconciled to the actual 2007 GCC rate when that rate becomes available. In reconciling the deferral account, the GCC ROE will be applied against the rate base (net of no-cost capital) determined in accordance with this Decision to be applicable for the 2007 test year. AG is directed to reflect these approved ROE figures in its Compliance filing.

3.3 Use of Short Term Debt

In Decision 2000-9, the Board directed Canadian Western Natural Gas (CWNG) to balance the difference between its capitalization and mid-year rate base using short-term debt.[185] The Board determined that where capitalization is less than the rate base it is supporting, the utility is considered to be using short-term debt as a source of financing for its utility assets. Consequently, the Board found that the difference between rate base and capitalization should be deemed short-term debt.

AG presented its forecast capital structure for the purposes of calculating Mid-Year Cost of Capital for the test period.[186] AGN proposed negative amounts for short-term debt in its capital structure for each of the test years. AG South proposed a negative short-term debt amount in 2006.[187] The Tables below show the proposed capitalization for both AG North and South for the test period:

[184] Decision 2004-052, page 61
[185] Decision 2000-9, page 83
[186] Application, Schedules 3.1-A and 3.1-B
[187] BR-AG-38(a) Attachment 2 Schedule 3.1-B

Table 10. AGN Proposed Mid-Year Capitalization (Schedule 3.1-A) ($000)[188]

	2005	2006	2007
Long Term Debt	$299,088	$307,221	$328,196
Short-Term Debt	$(39,314)	$(13,923)	$(11,356)
Preferred Shares	$36,584	$36,584	$36,584
No Cost Capital	$7,306	$5,081	$2,856
Common Equity	$205,632	$210,885	$223,710
TOTAL	$509,296	$545,885	$579,990

Table 11. AGS Proposed Mid-Year Capitalization (BR-AG-38(a) Att. 2 Sch. 3.1-B) ($000)

	2005	2006	2007
Long Term Debt	$309,004	$305,310	$311,401
Short-Term Debt	$12,819	$(2,072)	$9,406
Preferred Shares	$29,157	$29,157	$29,157
No Cost Capital	$3,303	$3,118	$2,933
Common Equity	$206,846	$204,713	$208,558
TOTAL	$561,129	$540,226	$561,455

CG argued that by using negative short-term debt in their Mid-Year capitalization, AG was increasing the total costs of financing for customers.[189] CG stated that when capitalization continually and significantly exceeds Rate Base, management has over-financed the company and is paying more in financing than required.[190] CG estimated that the total impact on customers of AGN's use of negative short-term debt in its capital structure was $2.692 million in 2005, $0.906 million in 2006 and $0.662 million in 2007. CG argued that in order to determine a fair return for AGN, it would be necessary to eliminate the negative short-term debt from the capital structure.

AG responded that it had not over-financed the company as CG contended. AG pointed out that short-term debt shown in schedules 3.1-A and 3.1-B did not represent a position of over-financing or under-financing on the part of the company.[191] According to AG, short-term debt is used to balance the actual mid-year capitalization of the company with the mid-year rate base. AG argued that CG had confused actual financing with deemed negative short-term debt.

In using short-term debt to balance rate base, AG claimed that it was following the direction of the Board as per Decision 2000-9.[192] AG also indicated that this approach is consistent with previous AG GRA applications and EUB Decisions.[193] AG stated that it did not support the use of short-term debt to balance rate base to capital structure, but contended that if short-term debt is to be used, it should be applied whether or not rate base is greater than or less than capitalization.[194] AG argued that it would be unfair to disallow negative short-term debt in the North while customers enjoyed the benefit of deemed short-term debt in the South.

188 Application Volume 1, Section 3, Schedule 3.1-A
189 Consumer Group Evidence, page 26
190 Consumer Group Evidence, page 26
191 AG Argument, page 27
192 AG Argument, page 26
193 AG Argument, page 26
194 AG Argument, page 26

The Canadian Federation of Independent Business (CFIB) argued that the inclusion of negative short-term debt in AG's capital structure is unfair and completely unnecessary.[195] The CFIB contended that AG's parent has in some sense made a mistake by over-allocating long term debt to AG.[196] The CFIB considered that AG's forecast cost of capital would leave customers paying costs associated with rate base that does not exist, and AG earning a return on capital it has not invested.[197]

The CFIB argued that a better approach would be to adjust the rate of the negative short-term debt so that it is equal to the long-term debt rate. According to the CFIB, the net effect of this would be that the costs of the excess long-term debt would be eliminated. The CFIB asserted that this approach would be the least punitive means of correcting the alleged over-allocation error by CU Inc.

The CFIB also contended that AG's appeal to fairness was misplaced. The CFIB argued that it is reasonable to assume that in the case where the rate base exceeds the sum of long-term debt, common equity and preferred shares, the difference would be funded with short-term debt. Some utilities, the CFIB noted, "maintain a short-term debt component in the capital structures as a matter of financing strategy."[198] The CFIB asserted that having greater capitalization than rate base was therefore completely different from having greater rate base than capitalization.

In response to the CFIB, AG reiterated that the company has not been over-financed over the test period. AG submitted pro forma cash flow statements as evidence that it has not over-capitalized either AGN or AGS.

Views of the Board

In Decision 2000-9, the Board directed CWNG to balance its capitalization to rate base using short-term debt. However, in that Decision the Board clearly intended that a utility's capitalization was not to exceed its rate base. The Board stated:

> The Company shall deem an amount of short-term debt that will balance the rate base and capitalization, plus or minus $500,000. The Company's **capitalization** (excluding short-term debt, but including other findings in this Decision regarding No-Cost Capital should **not exceed its rate base** as modified by this Decision.[199] (Emphasis added)

From Schedule 3.1-A, it appears that the sum of AGN's long-term debt, preferred shares and common equity is greater than the mid-year rate base for all three test years. As the above quote from Decision 2000-9 indicates, the Board considers this to be inappropriate. AGN's capitalization should not exceed its rate base and the Board does not see the use of the negative short term debt as an appropriate mechanism to bring capital structure and rate base into alignment where capitalization exceeds the rate base.

The Board also notes AG's argument that its use of short-term of debt is consistent with the GCC Decision in how debt impacts the 38% target equity ratio.[200] However, the Board notes that in

195 CFIB Argument, page 4
196 CFIB Argument, page 5
197 CFIB Argument, page 5
198 CFIB Argument, page 5
199 Decision 2000-9, page 83
200 AG Argument, page 26

Schedule 3.1-A, AGN does not include short-term debt in its calculation of the equity ratio. The following Table shows AGN's capital ratios for the test years with short-term debt included:

Table 12. AGN Capital Structure Ratios (BR-AG-16(d) Attachment 1, p. 1)

	2005	2006	2007
Long Term Debt	59.6%	56.8%	56.9%
Short Term Debt	-7.8%	-2.6%	-2.0%
Preferred Shares	7.3%	6.8%	6.3%
Common Equity	41.0%	39.0%	38.8%
Total	100.0%	100.0%	100.0%

The Board notes that inclusion of the short-term debt in the capital structure ratio causes AGN's capital structure to deviate from the approved GCC equity ratio of 38%. The Board also observes that using short-term debt to balance capitalization with rate base, regardless of whether or not capitalization is greater or lesser than rate base might hinder the utility's efforts to achieve the approved GCC equity ratio.

The Board notes that in Decision 2003-072, and the subsequent Compliance filing Decision 2004-036, AG was permitted to use negative short-term debt to balance its excess capitalization to its rate base. At the time of that Decision, the Board observed that the discrepancy between rate base and capitalization was trending toward equality and the Board considered that the difference would not be material in the future. In this Application it is clear that the discrepancy has persisted throughout the test periods. The Board notes that AG indicated this discrepancy would be largely resolved if the Board were to approve combining the AGN and AGS revenue requirements.

The Board acknowledges the concerns from the interveners that by permitting the use of negative short-term debt AG is allowed to achieve a return on an amount of capital that exceeds the utility rate base. With regards to the proposals put forth by CG and CFIB, the Board considers that these approaches reduce the return to the utility to levels that better reflect a fair return on capital used to support utility rate base. However, both approaches fail to address the fundamental issue that balancing capitalization to rate base using short-term debt makes it difficult for the utility to attain the approved GCC equity ratio.

In Decision 2000-9, the Board acknowledged that:

> it is clear a discrepancy between rate base and capitalization can lead to a higher, or lower, than intended return to shareholders… It is the Board's expectation that the difference between the financial and utility return of the Company should be primarily due to its non-regulated activities, rather than its financing practices, use of the midyear methodology, or the discrepancy between rate base and capitalization.[201]

In that Decision, the Board stated that it would reconsider deeming all of the components of AG's capital structure if the amounts for works-in-progress, disallowed assets and non-utility assets were significant.[202] These amounts are typically the causes of the discrepancy between the total capitalization and the rate base. If there were to be a continued and significant difference between capitalization and rate base, the Board should consider deeming the capital structure of

[201] Decision 2000-9, page 84
[202] Decision 2000-9, page 84

the utility for rate making purposes. The Board has adopted this practice with other utilities[203] and it has simplified the process of determining fair cost of capital. The Board notes that deeming AG's capital structure will ensure that the company achieves the approved GCC equity ratio whether or not capitalization is greater or less than rate base.

Rate of return regulation requires that the regulator enable the utility to achieve a fair return on capital used to finance utility rate base. A utility's capitalization for rate making purposes should therefore be equal to the rate base. The Required Invested Capital should therefore be equal to the rate base less No-Cost Capital (MY = Mid-Year):

Required Invested Capital_{MY} = Rate Base_{MY} – No-Cost Capital_{MY}

In Decision 2004-052, the Board established a formula that would calculate the generic cost of utility common equity. The Board also established an approved common equity ratio for each utility that participated in that proceeding. For AG, the Board approved a 38% equity ratio. This amount can be revised if AG can demonstrate that its risk level changes significantly or if the Board observes that the company utilizes significantly less equity than the approved ratio. The Board confirms that the deemed equity amount for both AGN and AGS is 38% of the Mid-Year Required Invested Capital.

In Decision 2004-052, the Board allowed AG to continue to use Preferred Shares in its capital structure. Pending the outcome of the Common Matters Application, the Board will allow AG to include a placeholder amount for Preferred Shares in the deemed capital structure at the current book value and at the current rate of return.

Having determined a deemed equity ratio and having allowed the existing amount of preferred shares in the capitalization structure, it follows logically that the debt ratio should be determined as the residual after accounting for common and preferred equity.

In determining the amount of deemed debt in the capital structure, the Board directs AG to use the following formula:

DebtMY = Required Invested CapitalMY – Common EquityMY – Preferred SharesMY

The cost of debt will be determined as the weighted average cost of debt, which is the weighted average cost of existing and forecast long-term and short-term debt for each utility. The Board intends that the utility be provided a fair opportunity to recover the cost of its debt used to finance utility rate base. The cost of debt shall reflect the actual mix of long-term and short-term debt instruments used by utility management to support the rate base. The cost of debt shall not reflect any "negative debt".

In summary, the Board directs AG to use a deemed capital structure to determine its cost of capital and return. AG is directed to comply with the following in determining its capital structure ratios and cost of capital:

- AG will earn a return only on Required Invested Capital determined by the following formula:

  Required Invested Capital_{MY} = Rate Base_{MY} – No-Cost Capital_{MY}

[203] ATCO Electric, EPCOR

- The Common Equity Ratio is the approved GCC Equity Ratio (38% for AG). The amount of Common Equity is calculated by multiplying this ratio by the total Required Invested Capital.
- The use of preferred shares is currently before the Board in a Common Matters[204] proceeding. Pending the outcome of that proceeding, AG is directed to include a placeholder amount for Preferred Shares in the capital structure at current book value.
- The total amount of debt in the capital structure is determined by the following formula:

  Debt_{MY} = Required Invested Capital_{MY} – Common Equity_{MY} – Preferred Shares_{MY}
- The cost of debt for the purposes of setting rates is calculated as the weighted average cost of debt, including short-term debt.

4 OPERATING EXPENSES

4.1 Historical Forecasting Accuracy (O&M)

In this section, the Board will review the appropriateness of comparing forecasts with actual expenditures and whether or not an assessment of this nature can be useful in determining the appropriateness of the forecast expenditures.

In Section 4.3 Attachment[205] of the Application, AG proposed O&M expenses, for the combined North and South systems, of $239.680 million, $251.224 million, and $259.552 million for the test years 2005 through 2007.

In its Argument, AG acknowledged that it had the burden of proof to support its applied for revenue requirement and submitted that it met that burden. AG submitted that it had demonstrated that both its forecast and its actions were prudent and reasonable. AG pointed to several authorities set out in Appendix 1 to its Argument and argued:

> The regulator should start with a presumption that the utility forecast was prepared prudently by utility management acting in good faith in an honest, efficient and effective manner. Absent compelling evidence demonstrating imprudence, the forecast should be accepted as reasonable, and the resulting costs included in the utility revenue requirement. This presumption of prudence can be overcome but only by a clear demonstration that the forecast was obviously wasteful, dishonest, excessive or extravagant. It is not sufficient to alter the forecast on the basis that interveners might prefer to do something differently. A mere substitution of their opinion for the experience and judgment of the management of the utility does not demonstrate imprudence.[206]

AG further stated:

> Just and reasonable rates result from the assessment of whether the forecasts supporting the expenditures and revenues included in the rate application are considered to be prudent forecasts of costs to be incurred in the provision of gas distribution service. The test for determining whether those forecasts are prudent is to assess whether reasonable

[204] Application No. 1407946
[205] Exhibit 02-025-001, Section 4.3 Attachment, revised September 6, 2005, page 10
[206] AG Argument dated October 14, pages 5-6

> utility management would make such a forecast, given the information they had, or reasonably should have had, at the time the forecast was prepared. That being the case, an intervener then must demonstrate that the costs forecast are obviously wasteful, dishonest, excessive or extravagant. As noted above, different people might reach different reasonable forecasts based on the same information. In that event, Dr. Gordon makes it clear that the regulator should defer to the utility management in such cases.[207]

The CFIB submitted that a fair and reasonable opportunity for AG to recover its costs could be achieved by allowing AG to include in its rates operating costs equal to 2004 actual values, (i.e. $223 million) less any forecast costs in categories that were determined not to be properly recoverable from customers, but that were nevertheless included in the reported 2004 actual expenditures. The CFIB proposed to add to this amount an adjustment of 1% to 2% of that adjusted actual value for each year in the test period.

A modest increase of this nature would allow AG to maintain or increase the operating expense components of its rates if it prevailed in relation to the various issues concerning what categories of costs should be recoverable from customers. The CFIB believed that such increases would reflect reasonable expectations of productivity improvements on the AG system, netted against inflation, given the incentive to generate productivity improvements that would be created if a three-year test period was approved. The CFIB submitted that a relatively modest allowed increase was appropriate in this case given the over-forecasting risks involved in AG's non-arm's length dealings with I-TEK and ITBS.

The CFIB view for fixing the allowed level of operating expenses for rate-making purposes was that it must involve the exercise of reasoned judgment, as opposed to a mechanistic application of a single pre-determined methodology. An approach that simply accepts utility forecasts unless they were patently unreasonable would be clearly wrong. An approach that simply applied an inflation factor to prior period actuals, without considering potential productivity improvements, the utility's history, and any special circumstances, would also be overly simplistic.

The CFIB concluded[208] that internal utility forecasts of operating expenses have significant weaknesses as tools for predicting the level of "prudent" operating expenses. This was primarily because, under a prospective rate-making regime, the utility had an economic incentive to over-forecast its expenses and to be unnecessarily conservative in its forecasting approach. The CFIB suggested that, in addition to the forecasts offered by the utility, evidence related to the forecasting methodologies used by the utility, historical information on forecasting accuracy and experienced utility returns, and any available indicators of what reasonable expectations should be in relation to management's ability to manage the utility system in an efficient and economic way should be considered. Then an objectively balanced determination of a "reasonable" allowed level of operating expenses could be made.

The CFIB considered that AG was confused between the asserted presumption of prudence for past expenditures and its suggested presumption of "prudence" for forward looking forecasts. The CFIB suggested that it made very little sense to say that a *forecast* was "prudent". It was also unclear how a forecast (as opposed to an actual expenditure) could ever be "obviously wasteful, dishonest, excessive, or extravagant" in order to overcome the alleged presumption of prudence. Forecasts can be "accurate", "unreasonable", "well-supported", "conservative",

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207 AG Argument dated October 14, page 7
208 Argument, section 4.1

"aggressive", and so on, but in a utility context it was clear that "prudent" was a term that could only have application when considering actual decisions made and implemented. A forecast of future expenditures can clearly be "unreasonable", in the sense that it is simply fails to be an accurate estimate of what future expenditures are actually likely to be, without itself being "obviously wasteful, dishonest, excessive or extravagant, and without the forecast level of expenses being "obviously" any of those things.

With respect to the list of authorities provided by AG in Appendix 1 to its Argument, the CFIB indicated that a review of those authorities:

> makes it clear that in all of those cases the presumption being discussed is the conventional presumption of prudence in relation to expenditures and management decisions that have already been made, and not the "prudence" of forecasts of future expenditures or future management decisions. By themselves, none of those authorities support the different and novel claim that there is a "presumption of reasonableness" in relation to forward-looking forecasts.[209]

The CFIB submitted that there was no basis for *presuming* that the utility's forecasts were correct or reasonable, or for shifting the burden of proof in relation to these issues to interveners. The proper approach was for the Board to consider and weigh all of the evidence, and apply its own judgment and expertise to arrive at a balanced and objectively reasonable forward-looking estimate of operating expenses.

The CFIB concluded its argument on AG's assertion of a presumption by stating:

> As a final point in this area, we wish to emphasize that we are not suggesting here, nor did we intend to suggest in our Argument, that there is a "presumption of unreasonableness" or "presumption of dishonesty" associated with internal utility forecasts. Our point is simply that there is no basis for *presuming* that the utility's forecasts are correct or reasonable, or for shifting the burden of proof in relation to these issues to interveners. The proper approach is for the Board to consider and weigh all of the evidence, and apply its own judgment and expertise to arrive at a balanced and objectively reasonable forward-looking estimate of operating expenses.[210]

AG took exception to the CFIB's recommendation that AG's operating cost forecast should be based on a 2004 adjusted actual increased by 1 to 2%. AG argued that there was no support provided as to why a rate of 1 to 2% should be considered reasonable in the booming Alberta marketplace in which AG was operating.[211] Furthermore, CFIB had acknowledged a significant increase in AG's costs as a result of increased transmission charges from ATCO Pipelines.[212] Also the proposal of CFIB did not acknowledge changes that AG had no control over, such as Measurement Canada requirements.

The CG reviewed the historical forecasting accuracy for AG Operating and Maintenance Expenses in Section 4.1 and Attachment 2 to its Evidence. The CG submitted that the Board should recognize the historical trend of over-forecasting O&M expenses when assessing individual components of the 2005 to 2007 operating expenses. The CG submitted that, as shown

[209] Reply Argument of the CFIB dated October 31, 2005, page 5
[210] Reply Argument of the CFIB dated October 31, 2005, page 7
[211] CG Evidence Exhibit 19-010 at page 4
[212] Transcript Volume 3, page 408, lines 21 - 22

in its Attachment 2[213], the Board allowed O&M Expenses were 8.27% less than requested by AGS for the 1998 and 2001-2004 test years. Actual expenses over that period were 1.45% higher than those allowed by the Board. The CG considered it noteworthy that AGS and AGN were able to connect and serve anywhere from 11% to 41% more customers than forecast during the period 2001-2004 and yet only exceed the Board allowed amounts by 1.45%. The CG recommended that the Board recognize this historical forecasting accuracy when it was assessing individual components of the 2005/2007 AG Operating Expenses.[214]

The CG disagreed with using only two years to assess O&M forecasting accuracy, noting that the actual O&M expenses in 2003 and 2004 would have been much lower if AG had not included some $4.5 million for monthly meter reading[215] plus a further $0.2 million of estimated operating expenses on 40 vehicles in both 2003 and 2004, $0.5 million of advertising expenses in 2004 and $1.5 million of Community Relations in 2003 and 2004, all of which were denied by the Board in Decision 2003-072.

The CG estimated that these expenses served to reduce actual O&M expenses by some $6 and $7 million respectively in 2003 and 2004. Forecast O&M expenses would have been 2.5% and 4.9% greater than actual O&M expenses in 2003 and 2004, absent the above Board disallowed expenses.

Views of the Board

The Board must assess the reasonableness of utility forecasts when considering an application to set revenue requirement for a particular test year. The Board agrees with the general view of interveners that historical forecasts and results should be taken into account when assessing the reasonableness of a utility's forecasts. The Board has discussed the use of actual results that become available after the date that forecasts are prepared in Section 1.3 of this Decision.

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

213 CG Evidence
214 CG Evidence, page 28
215 CG Argument, Section 2.1.5
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.

apply its own judgment and expertise in order to fulfill its statutory obligation of fixing just and reasonable rates.

This exercise includes an evaluation of the accuracy of historical results compared to past forecasts in order to assess the ability of the utility to forecast its expenses with a reasonable degree of precision. Where it can be demonstrated that there is a tendency for actual expenditures to deviate from forecasts in a particular way, without a reasonable explanation for the variance, the Board will take this into account when determining the O&M forecasts for the test years.

This approach is in keeping with recent prior decisions where the Board has explored the use of new information and financial results as discussed in Section 1.3 of this Decision, in assessing the accuracy and reasonableness of forecasts. Those decisions have indicated that:

> The Board also considers that it ought to use reasonably up-to-date actual data in assessing both the ability of the applicant to prepare accurate forecasts as well as the implications of actual costs (and revenues) on the future test year periods.[218]

It is also important, however, that such data be considered in light of any variance analysis or explanation, and with an awareness of:

> the need to balance positive and negative unforeseen circumstances. In this regard, the Board agrees with ATCO that focusing too heavily on prior year results could potentially overshadow unique circumstances in those years or changing circumstances in the test years[219]

The Board recognizes that during the past few years there has been a continual restructuring of the industry and of AG in particular. The Board considers that this provides a unique circumstance as referenced in the above quote. These events contribute to the difficulty in relying on comparisons of prior forecasts to actual results as a tool in assessing the reasonableness of AG's forecasts in this proceeding. This is further aggravated by the fact that such comparisons are not available for AGN prior to 2003 due to the existence of a negotiated settlement with ratepayers. Given these circumstances, the Board is of the view that comparisons of forecasts to actual expenditures for both North and South are appropriate primarily for the 2003 and 2004 test years, when adjusted for certain amounts and events.

[218] Decision 2003-071, 2003-2004 ATCO Electric Ltd. General Tariff Application, Rate Case Deferrals Application, 2001 Deferral Application, dated October 2, 2003, page 111

[219] Decision 2003-072, ATCO Gas 2003/2004 General Rate Application Phase I, dated October 1, 2003, pages 21 and 22

The AG forecast and actual O&M expenses for North, South and the combined Total for 2003[220] and 2004[221] were as follows:

Table 13. AG Forecast & Actual O&M Expenditures

2003 Forecast ($000)			2003 Actual ($000)			2004 Forecast ($000)			2004 Actual ($000)		
North	South	Total	North	South	Total	North	South	Total	North	South	Total
121,263	110,587	231,850	121,409	110,704	232,113	124,789	113,068	237,857	115596	107,930	223,526

In order to assess AG's ability to forecast accurately, the Board considers it necessary to make adjustments to the actual versus forecast comparison shown above. Certain categories of expenses that could distort the assessment should first be removed. These would include categories that are considered placeholders or deferral accounts, since these will be separately assessed and reconciled in some other proceeding. In some circumstances it may also be reasonable to remove certain expenses over which the company has little control, such as compressor fuel, and those categories in which the Board has made specific disallowances.

In making a comparison of actual to forecast O&M expenses for 2003 and 2004, the Board views it appropriate to remove the amounts for the Administration & General Transferred (Credit) (account 729), since the Board had disallowed the transfer of the O&M expenses to capital. The placeholders and deferral account related to Transportation of Gas by Others (account 663), Customer Billing and Accounting (account 713), Credit and Collections (account 714), Uncollectible Accounts (account 718), and Other Administrative and General Expenses (account 728) were removed. The Board will also remove Compressor (account 656), Advertising (account 701) and Administrative Expense (account 721) since these accounts contained certain expenses over which AG did not have independent control, i.e. the cost of compressor fuel and Board assessments which would have only become known to AG well into the test period. In addition, an adjustment is required to reflect the transfer of the retail business to DERS. The Board did not remove Meter Reading and Bill Delivery (account 712) as AG forecast the expense of monthly meter reading and had incurred the actual costs of doing so, despite the Board's disallowance of the expense in excess of bi-monthly meter reading.

The result of the above adjustments is as follows:

Table 14. Adjustment to AG O&M Expenditures for Placeholders, Deferral Accounts, and Exceptional Expenses

2003 Forecast ($000)			2003 Actual[222] ($000)			2004 Forecast ($000)			2004 Actual[223] ($000)		
North	South	Total	North	South	Total	North	South	Total	North	South	Total
53,543	48,449	101,992	53,760	45,312	99,072	56,097	50,268	106,365	56,203	46,461	102,664

The result shows that the total forecast in 2003 was under spent by $2.902 million or 2.9% and in 2004 under spent by $3.701 million or 3.48%. When these amounts are considered relative to the total forecast (after the adjustment for account 729, but before all other adjustments) the percentages become 1.22% and 1.51%. The Board considers these results to be within a

[220] Application, Tab 8, Table 4.4-4
[221] IW-AG-03 Attachment (b)
[222] Application, Tab 8, Table 4.4-4
[223] IW-AG-03 Attachment (b)

reasonable degree of accuracy for the purpose of assessing the presence of a trend, especially given the recent circumstances of reorganization and the sale of the retail business. Accordingly, the Board does not consider that an overall adjustment to the O&M forecasts for the test years is warranted. However, the Board will consider specific aspects of the forecasts in the following sections of this Decision.

4.2 Labor Expenses

In this section the Board will review certain labour expenses as proposed by AG in the Application.

4.2.1 Increase in Administrative and General Expense

AG forecast that the labour expense portion of Administrative and General Expense would increase from $9.855 million to $11.595 million, or 17.6%, between 2004 and 2005.[224] AG explained that the largest contributing factors to the increase were the change in variable officers' remuneration and growth in positions.[225] AG advised that the change in variable officers' remuneration was part of executive compensation to be dealt with in the Common Matters proceeding.[226] AG provided further details in Exhibit 25-009.

Views of the Board

The Board notes that most of the differences in Administrative and General Labour Expense are related to executive compensation, which is to be reviewed in the Common Matters process. AG is directed to provide, in the Compliance filing, the placeholder amounts for each test year that will be dealt with in the Common Matters proceeding.

4.2.2 Gas Utility Operator Positions

AG forecast the addition of 17 Gas Utility Operators (GUOs) during the test period.[227] AG stated that this represented annual growth of 1.6% in each of the test years.

The CG contended that the number of additional GUOs should be limited to a maximum of 10 over the test period and AG should be directed to adjust salaries and benefits accordingly in its Compliance filing.

The CG noted that the forecast additional GUOs were responsible for the installation of new distribution facilities and if not installing, then directly inspecting contractor installations, operating and maintaining distribution facilities and responding to emergencies.[228] AG's justification for the increase was the need for additional GUOs, driven by the increased size of the distribution system and the increased number of customers.[229]

224 Application, Table 4.3-23
225 Response to IW-AG-13
226 Transcript Volume 1, page 105
227 Application, Table 4.17 and note the following table which has been expanded to include the actual data for 1999 to 2002
228 Application, page 4.1-21
229 Application, page 4.1-21

The CG noted that there appeared to be a marked decline in the km/GUO and the number of customers/GUO metrics starting in 2003 based on the information provided by AG. CG provided the following table[230]:

Table 15. GUO Metrics

	1999A	2000A	2001A	2002A	2003A	2004A	2005F	2006F	2007F
km Main	32,977	33,436	33,982	33,923	34,366	34,903	35,399	35,893	36,380
Customers	798,012	815,455	837,003	861,952	887,749	914,347	939,141	963,826	988,172
GUO	289	285	280	306	358	360	369	376	377
km/GUO	114	117	121	111	96	97	96	95	96
Cust/GUO	2,761	2,861	2,989	2,817	2,480	2,540	2,545	2,563	2,621

The CG also noted that there was a reduction in the forecast number of new customers to be connected in the test period as compared to 2003/2004.[231] The CG considered that both of these metrics suggested that the required number of GUOs should remain as the status quo, rather than reflecting a forecast increase.

AG provided the following table in Rebuttal:[232]

Table 16. GUO Metrics – AG Adjusted

	1999A	2000A	2001A	2002A	2003A	2004A	2005F	2006F	2007F
km Main	32,977	33,436	33,982	33,923	34,366	34,903	35,399	35,893	36,380
Customers	798,012	815,455	837,003	861,952	887,749	914,347	939,141	963,826	988,172
MRRP Units	0	0	0	1,000	16,627	16,841	18,650	19,050	18,650
Regular GUO	289	285	280	306	291	293	302	309	310
MRRP GUO	0	0	0	0	67	67	67	67	67
TOTAL GUO	289	285	280	306	358	360	369	376	377
km/Regular GUO	114	117	121	111	118	119	117	116	117
Cust/Regular GUO	2,761	2,861	2,989	2,817	3,050	3,120	3,109	3,119	3,188
MRRP units/ MRRP GUO	0	0	0	0	248	251	278	284	278

AG submitted that there was confusion over the number of GUO positions. AG clarified that these positions encompassed both operation and maintenance activities to maintain the entire system and also included positions added in 2003 required for the MRRP project. By differentiating these two separate activities and applying corresponding measurements, the metrics reflect a steady level of productivity over the 1999 to 2007 years. AG submitted that this was true for both the regular O&M work and the MRRP work.

However, the CG considered that this new evidence was still flawed. If AG removed the 67 GUOs involved in MRRP to calculate “Regular GUOs”, the CG questioned why AG didn’t remove the 34% to 36% of GUOs involved in total capital, as shown at page 4.1-34 of the Application. The CG calculated the “Regular GUOs” based on the percentages of total labour dollars charged to O&M as shown at page 4.1-34 and based on the new methodology introduced by AG as follows:

[230] CG Argument, page 49
[231] CG Evidence, page 31
[232] Rebuttal Evidence, page 40

Table 17. GUO Metrics – CG Adjusted

	2003A	2004A	2005F	2006F	2007F
km Main	34,366	34,903	35,399	35,893	36,380
Customers (000's)	887.75	914.35	939.14	963.83	988.17
Total GUOs	358	360	369	376	377
% O&M	62%	60%	61%	62%	62%
Regular GUOs	222	216	225	233	234
km/Regular GUO	155	162	157	154	155
Cust/Regular GUO	3,999	4,233	4,174	4,136	4,223

The CG submitted that the above table presented “Regular GUOs” calculated using AG’s methodology, but applying the percentages of total labour charged to O&M as per page 4.1-34. The CG argued that this showed there was a reduction in productivity for both km/Regular GUO and Customers/Regular GUO in the test period as compared to 2004. Although the productivity declines were relatively small, the CG noted that the only explanation provided by AG for increased GUOs was a larger system and more customers (i.e. metrics only). It was then AG who provided the metrics that reflected removal of MRRP GUOs. However, the CG considered that AG had not reflected the total GUOs involved in capital projects, which included MRRP based on the percentages as shown at page 4.1-34. The CG argued that if there were no new GUOs added in the test period, the ratio of km/Regular GUO would remain at about 162 or very close to the 2004 ratio. However, the ratio of customers per Regular GUO would stay relatively flat over the three years if there were additions of 17 GUOs. In other words, based on metrics alone, which was essentially the only information provided by AG, AG would not need to add any GUOs to maintain the Customer/GUO ratio, but would need to add about 17 GUOs to maintain the km/GUO ratio. The CG therefore concluded that the number of additional GUOs should be limited to a maximum of 10 over the test period.

AG submitted that the CG’s reintroduction of their metric analysis erroneously combined both regular GUO and MRRP GUO positions. AG stated that these two different positions performed different work, which required analysis in finer detail, with the positions identified separately with corresponding metrics applied to the Regular GUO positions and MRRP GUO positions.[233] AG provided these metrics in Rebuttal Evidence, which AG argued showed steady productivity increases from 1999 through 2007 for both groups of GUOs.[234]

AG stated that the CG’s recommendation to remove 34% to 36% of GUOs involved in total capital, as shown at page 4.1-34,[235] illustrated the CG’s misconception that this 34% capital figure was representative of the capital completed by the GUOs. AG noted that this was not the case. The 34% was the portion of total in-house labour that was charged to all capital projects in the company. There was no correlation between the number of GUOs and the total amount of capital labour spent in AG. AG emphasized that this was the total capital labour, not just the capital portion spent by the GUO group.

AG claimed that the GUO metrics as outlined in its Rebuttal Evidence[236] stood as clear measures of productivity and efficiency. AG noted that as the system expands with the growth of new

[233] Rebuttal Evidence, page 40
[234] Rebuttal Evidence, page 40
[235] Argument, page 50, lines 15-16
[236] Rebuttal, page 40, lines 17-18

customers and as the system ages over time, there was a need for the addition of 17 GUOs over the three test years to service the customers and maintain the system. This was shown by the stable number of kilometres of pipe serviced per regular GUO and the number of customers serviced per regular GUO over the three test years.

Views of the Board

The Board agrees with AG that km/Regular GUO and Customers/Regular GUO are shown to be stable or demonstrate efficiencies. The Board agrees that utilizing the capital labour value will lead to a flawed analysis. The Board understands that GUO's can be utilized on either various capital projects or O&M, thereby reducing contractor costs and providing flexibility so that AG is able to shift resources to meet requirements. Therefore, the Board approves the number of GUOs forecast to be hired by AG during the test years.

4.2.3 Engineering Positions

AG proposed to add six engineering positions during the test period due to increased capital activity. AG claimed that the current level of engineering staff was able to keep up with design of immediate work, however, the new engineering positions were required to address long term planning, pipeline integrity analysis and more technical areas, such as measurement and communications.[237]

The CG submitted that AG had failed to meet its burden of proof to demonstrate that it required six additional engineers during the test period, and accordingly those salaries and related benefits should be excluded from the revenue requirements in the Compliance filing.

The CG noted that AG had provided the engineering complement, distribution and total capital expenditures over the period 1999 to 2007 and had indicated that the majority of staff was directed to work in the distribution function.[238] The CG believed that this suggested that engineering positions were driven by the increase in distribution capital expenditures. However, since only one engineer was involved in MRRP,[239] that capital should be removed from distribution capital for productivity analysis purposes. Although distribution capital, excluding MRRP, increased by 15% from 2003 to 2007, AG proposed to increase the engineering complement by 30% (49 to 64). It appeared to the CG that the increase of nine engineering positions in 2004 should be more than adequate to cover the increase in distribution capital expenditures less inflation over the test period.[240]

Having acknowledged that existing staff can keep up with immediate work, it appeared to the CG that AG was increasing its engineering complement for purposes of long-term planning/preparation of business cases. CG found the addition of six new engineers difficult to understand, given that AG was ultimately able to conduct the long-term planning and associated business cases for the test period with the existing complement of 58 engineers.[241] The CG submitted that AG had failed to meet its burden of proof to demonstrate that it required six additional engineers during the test period.

[237] Rebuttal, page 42, lines 27-29
[238] CG-AG-27(b)
[239] CG-AG-22(a)
[240] CG Evidence, page 30
[241] CG-AG-27(b)

AG noted that the CG had presented a more detailed analysis by stripping out non-labour intensive capital which reduced the capital increase which AG used to show the need for additional engineers. AG submitted that the CG's analysis ignored new workload for which engineering staff are responsible. AG argued that it requires these six engineering positions over the three year test period for long term planning involving research, economic analysis, alternative selection and documentation for Business Cases. The CG may have neglected to consider that the addition of the six positions was over a three year time frame and as the system expanded and aged, resources were required to maintain it in good working condition.

Views of the Board

The Board is satisfied that AG has studied its workload for engineers and has identified a need for additional engineers over the test period. On the understanding that the engineers will spend time on both capital and O&M related projects, as well as planning and analytical projects, the Board does not agree with the CG that AG failed to identify a need. Accordingly, the Board agrees with AG's proposed increase to its engineering complement during the test period.

4.2.4 Human Resource Advisors

In the Application, AG proposed an increase of three Human Resources (HR) Advisors positions in 2005. Over the test years, the Board notes a total of four additional HR Full Time Equivalents (FTEs).[242] The main driver for this increase was to provide general support for the total number of permanent and seasonal employees that AG has on staff. Increased retirements in the upcoming years and higher job postings in the meter reading group were specifically noted. AG also noted that there are other functions with heightened levels of activity such as benefits administration, compensation, and training and development. There was no one particular activity or role that these individuals were assigned to. Since HR is a very small group, all individuals do all aspects of work in the HR department in order to effectively use resources. AG submitted that it was the increase in the number of overall employees that was driving the need for these additional positions. AG believed that the HR metrics illustrated the reasonableness of the staff additions and noted that the AG metrics of 1.1 HR staff per 100 employees ranks below the national average for similar sized companies of 1.9[243] Human Resources staff per 100 employees for similar sized companies outlined in the Conference Board of Canada, Compensation Research Survey, 2001.[244]

The CG submitted that AG should be directed to reduce HR salaries and benefits for three FTEs in its Compliance filing. The CG noted that AG proposed to increase its HR Advisors from 18.6 to 22.6 FTEs[245] over the test period with a resultant ratio of 1.1 HR staff per 100 employees due to increased activity in benefits administration, training and development, compensation and job postings.[246] The CG summarized information regarding the number of utility FTEs and HR FTEs over the period 2000-2007 in the following table:[247]

242 CG-AG-27(c), see also Table 18
243 Rebuttal, page 43, lines 11-14
244 Application Volume 1, page 4.1-19
245 CG-AG-27(c)
246 Application Volume 1, page 4.1-18
247 CG Evidence, page 31

Table 18. HR FTEs

	2000A	2001A	2002A	2003A	2004A	2005A	2006F	2007F
FTEs	1,580	1,593	1,622	1,793	1,890	1,986	2,003	2,014
HR FTEs	16.6	16.6	17.6	18.6	18.6	21.6	22.6	22.6
HR/100 FTE	1.05	1.04	1.09	1.04	0.98	1.09	1.13	1.12

The CG pointed out that the addition of the four HR FTEs brought the HR/100 FTEs productivity ratio well above the 2000-2004 average ratio of 1.04 and well above the 0.98 ratio in 2004. The CG considered the additional activities, as noted by AG, appeared to be primarily proportional to the growth in overall FTEs. Maintaining the 2000 to 2004 ratio of 1.04 HR staff per 100 FTEs would result in 19.1 to 19.4 HR FTEs over the test period or an increase of just one HR FTE.

The CG considered that activities related to administration, compensation, and training and development were in turn a function of the total number of employees because AG provided no evidence to that effect. The CG submitted that there had been a loss of 10% to 15% in the HR productivity metrics as compared to 2000 to 2004 and 2004 respectively. If AG is directed to return to bi-monthly meter reading as proposed by the CG, there would be no requirement for any additional HR Advisors at current productivity metrics. The CG considered a 10% to 15% decrease to be a material loss of productivity and that AG should be directed to reduce HR FTEs by three in its Compliance filing.

AG argued that the CG calculations were wrong. AG submitted that if CG's table was recalculated for 2005 to 2007 with the HR/100 FTEs fixed at 1.04 as suggested by the CG, the recalculated correct HR FTEs would be 20.7, 20.8 and 20.9, for 2005, 2006 and 2007 respectively. Thus the increase in HR FTEs from 2004 to 2007 would be 2.3,[248] not 1 as the CG suggested.

AG submitted that the decision to add three HR positions was based on a thorough evaluation of the workload rather than a metrics calculation to the second decimal place. The workload per HR Advisor was increasing for benefits administration, training, compensation and job postings, which were being driven by significantly increasing retirements and statutory requirements such as privacy and harassment. Three HR Advisors were required in the test years to complete the forecast workload. The metric calculations in the Rebuttal Evidence[249] confirmed that these additions were reasonable.

Views of the Board

The Board notes that in recent years the HR FTEs/100 FTEs ratio has ranged between 0.98 and 1.09. The Board is satisfied that AG has been able to perform its business with such ratios and has successfully been able to do so at ratios below the national average. The Board is not persuaded that the ratio should exceed the high point of 1.09 and agrees with CG that fewer HR positions are needed. AG should be able to maintain levels between historical ratios of 0.98 and 1.09 HR FTEs/100 FTEs.

The Board observes that the HR Advisor complement of 21.6 in 2005 results in an HR FTEs/100 FTEs ratio of 1.09, equal to that in 2002. Any further additions during the test period would

[248] 20.9 HR FTE in 2007 less 18.6 HR FTE in 2004
[249] Rebuttal, page 43, lines 4-5

cause that ratio to be exceeded. Accordingly, the Board approves the HR Advisor addition for 2005, but not for the remaining test years and directs AG to make the necessary revisions to salaries and benefits in the Compliance filing.

4.2.5 Manager, Internal Controls

AG proposed to include a Manager, Internal Controls position, commencing in 2005, with the costs to be allocated 50% to AG and 50% to AE.[250]

Views of the Board

The Board notes that the justification provided by AG for this position was based on its stated need to comply with new corporate financial reporting requirements based upon Ontario Bill 198 and MI 52-109 definitions (CEO/CFO certification) and proposed timelines.[251]

The Board notes AG indicated that the unregulated affiliates have similar processes in place to make sure that the program is implemented, but that AG did not indicate whether the unregulated affiliates have similar positions in place.[252] The Board also notes that the position was vacant after June, 2005.[253]

AG indicated that many of the costs associated with implementation of its efforts to comply with MI 52-109 have been included in ATCO Head Office Costs of which a share has been allocated to AG.[254] Given that these costs arise from the corporate reporting obligations of Canadian Utilities Ltd. (CU), the Board is of the view that it is appropriate that the costs proposed to be borne by AG that relate to the public reporting obligations of CU should be considered as common corporate costs. Accordingly, AG should be allocated its proportionate share in accordance with the allocation formula approved by the Board in Section 4.4.5. Therefore, the Board directs AG to reduce the costs associated with the Manager, Internal Controls so that they reflect only AG's proportionate share of the common corporate costs for each of the test years. This reduction should be included in the Compliance filing along with an explanation of how the amount was calculated.

4.2.6 Capitalized Labour

AG provided the actual and forecast split between Capital and Operating Labour in Table 4.1.16, in the Application, for the years 2003 to 2007. Comparable information was provided in CG-AG-31(a) for the years 2000 to 2002. AG explained that the actual O&M allocation of labour dollars had been reduced from the 64.4% forecast for each of 2003 and 2004[255] to 62% in 2003 and 60% in 2004[256] due to the fact that employees could be deployed to either capital or O&M categories and that the increased charges to capital were due to increased workload.[257]

The CG recommended that the increases in capital labour be deemed to be operating expenses in each of 2003 and 2004; that the 2005 opening balance of PPE be reduced by $8.1 million; and

[250] Application, page 4.1-19
[251] Application, page 4.1-19
[252] Transcript, page 740, lines 13-15
[253] Transcript, page 754, line 18
[254] Transcript, page 740, lines 21-24
[255] Decision 2003-072, Table 8
[256] Application, Table 4.1.16
[257] CG-AG-31(b)

that AG make the corresponding adjustments to depreciation and CCA in the Compliance filing.[258]

The CG was concerned about the increased charges to capital and reduced charges to O&M, and prepared Attachment 3 to its Evidence to summarize those changes as well as to provide forecast and actual capital expenditures and O&M expense.

The CG noted that in 2003, actual O&M labour was $3.4 million less than forecast and capital labour was $2.7 million more than forecast. In 2004, O&M labour was $3.3 million less than forecast and capital labour was $5.4 million more than forecast.

Although AG attributed the increased labour charges to capital to increased workload, CG noted that 2003 capital was only $1 million greater than forecast, but $10 million below forecast after deducting moveable equipment, meters and instruments, and IT projects, three areas which should attract very little capital labour. For 2004, forecast expenditures were about $20 million greater than forecast, but only $5 million above forecast if the same three areas were deducted. After analyzing the reasons for capital expenditures exceeding forecast, CG concluded that there was no evidence to support AG's contention that capital labour had increased by $2.7 and $5.4 million with concomitant decreases to O&M.

AG asserted that capital work did increase significantly in 2003 and 2004. Based on backing out the capital costs deemed not to be labour intensive, as proposed by the CG, AG noted that labour-intensive capital work increased by 31.5% in 2003 and 13.6% in 2004.[259]

The CG clarified its concern that AG forecast that 64.4% of labour would be charged to O&M in 2003 ($65.993 million) and 2004 ($68.796 million), but that AG only booked 62% ($62.568 million) and 60% ($65.481 million) in those years. The differences between forecast and booked amounts flow to the bottom line. The forecast amount was included in revenue requirement and recovered from customers through rates. The CG noted that, in 2003, actual O&M labour was $3.4 million less than forecast and capital labour was $2.7 million more than forecast. In 2004, O&M labour was $3.3 million less than forecast and capital labour was $5.4 million more than forecast.[260] The CG considered that the shift from O&M to capital had dramatically improved the bottom line for 2003 and 2004. CG submitted that AG had failed to meet its burden of proof to demonstrate why it shifted significant dollars from forecast O&M to booked capital in 2003 and 2004. Under these circumstances, CG submitted that the Board should reduce the 2005 opening balance of PPE and related accounting entries by $8.1 million and direct AG to make the corresponding adjustments to depreciation and CCA in its Compliance filing.

AG responded that there was no evidence to make this claim and that the CG had not clearly outlined how they arrived at the $8.1 million figure.

AG submitted that it had fully supported with detailed information[261] that capital work requiring capital labour did increase from 2003 to 2004, and was higher than originally forecast in both years. AG stated that this was real incremental capital labour, not an accounting reallocation of

[258] CG Evidence, page 34
[259] Rebuttal, page 43
[260] CG Evidence, Attachment 3
[261] AG Rebuttal Evidence, pages 43-44

dollars. AG considered that the CG's assertion to cut $8.1 million from rate base was totally unfounded. AG stated that it had provided detailed explanations of the reasons for differences between the 2003 and 2004 actuals and GRA forecasts. The differences were as a result of many causes, none of which involved a change in capitalization policy by AG.

AG argued that it was clear that it was the increase in capital workload, requiring additional labour to complete the work, which resulted in an increase in capital labour in 2003 and 2004. The capital work as booked was fully justified and appropriately recognized as capital.

Views of the Board
The Board notes AG's comment:

> ATCO Gas does not have formal policies for the development of forecasts for capital expenditures. Section 2.1 of the Application provides an explanation of the process to develop the forecast for each of the categories of capital. The forecast methodology includes a review of historical or unit costs and a portion of these costs are related to indirect costs. As such, forecasts included indirect costs at historical rates unless specifically forecast.[262]

The Board accepts that AG's capital projects were necessary and therefore the magnitude of the labour which is capitalized is appropriate. The Board further recognizes that AG can shift resources between O&M and capital to meet the workload, which will include balancing the workload with contractor assignments. Therefore, it would not be correct to reduce the opening balance of PPE.

The Board also notes that AG developed an O&M forecast which includes a labour forecast and the capitalized labour is generally the difference between O&M labour and total labour. However, the Board does understand that the difference between forecast O&M labour and actual can result in an improvement to the bottom line, although the improvement may be reduced depending on the magnitude of the contracted work, which will show as an increase in O&M supplies. The differences between O&M forecasts and actuals are significant however, and will be taken into consideration when the Board is assessing the overall accuracy of the historical forecasts.

4.2.7 Variable Pay Program

AG submitted that it had proposed an innovative Variable Pay Plan (VPP) for select senior staff in the organization. In its evidence, AG filed the details of the plan, and proposed a deferral account to deal with issues that AG believed had concerned the Board in previous proceedings. The VPP was proposed to commence in 2005 for approximately 15 individuals in the organization. The forecast cost in 2005 was $269,000, with $195,000 charged to O&M and $74,000 to capital. The forecasts for 2006 and 2007 were to be adjusted for inflation. The first 50% of the variable compensation was to be based on achieving pre-stated metrics related to operational performance and would be paid irrespective of whether the earnings targets were met. The remaining 50% of variable compensation was based on achieving earnings commencing with the approved utility return on common equity and would only be paid if the

[262] Response to BR-AG-1

operational metrics had been achieved. Ten percent of the earnings component would be paid at 9.5% return on equity[263] and the full 50% would be paid at 10.5% return on equity.[264]

The CG submitted that only the 50% portion of variable pay related to customer goals should be included in the test year O&M and capital expenditures and that the portion for financial performance should be denied.

AG first dealt with the concern that the pursuit of shareholder goals may come at the expense of customers. The structure of the VPP mandated that operational excellence objectives be achieved before there was any eligibility for the component of variable pay associated with financial performance.

Secondly, AG stated that customers would benefit from the achievement of financial objectives. Increases in earnings were generally a result of efficiencies that the company finds during the course of a test period. Such improvements would carry on into the future to the benefit of customers. As discussed by AG's witness, Dr. Gordon,[265] incentive-based compensation should be used to search for ways to improve customer service, deploy state of the art technology, and increase the firm's operating efficiency. AG claimed that the VPP met these criteria.

AG claimed[266] that this type of compensation was a cost of doing business in Alberta, and that AG's plan was quite modest. Therefore, AG submitted that it should be allowed to recover the cost in its revenue requirement. AG submitted that it needs to be able to compete in a marketplace that was increasingly using variable compensation to ensure that it was able to hire and retain a skilled workforce.

AG argued that failure to include the full amount of the VPP in revenue requirement would deny AG its legislated right to recover its prudent costs and therefore could not be said to provide the utility its reasonable opportunity to achieve its allowed return on capital. AG claimed that if the regulator did not include a portion of the payments to be made under this plan, there was only one effect, and that was to otherwise reduce the return to which the utility was entitled.

AG noted that during the course of the proceeding, there was some discussion about sharing the cost of the VPP between customers and shareowners on the basis that both might benefit from the operation of such a plan. AG submitted that while an improvement over a complete disallowance, such an approach would be an equal affront to the concept of regulatory fairness and to the prudence standard. AG argued that it would be inappropriate, therefore, to only allow a portion of the costs of the plan to be recovered in the revenue requirement

The CG's primary area of concern[267] was with the 50% of the variable compensation that related to earnings, and agreed the 50% portion related to customer goals and benefits should be included in O&M expense or capitalized.

[263] CG-AG-25(d)
[264] BR-AG-18(d)
[265] Evidence of Dr. Ken Gordon, page 14, lines 3-9
[266] As discussed in the Application at pages 4.1-10 to 4.1-11, and at page 29 of the CG Evidence (lines 28-29), this issue has been addressed recently in various regulatory forums for several utilities.
[267] Exhibit 19-011, page 29

The CG noted that Board had dealt with this issue in a number of prior proceedings. In Decision 2003-061 respecting AltaLink, the Board considered that, "the expenses related to the portion of the benefit gained by shareholders should not be borne by customers" and accordingly allowed only 50% of the requested amount as an estimate of the benefits resulting from permanent cost reductions to the benefit of customers in the future. The Board disallowed the entire amount related to AltaLink's Long Term Incentive Plan.[268]

The CG also noted that in the ensuing application, AltaLink again requested approval of a Long Term Incentive Plan, but it was again denied as the Board considered the goals to be complementary to the interests of shareholders.[269] The Board determined similar treatment for ENMAX[270] and EPCOR Distribution Inc.[271]

The CG did not agree with AG that the deferral issue was the major issue in previous decisions. The major issue was whether or not customers should bear any portion of the cost related to shareholder goals. CG was not persuaded that the achievement of higher earnings would necessarily translate to improving utility efficiency as asserted by AG.

The CG submitted that this issue had been fairly and consistently dealt with by the Board in several prior proceedings as previously noted, and that AG had not provided compelling evidence to persuade the CG that this issue should be treated otherwise. CG also submitted that the Board should not be influenced by the modest amount that AG was requesting and should deal with this issue in principle as it might set an important regulatory precedent for AG and other utilities.

The CG argued that while incentive compensation may be becoming more prevalent for non-regulated entities in Alberta, it was shareholders who ultimately bore those costs and received the benefits. The CG submitted that allowing AG to recover the costs associated with the performance metrics from customers, but with shareholders bearing the costs and receiving the benefits associated with the financial performance, was reasonable for a regulated utility in Alberta.

The CG argued that the shareholder costs and benefits should be put into perspective. Where AG indicated that the full 50% payout for financial performance under the VPP would occur if AG achieved a 10.5% return on equity[272] the shareholders would be required to pay out about one-half of the $269,000 of VPP or $135,000. However, shareholders would earn $4 million ($404 million equity rate base x 1%). CG stated that shareholders would still be rewarded even if they were required to pay the cost of the financial portion of the VPP.

Views of the Board

Similar to the CG, the Board is not persuaded that the achievement of higher earnings will necessarily translate to improving utility efficiency as asserted by AG. The Board also agrees with CG that only the 50% portion of the VPP that addresses operational performance should be recovered through customer's rates. The Board considers that where the benefits will ultimately

[268] Decision 2003-061, page 52
[269] Decision 2005-019, page 34
[270] Decision 2004-066, page 27
[271] Decision 2004-067, page39
[272] BR-AG-18(d)

add to the efficiency of the company, there is merit to the applicable portion of the VPP being included in revenue requirement. However, where the benefit is increased return to AG, the Board does not view funding that portion of the VPP through rates to be appropriate. This would be consistent with previous Board decisions. Therefore, the Board denies inclusion of the 50% of the VPP that focuses on financial returns, but approves the 50% that will be awarded for operational targets. The Board also approves the use of a deferral account to reconcile the VPP for the operational component.

4.2.8 Step Increases

AG submitted that:

> Steps recognize that it takes a number of years for a new employee to become fully competent in their position. A new employee will receive step adjustments each year in addition to the economic adjustment until that employee becomes fully competent. There are 4 to 6 steps, depending on the position, to progress from the minimum pay level to the maximum pay level. While steps are not new, until recently they have been insignificant as the majority of our workforce had reached the fully competent level and were already at the maximum wage for their positions. However, since hiring 250 new employees in 2003 and 2004, steps have become a significant component of overall wage adjustments.[273]

Step increases accounted for 1.07%, 0.90% and 0.70% of the increases for occupational employees in 2005, 2006 and 2007.[274] AG also noted that if the impact of the 131 monthly meter readers, previously denied by the Board in Decision 2003-072, was removed from the step increase calculation, the step increases would be in the half percentage range.[275]

CG submitted that the monthly meter readers made up only 131 out of the 250 new hires and therefore removing the impact of monthly meter readers would reduce the step portion of wage adjustments by about 0.30% in each of 2005, 2006 and 2007. CG argued that the wage adjustments for occupational employees set out in Table 4.2.1 in the Application should be reduced by those amounts.

Views of the Board

The Board understands that the average of step increases will be influenced by the number of new hires and that new hires would tend to lower the average. Therefore, if the new hires include positions that are ultimately considered by the Board to be unacceptable for inclusion in determination of the revenue requirement, the Board will expect AG to reduce the overall average labour step increases accordingly, and to demonstrate such in the Compliance filing. Therefore, the Board directs AG to make any changes to the overall amounts of step labour increases that follow from the Board's determinations in other sections of this Decision.

4.2.9 Pension and Post-Employment Expense

The following was noted in an informational letter from the Board:

> The Board notes that in fact, pension expense for all other employees was not dealt with in the ATCO Gas proceeding nor in the subsequent ATCO Electric proceeding. The

273 Application, page 4.2-2
274 Details of step increases provided in response to CG-AG-32(a)
275 Transcript Volume 1, page 48

> Board hereby clarifies that all matters related to pension including pension expense for other employees will be dealt with in the common matters proceeding.[276]

Also it is noted that as per the Board's preliminary issues list of September 7, 2005 for the Common Matters Proceeding, Application No. 1407946, and as per the Application, Volume 1, Page 1.0-6, "Other executive and non-executive pension related matters" were to be addressed in the Common Matters Proceeding.

Accordingly, issues related to Pensions and Post Employment Expenses are to be dealt with in the Common Matters process. For purposes of establishing the revenue requirement in this proceeding, AG is directed to isolate, identify and provide the placeholder amounts in a Compliance filing.

4.3 Inflation

AG noted that the methodology used to develop the inflation rates for both labour and supplies was outlined in Section 4.2 of the Application. The occupational wage adjustments were built based on a comprehensive review and comparison of other external wage settlement agreements in other utility and oil and gas companies operating in Alberta. Likewise, the supervisory wage adjustments were determined by using external market salary forecasts and economic indicators. The forecast inflation for supplies over the test years was based on Consumer Price Index (CPI) forecasts unless more specific information was available on individual supply items. The inflation rates as outlined in the Application were based on independent review of the general economic climate in Alberta and appear reasonable.

Views of the Board

The following table was provided by AG in the Application:

Table 19. Consumer Price Index (CPI)[277]

		2005	2006	2007
Edmonton CPI*	Nov 04	1.9%	1.9%	1.9%
Calgary CPI**	Oct 04	2.3%	2.3%	2.3%
TD Securities Inc	Jan 05	2.3%	N/A	N/A
RBC Dominion Securities	Jan 05	2.4%	2.2%	2.0%
BMO Nesbitt Burns	Jan 05	2.4%	2.4%	2.3%
Beutel, Goodman & Company	Jan 05	2.0%	2.3%	2.2%
Phillips, Hager & North	Jan 05	2.1%	2.1%	2.1%
Average		2.2%	2.2%	2.1%

* 2005 Greater Edmonton Economic Forecast, November 2004
**City of Calgary Quarterly Economic Report, October 2004
N/A – Forecast not available from these sources

The Board notes there were no information requests, evidence or cross-examination regarding inflation. The Board considers that AG used a reasonable approach to develop its forecast inflation rates. Therefore, the Board accepts the inflation rates used by AG to develop its forecasts.

276 EUB Information Letter Dated October 20, 2005
277 Application, Table 4.2.5

4.4 Non-Labor Expenses

In this section the Board will review and consider the non-labour O&M expenses of the Application, although some expenses will require placeholders pending the outcome of other proceedings which are underway.

4.4.1 I-Tek Operating Expenses & ITBS Operating Expenses

AG requested approval with respect to forecast service volumes for information technology services (I-Tek Volumes) provided by ATCO I-Tek and for forecast Customer Care and Billing services volumes provided by ATCO I-Tek Business Services (ITBS Volumes). Pricing related issues applicable to operating expenses for information technology services provided by ATCO I-Tek (I-Tek Operating Expenses) and the operating expenses for customer care and billing services provided by ATCO I-Tek Business Services (ITBS Operating Expenses) will be resolved in the ongoing Benchmarking Process.[278] Accordingly, AG requested approval of placeholders in the revenue requirement for each of the test years until the Benchmarking Process was completed. Once the Benchmarking Process is completed, the Benchmarking Process should be able to resolve the I-Tek Operating Expense and ITBS Operating Expense placeholders by inserting the unit volumes multiplied by the unit fair market value (FMV) price.

AG requested forecast ITBS Operating Expenses of $22,455,000 in 2005, $23,782,000 in 2006, and $24,771,000 in 2007.[279] These amounts were also ITBS operating expense placeholders for the I-Tek Benchmarking Process.[280]

Calgary submitted that AG had filed the necessary ITBS Volumes and Statements of Work required for the ITBS Benchmarking Process.[281] However, Calgary was not in agreement that AG filed the necessary I-Tek Volumes.

The CG/Utilities Consumer Advocate (UCA) submitted that, given that the Board directed a 7.5% reduction to ATCO I-Tek charges in the Affiliated Transactions Decision, Decision 2002-069 (p. 51), ATCO I-Tek charges in 2005 should be reduced for interim purposes. The CG/UCA also noted that part of the proposed reduction was attributable to AGN.

Similar to the ATCO I-Tek charges, CG submitted that the Board reduced the SinglePoint (now ITBS) charges by 11.1% in the Affiliated Transactions Decision 2002-069 (p. 66). The CG proposed that the $22.5 million of ITBS Operating Expenses forecast for 2005 be reduced by 11.1% or $2.5 million for interim purposes, $1.3 million of which was attributable to AGN.

Views of the Board

The Board has reviewed AG's forecast ITBS Volumes shown in Tab 4.2 and has determined that the volumes are reasonable. The Board notes that AG confirmed[282] that its placeholder forecasts did not reflect the reduction used by the Board in Decision 2002-069. The Board directs AG in its compliance filing, to apply the 11.1% reduction to its placeholder forecast ITBS Operating Expenses as directed in Decision 2002-069.

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278 Application No. 1403050
279 Ex 02-001, Application Volume 1, page 4.3-43, Table 4.3.22 as well as TAB 4.2.
280 Ex 02-015-001, BR-AG-30 and Ex 02-001-002, Application Volume 3, Tab 6.1 Affiliate Transactions, Affiliate Expense, page 3
281 City of Calgary final Argument, page 28
282 Response to CAL-AG-16

The Board has reviewed the forecast I-Tek Volumes shown in Tab 4.3 and has determined that the volumes are reasonable. However, the Board directs AG in its Compliance filing, to reduce its placeholder forecast I-Tek Operating Expenses by 7.5% in all applicable O&M schedules.

The Board agrees with CG's submission that the placeholder amounts for I-Tek Operating Expenses and ITBS Operating Expenses should reflect the foregoing reductions until the benchmarking of FMV services for these two areas is completed.

Distributed Disaster Recovery (DDR)

AG submitted that they were moving most of their business applications from a mainframe system to a distributed platform. In order to develop and test its disaster recovery plan AG submitted a business case for its DDR plan for IT. AG requested a $14 monthly charge per User ID for 2006 and 2007 in order to build and maintain a DDR testing environment.[283] The CG considered that the proposed $14 per month/user charge should be rejected by the Board. The CG argued that AG failed to provide adequate support for the need for the charge or how customers would benefit from the service proposed. CG commented that the plan appeared to be in the conceptual stage, and lacking in any detail. The CG recommended that it be rejected.

Views of the Board

Based on the AG Business Case for DDR,[284] the Board considers that AG's request to develop and test its disaster recovery plan is reasonable.

4.4.2 Impact of the Retail Transfer Decision 2005-039

The Board issued the AG Impact of the Retail Transfer and ITBS Volume Forecast Decision 2005-039 on May 3, 2005 (the Gas Impact of Retail Transfer Decision) in which the Board reduced certain communication and administration costs as a result of the transfer of the retail function to Direct Energy Regulated Services (DERS). However, AG indicated that the impact of that Decision was not reflected in its forecast revenue requirement.[285] AG submitted that the forecast for 2005, 2006 and 2007 reflected cost reductions related to the transfer of the retail function to the extent that AG was able to achieve reductions. AG did not reflect any of the reductions or identify the changes as compared to those imposed by the Board in the Gas Impact of Retail Transfer Decision. In Decision 2003-072,[286] the Board stated its expectations for future filings as follows:

> The Board is supportive of any initiative to enhance the regulatory process, and notes the concerns expressed by interveners during the course of these proceedings with respect to the absence of comprehensive underlying support for information in the Application. The Board notes intervener comments that this created a situation where "challenges to the position of the Applicant are then based on less than the full and complete facts known by the Applicant in support of its case"[287] and that "a GRA is not a game of hide and seek or 20 questions."[288] The Board notes intervener claims that this condition resulted in the need for a more extensive interrogatory process, and notes that the condition was also

[283] AGAG 2005-7 GRA Volume 2, Tab 2.1, BC 19, pages 1-7
[284] Business Case 19 filed in TAB 2.1
[285] CG-AG-2(a)
[286] Decision 2003-072, page 24
[287] Calgary Evidence, page 14 of 71
[288] CG Argument, page 113

> manifest in situations where test year forecasts reflected a methodology different from that previously approved by the Board.
>
> The Board expects that test year forecasts in rate filings should, at a minimum, be based on previously approved methodologies or policies, and that where the Applicant proposes a change to the approved practices, those changes should be presented in the filing as proposals, indicating the impact relative to the approved policies. The Board notes that the Application was not presented in this manner with respect to all initiatives and changes, which made it difficult for all parties to understand the impact of some of the changes and reconcile them with previous practice.

Views of the Board

Although the Gas Impact of Retail Transfer Decision was released shortly prior to the filing of the Application, the need for AG to address the changes required by the Gas Impact of Retail Transfer Decision falls within the group of concerns highlighted by the above quote. Any proposal for change to previously approved costs or to the status quo and all new material programs need to be presented in a fashion that makes it easy for all interested parties to understand the impact. The failure to highlight proposed changes and to set out the impact of a change does not lend itself to efficient review of rate filings. In future applications the Board directs AG to comply with the Board's expectation as stated above in the next GRA.

The Board notes that the CG proposed a reduction to communication costs of $214,000 for each of AGN and AGS and reductions in administration costs of $1,582,000 in the North and $1,647,000 in the South. These reductions will be incorporated in this Decision as they reflect the adjustments made by the Board in the Gas Impact of Retail Transfer decision.

4.4.3 Sales and Transportation Promotion Function

AG requested increases in the O&M forecasts related to corporate communication.[289] In particular, the forecasted expenses for the Sales and Transportation Promotion Function were $8.630 million, $8.074 million and $8.411 million for 2005, 2006 and 2007 respectively. The Sales and Transportation Promotion Function included expenses for Advertising, Demonstration and Selling, and Home Service. AG submitted it had relied on customer surveys or other customer feedback to develop their position. The forecast expenses for Sales and Transportation Promotion Function had increased over those approved in the 2003/2004 GRA and most recently in the Gas Impact of Retail Transfer Decision which approved an amount of $2.628 million for 2004, or $2.378 million when adjusted to a full year, to recognize that AG no longer performed the retail function.

The Board notes that expenditures related to the Blue Flame Kitchen, which are included in this function, will be discussed separately in a following section.

Public Safety/Customer Education

AG stated it had identified several public safety concerns related to uncapped lines and open valves in customer homes, carbon monoxide, and hit lines. AG submitted that these were important issues which deserved more attention until significant progress was made in reducing these public safety risks. For this program AG forecast an expense of $900,000, $920,000 and $930,000 for 2005, 2006 and 2007, respectively.

[289] Application, page 4.3-22

With respect to Public Safety the CG submitted that AG should not be allowed to selectively increase its forecast revenue requirements for this one item. No reasons were provided by AG for increasing expenditures by five-fold for programs related to carbon monoxide from 2004 other than indicating that advertising must achieve adequate levels of reach and frequencies to maintain a high level of awareness.[290] Absent any definitive reasons for this increase, the CG considered that one print program, one radio program and perhaps a bill insert should substantively increase the "reach" over the 2004 program. The CG also considered that the proposed increases in expenditures for the "Dig a Whole Lot Smarter" homeowners program were excessive and should also be reduced. The CG questioned the value of the second phase of the program in October-November considering the program was aimed at hit lines by homebuilders, excavators, landscaping companies and homeowners building decks, fences and landscaping their yards. The CG recommended that the 2005 advertising allowance for safety be limited to $580,000 with corresponding adjustments for 2006 and 2007.[291]

AG considered that the Ipsos Reid survey[292] it had commissioned showed that customers continue to be confused about the roles of various participants in the natural gas industry and that customers wanted to access information about this issue. To provide for customer education and to address industry structure/role advertising AG forecast $1.2 million, $1.226 million and $1.252 million for 2005, 2006 and 2007 respectively.

The CG considered that the proposed increases in expenditures for this program be limited to $600,000 in 2005, $400,000 in 2006 and $200,000 in 2007 reasoning that advertising costs associated with industry restructuring should decline over time as customers became more familiar with the restructured industry.

Views of the Board

The Board notes that the CG considered the answer to the following Ipsos Reid Customer Satisfaction Survey question was insufficient reason for the significant increase in Customer Education expenditures:

> AG customers have a fairly strong awareness of communications materials. Nearly three-quarters of respondents (74%) state they recall seeing communications materials from the company.[293]

The Board agrees with the CG that survey evidence demonstrating that customers recall seeing communications materials does not justify increasing Customer Education expenditures from $0.1 million in 2003 and $0.5 million in 2004 to $1.2 million in each of the test years.[294]

The Board also dealt with a similar issue in the DERS 2004 GRA[295] and concluded as follows:

> Therefore, the Board will approve the amounts requested by DERS for deregulation and customer choice education for the proposed print campaign and the proposed bill inserts.

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[290] CG-AG-34(d)
[291] AG had noted that there was a difference of $257,000 between the GRA forecast and the amounts listed in CG-AG-34(a).
[292] Application Tab 9.0
[293] Ipsos Reid Survey, page 14
[294] CG Reply Argument, pages 38-39
[295] Decision 2003-106 Direct Energy Regulated Services Electric Regulated Rate Tariff and Gas Default Rate Tariff, December 18, 2003

> However, the Board does not agree with DERS that it is necessary or appropriate for RRP's to engage in television or radio campaigns with respect to this matter.[296]

As noted by the CG, the Board approved an annualized amount of $592,000 for DERS to conduct a print/insert campaign. This amount is considerably less than the amount proposed by AG.

The Board remains unconvinced that AG is required to increase its expenditures in this category to the extent proposed. While the expenditures for Demonstrating and Selling appear reasonable, given the increased effort by EnergySense which produces offsetting revenues, the expenses for Advertising do not. AG has not persuaded the Board that there is a need to increase its Advertising budget over historical levels. The Board is satisfied that safety issues and customer education can be adequately covered with historical levels of expenditures. In particular, customer education has to be a shared responsibility and expenditures by DERS provides for a portion of such education. The Board agrees with the CG that reductions to the forecast are warranted, but prefers to primarily address the overall expense rather than specific pieces, leaving it up to AG as to how to make the specific adjustments. The Board believes the level of expenditures approved in Decision 2005-039, adjusted to a full year for 2004, can be used to establish the base from which to project expenditures for approval. Allowing for inflation the factor of 2.2% will be applied for 2005 and 2006 and 2.1% for 2007 and accordingly the Board hereby approves Advertising expense (Account 701) for 2005 to 2007 in the amounts of $2.430 million, $2.484 million and $2.536 million respectively.

Centennial Program

AG submitted that 2005 was a special year in regard to the community relations expense. As the centennial of the province of Alberta, this was a special time, and it deserved special efforts on behalf of those corporations with a significant presence in Alberta. AG sponsored a share of the AG Centennial project, which was to total $1.616 million. AG explained its share was $600,000.[297]

The CG did not consider that costs relating to the Centennial Program should be included in revenue requirement and argued that AG failed to demonstrate that these costs were necessary for the distribution of natural gas and were therefore not needed expenditures. CG argued that if AG shareholders wished to undertake such a program they should be expected to fund the program.

Views of the Board

The Board accepts AG's assertion that the Centennial Program was a worthwhile expense in celebrating the 100th anniversary of the Province and the contributions of the gas utility to the Province's development and future possibilities. The positive comments received from the many customers that viewed the display as it toured the Province are persuasive as to its value. The Board notes that AG had estimated its share as being $600,000 but did not explain the share derivation. The Board considers that since the program was a centennial celebration of the AG corporate family it would be appropriate for AG's share to be allocated based on the percentage that is relative to all the AG companies. In response to CG-AG-41(a) AG provided a table which indicates the percentages on which corporate costs are allocated. The factor for AG that would conform to the Affiliate Decision appears to be 16.4%. Therefore the Board directs AG to use

296 Decision 2003-106, page 104
297 BR-AG-27(j)

this factor to determine AG's share, which the Board calculates to be $272,290.[298] Adding this amount to the amount previously approved, the total approved Advertising Expense for 2005 will be $2,702,290.

The Board directs AG to confirm its forecast amounts for the Sales and Transportation Promotion function expenses to the Board approved amounts in the Compliance filing.

4.4.4 Blue Flame Kitchen

AG asserted that the Blue Flame Kitchen has been an Alberta tradition for three quarters of a century. Professional home economists help customers with home-making activities by providing reliable advice and information. Staff handle thousands of inquires every year, and customer demand for the Blue Flame Kitchen's cookbooks continues to grow.

AG submitted that as the Blue Flame Kitchen increased in popularity, so too did the need for more home economists. In 2003 an additional full time home economist and four permanent part-time home economists were hired, bringing the total to three full-time permanent, four casual employees, and a clerk. In 2004, due to increasing media appearances and participation in community trade shows across the Province, another clerk was hired and the budget was increased for casual staff to help cover summer vacations.

AG claimed that the services provided by the Blue Flame Kitchen were expected by its customers, and it provided AG with a point of contact with its customers, which was important for gauging customer satisfaction and franchise retention. The costs associated with the Blue Flame Kitchen were not considered significant and the overall cost to customers of providing this service was minimal.

AG forecast expenditures of $687,000, $706,000 and $722,000 for 2005, 2006, and 2007 respectively for the Blue Flame Kitchen.[299] The Board notes that this forecast does not correlate with a specific account under Sales & Transportation Promotion and AG did not provide how the correlation occurs as requested in BR-AG-27(a).

The CG did not support the inclusion of costs associated with the Blue Flame Kitchen in the revenue requirement of AG. The Blue Flame Kitchen was considered not an essential service of a natural gas distribution company and consequently should not be paid for by customers in their regulated rates. The CG recommended that Blue Flame Kitchen costs be removed from the revenue requirement for the test years.[300] If anything, the CG considered the Blue Flame Kitchen should be paid for by the customers actually using the service; not by distribution customers in general.

Views of the Board

The Board recognizes and agrees with AG that the Blue Flame Kitchen is a long standing institution appreciated by many customers. Like other services, such as furnace checks, not all customers take advantage of the service even though it is included in the rates. The Blue Flame Kitchen does produce offsetting revenue from many of the users of its service. The service could be characterized as a "legacy" service, which provides AG with an important point of contact

[298] $1,660,300 x 16.4%
[299] Application, Volume 1, page 4.3-35, Table 4.3.19
[300] Exhibit 19-11, page 40

with customers on a daily basis. The Board considers that the Blue Flame Kitchen performs a worthwhile function for AG, as it has done for many years, at an expense that is not excessive.

As noted previously, the total expenses forecast by AG have not been correlated to specific accounts however, the Board will approve the labour component for the test years as was indicated on Table 4.3.19. The Board directs AG to adjust the accounts in Sales & Transportation Promotion function to reflect the Board's approvals in this section and Section 4.4.3 of this Decision and provide an explanation including the detail of the calculation in the Compliance filing.

4.4.5 Administrative and General Expense

AG forecast Administrative Expenses (Account 721) of $41.242 million, $41.789 million and $42.746 million for 2005, 2006 and 2007 respectively.[301] In support of these estimates, AG provided an analysis of Administrative and General Expense as a percentage of Total O&M for AltaGas Utilities Inc., EPCOR Distribution Inc., and ENMAX Energy Corporation.

The CG understood that AG had not reflected the findings of the Gas Impact of Retail Transfer Decision, Decision 2005-039 in its 2005, 2006 and 2007 revenue requirements. This was of a significant concern to CG because there were two areas where the Board had agreed with interveners that the reductions resulting from the retail transfer should be greater than forecast by AG in the Impact of the Retail Transfer Application. In this regard the Board notes AG has increased its forecast for Administrative, Account 721, but has not highlighted the specific differences relative to Decision 2005-039 as expected in 2003-072 (2003/04 GRA) and discussed previously in this Decision.

The CG recommended that Administration Expense be reduced by $1,582,000 in the North and by $1,647,000 in the South, in each of the test years to reflect the transfer of the retail function.[302]

The CG also advised caution when comparing the administrative costs as a percentage of total O&M as between large and small, public and private, gas and electric utilities and retailers. CG had not researched that information in any great detail, but noted that AltaGas Utilities Inc. was a small gas distribution utility that still provided retail service. ENMAX Energy Corporation was a municipally owned electric and gas retailer. EPCOR Distribution Inc. was a municipally owned electric distribution wires utility. CG noted that the reductions proposed to administration and general expense would only result in a small reduction to the percentage shown by AG from 24.31% to 22.86%. The CG submitted there was no way of knowing from the evidence provided whether that percentage was reasonable for a utility of AG's size that does not provide retail service.

Views of the Board

AG argued that the costs incurred by AG in 2004, which had formed the starting point for the development of the GRA forecast, were prudent and necessary. The Board generally agrees with AG that 2004 is a good staring point, but notes that AG was not performing a pure distribution function during 2004. As a consequence, the Board is of the view that the Administrative Expenses approved in Decision 2005-039 and adjusted to an annual basis is the reasonable starting point. The Board also notes that there are a number of sub-categories of expenses within

301 Application Volume 1, page 4.3-4.4, Table 4.3.23
302 BR-CG-12

Administrative Expense[303] that will be subject to either benchmarking or the Common Matters Proceeding, and as such will be considered placeholders for revenue requirement purposes pending the outcome of those processes.

However, the Board considers it appropriate to deal with the Administrative Expense, Account 721, on an overall basis, as it has done in the past, and will provide direction on how to factor in the placeholders.

In response to BR-AG-38, Attachment 2, Schedule 4.3, the total for Administrative Expenses, including Carbon, was shown to be $41.674 million, $42.391 million and $43.363 million for each successive test year.

AG provided the following table, not including Carbon:

Table 20. AG 2005-2007 GRA Account 721 (CG-AG-38 Attachment 1) ($000s) [304]

	2003 Actual	2004 Actual	2005 GRA	2006 GRA	2007 GRA
Labour	$10,022	$9,631	$11,321	$11,822	$12,234
Airfares, Lodging, Vehicles, Mileage	$313	$356	$357	$363	$370
AG Corp. Services	$2,873	$3,663	$4,716	$4,858	$5,001
AG I-Tek	$11,435	$11,069	$14,000	$13,880	$14,080
Contract Labour	$273	$161	$53	$54	$56
Conventions	$238	$225	$344	$338	$359
Corporate Aircraft	$458	$700	$621	$635	$648
Courier Services	$201	$197	$201	$201	$204
Directory Telephone Advertising	$291	$359	$296	$303	$309
Employee Relocation	$593	$628	$642	$676	$732
Facilities Management	$519	4613	$646	$658	$669
Mgmt. Development & Training	$72	$119	$162	$170	$178
Office Rent	$6,161	$6,180	$6,427	$6,499	$6,573
Stationary, Printing, Photocopier	$1,043	$1,066	$852	$849	$853
Telephone Rental & Tolls, Fax	$313	$349	$318	$323	$328
Other Supplies	$810	$977	$286	$160	$152
TOTAL	$35,615	$36,293	$41,242	$41,789	$42,746

The Board notes that it is not clear how each item within Account 721 is affected by Carbon. AG is directed to provide this detail in its Compliance filing.

The Board notes that the components of Labour, AG Corporate Services, and Office Rent include items that will be discussed in the Common Matters proceeding, such as Executive Compensation and Head Office Rent. AG I-Tek and ITBS amounts will also be determined in a future benchmarking proceeding. These will be treated as placeholders for the purposes of this Decision.

The Board notes AG's submission[305] regarding ATCO/CU Corporate Administrative expenses cost allocation percentages for the test years. The Board notes that parties did not provide argument regarding the allocation percentages. The Board has reviewed the allocation factors

303 Refer to table from CG-AG-38 Attachment 1 reproduced in this Section
304 Response to CG-AG-38, Attachment 1
305 AG Application, Tab 4.4 – Head Office Costs

proposed for the sharing of ATCO/CU Corporate Administrative expenses to the utilities, and finds the proposed percentage allocation to AG is reasonable. However, certain costs used in the derivation of those percentages will remain as placeholders pending the outcome of the Common Matters proceeding.

Therefore, the Board approves the allocation percentages proposed by AG subject to further adjustments resulting from the resolution of the amounts associated with the cost items to be resolved in the Common Issues proceeding.

As stated above, the Board will make adjustments on an overall basis to Account 721. The Board will use the directions provided by Decision 2005-039, adjusted to a full year for 2004, as a starting point. This will establish a base for 2004 to which the inflation factor of 2.2% will be applied for 2005 and 2006 and 2.1% for 2007 to arrive at the approved amounts for the test years. The calculation for 2004 is as follows in millions of dollars:

> 36.293[2004 actual] minus 33.866[approved for 2004 Decision 2005-039] plus 32.369[Decision 2005-039 adjusted to a full year] = 34.796

Starting with the calculated value for 2004 and applying the appropriate inflation, the value for 2005 becomes $35.562 million, and $36.344 million for 2006 and $37.107 million for 2007. These are the amounts approved by the Board for Administrative Expense, Account 721, subject to revision by the aforementioned placeholders. The total amount shall be revised by the difference between the placeholder and the final amounts approved in the other noted proceedings.

AG is directed to adjust the revenue requirement, including Carbon, using the approved totals and to clearly identify placeholder amounts in each sub-category when submitting its Compliance filing.

Cost categories included within Administrative and General Expenses, that are not specifically addressed elsewhere in this Decision are hereby approved.

4.4.6 Charitable Donations

AG included expenditures in Account 728 for donations of $657,000, $674,000 and $689,000 for 2005, 2006 and 2007 respectively. AG claimed that the amount of forecast expenditures was a normal business expense of similar non-regulated companies and benefited customers in a number of ways by enhancing the ability of the utility to efficiently carry out its business in the communities in which it operates and to attract employees. AG argued that the amounts forecast were modest and reasonable as was shown in the Customer Survey results provided within the Application.[306]

The CG provided a number of references to previous Board decisions that had all disallowed the inclusion of charitable donations. These included Decision U97065 respecting the 1996 Electric Tariff Applications,[307] Decision 2001-96 respecting AG South,[308] Decision 2003-106 respecting

[306] Application Volume 4, Tab 9
[307] Decision U97065, page 520
[308] Decision 2001-096, page 98

DERS 2004 GRA,[309] Decision 2004-067 respecting EPCOR Distribution,[310] and Decision 2004-069 respecting NGTL for 2004.[311] The CG considered that charitable donations were not a required function for a natural gas distribution business and therefore should not be included in rates. The CG supported the continued exclusion of charitable donations from revenue requirement to avoid the implication that customers were making forced donations.

The CFIB also did not support the inclusion of donations in revenue requirement. The CFIB considered that, in order for AG to successfully claim that its donations were a "reasonable cost of doing business", it must demonstrate that these costs somehow created a competitive benefit for AG.

Views of the Board

The Board notes that it has consistently disallowed the inclusion of donations in revenue requirement, as pointed out by the CG. The Board, once again, is not persuaded by AG's argument. While the Board acknowledges that AG is behaving as expected for a major company in its service territories by providing charitable donations, these amounts should not be supported by customers. Customers have the right to choose to support whichever worthy causes they choose through their own donation dollars and should not be expected to provide the funds to support the causes that AG has chosen and for which AG receives the acknowledgement.

The Board also notes the response to CG-AG-34(j) in which AG provide "Table A Sponsorships". The total amount of forecast sponsorship expenditures indicated by the table was $858,995 for 2005. This amount is in addition to the $657,000[312] earmarked as donations for 2005. Upon review of what AG plans to support under "Sponsorships", the Board does not consider there is sufficient distinction from those in "Donations" to separate the two categories. The Board considers they are one and the same and, as has been the consistent practice of the Board,[313] [314] the amounts included in the Application as "Sponsorships" and "Donations" are therefore disallowed. (For greater certainty, the amount disallowed for 2005 is the sum of $858,995 and $657,000). AG is directed to remove these expenditures from the revenue requirement for each of the test years and to confirm the amounts that are to be removed for each test year in the Compliance filing.

4.4.7 Transportation Service Charges

Table 21 shows forecast peak demand and demand charges for AGN and AGS for the test period years.

Table 21. Transportation Service Charges ($000s)[315]

	2005		2006		2007	
	North	South	North	South	North	South
Demand (TJs)	1271	1138	1363	1220	1390	1245
Rate ($/GJ)	$2.258	$1.827	$2.258	$1.827	$2.258	$1.827
TOTAL	$34,433	$24,948	$36,921	$26,752	$37,658	$27,286

309 Decision 2003-106, page 104
310 Decision 2004-067, page 50
311 Decision 2004-069, page 13
312 Application Volume 1, page 4.3-61, Table 4.3.33
313 Decision 2003-106, page 104
314 Decision 2001-096, page 98
315 Application Volume 1, page 4.3-14

AG submitted its forecast of Peak Demand in the Peak Demand Study in Tab 4.1 of the Application. Transportation service charges from ATCO Pipelines are determined by the application of demand rates which are set by the Board in the ATCO Pipelines GRA.

Views of the Board

The Board acknowledges that AG does not have control over the demand rate for transportation service charged by ATCO Pipelines and that the demand rate is set in the ATCO Pipelines GRA. Consequently, to deal with the uncertainty of the transportation charge from ATCO Pipelines, AG applied for and, in Section 9.11 of this Decision, the Board dealt with AG's request to initiate a deferral account for transportation charges.

The Board notes that no interveners made any submissions and provided any commentary regarding the forecasted peak demand study. The Board has reviewed AG's Peak Demand Study and is satisfied that AG's forecast is reasonable and hereby approves the forecast of peak demand for the North and South as shown in the Application.

4.5 Meter Reading

In the Application, AG proposed to include within the O&M portion of revenue requirement forecasted expenses to read all meters monthly. In support of its proposal AG submitted a business case (BC-23) and a customer survey which indicated that customers were in favour of actual meter readings as opposed to estimates. AG had also made the same proposal during its 2003/2004 GRA. In Decision 2003-072, the Board denied the inclusion of the expense to read meters monthly, however, AG continued to read meters on a monthly basis.

AG argued that there are important differences between current market conditions and those during the previous GRA. The critical differences emphasized by AG were first, that gas costs have doubled since 2003. Even with the government Natural Gas Protection Program, AG contended that residential customers are likely to face prices of $8.75/GJ in peak season. Secondly, AG noted that since the 2003/4 GRA, the competitive gas retail market has developed significantly. For retailers, AG argued that meter reads have "broader implications than customer satisfaction as Retailers are concerned with customer account balancing, load balancing and load settlement respecting Retailer Service and Gas Utilities Act compliance."[316]

AG provided the following actual and forecast expenses for Meter Reading and Bill Delivery, Account 712, for both AGN and AGS in the Application:[317]

Table 22. AG Meter Reading and Bill Delivery Expenses ($000)

	2003 Actual	2004 Actual	2005 Forecast	2006 Forecast	2007 Forecast
Account 712	$12,148	$12,753	$14,013	$14,954	$15,972

The above compares to $9.690 million approved by the Board on the basis of bi-monthly meter readings in Decision 2005-036, dated April 28, 2004, and Decision 2004-047, dated June 15, 2004.

[316] Argument pages 55-56
[317] Application Volume 1, page 4.3-37, Table 4.3.21

Views of the Board

DEML submitted that disallowance of AG's costs to read meters monthly would prompt AG to revert to reading most meters bi-monthly and would result in meter readings without an actual meter read within the month for at least half of the customer bills it provides to Rate 1 customers. This would greatly increase the degree to which those bills were based on estimates. Although DEML was unable to quantify the impact, it considered that this would have the following consequences:

- lower customer satisfaction[318]
- increased customer care costs[319]
- increased bad debt exposure and higher working capital for DEML[320]
- impede Alberta Government initiatives to restructure the framework of the natural gas retail market[321]
- impede the early identification of metering issues[322]

Calgary noted that, although it supported accurate gas bills as a desirable goal, it was opposed to monthly meter reading. This was consistent with Calgary's position in the last GRA. Calgary noted that there were a significant number of customers who took advantage of the budget plan, so that month-to-month variations were not a major concern for them. Calgary submitted that there continued to be no justification in this GRA for the need to read meters monthly. Calgary further noted that, as provided for in Decision 2001-75, the energy charge for gas consumed changes the first of every month for default supply customers, and unless the customer's meter reading date was always on the first of the month, there would always be extrapolations in calculating customers' bills. Calgary suggested that if parties such as DEML want the data monthly, then they should pay for it rather than having all customers pay for the service.

CG also continued to be opposed to monthly meter reading, as they were in the 2003-2004 GRA. CG considered that bi-monthly meter reading would provide consumers with accurate bills and would not impose harm on consumers. It was the CG's view that there had been no quantitative or qualitative proof by AG that the additional cost of monthly meter reading would provide benefits to consumers, commensurate with the cost. The CG were also of the view that the costs to be removed from the Application should approach $4,500,000 per year, as indicated by AG in response to AUMA/EDM-AG-46 in the 2003-2004 GRA, in addition to the reductions required for transportation equipment and implementation.

AG provided[323] a business case regarding the potential impact of estimated meter reads. The CG, in their review of the business case, took issue with the conclusions of AG with respect to the impacts, and the CG provided their calculations of the cost of errors.

The Board is not persuaded by either party that their view of the cost of errors or estimates is correct. The Board notes that neither party seemed to focus on the differential of the cost of gas

318 Exhibit 13 & 14-002, page 1, para. 2; BR-DEML-01, page 2, last paragraph [Exhibit 13 & 14-004-001]; T941, ll. 11-12, T974, ll. 22-25 and T975, ll. 1-14
319 Transcript, page 961, ll. 18-25 and Transcript, page 962, ll. 1-4
320 Transcript, page 961, ll. 20 & 21
321 Transcript, page 947, ll. 18-24
322 Transcript, page 950, ll. 13-22
323 Application Volume 2, Business Case 23

between months when costing the potential impacts. It seems to the Board that since gas prices will go up and down, it is the differential over time that will provide a measure of the impact.

AG referred to the cost of monthly meter reading as $0.62 per month/customer.[324] AG provided[325] the derivation of the $0.62 as follows:

Table 23. Incremental Cost of Monthly Meter Reading ($000)

	Labour Costs	Supplies	Fringe Benefits	I-Tek	Total
North	$1,422	$147	$198	$41	$1,808
South	$860	$56	$120	$18	$1,054
					$2,862

- Project incremental number of attempts 4,600,000
- 900,000 customers*6 reads *85% = 4,590,000
- Incremental cost per attempt to provide monthly meter reading is calculated as $2,862,000/4,600,000 = $0.62 per month/customer

As noted by the CG[326], AG calculated the annual incremental cost of monthly meter reading to be $2,862,000. However AG also stated[327] that the annual incremental cost of monthly meter reading was as high as $3,318,000. In the 2003-04 GRA, AG estimated that the cost of implementing monthly meter reading would be $9,000,000 over the two test years, excluding vehicles and related items to implement the process.[328] This equated to approximately $4,500,000 per year excluding vehicles and related implementation costs. The CG used the $4,500,000 number and applied the same calculation ($4,500,000/4,600,000) proffered in CG-AG-36(a) to determine a potential monthly meter read cost of $0.98 per month.

In its business case, AG provided a customer survey, and in respect of the $0.62 calculation, AG makes the following observation:

> 40% of customers who report that they have not been receiving regular monthly meter read would be willing to pay $0.50 per month or $6 per year for monthly meter reading. The average price customers are willing to pay for monthly meter reading is 34 cents per month and this is less than the cost of monthly meter reading (approximately 62 cents per month).[329]

The CG noted that according to the AG customer survey, customers on average were only willing to pay $0.34 cents per month for monthly meter reading or about a third of the $0.98 cost. Under these conditions, the CG concluded customers were not willing to pay for the cost of monthly meter reading.

The foregoing discrepancies are problematic when evaluating the pros and cons of monthly meter reading versus bi-monthly meter reading. In general the Board did not find the customer survey particularly helpful or persuasive in advancing AG's case. It did not appear the customers

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324 Application Volume 2, Business Case 23, page 5 of 100
325 Response to CG-AG-36(a)
326 Response to CG-AG-36(a)
327 Response to BR-AG-28(a)
328 AUMA/EDM-AG-46
329 Application Volume 2, Business Case 23, page 5 of 100

surveyed were knowledgeable about the current period of meter reading and it was not clear they would agree to increased rates to pay for monthly meter reading. The CG made similar observations:

> Customers were not informed as to the status of meter reading at the time of the survey nor were they provided with the increase in cost. Customers were not informed that the Board had very recently rejected the AG proposal to implement monthly meter reading.[330]

The CG believed that bi-monthly meter reading provided an appropriate trade-off between cost versus acceptable error.

AG stated:

> Other utilities regulated by the EUB undertake monthly meter reading attempts and have had the costs to perform monthly meter reading included in their rates. In addition, there are a number of other utilities, gas, electric, and water, in other jurisdictions that have opted to read meters monthly.[331]

The AESO System Settlement Code Version 9.9 dated March 30, 2005[332] was referenced during cross examination. Reference to Appendix B Section 4.1.1 appears to require actual meter reads from 100% of all meters every two months[333] and would support AG's claim that monthly meter reads were required. However, at the present time there is no comparable System Settlement Code applicable to gas utilities. AG noted:

> With the expectation that gas meters will eventually be subject to the same requirements as electric meters, the requirements currently set out in the AESO System Settlement Code is the standard expected for gas meters. To obtain at least one meter reading from 100% of meters every two months cannot be met with bi-monthly meter reading attempts.[334]

The CG disputed AG's interpretation of the requirements of the AESO System Settlement Code criteria and believed they were based on the need for hourly and daily data for the purpose of electric load settlement and that they would not be applicable to gas which will likely not have the same load settlement needs. The CG further considered that the electric criteria did not address meter reading at small customer meters, rather they were focused on upstream custody transfer points.

The CG suggested that DEML's evidence was not helpful. The CG argued that DEML was not testifying on behalf of the Retailer Group. Thus there was an issue as to both the relevance and helpfulness of anything attributed to the Retailer Group.[335]

The CG submitted that the evidence of DEML appeared to be designed to impose additional cost upon ratepayers in order to provide perceived benefits to DEML, without a sharing of the cost of

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[330] CG Argument, pages 77-78
[331] Application Volume 2, Business Case 23, page 4
[332] Transcript, page 1018
[333] Transcript, page 1017
[334] Application Volume 2, BC 23, page 11
[335] Transcript, Volume 6, page 959, lines 6 - 11

receiving these benefits.[336] In CG's view the evidence of DERS seemed to address potential commercial benefits to be derived by increased costs to ratepayers.

The CG noted that both it and Calgary, in their evidence in the 2003/2004 GRA proceeding, addressed a number of points in detail which remained applicable. The CG noted that the Board in Decision 2002-072 stated:

> Given the overwhelming opposition to ATCO's proposal for monthly meter reading, the Board questions the need to significantly increase costs to customers who apparently have little concern with the present level of service. The Board agrees with interveners that the need for reading meters on a monthly frequency has not been demonstrated at this time. Accordingly, the Board directs ATCO to revise each of the test year forecasts for the meter reading program to reflect the costs of reading meters every two months.

The CG asserted that the opposition had not abated in the 11 months that passed from the issuance of Decision 2004-047 to the filing of this Application. Having reviewed the IR responses and the business case, the CG submitted that AG had not made any better case for monthly meter reading in this proceeding than it made in its last GRA.

AG strongly believed that monthly meter reading was the appropriate and necessary level of service and, in spite of disallowed costs, continued to provide monthly meter reading in 2003 and 2004. AG submitted that since that time several fundamental dynamic changes had taken place, making the need for monthly meter reading even more acute. AG believed it had put forward a compelling case for monthly meter reading in this proceeding; however, it would not continue to read meters monthly should the Board again disallow costs.[337] AG felt it would be obligated to communicate to customers that it had been directed to stop providing this level of service. AG stated it could not continue to provide this level of service while shareowners absorbed the significant incremental costs. Moreover, AG was concerned with the likely escalation of customer care costs in the event monthly meter reading was discontinued.

AG argued[338] the following reasons in support of monthly meter reading:

- Ensure customer satisfaction with their billing in a changed environment of increased natural gas price and volatility.
- Position itself to meet enhanced AEUB and other government expectations in terms of billing accuracy and intervals between actual reads.
- Provide a level of service in meter reading that is commensurate with that of other utilities.

Also in support of its case, AG submitted that the gas utility environment has changed significantly in the last several years. AG argued:

> The gas utility environment began to change significantly upon completion of the Alliance Pipeline to Chicago late in 2000. Export of Alberta's gas production was no longer limited by pipeline capacity. Albertans suddenly found themselves competing with the entire North American market and prices quickly tripled from the historical rate of

[336] Transcript, Volume 6, pages 963 - 964
[337] AG Argument, page 44, lines 11-17
[338] Application, Volume 2, Business Case 23

> \$2.00 /GJ to over \$6.00/GJ. The commodity cost of gas also became much more volatile. The EUB reacted with Decision 2001-75 leading to a Gas Cost Recovery Rate (GCRR) calculated monthly realizing that the old way of adjusting the GCRR only twice a year was no longer adequate in an environment of significantly higher and more volatile gas costs. ATCO Gas reacted with instituting monthly meter reading on a temporary basis from January through April, 2001. The environment of high and volatile gas commodity costs has not been temporary, it is still the environment today. Realizing that natural gas is a finite resource and demand for natural gas is increasing rapidly throughout North America, there is no reason to believe the environment of high and volatile high gas costs will ever reverse.[339]

AG went on to state that increased deregulation, Directive 003 from the EUB in 2003, the establishment of an Alberta Utilities Consumer Advocate in 2004, and new standards being introduced by Measurement Canada, all contributed to a changed or changing environment.

AG emphasized that there were critical difference between current market conditions and those that existed during the previous GRA including the doubling of the price of natural gas since 2003 and the high prices that customers were required to pay despite the government Natural Gas Protection Program. AG noted that since the 2003/2004 GRA, the competitive gas retail market has developed significantly and that monthly meter reading would assist the development of customer account balancing and load settlement practices.

Furthermore, AG focused on the additional billing errors that would be caused by reverting to bi-monthly meter reading. In CG-AG-18(e), AG indicated that during the winter months, one third of all customers would be billed with an estimating error of 5 GJ or more if meters were read bi-monthly. AG argued that at \$8.75 per month, the error due to the estimate could be as high as \$43.75 per customer. AG pointed out that the error would be corrected in the following month, however, due to changes in gas costs from month to month, there would be some residual error in the amount billed. The error would become greater as the volatility of the monthly gas costs increases.

The Board notes that all customer representatives continue to oppose the costs of monthly meter reading being included in revenue requirement.

There continues to be a wide difference of opinion as to the benefits and potential costs of reading or not reading meters monthly, with both sides providing their views of the impact on customers. The potential for increased customer service costs, in the event that AG was not to continue reading monthly, was not quantified by either AG or DEML.

Upon weighing the various arguments presented, the Board is persuaded that AG’s proposal to include the costs of monthly meter reading in the revenue requirements is justified in this GRA, for the following reasons:

- In this GRA, the cost of gas has increased substantially from the time of the 2003-2004 GRA. The forward average price in the 2003-2004 GRA was in the range of \$4.00/GJ, whereas in the 2005-2007 GRA the winter forward price for 2005-2006 was \$14.00. The Alberta Government Natural Gas Rebate Program limits customer’s rates to a maximum range from \$5.50 to \$8.75 per GJ dependent upon the market price.

[339] Application, page 4.3-38

- Both the market price and the price after the rebate show significant variability in this GRA test periods.
- The significant increase in natural gas prices and the increased volatility of prices since the last GRA will undoubtedly result in greater customer focus on the accuracy of their gas bills. It is unlikely that this situation will change during the course of the test period. In this environment, the Board finds the reasoning of AG compelling that any reduction in billing accuracy resulting from a change from monthly meter reading to bi-monthly meter reading is likely to generate significant customer anxiety which will lead to higher customer service costs. Avoiding customer anxiety is desirable where cost effective measures are available. While additional costs for dealing with customer enquiries related to consumption estimates on billing was not estimated by either AG or DERS, it is possible that savings resulting from bi-monthly meter readings could be partially offset by additional complaints and call centre volumes.
- There can be no assurance that the Natural Gas Rebate Program will continue in its present form throughout the test period.
- Monthly meter reading will reduce the magnitude of billing errors and permit the correction of estimation errors twice as frequently as bi-monthly meter reading. Accordingly, monthly meter reading will reduce the billing error that would not be corrected on the following month's bill if meters were read bi-monthly. This billing error can be significant to an individual customer, if the variation in the cost of gas between months is significant.
- The market place at the time of this GRA has changed substantially since the 2003-2004 GRA. A number of retailers are now providing services that AG was providing in the last GRA. DERS has stated its desire for monthly meter reading to minimize the effects on its business due to errors in consumption.
- Monthly meter reading may be a benefit to commercial transactions that depend on actual meter reads and may facilitate the development of an effective gas System Settlement Code.
- Maintaining monthly meter reading in a high priced, volatile gas environment will provide greater public confidence in the accuracy of bills and may enhance the environment for retail gas competition in the market place.

4.6 Gas Balancing

In the Revised Issues List of June 24, 2005, provided in Exhibit 01-006, the Board indicated the following with respect to this issue and what would be included for GRA purposes:

> Issues not covered in ATCO Gas Retailer Service and Gas Utilities Act Compliance Application, Application No. 1380942.[340]

AG was not aware of any issues that had been identified in the current GRA proceeding with respect to gas balancing. AG had indicated[341] that the proceeding with respect to finalizing the terms and conditions for Retailer Service would not be completed until 2006, which could impact the 2005 – 2007 GRA revenue requirement forecast. As indicated in the Overview, AG stated it would provide an update to the revenue requirement forecast if required, once that proceeding had been completed.

[340] Now Application No. 1411635
[341] Application, Overview, page 1.0-5

The Board notes that no issues were raised during the hearing. Further, the Board notes that in its correspondence with respect to Application No. 1411635, dated December 22, 2005, the Board scheduled an oral hearing in June 2006 to deal with the first two modules of five modules. It is clear that that process will not be completed until well after June. Consequently, AG is directed to indicate the amount of any placeholder related to gas balancing for revenue requirement purposes in the Compliance filing

5 DEPRECIATION AND AMORTIZATION[342]

5.1 Depreciation and Amortization Expense

AG forecast Net Utility depreciation and amortization expense of $70,484,000, $76,162,000 and $81,078,000 for 2005, 2006 and 2007 respectively.

AG submitted that its fixed assets were depreciated or amortized using one of four methods of calculation:

1. Study Assets (Straight Line Method – Equal Life Group Procedure)
2. Unit of Production Method (UOP)
3. Contract Life
4. Straight Line Fixed Rate

AG conducted a new depreciation study using historical data to the end of 2003 on a combined base of assets with one set of depreciation rates.[343]

Amortization of reserve differences by fixed asset account were calculated by comparing the actual accumulated depreciation to the theoretical accumulated depreciation. Differences greater than +/- 5% were amortized over the remaining life of the fixed asset account. A minimum 5 year period was used to amortize the surplus or deficit for each account.

Contributions were depreciated based on the approved life parameters of the corresponding fixed asset account, with a net salvage of 0%, and applied to contribution vintage balances.

Amortization of contribution reserve differences by contribution account were calculated by comparing the actual accumulated depreciation to the theoretical accumulated depreciation. Differences greater than +/- 5% were amortized over the remaining life of the contribution account. A minimum 5 year period was used to amortize the surplus or deficit for each account.

AG submitted that the methodology used by the Company was in accordance with the Board's requirements.

AG noted that the recommendations of AG' latest depreciation study would result in an approximate increase of $1,683,000 (excluding production assets) compared to depreciation

[342] Depreciation distributes fixed capital costs less net salvage over the forecast service life of the asset by allocating annual amounts to expense. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, or over the life of the asset or liability to which the account applies, or over the period during which it is anticipated that the benefit will be realized. Normally the distribution of the total is in equal amounts to each year of the amortization period.

[343] Method approved in Decision 2003-72, page 218

expense using currently approved rates. AG explained the increase was due to the combined effect of five types of changes:

1. Change due to a redistribution of vintage investment resulting from additions and retirements would decrease depreciation expense by approximately $32,000.
2. Change due to average service lives would increase depreciation expense by approximately $448,000.
3. Change due to Iowa curves would increase depreciation expense by approximately $53,000.
4. Change due to net salvage would increase depreciation expense by approximately $964,000.
5. Change due to amortization of differences would increase depreciation expense by approximately $250,000.

5.1.1 Amortization of AG CIS

In response to CAL-AG-21(a)[344] AG indicated that AG CIS would be fully depreciated by 2010. Enhancement costs to the AG CIS system forecast until 2007 would be fully depreciated by 2012.[345] AG CIS Enhancement costs incurred after 2007 would be "…fully depreciated 5 years after the last enhancement costs were incurred."[346] In the "Guidelines for Amortizing Investment in Software Projects"[347] AG stated that when a major enhancement or upgrade to Account 499 Major Software takes place, the cost of the enhancement would be capitalized and amortized over the expected useful life of the enhancement at the time the enhancement was implemented.

Views of the Board

The Board notes CG's argument that, given AG was predicting that Enhancement costs prior to 2007 included in the Application would be fully depreciated by 2012 (i.e. 20% rate or 5 year life), the minimum life for AG CIS should be until 2012, or 12 years rather than the current 10 years. Further, given that AG had indicated that CIS Enhancement costs incurred after 2007 would be fully depreciated 5 years after the last enhancement, CG concluded that perhaps the final retirement date for the AG CIS system should be 2013 or later. In CG's view, the expected life of the enhancements should not exceed the final retirement date of AG CIS (i.e. 2010). Thus CG recommended that the amortization period for AG CIS and CIS Enhancements be changed from the current 10 years and 5 years respectively, to the year of final retirement of 2013 to recognize that the forecast retirement date of 2010 for AG CIS is no longer reasonable. Following the same criteria as above, the CG considered that the CIS Contributions and CIS Contributions – Royalty should also have the same final date of 2013. The CG submitted that the Board should direct AG to incorporate these changes in its Compliance filing.

The Board notes AG's argument that there were two flaws in the CG's logic. First, Enhancement costs were not life extension costs. These costs were incurred to increase the functionality of AG CIS to meet government and regulatory requirements.[348] AG submitted these Enhancement costs have no bearing on the life of AG CIS. The life of AG CIS drove the life of these regulatory Enhancement costs. Second, AG submitted the CG was under the assumption that each vintage

[344] Exhibit 02-015-002
[345] Ibid
[346] Ibid
[347] Exhibit 02-001, Section 5.0, Appendix B, page 5.1B-54
[348] Application, Section 2.1.3.11, page 2.1-68, lines 4-21

for Enhancements was tracked separately and depreciated with a vintage rate of 20%. AG submitted this was not the case. All AG CIS Enhancement costs were capitalized to one account with a rate of 20% applied to the total account depreciable base.[349] This would result in the complete recovery of all Enhancement costs prior to the expected 2010 retirement date of AG CIS. In effect, AG's process would closely mimic the results of using a Lifespan approach with a 2010 year of final retirement.

The Board notes that in response to the question by Calgary on whether it planned on replacing AG CIS in the next 5 years, AG replied that it had not initiated a review of the life of AG CIS.[350] In CG's view, it was unlikely that AG could investigate, compare, select, test and implement a new CIS system in the foreseeable future which CG suggested should extend out to at least 2013.

The Board agrees with AG that the life span of the AG CIS is not likely extended by the enhancements forecast in this 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.[351]

The Board agrees that AG's current practice of amortizing enhancement costs using one account and one rate remains reasonable. The Board further notes that, consistent with the current practice, certain enhancement costs would be amortized after the physical retirement of the major software. This residual unamortized amount would form part of the remaining unamortized amounts included in the enhancement account, to be grouped with other enhancements and to be amortized in future years.

CG submitted that AG should be directed to follow the usual practice for other assets that were amortized, of including an Asset Reserve Amortization amount[352] to ensure that any over or under-recoveries of depreciation expense in the past were refunded to or collected from customers over the average remaining life of the asset account. CG further submitted that this calculation should apply to each of the major software projects that were included in Account 499, to ensure that customers paid for the assets and any refund or collection for past changes, over the life of the assets. In regards to including an amortization of differences calculation for all software accounts, AG submitted that with AG's current process, the use of an amortization of differences calculation would add nothing to the depreciation expense calculation and, as such, was not applicable.

The Board agrees with AG that an asset reserve account for each major software program in Account 499 would not be beneficial, since the differences are identified in other accounts through the results of a depreciation study using historical data and actuarial studies.

349 CG-AG-50(a) Attachment 1, Account 49911
350 Exhibit 02-015-002, CAL-AG-21(d)
351 Section 2.1.5 Other Replacement Projects
352 Exhibit 02-001, Section 5.0 Appendix A, Schedule 1, Column VIII

5.1.2 Negative Net Salvage

AG proposed a rate of -1% net salvage for major software.[353] In support of this small amount of negative net salvage, AG provided a high level cost estimate that had been prepared to determine forecast decommissioning costs for the AG CIS system.[354]

Views of the Board
The Board notes that while the CG did not dispute the decommissioning study submitted in response to CG-AG-50(b) Attachment 1, it submitted that the procedure itself was somewhat complex and bureaucratic. In addition, the CG felt it would be unwise and costly to undertake a similar process to review what the simple cost of retiring a major software system would be. Additional procedures and processes to handle a simple process did not seem appropriate in this case, in the CG's view.

The CG noted that one year's history of a $9,000 cost of removal was hardly evidence enough that there needed to be negative net salvage incorporated into the amortization rate for major software projects. The CG further submitted that AG's proposal to include a -1% net salvage rate in major software amortization may be premature and not necessary for such a small amount of dollars. The CG proposed that the Board reject AG's proposal.

The Board notes AG's argument that gradually the complexity and inter-relationships of software applications had increased to the point where removal of expired software applications was no longer a simple delete function. Further, removal costs were being incurred and charged to accumulated depreciation. To recognize removal costs, AG recommended that a 1% cost of removal be incorporated in all software applications. The 1% cost of removal would be modified accordingly as more years of actual removal experience dictated.[355] AG replied that small costs or not, intergenerational equity demanded that those customers that received the benefit should pay the costs.[356] According to AG, software removal costs were not "premature" as they would occur.

The Board acknowledges that, while some cost of removal is expected, and although 1% appears to be a small percentage, there was no substantiation, either from history or from quotes for future work, as to a reasonable estimate of time or cost expected for ATCO I-Tek to remove the software. The Board considers that the provision of -1% net salvage is premature at this time since there is insufficient history available to justify that percentage. Therefore, the Board denies the inclusion of -1% net salvage to provide for the removal of software programs and directs AG in the Compliance filing to make all the adjustment necessary to the financial schedules to reflect this direction.

In addition, the Board expects AG to obtain estimates from I-Tek for the cost of program removals and to justify these costs if requested in a subsequent review of actual costs.

5.1.3 Retirement of Contributions

AG applied for[357] permission to commence retiring contributions and to adjust the asset contribution account for a one time contribution adjustment amount of $10.6 million in 2005.

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353 Exhibit 02-001, Section 5.0 Appendix B, Page 5.1B-55
354 Exhibit 02-015-005, CG-AG-50(b) Attachment 1
355 Section 5, Appendix B, page 5.1B-55, lines 20-32
356 BR-AG-42 (a,b), last sentence
357 Exhibit 02-001

AG submitted that this one-time adjustment was required to bring past contribution records in line with the proposed methodology.

AG recommended that contributions be retired in direct proportion to the related fixed asset account retirement.[358] AG submitted that currently no processes were in place to retire unamortized contributions. When plant was constructed with customer contributions, both the fixed asset cost and customer contribution were capitalized to their respective accounts. Throughout the asset's life, retirements occurred and were processed through the appropriate fixed asset account. However no related contributions were similarly retired.

Views of the Board

The Board notes that the CG agreed that the process of retiring contributions was appropriate and supported AG in its proposal.

The Board also notes that AG amortized contributions along with the depreciation charge. However, it appears that AG had not retired the unamortized contribution for plant when the plant was retired. When plant was retired, the residual undepreciated amount of the asset was retired, but the remaining unamortized contribution was not similarly written off, as it should have been. Further, the CG agreed with the proposal to retire contributions, and also agreed that the one-time adjustment should be effected in 2005.

The Board agrees with AG and CG that retiring the unamortized amount of contributions associated with a retirement of specific asset is the correct procedure. Therefore, the Board approves the requested change in accounting to commence the retirement of unamortized contributions associated with retirement of specific assets.

In addition, the Board approves an adjustment the asset contribution accounts for a one time contribution adjustment amount of $10.6 million in 2005. The Board directs AG in the Compliance filing to show the account entries and the related amounts.

5.1.4 Changes to Parameters and Specific Accounts

Assets Associated with Contract Life

AG recommended that the term of depreciation for assets associated with a contract should be depreciated over the contract life plus one renewal period.[359]

Account 47200 – Distribution Structures and Improvements

AG recommended changes to its curve and average service life parameters from a R3 curve and 50 year average service life to a R2.5 curve and 55 year average service life.[360] This change was recommended due to the longer life indications of the historical analysis.[361]

Account 47400 – Distribution Regulator and Meter Installations

AG recommended a change to its net salvage parameter from -25% to -30%.[362] This change was recommended due to the changing net salvage indications of the historical analysis.[363]

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358 Section 5.1.6 Contributions, Page 5.1-7, lines 19-20
359 Section 5.1.4 Contract Life, page 5.1-6
360 Section 5.1, Appendix A, page 1 and Appendix B, page 5.1B-12, lines 17-18
361 Section 5.1, Appendix B, page 5.1B-11, lines 25-34 to page 5.1B-12, lines 3-6
362 Section 5.1, Appendix A, page 1 and Appendix B, page 5.1B-16, line 33

Account 47500 – Distribution Mains

AG recommended a change to its net salvage parameter from -50% to -60%.[364] This change was recommended in response to the consistent lower net salvage as indicated in the historical analysis.[365]

Account 47700 – Distribution Measuring and Regulating Equipment

AG recommended a change to its average service life parameter from 35 years to 38 years[366]. This change was recommended in response to the longer life indications of the historical analysis.[367]

Account 47800 – Distribution Meter Equipment

AG recommended changes to its average service life and net salvage parameters from a 30 year average service life with a 1% net salvage to a 25 year average service life with a 10% net salvage.[368] This change was recommended in response to the change from "cradle to grave" to "location" accounting.[369]

Account 48201 – General Structures and Improvements (Security Systems)

AG recommended a change to its curve parameter from a R5 curve to an R2.5 curve.[370] This change was recommended in response to the wider retirement dispersion indications of the historical analysis.[371]

Account 48300 – General Office Furniture and Equipment

AG recommended a change to its net salvage parameter from 5% to 2%.[372] This change was recommended in response to the decreasing net salvage indications of the historical analysis.[373]

Account 48500 – General Heavy Work Equipment

AG recommended a change to its curve and average service life parameters from a L2 curve with a 14 year average service life to a L2.5 curve with a 13 year average service life.[374] This change was recommended in response to the indications of the historical analysis.[375]

Account 48900 – General Stores, Shop & Garage Equipment

AG recommended a change to its net salvage parameter from 5% to 10%.[376] This change was recommended in response to the net salvage indications of the historical analysis.[377]

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[363] Section 5.1, Appendix B, page 5.1B-16, lines 16-26
[364] Section 5.1, Appendix A, page 1 and Appendix B, page 5.1B-20, line 36
[365] Section 5.1 Appendix B, page 5.1B-20, lines 22-29
[366] Section 5.1, Appendix A, page 1 and Appendix B, page 5.1B-22, line 13
[367] Section 5.1, Appendix B, page 5.1B-21, lines 28-34 to page 5.1B-22, lines 3-4
[368] Section 5.1, Appendix A, page 1 and Appendix B, page 5.1B-25, lines 37 & 41
[369] Section 5.1 Appendix B, page 5.1B-25, lines 3-34
[370] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-31, line 6
[371] Section 5.1 Appendix B, page 5.1B-30, lines 20-25
[372] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-33, line 8
[373] Section 5.1 Appendix B, page 5.1B-32, lines 27-32
[374] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-39, lines 13-14
[375] Section 5.1 Appendix B, page 5.1B-38, lines 27-33 to page 5.1B-39, lines 3-5
[376] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-47, line 8
[377] Section 5.1 Appendix B, page 5.1B-46, lines 27-32

Account 49001 - General Natural Gas Vehicle Refueling Equipment
AG recommended a change to its average service life parameter from 15 years to 19 years[378]. This change was recommended in response to the longer life indications of the historical analysis.[379]

Account 49600 – General Computer & Electronic Office Equipment
AG recommended a change in its curve and average service life parameters from a S6 curve with an 8 year average service life to a R4 curve with a 10 year average service life.[380] This change was recommended in response to the longer life indications of a future analysis.[381]

The Board has reviewed AG's specific recommendations regarding changes to the parameters for the accounts listed above. The Board views these recommendations as reasonable in light of the evidence and herein approves the changes as listed.

The Board has reviewed AG's methodology in the depreciation study for determining the amount of the difference between the asset reserve requirement and the book reserve amount and the method of determining the difference between the contribution reserve requirement and book reserve of contributions. The Board finds that the methods are consistent with previous applications. The Board views the results of the study as reasonable, and considers that the method is consistent with the method approved in Decision 2003-72.

The Board notes that AG discovered an error in its UOP calculation BR-AG-43(a, b) Attachment 2. AG submitted that the change was minimal and AG would reflect this change in the Compliance filing. In addition, the Board notes AG's correction in TAB 5.5, for AGS page 2 of 2. The Board directs AG in the Compliance filing to effect these corrections in the applicable schedules.

As a result of changes to the capital programs approved in this Decision, the Board directs AG in the Compliance filing to revise the forecasts of depreciation expense, amortization of contributions and all associated items in all schedules affected by the changes to the capital programs.

6 INCOME TAX

AG forecast utility income tax expense for the North in the amounts of \$11.8 million, \$12.3 million and \$13.5 million for the 2005, 2006 and 2007 test years respectively. For the South, AG forecast utility income tax expense in the amounts of \$10.4 million, \$11.0 million and \$11.7 million for the 2005, 2006 and 2007 test years respectively.[382] These forecasts were prepared using the federal and provincial rates in effect at the filing date. AG proposed to continue the past practice of fully deferring the income tax timing differences associated with deferrals including gas costs, deferred hearing costs, north production abandonment costs, ATCO CIS royalties and the Reserve for Injuries and Damages (RID). AG also identified the

[378] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-49, line 4
[379] Section 5.1 Appendix B, page 5.1B-48, lines 15-29
[380] Section 5.1, Appendix A, page 2 and Appendix B, page 5.1B-53, lines 5-6
[381] Section 5, Appendix B, page 5.1B-52, lines 20-26
[382] Exhibit 02-025-001 Schedules Including Carbon Related Assets, Schedule 6.0-F

methodology it proposed to use for adjusting the UCC pools when assets are removed from utility service.

Views of the Board

The Board notes that parties did not provide comments regarding AG's assumptions, methods or amount of revenue requirement for income tax expense.

The Board also notes that AG identified that it had not deferred income tax related to the EUB assessment payments included in the deferred hearing cost account. AG proposed to correct this oversight in the Compliance filing. The Board accepts AG's proposal to correct this oversight in the Compliance filing.

The Board has reviewed AG's assumptions and methods it used to forecast the revenue requirement to provide for income tax expense. For this Application, Board approves the assumptions and methods utilized by AG. However, in the Compliance filing, AG is directed to revise the forecast to take into account the effect of the revisions in this Decision to revenue requirements that affect the forecast of income tax expense.

7 UTILITY REVENUE

7.1 Growth Forecast

In the North, AG forecast 11,688 new customers in 2005, 11,922 in 2006 and 11,932 in 2007. In the South, AG forecast slightly greater growth at 13,103 in 2005, 12,763 in 2006 and 12,414 in 2007.[383] In both service territories AG forecast less growth for the test period years than 2004 actual results.

Views of the Board

The Board notes CG's argument that in the previous GRA, AG significantly under forecast its customer growth.[384] CG indicated that actual customer additions in 2003 and 2004 were 30% greater than forecast by AG in its 2003/2004 GRA. Because AG employed the same forecasting methodology in its current GRA, CG contended that it was reasonable to conclude that the current customer growth forecasts were too low.

The Board notes AG's response that actual 2003/04 customer growth may have been higher than was forecast in the previous GRA, but an over forecast of throughput, resulted in delivery service revenues being within 1% or less[385] of the forecast revenue figure from the 2003/2004 GRA. In addition, AG argued that the utility does not benefit from under forecasting customer growth. AG indicated that there is no incentive to under forecast customer growth given that the supplemental revenues would not offset the incremental costs of the additional new customers in the short term.[386]

Although the evidence suggests that the forecast of new customer additions appears low, and that the revenue forecasts may be understated, the Board agrees that there is an offset in the forecast

[383] Application Volume 1, Section 7, page 7.0-6
[384] Argument, page 87
[385] Argument, page 73
[386] Reply Argument, page 88

revenue requirements to serve new customers. The Board agrees with AG that if customer growth exceeded forecast levels the additional revenues would not offset the incremental costs of the adding the new customers in the short term. Therefore, the Board considers that if the forecast of new customers is understated, the effect on any reduction in revenue requirement net of new revenues is offset. Therefore, the Board accepts the forecast of new customers as reasonable for the purposes of determining the net revenue requirement and approves the forecast as shown in the Application.

7.2 Forecast of Throughput

AG prepared a throughput forecast for the various rate classes based on the results of a multiple regression model. The results of that model are supported by other methods including a vintage analysis, 12 month rolling graphs and trend forecast. The forecast indicates that per customer throughput will decline by approximately 1-2% per year over the test period across the various rate classes.

Views of the Board
The Board notes that no party objected to the forecast of sales per customer for the customer classes. The Board has reviewed the multiple regression analysis and finds that the forecast of customer throughput has been prepared in a reasonable manner. Therefore, the Board approves the forecast sales per customer class as shown in the Application.

7.3 Forecast Other Revenues

AG forecast other revenues for AGN of $8.35, $8.66 and $8.59 million over the three year test period. For AGS, $5.50, $5.46 and $5.35 million are forecast for other revenues for 2005, 2006 and 2007 respectively.

Views of the Board
The Board notes Calgary's argument that in the South, revenue from Carbon should be included in the GRA forecast with a deferral account.[387] The Board addresses this issue in Section 8 of this Decision.

The Board notes that parties did not provide commentary on AG's forecast of other revenues. The Board has reviewed the forecast of other revenues and except for those concerns regarding Carbon, has determined that AG's forecast appears to have been prepared in a reasonable manner and approves the forecast for other revenue as filed.

8 CARBON STORAGE

In this section, the Board will review issues raised with respect to the Carbon Storage Facility. The issues were with respect to Order U2005-133 issued by the Board on March 23, 2005, stated:

[387] City of Calgary Argument, page 30

THEREFORE, IT IS ORDERED THAT:

(1) The Carbon Storage facility and the Carbon producing properties and all associated property and assets in the AGS 2004 rate base, adjusted in the ordinary course as required, shall continue in AGS' rate base until such time as the Board may otherwise determine.

(2) AGS shall continue to include in revenue requirement all operating expenses, working capital, depreciation, taxes, return, and other related costs and shall continue to account for applicable revenue credits, in respect of the Carbon related assets in the same manner as it does presently, with any necessary adjustments, until such time as the Board may otherwise determine.

(3) AGS may apply for new capital additions to rate base in respect of the Carbon related assets in the ordinary course during the time period that this Interim Order is in effect.

(4) AGS is given approval to lease the entire storage capacity of the Carbon storage to ATCO Midstream for the 2005/2006 storage year and for each subsequent storage year until such time as the Board may otherwise determine.

(5) On November 22, 2004, the Board issued direction with respect to a placeholder of $0.45/gigajoule to be used commencing April 1, 2005 in respect of the fee to be paid by ATCO Midstream in the 2005/2006 storage year in respect of a storage year lease of the entire storage capacity of the Carbon facility. The Board continues to consider that the use of such a placeholder is appropriate and amends the previous order by directing AGS to reflect such placeholder in its 2005 revenue requirement and in the revenue requirement of each subsequent year until such time as the Board may otherwise determine.

(6) The Riders G, H and I will continue in effect and the current process to establish their value on a monthly basis will continue until such time as the Board may otherwise determine.

(7) This Interim Order is effective as of the date hereof and shall remain in effect until such time as it is terminated or otherwise modified by the Board.

8.1 General Matters Related to Carbon Storage

AG submitted that it had complied with the Board's Interim Order U2005-133 in full, while preserving its objections, as fully detailed in the Application under Tab Board Order U2005-133.

AG prepared its revenue requirement forecasts on the basis of what it perceived as necessary for the provision of utility distribution service, which excluded the Carbon related assets and a separate revenue requirement associated with the Carbon assets. AG claimed it had developed the Carbon revenue requirement forecast with the same rigor used in the development of other components of the forecast. In response to BR-AG-38(a), AG provided revenue requirement information on a consolidated basis.

AG identified in the Overview[388] its understanding of the changes that would be required with respect to the revenue requirement forecast in the event the Carbon related assets were not included in rate base past April 1, 2005.

Views of the Board
The Board will address AG's compliance with Order U2005-133 in a subsequent section.

8.2 Carbon Revenue Forecast

AG included Carbon revenue from ATCO Midstream in its revenue requirement forecast provided in response to Board Order U2005-133.[389] AG also reflected the fact that this revenue would be provided to customers through the Company Owned Storage Rate Rider (COSRR).

With respect to the 2007 test year, AG indicated that if necessary, the appropriate allocation for the Carbon storage and production facilities could be addressed at the time of the 2007 Phase II application by way of a rate rider.

The Alberta Irrigation Projects Association (AIPA) raised concerns with the amount of the monthly COSRR for Rate 5 and Rate 18 customers, which were irrigation customers of AGS.

As an undertaking on the issue AG provided a response which was filed as Exhibit 25-017. The following extract from Decision 2002-034 (page 16) was provided as an attachment to Exhibit 25-017 which AIPA considered was confirmation of its understanding that the Board's intent was to set the COSRR for Rates 5 and 18 at the current rate for uncontracted storage, subject to any submissions at the final unbundled rate review required by Decision 2001-75:

> Therefore, the Board is of the view that, on an interim basis, a proxy value equal to the notional market value of storage paid by ATCO Midstream for use of a portion of the Carbon facility should be allocated to Rate 5 customers as their COSRR benefit. ATCO has noted in its filing that this amount is $0.32/GJ. The Board recognizes that this may not be a perfect solution to addressing this problem. However, the Board is of the view that this will be a practical solution on an interim basis. The Board invites parties to make submissions regarding the COSRR for Rate 5 customers at the time of the final unbundled rate review required by Decision 2001-75.

In the undertaking response AG stated:

> ATCO Gas would note that no parties made submission regarding the COSRR for Rate 5 customers at the final unbundling proceeding. As such, ATCO Gas intends to seek guidance from the Board with respect to this rate at the time of the October Rider H and Rider I applications which should be filed on September 26, 2005.

AG filed a letter seeking the Board's advice on September 26, 2005, concerning the administration of the COSRR for Rate 5 customers under Rider I.

AIPA further noted that the Board acknowledgement letter of September 29, 2005, concerning the COSRR for October 2005, indicated:

[388] Refer to Section 1.5 of the Overview, commencing at page 1.0-6
[389] Refer to Schedule F of Interim Order U2005-133

> The Board notes ATCO Gas' letter dated September 26, 2005, concerning the administration of the COSRR for Rate 5 (irrigation) customers under Rider I, the matter of which arose during the recent Phase I hearing of the 2004-2007 [sic] general rate application for ATCO Gas (Application No. 1400690). Subject to any decision regarding the operation of the COSRRs arising in respect of the said Application, the Board will review the matter and advise ATCO Gas in due course.

During the hearing, AG confirmed that the current rate for uncontracted storage was $0.45/GJ,[390] as per Order U2005-133. On the basis of the foregoing, AIPA submitted that Rider I for irrigation service should be set at a credit rate of $0.45/GJ.

Calgary, supported by the CG, recommended that the revenue from Carbon be included in the AG revenue requirement rather than be continued as a separate rider. Calgary submitted that the continued monthly filing of a rider was inconsistent with the Board's stated goal of improving the regulatory process. Calgary also submitted that the crediting of the revenues from both storage and production against the cost of service was consistent with one of the objectives of Decision 2001-75, that the revenues not impact the relative competitive position of system supply and third party suppliers.[391] However, because the storage revenue for that portion of the facility that may be rented out is set annually commencing April 1 each year, Calgary considered a deferral account would be required to record the difference between forecast and actual revenues.

AG submitted that the status quo should be maintained until matters with respect to the Carbon related assets were resolved, so as to ensure fairness to all parties.

Views of the Board
Other than in respect of Rate Rider I, the Board concurs with AG that the status quo should be maintained pending the outcome of the Carbon process, and confirms that this is what was intended by Order U2005-133. Therefore, the Board rejects Calgary's proposal at this time.

With respect to AIPA's concern, the Board agrees that the existing COSRR of $0.32/GJ for Rates 5 and 18 should be changed to reflect the current rate of $0.45/GJ. Therefore, effective February 1, 2006, the Board directs AG to adjust the 2006 COSRR for Rates 5 and 18 to $0.45/GJ on an interim basis to bring Rate Rider I within the scope of the directions contained in Order U2005-133.

8.3 Carbon Capital and Operating Cost Forecasts

AG submitted that the revenue, capital and operating cost forecasts related to Carbon for purposes of the finalization of the 2004/2005 storage year, and as per Order U2005-133, should be approved as filed.

Views of the Board
The Board notes that no evidence was filed by interveners with respect to capital costs and operating expenses, and no concerns were raised with respect to the Carbon capital and operating cost forecasts. Accordingly, the Board approves the content of the capital costs and the operating expenses filed in the Application.

[390] Transcript Volume 3, page 397, lines 13-16
[391] Now defined as Retailers

However, the Board does not approve the separate format in which the Carbon related forecasts were filed. The Board considers that the directions set out in Order U2005-133 require that nothing be done differently than has been the historical practice. Therefore, the Carbon related assets are to remain in Rate Base, the O&M expenses are to be included in the revenue requirement, and the revenue will be collected and distributed in the COSRR in accordance with the provisions of Order U2005-133. The Board directs AG to include all the accounting for Carbon on a consolidated basis with the balance of the company revenue requirement and revenue determinations when submitting its Compliance filing.

9 OTHER MATTERS

9.1 Separation Between ATCO Gas North and South

In the Application, AG requested that the Board approve one combined revenue requirement forecast commencing January 1, 2007. AG indicated its intention to seek approval to implement uniform postage stamp rates by 2007 on a province wide basis in its recently filed 2003/2004 Phase II Application.[392] However, AG indicated that even if it was unable to convince the Board to approve province wide uniform rates in the Phase II Application, it would still want approval of one combined revenue requirement commencing in 2007.[393]

The request to combine North and South revenue requirements was also before the Board with respect to the 2003/2004 Phase I GRA. In Decision 2003-072, the Board made the following statements with respect to the merging of North and South revenue requirements:[394]

> However, the Board considers that there is merit in the submissions of the interveners that there are too many differences and related considerations to be addressed at this time to accommodate allocation of costs in a Phase II unless separate revenue requirements are maintained. The Board shares the concerns of interveners that there would be no way to make a comparison of rates under merged versus separate revenue requirements without evaluating the allocation of costs to rate classes on a combined and separate basis.
>
> …..
>
> In the Board's view, as the first step towards implementation of a single revenue requirement, there is a need to establish separate revenue requirements for North and South, and develop separate Cost of Service studies to determine the similarities or reasons for significant difference between the rates and rate structure in each region.
>
> Based on the foregoing, the Board directs ATCO, in refiling its GRA to reflect the results of this Decision, to file the revenue requirement separately for North and South. The Board therefore expects that the outcome of this Phase I process will be the setting of separate revenue requirements for North and South, and that separate rates could be set for North and South in the subsequent 2003/2004 Phase II. The Board considers that before a single revenue requirement is implemented, ATCO must be able to demonstrate harmonization in accounting treatment in the North and South by resolving differences in treatment of issues such as no-cost capital, negative salvage, COP facilities and the Carbon reservoir. In addition, the Board considers that ATCO needs to propose a

392 Application No. 1416346
393 Transcript, page 480, lines 7-10
394 Decision 2003-072, pages 11-12

> methodology in the rate design process to address any residual cross subsidization issues between North and South.

AIPA submitted that little had changed since the issue of consolidating the North and South revenue requirements was last considered in Decision 2003-072. Further, AG had not demonstrated the benefits of consolidation when compared to the cost differences in the revenue requirements between the North and South and the potential for more rate riders. AIPA considered that the potential for more riders to account for North and South cost differences only added to customer confusion on the bills.

AIPA submitted that since AG had indicated there were no overall cost savings[395] that would accrue to ratepayers from consolidating the North and South revenue requirements into a single revenue requirement, it was premature at this time to allow such a consolidation as a precursor to uniform rates.

AIPA noted that regulated natural gas distribution service was not exclusive to AG in the province. Natural gas service was provided to other parts of the province by other utilities such as AltaGas Utilities, the rates of which were different than either AGN or AGS rates for comparable service. AIPA also noted that there was no legislative mandate for province wide postage stamp distribution rates in a similar manner to the legislation for provincial postage stamp electricity transmission rates.

Calgary submitted that AG had not made a case that AGS customers would benefit, or would in any event not be harmed, if the North and the South rates were combined. Accordingly, the proposal to combine the North and South revenue requirements should not be approved.

Calgary considered that based on the information filed in the Application, there were, despite the number of allocations between the North and South using a 50% convention, significant cost differences. Calgary submitted that comparing Schedules 1.60-E[396] and 1.60-F[397] showed that the North’s shortfall in 2005 was over 2.5 times the South, based upon existing rates. Similarly in 2006 and 2007 there were large differences between the shortfalls in the North and the South. Calgary argued that the two segments were not integrated operationally; and gas did not generally flow from one system to the other. Further, having one postage stamp rate was contrary to the concept of more accurate costs and providing customers with better price signals.

Calgary stated that it had provided detailed evidence in AG’s 2003/2004 GRA as to why the North and South divisions should not be combined and was of the view that AG had not provided sufficient evidence in this proceeding to support its proposal for combining them. Calgary noted that AG appeared to rely upon its recently filed and untested 2003/2004 Phase II filing to support its position to combine revenue requirements. Calgary submitted that it would be inappropriate and contrary to the principles of natural justice for any reliance to be placed upon evidence that was not part of the current proceeding and was not available to be tested by it and interested parties.

The CG considered that the proposal by AG to consolidate the North and South into a single revenue requirement in 2007 was of such a magnitude that it should be made at a time much

[395] Transcript Volume 3, pages 472-477
[396] Exhibit 02-025-001
[397] Exhibit 02-001

closer to the proposed implementation date and based upon the very best, most complete and current data available at that time, and not on the forecast data found in the Application.

In this respect, the CG submitted that a 2007 forecast supported by actual 2005 and 2006 data would provide a superior foundation for all parties to consider a step of this magnitude. There were numerous cost differences[398] between North and South, as well as current rate differentials. The CG argued that, should the Board determine that 2007 was to be included as a test year in this proceeding, the Board should maintain a separate revenue requirement for 2007 for the North and South.

AG proposed that some of the existing cost differentials such as transmission rates, Carbon Storage, and Company Owned Production[399] could be addressed through distinct riders. The CG argued that the need for riders indicated that there were substantive cost differentials between the two systems which should be evaluated on a stand alone basis. The CG believed that when riders were a prerequisite to a costing/ratemaking initiative, it was a prime indication that there were underlying issues which indicated the proposed action had fundamental problems.

AG submitted that it had addressed the Board's concerns as identified in Decision 2003-072.[400] Specifically, the differences between no-cost capital would be basically non-existent by 2007, and were expected to remain so in the future. AG noted that through the approval of common depreciation rates in the 2003/2004 GRA, the Board had acknowledged that the differences in negative salvage between the North and the South were not significant enough to require distinct depreciation rates. AG considered that matters such as different approved transmission rates and the production and storage assets could be addressed through the use of distinct riders, if required. AG submitted that the information provided in its filed 2003/2004 Phase II Application would show that no significant cross-subsidization would occur by moving to postage stamp rates on a province wide basis.[401]

AG submitted that it was not necessary for the Board to consider rate matters for the North and the South in this proceeding, but it was important to note that it would be the rate studies which provide the ultimate test of whether cross subsidization was occurring to any material extent. AG argued that a Phase II proceeding was the appropriate place to deal with the full effect of differences in the revenue requirement forecast, differences in throughput and number of customers, and the presence of anomalies, such as transmission, production and storage which can be handled through riders. To only focus on any one component of these matters without looking to the other components, could result in a misleading interpretation of what the actual affect on customers would be.

Views of the Board

The Board acknowledges that AG has been able to remove some of the differences that existed between the North and South service territories. However, as stated by the Board in Decision 2003-072 with respect to establishing a single revenue requirement, the Board considered that "the first step" included both the establishment of separate revenue requirements and the development of "separate Cost of Service studies". AG has submitted the Cost of Service

[398] Transcript, pages 527-528
[399] AG Argument, page 76, line 28
[400] Application, Tab 1
[401] Transcript Volume 3, page 486, lines 1-8

studies as part of its 2003/2004 Phase II Application.[402] The Board remains reluctant to approve a single revenue requirement in this proceeding, before the full examination afforded by the Phase II process is complete, as was contemplated in Decision 2003-072.

Accordingly, the Board considers that it remains appropriate to continue to separate the North revenue requirement from the South revenue requirement for the 2007 test year. However, AG is free to apply to the Board to combine the separate 2007 North/South revenue requirements in connection with determining rates as part of its 2005-2007 Phase II application should the Board determine in the 2003/2004 Phase II proceeding that combined rates may be appropriate for 2007.

9.2 Refund of Deferred Income Tax

In the 2003/2004 GRA, AG proposed to refund the deferred income taxes accumulated in AGN as a consequence of a change in income tax methodology. The Board subsequently approved the income tax methods used by AG in Decision 2003-072.[403] In Decision 2004-036,[404] the Board confirmed that the treatment proposed by AG in the 2003/2004 GRA for dealing with the deferred tax refund was reasonable. The Board also accepted AG's proposal for refund of the deferred tax balance by rate rider, subject to AG conducting a subsequent review and reconciliation of the balance. Consequently, AG estimated the balance to be approximately $6 million.

Views of the Board

The Board notes CG's proposal that all one-time charges and refunds should be netted and calculated in conjunction with any 2005/2006 surplus/shortfall in order to establish appropriate rate riders.[405] AG concurred with the comments of the CG.[406]

The Board notes that by recognizing the refund in 2006, the extent to which customer rates will be increasing in 2006 is minimized. The Board agrees that AG's proposal to offset the deferred income tax refund for the North in the amount of $5.981 million is appropriate and shall be used to offset one-time adjustments in 2006 to determine the one-time rider for the North.

9.3 Recovery of Hearing Costs

AG requested a one-time recovery of hearing costs in 2006 of $4.35 million for AGN and $4.45 million for AGS. AG noted that this approach was consistent with the approach approved by the Board in Decisions 2001-096 and 2003-072.

In addition, AG included $500,000 in 2005, $250,000 in 2006 and $100,000 in 2007 for legal fees in excess of the Board's Scale of Costs. AG also forecast $300,000 in 2005 for consultant fees in excess of the scale. CG did not support the inclusion of AG's legal and consultant fees in excess of the Board's Scale of Costs into the revenue requirement.

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402 Application No. 1416346
403 Decision 2003-072, pages 227-237
404 Decision 2004-036, pages 46-47
405 CG Argument, page 89, lines 20-22
406 AG Reply Argument, page 95, lines 9-10

The CG noted that the Board has addressed cost recovery in respect of utility proceedings in several rules and bulletins; including:

- Part 5 of Regulation AR 101/2001 Alberta Energy and Utilities Board Rules of Practice (The Board's Rules of Practice);
- Section 11 of EUB Guide 29: Energy and Utility Development Applications and the Hearing Process (January 2003), and
- EUB Guide 31B*: Guidelines for Utility Cost Claims (January 2004) (Utility Cost Guide).*

CG argued that these guidelines and cost recovery rules should apply to all participants. In requesting inclusion of costs in the revenue requirement in excess of the Board's scale, AG was in fact suggesting that the applicant should be held to a different standard than interveners. The CG argued that the resources available to interveners were significantly less than that available to utilities and that it would not be fair to require interveners to operate within the Board's Scale of Costs and not have the same requirement of AG.

In addition, CG argued that it was incumbent on AG to demonstrate that it had not included any regulatory costs in excess of the Board scale in revenue requirements in other accounts. If AG had included these costs in other accounts, the CG submitted these costs must be considered non-utility and excluded from revenue requirement. CG argued that it was inappropriate to circumvent the Board's cost procedures and rulings by charging costs in excess of the Scale of Costs to Account 722 or any other regulated account. The CG submitted that the key issue was whether or not there would be a dual standard for the recovery of costs between the utility and interveners.

CG also noted AG's indication that its $600,000 forecast of Carbon proceeding costs included costs in excess of the Board's Scale of Costs.[407] AG should be directed to remove and treat as non-utility all costs that are in excess of the Board's Scale of Costs unless specifically allowed by the Board.

CG also noted AG's indication that it has not been subject to regulatory disallowances of costs in excess of the Board scale in the last ten years.[408] The CG considered that AG should be directed by the Board to credit back all amounts that were charged to utility accounts related to legal and consultant fees that were in excess of the Board's Scale of Costs that relate to hearings in which hearing cost orders were issued.[409]

The CG submitted that legal fees of $500,000, $250,000, and $100,000 should be removed from the revenue requirement in 2005, 2006 and 2007 respectively, as these amounts would be in excess of the Board's Scale of Costs. Additionally, $300,000 should be removed from the 2005 revenue requirement for consulting fees in excess of Board scale.

AG noted that the issue of the one-time recovery of hearing costs in 2006 of $4.35 million from AGN and $4.45 million from AGS was not addressed by any interveners in Argument.

[407] CAL-AG-14
[408] CG-AG-94
[409] Exhibit 19-011, PP 55-56

AG proposed that it be allowed to continue to collect the full cost of regulatory proceedings, judicial appeals and Review and Variance applications in excess of the Board's Scale of Costs. AG proposed to recover costs up to the Board's Scale through the cost claim process and recover in excess of the Board's scale through inclusion in the revenue requirement through the use of account 722 being included in the revenue requirement. AG defended this position on the primary grounds that these were prudent costs incurred in the course of conducting its business as a regulated public utility. AG pointed to the Roles, Relationships and Responsibilities Regulation AR186/2003 which provides in Subsection 4(1) for the functions of a gas distributor and then states in Subsection 4(3):

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

AG also indicated that it sought and obtained approval for the recovery of these types of costs in the 2003/2004 GRA. In its Argument, AG stated that it "has never hidden the fact that it has included these types of costs in its forecasts," and cites CAL-AG-116(e) from the 2003/2004 GRA.[410] Under cross-examination, AG indicated that in previous decisions, it had included costs in the revenue requirement through account 722.[411]

In the 2003/2004 GRA proceeding, a request was made in CAL-AG-116(e) for AG to provide details on the legal fees and regulatory items included in Account 722 for each of the years shown (including the number of hours and the rates charged) and, to the extent that any of the rates exceeded the Board's guidelines, to indicate where the additional amounts have been charged to non-utility accounts. AG responded by stating that an unreasonable amount of effort would be required to provide the information requested and that AG "records all operational legal fees to one account. Included in that account would be amounts related to regulatory activity that have not been charged to the hearing reserve account. AG does not consider that legal fees related to regulatory activity are non-utility expenditures…"[412]

AG submitted that they had clearly identified the amount of these costs that it included in its 2005-2007 revenue requirement forecasts. AG submitted that it had consistently treated its hearing expenses in excess of the Scale of Costs as prudent costs of providing regulated service.

AG argued that whatever grievances interveners may have had with respect to the extent of their hearing cost recovery, the law required that AG continue to be permitted to recover its prudently incurred costs.[413] AG further stated:

> As a regulated entity, ATCO Gas is obligated to comply with the Board's legislation. Hearing related costs are necessary and prudent costs incurred by ATCO Gas in order to allow it to comply with the regulatory requirements for utilities in Alberta. The governing legislation, regulatory principles, and the evidence of Dr. Gordon all stipulate that the utility is entitled to recovery of all prudent costs of the utility. This includes participation in regulatory proceedings. It is, therefore, an unreasonable stretch on the part of interveners to argue that the cost of complying with mandatory, regulatory requirements

[410] AG Argument, page 74, lines 22-23
[411] Transcript, page 697, lines 15-20
[412] 2003/2004 GRA, AG response to CAL-AG-116(e)
[413] Argument of AG dated October 14, 2005, pages 47 - 49

> which are a core aspect of providing regulated distribution service should be reduced to an arbitrary level simply because interveners are subject to cost guidelines.[414]

AG also noted that the costs of the UCA and the EUB participation in regulatory proceedings are recovered through a special levy and that business related interveners may not recover any hearing costs in the Hearing Reserve Account. Nevertheless, AG argued they must respond to the matters raised by all of them in regulatory proceedings. However, AG submitted that AG and interveners were treated similarly to the extent that the costs approved and recorded in the Hearing Reserve Account were recovered through rates.

AG argued that these costs were prudently incurred and necessary to the provision of utility service. AG suggested that the interveners appeared to acknowledge this and that the real issue was "who should pay". With respect to who should pay for interveners' costs in excess of the scale, AG submitted that may be an issue for a different forum, but had no relevance to the matter now before the Board.

With respect to the CG suggestion that AG should be required to credit all amounts back to the hearing cost reserve that were in excess of scale since ATCO Gas and Pipelines Ltd. were formed, AG suggested that the CG's recommendation invited the Board to engage in retroactive ratemaking. More importantly, in past decisions AG was never directed to exclude any forecast expenditures in excess of the Board's scale from its revenue requirement. Those past revenue requirements were a settled issue.

Views of the Board

The Board essentially agrees with the summary position in AG's Argument, that hearing related costs are necessarily incurred by AG in order to allow it to comply with the regulatory requirements in Alberta. The Board agrees that the governing legislation and regulatory principles stipulate that the utility is entitled to the recovery of prudent costs, as determined by the Board, that are incurred in connection with the performance of its utility functions, including reasonable costs incurred in connection with regulatory proceedings. The primary question, in the Board's view, is how the reasonableness of those costs is determined and how they are recovered.

Section 68 of the PUB Act provides the Board with the jurisdiction to award costs with respect to utility proceedings. It further provides that the costs are in the discretion of the Board and that the Board may prescribe a scale pursuant to which costs are to be awarded. Part 5 of the Board's Rules of Practice provides a process by which a "participant" may apply for payment of costs incurred in a utility proceeding. "Participant" includes a utility applicant. Rule 53(2) provides that a participant may only claim costs in accordance with the Scale of Costs. Rule 55(1)(a) provides that the Board may award costs, in accordance with the Scale of Costs, to a participant if the Board is of the opinion that the costs are reasonable and directly and necessarily related to the proceeding.

The Board's Utility Cost Guide, in Section 1, establishes that the Board's cost recovery process is to address necessary and reasonable costs, consistent with the summary position espoused by AG:

[414] Argument of AG dated October 14, 2005, page 51

> The onus of demonstrating that the costs claimed are reasonable and directly and necessarily related to the proceeding rests with the claimant.

Section 2.3 of the Utility Cost Guide provides the Scale of Costs (Appendix C), which details what fees and disbursements are eligible for reimbursement in relation to a party's participation in a proceeding before the Board. The Scale of Costs represents a fair tariff to provide an interested party with adequate, competent, and professional assistance in making an effective submission before the Board. The section also provides that:

> If a party can advance persuasive argument that the tariff is inadequate given the complexity of the case, the Board may adjust the Scale of Costs to address such unique circumstances.

The Utility Cost Guide demonstrates that the Board has established a specific process in which it will consider participant costs incurred in connection with proceedings before it. The process is all inclusive, meaning that it applies to both utility applicants and interveners and that it applies to all costs for which a participant seeks to gain recovery from ratepayers. The nature of the process is that the Board has developed a Scale of Costs which it has determined to be reasonable for most situations. Participants bear the onus to demonstrate that their costs are appropriate for reimbursement in accordance with the Scale of Costs or to demonstrate to the satisfaction of the Board that special circumstances exist so as to merit a cost award in excess of the Scale of Costs.

The cost recovery framework established by the Board, on its face addresses the legislative and regulatory principle of recovery of reasonable and necessary costs. While the Board's Scale of Costs limits recovery to a specified hourly rate for lawyers and consultants in the ordinary course, it has the flexibility to provide adjustments in appropriate circumstances. Following a review of recent Cost Orders, the Board is unaware of any occasion where AG has requested the Board to consider an adjustment to the Board's Scale of Costs to permit cost recovery in excess of the Board's scale.

It is through the Board's cost process that the reasonableness of all costs incurred in connection with a regulatory proceeding are intended to be reviewed, tested and adjudicated upon. The Board does not see it as appropriate for AG to seek recovery from ratepayers for some costs incurred in connection with regulatory proceedings through the Board's cost process and then seek recovery of costs in excess of scale through a forecast account in a GRA. To allow a utility to seek recovery of costs up to the Scale of Costs through the Board's cost process and then to recover costs in excess of that Scale of Costs through a forecasted account included in revenue requirement would create a "two-staged" cost recovery process unavailable to interveners and create the inefficiency associated with considering regulatory costs in respect of the same set of proceedings (one retrospectively and one prospectively) in two different Board processes. The Board does not see it as appropriate for AG to be able to recover from ratepayers regulatory proceeding costs in excess of the amounts requested and awarded through the established Board cost recovery process.

In accordance with its statutory authority to deal with costs of regulatory proceedings in the manner it finds appropriate, the Board has determined its cost recovery process as the exclusive mechanism for the recovery of all reasonable external legal and consulting costs, properly incurred for all participants, including utility applicants. AG must avail itself of that process and the mechanisms thereunder for recovery of costs incurred in excess of the Scale of Costs if it wishes to have recovery of those costs from ratepayers. The Board considers that it is appropriate that all external legal and consulting costs related to regulatory proceedings that are to be recovered through rates should be included in the hearing cost reserve account following consideration through the Board's cost recovery process.

With respect to the inclusion of appeal costs and regulatory proceeding costs in excess of the Board's Scale of Costs in the approved revenue requirement for 2003 and 2004, the Board notes that a specific breakdown description of the legal costs included in Account 722 identifying these costs as appeal costs or costs in excess of scale or in connection with appeals does not appear to have been provided to the Board.

Accordingly, the forecast costs for legal and consulting fees in excess of the Board's Scale of Costs in connection with proceedings before the Board, including Review and Variance applications, are denied.

With respect to costs in connection with appeals of Board decisions, the Board sees these costs as costs incurred for the benefit of the utility's shareholders and accordingly are not appropriate to be recovered through utility rates. The Board also notes that a separate cost recovery mechanism may be available in some circumstances to successful participants in the appellate process.

The Board directs AG in the Compliance filing to reduce the revenue requirement amounts of \$500,000 in 2005, \$250,000 in 2006 and \$100,000 in 2007 to reflect legal fees in excess of the Board's Scale of Costs and \$300,000 in 2005 for consultant fees in excess of the scale. This directive is applicable to the test years only and no retroactive adjustments are required.

With respect to the request by AG for a one-time recovery of hearing costs in 2006 of \$4.35 million for AGN and \$4.45 million for AGS, the Board notes that this request is consistent with past practices. The Board further notes that no parties objected to this one-time recovery. The Board approves the requested one-time recovery of hearing costs in 2006 of \$4.35 million for AGN and \$4.45 million for AGS.

9.4 Reserve for Injuries and Damages

AG requested that insurance costs continue to be included in the Reserve for Injuries and Damages (RID) during the test period. AG suggested that there was no evidence that the volatility in insurance premiums was over and that a stable pattern was expected for the forecast period.

AG also proposed to make a one-time refund related to the RID in 2006 in the amounts of \$0.413 million for the North and \$0.37 million for the South. This one-time refund was proposed to keep the combined reserve balance at the target level of \$0.6 million.

In addition, CG requested that the practice regarding the accounting treatment of the RID account as set out in Section 292 of Alberta Regulation 546/63 be reviewed. Section 292 provides:

> 292. INJURIES AND DAMAGES RESERVES
> This account shall be credited with amounts charged to account No. 724, "Injuries and Damages", or other appropriate accounts, to meet the probable liability, or co-insurance costs, or items not covered by insurance, for death or injuries to employees and others, and for damages to property neither owned nor held under lease by the utility.
>
> When liability for injury or damage is admitted by the utility either voluntarily or because of the decision by the court or other lawful authority, the amount of the admitted liability shall be charged to this account and credited to the appropriate liability account. Details of these charges shall be maintained according to the year the casualty occurred which gave rise to the loss.
>
> Note – Recoveries or reimbursements for losses charged to this account shall be credited hereto; the cost of repairs to property of others if provided for herein shall also be charged to this account.

CG observed that the Board was very specific in only allowing damages to property neither owned nor held by the utility in the RID account.

CG submitted that the asset cost for gas plant owned by the utility should be added to rate base and that insurance proceeds should be a credit to rate base. In addition, the deductible for plant owned by the utility should not be charged to the RID. The deductible or asset cost less insurance proceeds should remain in rate base to preserve the matching principle and comply with Alberta Regulation 546/63.

AG assured that Board that "its internal accounting policies and procedures regarding the Reserve for Injuries and Damages complies with the government regulations."[415] CG argued that although AG agreed with CG's position, the Board should make a ruling with regards to this issue "because other utilities do not appear to be following this methodology."[416]

Views of the Board

The Board agrees with AG that the premiums for insurance appear to remain volatile at this time and, therefore, the Board approves a continuation of the practice of charging the insurance premiums to the RID for the test period. However, AG is directed at the next GRA to re-visit this issue and propose a methodology for the treatment of insurance costs at that time.

In addition, the Board approves the one-time refund to be reflected in 2006 to bring the RID to a total of $600,000, which is a refund of $413,000 for the North and $370,000 for the South. The Board also finds that the balance in the RID of $600,000 continues to be appropriate.

The Board notes AG's confirmation that its accounting practice regarding the accounting treatment of the RID account as set out in Section 292 of Alberta Regulation 546/63 complies with the regulation.[417] Therefore, there does not seem to be any decision required in connection with the present Application regarding the accounting treatment of the RID account as set out in

[415] AG Rebuttal Evidence, page 44
[416] CG Argument, page 94
[417] AG Rebuttal, page 44, lines 14-16

Section 292 of Alberta Regulation 546/63. The Board prefers to make determinations related to the practice of other utilities in applications where there is a specific issue around that application related to Section 292 of Alberta Regulation 546/63. Therefore, the Board will not provide a ruling as requested by CG.

9.5 Bad Debt Expense, Collection Agency Fees and Late Payment Revenue

AG requested a one-time recovery related to the net of these costs in 2006 as outlined in Section 8.5 of the filing. AG indicated it would update the amount of the recovery required at the time of the Compliance filing. The Application indicated a net total for AGN and AGS of $2.6 million as of December 31, 2004.

The CG noted that AG was proposing that it would accept the risk of the account going forward.[418] However, the CG did not consider it appropriate that AG was proposing was that it be able to collect further amounts related to bad debts and not credit these amounts back to revenue requirement. The CG considered that the reserve or deferral account should remain in place until all collection activities cease and collected amounts were included in the revenue requirement as customers had been charged and had funded the bad debts.

The CG considered that the deferral account should continue past this application to allow for all collections against bad debts that were funded by customers to be returned to customers.

AG noted that when it submits the Compliance filing for this application, it will have been almost two years since the retail transfer. Any potential minor collections remaining would not justify the administrative effort of maintaining and reporting this deferral account to the Board.

Views of the Board

In Decision 2005-039 the Board stated:

> The Board agrees with ATCO that the use of a deferral account will assist it in the transition period following the Retail Transfer. The Board appreciates that it may be difficult to forecast the resulting levels of bad debt and that ATCO will need to gain some experience. Accordingly, the Board grants ATCO's request for a deferral account in respect of bad debts, however the need for a deferral account shall be revisited at the next opportunity occurring after the next GRA.[419]

The Board agrees with AG that the deferral account could be discontinued, but as noted in the preceding quote, the deferred account was approved until AG had gained experience and that it should continue until "after the next GRA." The Board does not consider there has been sufficient time to gain the experience necessary to discontinue the deferral account at this time, but expects that it could be discontinued after the next GRA. This should give sufficient time between the Retail Transfer and the new configuration for the business to stabilize, such that AG can provide reasonable forecasts that will have the confidence of all parties.

For the purpose of reconciling the deferral account the Board hereby approves, as requested, the one time recovery, to be updated in the Compliance filing.

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[418] Transcript, page 226

[419] Decision 2005-039, page 40

9.6 Utilities Consumer Advocate Funding

In the Application, AG proposed recovery of $228,000 for UCA funding for each of AGN and AGS in 2006.

The Board notes that no concerns were raised in evidence or cross-examination regarding the one-time recovery of these UCA costs and therefore approves the recovery as filed.

9.7 Production Abandonment Costs

In the Application, AG proposed recovery of Abandonment costs and provision of an ongoing expense to cover future costs. AG also acknowledged that it was willing to recover the one-time adjustments over the test period.

North Production Abandonment Costs
AG proposed a one time recovery of North production abandonment and removal costs and stated that the recovery of these amounts from customers was consistent with the North Core Settlement Agreements, as discussed in Section 8 of the Application.

AG summarized its request that the Board approve the following with respect to these costs:

- A one time recovery of costs which have been identified in the Application in the amount of $1.7 million. AG would update the costs for additional costs incurred at the time of the compliance filing. AG was also willing to spread the recovery of these costs over the three year test period, which would require an adjustment to the amounts in NWC if the Board viewed this change should be made.
- Approval of the continued use of a deferral account for additional costs that AG anticipated it would incur related to the north production properties. AG would seek recovery of this deferral account through future GRA's. This deferral account would be included in NWC commencing in the year 2005.
- Approval of an annual expense amount of $100,000 related to these costs. The difference between this annual expense amount and the actual costs incurred would reside in the deferral account discussed above.

South Production Abandonment Costs
AG proposed a one time recovery of South production abandonment and removal costs related to non-Carbon production properties. These properties were used to provide service to customers some time ago. The largest contributor to these costs, Bow Island field, was retired in 1996. The recovery of these costs would normally occur through the negative salvage that was recognized each year through the UOP depreciation expense. AG contended there were several issues with continuing to recover these costs on this basis. One issue related to the fact that based on the remaining life of the Carbon reserves, the recovery would take a very significant amount of time. The second issue related to the fact that AG did not believe that the Carbon related assets were required in the provision of utility distribution service, in which event AG would no longer recover negative salvage through UOP depreciation. The final issue related to the fact that AG had not included any negative salvage for these properties in its UOP depreciation since the Canadian Western 1998 GRA, so that the negative salvage being recovered was insufficient.[420]

[420] CG-AG-99(e)

Given all of these issues, and the fact that the assets were retired some time ago, AG considered it more appropriate to recover these costs now through a one time adjustment.

AG summarized its request that the Board approve the following with respect to these costs:

- A one time recovery of costs which had been identified in the Application in the amount of $3.1 million plus income tax in the amount of $1.5 million. AG would update the costs for additional costs incurred at the time of the compliance filing. AG was also willing to spread the recovery of these costs over the three year test period, which would require an adjustment to the amounts in NWC if the Board viewed this change should be made.
- Approval of the use of a deferral account for additional costs that AG anticipated it would incur related to the south non-Carbon production properties. AG would seek recovery of this deferral account through future GRA's. This deferral account would be included in NWC commencing in the year 2005.
- Approval of an annual expense amount of $250,000 related to these costs. The difference between this annual expense amount and the actual costs incurred would reside in the deferral account discussed above.

The Board notes that in the Application, AG explained the reason for the Income Tax component as follows:

> Due to the fact that ATCO Gas (and its predecessor CWNG) did not defer income taxes related to removal costs, the income tax deduction associated with these costs have been provided to customers either through the CCA income tax pools, or through income tax deductions in the year incurred. As the amount recovered from customers will be taxable, the recovery must be increased to account for the income tax effect. ATCO Gas is therefore seeking a one-time recovery of $3.1 million plus income tax in the amount of $1.5 million.[421]

The areas of concern with respect to recovery appeared to be the magnitude of the costs incurred and the negative salvage that had been accumulated.

As discussed by AG, some of the Bow Island wells were among the oldest wells in Alberta, drilled with cable tool drilling rigs back in the early 1900's.[422] This was a significant contributor to the level of cost required to properly abandon these wells. Furthermore, the legal requirements with respect to well site reclamation standards were set by Alberta Environment. These requirements and standards had changed over time, requiring all operators to undertake additional reclamation work at well sites. Further detailed information with respect to the work undertaken by AG was provided in the response to CG-AG-99. AG submitted that while the costs may have been significant, they were prudently incurred, and should be approved for recovery.

AG indicated[423] that it had accrued approximately $755,000 of negative salvage to the non-Carbon south production properties. The amount that AG was seeking to recover was net of this recovery. Although AG recovered negative salvage through UOP on a pooled basis, it had

[421] Application, page 8.0-7
[422] Transcript Volume 1, page 129, lines 20 - 25
[423] IW-AG-17

relied on a long standing accounting practice to allocate the negative salvage recovered to individual production fields. It would be inappropriate to suggest that some of the negative salvage from the Carbon asset accounts be used to offset this amount, because that negative salvage was required for the Carbon related removal costs that had already been incurred or would be incurred in the future. Furthermore, as noted above, AG submitted that it had not included any negative salvage for the non-Carbon properties in its UOP depreciation calculations since the CWNG 1998 GRA, due to the fact that the properties had been retired. As a result, some of the $755,000 accrued negative salvage that had been allocated to these properties should actually have been fully allocated to the Carbon properties.

Calgary noted in its evidence[424] that there appeared to be a difference in treatment by AG for assets that had ongoing benefits that AG perceived were not required for utility service, such as the Carbon assets, and the ongoing costs associated with the abandonment of certain oil and gas properties.

Calgary requested that the Board clearly enunciate its policy with respect to abandonment costs. Calgary stated that at the present time it appeared that the AG approach was that if an asset, that in their view was not needed for utility service had a net future liability, the customers pay and if it had a net future benefit, the shareholders were entitled to the gain. Calgary argued that if customers were to bear the costs of abandonment and negative salvage, then they should receive the benefits of sale and positive salvage irrespective of whether the asset was depreciable/depletable or amortizable.[425]

As a general proposition, Calgary recognized that abandonment costs were the costs associated with the provision of services with respect to the assets. However, Calgary did not consider it appropriate to wait nine and ten years after the fields were finished producing before completing the abandonment process; there was no reason why the time period should be so long or why AG waited until 2005 to seek to recover these costs, some of which had been known for many years.[426]

AG countered that the Board should not believe that there was something more to this matter than simply the recovery of the remaining costs associated with assets that were fully used in the provision of utility service. AG had not made any request with respect to the recovery of future abandonment costs related to the Carbon assets in this proceeding. AG claimed that they were not at issue as explained by the AG witness who stated under cross-examination[427] by counsel for the City of Calgary that AG would assume responsibility for the abandonment costs associated with the Carbon properties from the point of time that they were removed from utility service going forward. AG submitted that this was not the same situation as with respect to the non-Carbon production assets which were fully used in the provision of utility service and retired some time ago. AG considered that the benefit to customers from the use of these assets had already been fully realized and that customers now should be accountable for the costs.

Views of the Board

As with other aspects of the Carbon properties the Board considers that the status quo should be maintained, pending resolution of a separate process dealing with Carbon. Therefore, AG is

[424] Exhibit 10-008-001, page 6
[425] Calgary Argument, page 33
[426] Reply, page 11
[427] Transcript Volume 3, page 389, lines 20-23

directed to account for Carbon related abandonment's and negative salvage as is the usual practice and to include them together with the non-Carbon properties in its calculation of the one-time recovery in the south.

9.7.1 Common Abandonment Issues

AG noted that the main area of concern with respect to the recovery of these costs appeared to relate to the Allowance for Funds Used During Construction (AFUDC) that AG had applied. As confirmed during cross-examination,[428] AG had recognized AFUDC on these costs due to the fact that it no longer had production asset accounts in rate base in the north. AG contended that this was a standard practice, not unlike the recognition of AFUDC on unsuccessful exploration which was also not recorded to rate base and was recovered through future regulatory proceedings. AG indicated that there was no requirement to obtain "agreement" on the part of customers with respect to something which had been fully consistent with AG's past practices. Commencing in the year 2005, AG had reflected the account balance as part of NWC, so AFUDC would no longer accrue to the account going forward.

Calgary submitted that it was inappropriate for AG to recover any carrying costs on this amount since AG would have been entitled to deduct these costs for income tax purposes at the time incurred. Calgary considered that the income tax saving that AG had achieved more than offset the carrying costs.

The CG also had some concerns about whether AFUDC should be paid for by customers in the North for payment of abandonment costs that arose out of a prior negotiated settlement, however, the CG did not object to the AGN proposal and amount of abandonment and removal costs forecast. The CG did not object subject to comments on errors and adjustments regarding recovery of the abandonment costs over the test period ultimately determined by the Board in this GRA. The CG had concerns that the "real" information on the significant Bow Island costs was not provided until after the hearing in a 59 page response.[429] This response was a final result of a number of undertakings requested by the CG that arose out of CG-AG-48(h) and (i). The CG considered that this information should have been provided in the original information request or in the first undertaking associated with the information request, not at the conclusion of the hearing. The CG had reviewed CG-AG-99 and did not object to AGS's proposal and amount of abandonment and removal cost forecast, subject to the CG's comments on errors and adjustments regarding recovery of the abandonment costs over the test period determined by the Board in this GRA.

Views of the Board

The Board notes that the issue of AFUDC was related to the abandonment costs in the North only, which raises a question of consistency. However, the Board notes that no party raised this issue. Further, while AG draws a parallel with AFUDC being applied to unsuccessful exploration, the Board does not agree that AFUDC is applicable to abandonment costs. AFUDC is applied to capital costs that could end up in rate base. Abandonment costs are most unlikely to end up in rate base. Therefore, with respect to the collection of AFUDC, the Board is of the view that AFUDC should not be included in the amount to be collected. If AG wishes to claim a carrying cost, it should apply an appropriate interest charge.

[428] Transcript Volume 1, page 142
[429] CG-AG-99

The CG noted that in response to several information requests, AG identified errors and adjustments in the depreciation area that it was prepared to accept. The CG referenced these errors and adjustments to ensure that they were included in the Compliance filing.

The CG submitted that the errors and omissions were contained in the following information responses:

- CG-AG-47(e) – error in Tab 5.5, Page 2 of 2;
- CG-AG-48(a) – AG is not objecting to the recovery of abandonment and removal costs over the test period; and
- CG-AG-48(j) – inclusion of annual expense amounts for North and South of $100,000 and $250,000 respectively forecast to recover additional abandonment and reclamation costs "going forward" and use of a deferral account for these costs.

AG noted that in the response to CG-AG-48, certain matters were identified which had the ability to impact the amount of costs to be recovered. The first matter related to the response to part (a) of the question, where AG had indicated that it would not object to recovering these amounts over the three year test period. The unrecovered balance in each year would be included in NWC, as shown on Schedule 2.6-A and Schedule 2.6-C. The second matter related to a correction between the north and south costs in the amount of $816 as discussed in the response to part (g) of the question. Subsequently, AG determined that it was the description provided on Section 8.7.2 Attachment that was incorrect, not where the dollars had been reflected (i.e. between North and South). AG had also identified in the Application that it proposed to update the amount of the one-time recovery at the time of the Compliance filing for any additional costs that had been incurred.

The final matter related to the additional reclamation and re-abandonment work that AG anticipates. As identified by the AG witness under cross-examination by counsel for the CG,[430] the company retains the liability of owning these previously abandoned wells forever. It is a normal cost associated with owning these types of assets. In the response to CG-AG-48(j), AG had indicated that it might be more appropriate to include an annual expense amount in the revenue requirement forecast for these costs. AG proposed an annual expense amount of $100,000 for the North and $250,000 for the South. Regardless of whether the Board approved an annual expense amount, AG requested that it be allowed to defer any South non-Carbon abandonment and removal costs for production assets that it incurs similar to the process currently being used in the North, which would be addressed at a future GRA filing.

The Board is satisfied that AG will make any necessary corrections that have been identified when it submits the Compliance filing. Further, the Board agrees and directs that an annual expense of $100,000 for the North and $250,000 for the South should be initiated to spread out the collection of abandonment costs. Also, any costs that have accumulated can be deferred and addressed and reconciled at the next GRA.

The Board hereby approves in principle, and subject to being updated as proposed by AG in the Compliance filing, the one-time recovery of $1.7 million in the North (not including AFUDC) and $4.6 million (income tax included) in the South. The collection is to be completed over the remaining test years following 2005, as herein approved.

[430] Transcript Volume 1, page 129, lines 9-15

9.8 Three Year Test Period

AG applied for three test years, 2005, 2006 and 2007. AG noted that in Decision 2003-072, the Board emphasized the importance of having the most up to date actual information for the year prior to the first test period.[431] In keeping with this view, AG used the 2004 actuals in the development of the test year forecasts, resulting in the regulatory proceeding occurring within the first test year. AG did not believe this met the true definition of a prospective test period. AG considered that the three year test period would ensure that it would have at least two years that were on a truly prospective basis. AG also submitted that the addition of a third test period should result in reduced hearing costs for customers.

AG determined a separate revenue requirement forecast for each of the North and the South service territories in the Application, but requested that the Board approve one combined revenue requirement for AG commencing in the year 2007.

As AIPA disagreed with the consolidation of the North and South service territories, AIPA also considered that a three year test period was inappropriate, with significant issues such as the treatment of Carbon outstanding. AIPA considered a two year test period would be appropriate in these circumstances.

AIPA submitted that contrary to the AG position of flat expenditures during the test period, the increasing divergence of forecast capital expenditures between the South and the North divisions supported the position that there should not be a combined revenue requirement for 2007, and that 2007 should not be included as a test year.

Calgary submitted that it opposed the three year test period for several reasons. First, the historical record[432] of AG's forecasting did not provide a level of confidence that would support a three year test period. Second, there were still issues around some of the placeholders, and certain placeholders were not available for 2007, such as those related to I-Tek amounts.[433] Third, AG's proposal to combine the revenue requirement of AGS and AGN in 2007 appeared to be harmful to AGS customers. Calgary also suggested that if AG wanted to avoid another Phase I GRA until 2008, it could have managed the operation and achieved all the efficiencies that AG claimed they were achieving in 2007 without having 2007 as a test period.

The CG also recommended that 2007 not be accepted as a test year. The CG considered it would be inappropriate to base the decision to consolidate the North and South into a single entity without the best, most complete and current data available. CG stated that there was significant concern with the accuracy of expense forecasting demonstrated by AG and this would suggest that a third test year in the current Application should not be accepted. The CG submitted that the separation between AGN and AGS and the potentially significant cost reallocations implicit in moving to common North and South rates should be examined in light of accurate information. CG argued that there was no reason to expect that a 2007 forecast of expenditures was accurate enough for this exercise.

[431] Decision 2003-072, page 20
[432] CG Evidence, Exhibit 19-011
[433] Transcript Volume 7, page 1184

The CG noted that while a three-year test period could be viewed as a means of avoiding a test year or extending a test period, the advantages and disadvantages must be considered. The CG believed that inclusion of a three-year test period took on some of the attributes of performance-based rates, but without any sharing provisions. The CG referenced as a concern the staffing reductions, corporate head office restructuring and the change to tri-monthly meter reading that occurred in the North in late 1997 following the signing of the five year PBR Agreement.

In CFIB's view, acceptance of AG's filed proposal would carry with it a very high risk that AG's rates would be excessive, essentially because of the significant risk to customers associated with AG's forecasts. CFIB considered that if AG's basic approach was accepted, it would be necessary to mitigate that risk by shortening the test period to include only 2005 and 2006. In principle, under a pure "internal utility forecast" approach to fixing rates, one-year test periods would probably be appropriate. CFIB noted that since a Board decision on this Application would not be issued until 2006, final determinations of all revenue requirement components would not likely be made until late in 2006, and final rates pursuant to a Phase II proceeding might not be determined until some time after that. Therefore it made practical sense to CFIB to allow a two year test period in this instance.

CFIB stated that its concerns with a three year test period would be reduced if the Board accepted CFIB's proposal that it determine the operating expense component of AG's revenue requirement on the basis of percentage increases fixed on the basis of an evaluation of both AG's forecasts and the other factors that were discussed.[434] Even with that, however, CFIB believed that a better course would be for the Board to shorten the test period by one year as a means of encouraging AG to propose a PBR approach that would resolve these issues for a reasonable period on a balanced and objectively fair basis.

Views of the Board

The Board notes AG's Argument which states:

> ATCO Gas believed that this issue should be put into perspective. The onus to make an application initially rests with the utility. Where the utility believes that it will not be able to earn its allowed return on capital, legislation allows it to prepare and file an application to adjust rates. If a gas utility concluded that it could avoid filing such an application, current legislation allows the utility to simply continue into a non-test year using the rates which were approved for the last test year. Interveners and the Board have the ability to call a gas utility in for a review of its rates if they suspect that continuing with the currently approved rates may not be just and reasonable (i.e. a rate decrease may be appropriate). It should be noted that this is not the case for electric utilities. As a result of the operation of the Electric Utilities Act electric utilities do not have an automatic right to simply continue into a non-test year using rates which were previously approved for the last test year.
>
> This approach of setting rates for a prospective test year, and providing the utility with the opportunity to forego a subsequent rate application has been well-tested, and has served the industry well for years. It results in an opportunity to reduce regulatory costs, and creates incentives for the utility to operate as if it was under price cap regulation outside the test years. [435]

[434] CFIB Argument, section 4.1
[435] AG Argument, pages 84-85

The Board acknowledges that the foregoing quote captures some of the essential considerations in setting a test period and agrees that a longer period that includes 2007 is in keeping with the prospective form of rate making. While the Board notes that interveners preferred only two test years due mainly to concerns with the third year's estimates being potentially less than accurate, the Board also notes that AG identified certain projects during the hearing that would alter the forecast and AG has not proposed to include them. AG was prepared to accept the forecasting risk and in any event where the changes to costs are in relation to growth, the revenue from customer additions will follow accordingly. The Board notes that if there are any inaccuracies existing in the forecasts for 2007, they are not necessarily to AG's benefit.

In terms of being able to evaluate AG's estimates versus actual costs in the future, a three year test period will provide an additional three years to compare, for both the North and the South (if not combined), when added to the two years that the Board considered were appropriate for review in this proceeding. Also, where AG is able to develop efficiencies on its own behalf, such efficiencies will be available for capture on the customer's behalf at a subsequent GRA. This is the essence of the prospective nature of regulation of the gas utilities in Alberta.

The setting of three test years will allow AG to operate without the need for another GRA before 2008 and therefore will provide savings to the regulatory process. The Board notes that AG should now be operating a more stable business environment, given it has almost completed restructuring its business. The Board expects that AG's estimates will have taken this into account. The longer test period will also provide the time necessary to complete the valuation of the remaining placeholders, and the benchmarking that will affect the revenue requirements for the future.

For all the foregoing reasons, the Board approves the three year test period of 2005, 2006 and 2007. The Board directs AG to provide the revenue requirements as herein approved for both the North and the South separately for all three test years.

9.9 Performance Levels

IAG submitted a list of measures and targets which were presented in Table 1.0 of the Application and grouped in the following categories:

- Public Safety
- Worker Health and Safety
- Cost Efficiency
- Service Levels
- Environment
- Call Centre

AG stated that in 2005 it would focus on data gathering and internal focus and communication of these metrics. Once it had gained experience with the metrics AG may or may not adjust them.

The CG's position on performance levels, stated in its evidence, was as follows:

> CG submits that the Board and interveners be involved in the selection of appropriate measures, the setting of any targets for performance measures, the reporting schedule and methods, the appropriate use of the measures, and in any benchmarking of results. This is the only way stakeholders can gain comfort that the correct measures are being tracked

and reported. Further, the CG submits that AG survey other organizations (both utility and non-utility) to determine what measures are used and the purpose of each measure.[436]

The CG submitted that the Board should direct AG to establish a process to involve interested parties in the development of performance measures to ensure that their views were taken into account in the determination of appropriate performance measures and the reporting of those measures.

AG stated in Rebuttal[437] that management was firmly of the belief that management, and management alone, had the responsibility to set internal performance measures. Any suggestion to the contrary would represent the displacement of AG management responsibilities by parties who did not have responsibility for, and who were not familiar with, managing a natural gas utility.

Views of the Board

While the Board considers that it is AG that has the responsibility to set performance levels, the Board would see an advantage to working with interested parties to develop performance standards in order to reduce potentially contentious items The Board notes that AG has been previously willing to discuss performance levels during negotiated settlements. Although the Board encourages, the Board will not compel AG to collaborate with others.

9.10 Deferral Accounts

AG requested approval for new deferral accounts for the following matters:

- Variable Pay Program;
- the difference between the amounts due and the actual amounts collected from defaulting retailers after realization of security deposits;
- funding assessments for the Utilities Consumer Advocate;
- the Government of Alberta Consumer Protection and Customer Choice Campaign; and
- non-Carbon production abandonment and removal costs for the South, similar to the account that is currently in place in the North.

AG requested approval for the continued use of the North production abandonment and removal costs deferral account.

Views of the Board

The Board notes that the interveners had no comment on the establishment of the proposed new deferral accounts, other than an objection to the variable pay program as a whole. The Board also observes that each of these items, other than the VPP, cover amounts that are beyond the control of AG and therefore not within the ability of the utility to accurately forecast and that they otherwise meet the criteria established by the Board for the creation of deferral accounts.[438] The deferral account requested in connection with the VPP was proposed in response to the concerns of the Board and interveners that forecasted amounts for variable compensation would accrue to the utility in the event that full payout of the program was not achieved.

[436] CG Evidence, page 57
[437] Rebuttal, page 14
[438] Decision 2003-100, pages 115-116

The Board finds AG's request for the proposed new deferral accounts listed above is reasonable as they cover amounts that are difficult to forecast and that are largely beyond the control of AG. Therefore, the Board approves the addition of the deferral accounts in the Application. The Board also considers that the necessity to continue to use the specified deferral accounts should be reviewed periodically as circumstances surrounding the related expenses can change over time.

In addition, the Board approves the continuation of the deferral account for collection of abandonment and removal costs for the North Production facilities.

9.11 One Time Adjustments

AG proposed a number of one-time adjustments to address unique items. These items are presented in Table 24 below:

Table 24. One-Time Adjustments[439]

($000)	North	South	Section
Federal Deferred Income Tax Refund	$(5,981)	-	9.2
Hearing Cost Recovery	$4,350	$4,450	9.3
Reserve for Injuries and Damage Adjustment	$(413)	$(370)	9.4
Bad Debt Expense, Collection Agency Fees, Late Payment Revenue	$1,043	$1,557	9.5
UCA Funding Recovery	$228	$228	9.6
Production Abandonment Costs	$1,702	$4,639	9.7 & 9.8
One Time Collection Rider in 2006	$929	$10,504	

Each proposed one-time adjustment has been considered individually and approved in different sections of this Decision.

Views of the Board

Since the Board has approved the one-time adjustments in Table 24, the Board also approves the collection of these amounts in a separate rate rider in 2006. These amounts should not be reflected in the revenue requirement for 2006 or the other test years.

10 OUTSTANDING BOARD DIRECTIONS FROM DECISION 2003-072

10.1 Direction 6: Adequacy of Business Cases

The Board directed AG in Decision 2003-072:

> to continue to promote efficiency in the hearing process, the Board again directs AG, in future rate applications, to file business cases for all major capital additions in accordance with the directions in Decision 2001-96, so as to include:
>
> - A detailed justification including demand, energy and supply information;
> - A breakdown of the project cost;
> - The options considered and their economics; and
> - A discussion of the need for the project.[440]

[439] Application, Volume 1, 8.0-1
[440] Decision 2003-072, page 260

Views of the Board

The Board notes Calgary's argument that many of the business cases filed by AG were deficient. Calgary noted that "AG has admitted… that it has omitted to file its economic analyses in cases where economic analysis was not the "basis of the decision".[441] Calgary contended that this was a direct contravention of Direction 6.[442] Calgary recommended that the Board should disallow all projects where either no business case is submitted or the business case that is submitted is deficient.

The CG stated that the number of business cases filed by AG was a great improvement over the previous GRA.[443] However, the CG echoed Calgary's concerns regarding the level of detail submitted with the business cases. The CG contended that future business cases should be more comprehensive. Specifically, the CG requested that AG include information regarding alternatives considered, business drivers and the cost/benefit analysis of alternatives.[444] The CG also indicated that AG should include more information about the internal approval process for capital projects.

The Board notes that AG included business cases with the filing of its GRA material and that these business cases were of substantial benefit to the Board and parties in reviewing the Application. However, the Board agrees with the interveners that in some instances, AG's business cases did not identify options or the economics of those options. Two examples of this include the MRRP and UMR. In future Applications, the Board requires that AG submit complete business cases for all capital projects and major business decisions. The Board issued general guidance to AG in Decision 2001-96 regarding the basic elements required in a business case which included the identification of options and the related economics. The Board acknowledges that not all business decisions are based exclusively on economic criteria, especially where safety is an issue such as with MRRP or UMR. However, the Board continues to view an economic analysis, complete with options, as essential to assessing the reasonableness of forecast capital expenditures. Where the least cost alternative is not the selected option, it is incumbent on the utility to provide a satisfactory rational for the option selected.

10.2 Directions 10 & 12: Urban Feeder Mains and Gate Station Forecasting

AG used a three-year average method to forecast the capital expenditures for Urban Feeder Mains and Gate Stations.

In Decision 2003-072, the Board directed AG as follows:

> The Board also considers that there is merit in AUMA/Edm's recommendation regarding the identification of future projects. Accordingly, the Board also directs AG in future rate applications, to clearly identify all specified Urban Feeder Mains projects, their cost, the probability of proceeding and the basis for that probability, to identify unspecified projects in the total and to provide historical substantiation for the percentage expected to proceed.[445]

441 City of Calgary Reply Argument, page 13
442 City of Calgary Reply Argument, page 13
443 Consumer Group Argument, page 96
444 Consumer Group Argument, page 96
445 Decision 2003-072, Direction 10, page 39

Views of the Board

The Board notes that CG accepted the forecasting methodology proposed by AG, but requested that the Board review the forecasts in future applications to determine whether or not the method smoothes out the variability around major projects.[446]

The Board notes AG's submission that it was difficult to respond to this Direction because AG was unable to identify a systematic process by which it could assign probabilities to various projects.[447] AG argued that it does not have any control over when or if developments go forward. As such, AG proposed to base Urban Feeder Mains and Gate Station forecasts on the three-year average of historical Urban Feeder Mains and Gate Station expenditures adjusted for inflation.

The Board notes the concerns of the CG, but considers that AG cannot control the schedule for the installation of Urban Feeder Mains and Gate Stations which are driven by the needs of other entities. In these circumstances, the Board is prepared to accept the three-year average method as reasonable for forecasting Urban Feeder Mains and Gate Station capital expenditures and, therefore, the Board approves the forecasts as submitted in the Application.

10.3 Direction 14: Forecasting of Urban and Rural Main Projects

AG used a three year average method to forecast the capital expenditures for urban and rural main projects.

In Decision 2003-072, the Board directed AG as follows:

> The Board also directs AG, in future rate applications, to clearly identify all specified urban and rural main projects, their cost, the probability of proceeding and the basis for that probability, to identify unspecified projects in total and to provide historical substantiation for the percentage expected to proceed.[448]

Views of the Board

AG argued that because most of the projects in this area are identified and installed in the same calendar year using probabilities to develop the forecast would not enhance the accuracy of the forecast. As with Urban Feeder Mains and Gate Stations, the construction agenda is generally driven by the needs of third parties, including developers.

In view of AG's requirement to respond to third party's schedules with the provision of natural gas service to their developments, the Board finds that AG may have little control over the variability in expenditures. In these circumstances, the Board accepts the three-year average method as reasonable for forecasting urban and rural main projects capital expenditures and, therefore, approves the forecasts as submitted in the Application.

[446] CG Argument, page 97
[447] AG Argument, page 87
[448] Decision 2003-072, Direction 14, page 207

10.4 Direction 45: Legal Fees in Reserve for Injuries and Damages

AG was directed to clarify its operating procedures with respect to the Reserve for Injuries and Damages regarding legal fees notwithstanding the findings in Decision E93004[449]. Presently, legal fees for Injuries and Damages are being charged to Account 292.

Alberta Regulation 546/63 states that legal fees are not to be charged to Account 724 Injuries and Damages. Regarding Account 292, the regulation reads:

> This account [292] shall be credited with amounts charged to account No. 724, "Injuries and Damages", or ***other appropriate accounts***, to meet the probable liability, or co-insurance costs, or items not covered by insurance… (Emphasis Added)[450]

CG submitted that Alberta Regulation 546/63 specifically prohibits the inclusion of legal fees in Account 724 Injuries and Damages.[451] Account 292 Injuries and Damages Reserve is credited with amounts charged to Account 724. Accordingly, CG argued that legal fees should not be collected in Account 292.

Views of the Board

The Board notes that Account 292, Injuries and Damages Reserve states that it should be credited with amounts charged to Account 724, Injuries and Damages, or other appropriate accounts. From the Board's reading of these accounts, it considers that while legal fees can't be charged to Account 724, there is nothing prohibiting appropriate legal fees from being credited to Account 292 from some other appropriate account. The Board notes that, as described by AG, the types of legal fees that are being included in Account 292 are the legal fees incurred by AG to mitigate the amounts that have already been included in that Account. Since it is in the best interest of both AG and customers that all reasonable efforts are made to mitigate the amounts charged to the Reserve for Injuries and Damages, it is reasonable that these amounts should be recoverable from customers. The only issue that remains is the appropriateness of which account these amounts should be charged to. Since Account 292 allows for amounts to be credited to it from accounts other than Account 724, the Board therefore finds that it is appropriate to include corresponding legal fees in Account 292, Injuries and Damages Reserve. To account for, and identify, the proper legal expenses to be credited to Account 292, the Board directs AG to accrue these expenses separately in a sub-account of Account 722, or in a sub-account of such other account as AG considers to be more appropriate for the purpose. AG is directed to identify its approach in the Compliance filing.

10.5 Board Direction 69: Temperature Zone Study

In Decision 2003-072, the Board directed AG to file 20 years of weather data for Red Deer, Lethbridge, Grand Prairie and Fort McMurray and demonstrate the significance of using additional weather stations as compared to using only Calgary and Edmonton.[452]

AG provided a study that compared the 20-year average monthly degree days for Calgary and Edmonton with the 20-year average monthly degree days for each of Lethbridge, Red Deer, Grand Prairie and Fort McMurray. The study used 20-year average data from two periods, from

[449] CWNG 1992/93 GRA
[450] Alberta Regulation 546/63 Uniform System of Accounting for Natural Gas Utilities Regulations, Account 292
[451] Consumer Group Argument, page 97
[452] Decision 2003-072, page 244

1983-2002 and from 1984-2003. AG presented an analysis of residential throughput that compared the results of the current normalizing process for each of the North and the South with the results using degree day information from the additional weather centres.

The results of the study confirmed that the difference between using two and six weather stations is insignificant. Compared with Edmonton temperatures, the difference in normalized throughput using Fort McMurray, Grande Prairie and Red Deer temperatures was -2.46%, 0.39% and -1.18% respectively. In terms of total throughput for AGN, the impact of these differences on forecast sales was -0.13% from AG's forecast of sales using the Edmonton temperatures as the current single zone. In the South, the impact on total sales was a difference of 0.12%.[453]

Views of the Board

The Board notes that interveners did not comment on the results of the temperature study. The Board has examined the results of AG's analysis and is satisfied at this time that using six temperature zones to forecast normalized throughput would not significantly improve the precision of the forecast. Therefore, the Board approves the use of two temperature zones to forecast the sales is approved for the test years.

[453] Application Volume 1, Tab 1.0, Board Direction 69

11 ORDER

IT IS HEREBY ORDERED THAT:

(1) AG shall comply with all Board directions in this Decision.

(2) AG shall refile its 2005/2007 GRA (the Compliance filing), on or before March 17, 2006, incorporating the findings in this Decision.

(3) AG shall specifically identify in the Compliance filing, those items to be included in the revenue requirement as placeholders for the test years, and their related amounts.

(4) In the Compliance filing, AG shall include all of the supporting schedules necessary for the Board to make its final determination respecting AG's 2005/2007 revenue requirement, subject to the replacement of placeholder amounts. The Compliance filing shall be at a level of detail sufficient to reconcile with the original filing, and to demonstrate compliance with the Board's findings.

Dated in Calgary, Alberta on January 27, 2006.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

B. T. McManus Q.C.
Presiding Member

(original signed by)

Gordon J. Miller
Member

(original signed by)

Laurie J. Bayda
Acting Member

APPENDIX 1 – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
ATCO Gas	
(ATCO, AG, or the Company)	J. Beckett
L. E. Smith	D. Wilson
K. Beattie	B. Bale
	G. Fraser-Steffler
	G. Schmidt
	A. Dixon
	J. Janow
	Dr. K. Gordon
Aboriginal Communities	
J. Graves	
Alberta Irrigation Projects Association (AIPA)	
H. Unryn	
Alberta Urban Municipalities Association (AUMA)/ City of Edmonton (EDM)	
J. Bryan	
Canadian Federation of Independent Business	
M. Stauft	
City of Calgary (Calgary)	
D. Evanchuk	H. Johnson
	J. Stephens
Consumers Coalition of Alberta (CCA)	
J. Wachowich	
Consumers Group – Comprising:	
Alberta Urban Municipalities Association/City of Edmonton (AUMA/EDM)	D. Gray
	R. Bruggeman
Consumers Coalition of Alberta (CCA)	H. Vander Veen
Public Institutional Consumers of Alberta (PICA)	J. Jodoin
Utilities Consumer Advocate (UCA)	
J. Bryan	

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
Direct Energy Marketing Limited (DEML)	
K. Miller	T. Kozak
	C. Davidson
	D. Gibbons
Public Institutional Consumers of Alberta (PICA)	
N. McKenzie	
Rate 13 Group	
L. Manning	
Utilities Consumer Advocate (UCA)	
R. Bell	
H. Vander Veen	

Alberta Energy and Utilities Board
Board Panel:
- B. T. McManus Q.C., Presiding Member
- Gordon J. Miller, Member
- Laurie J. Bayda, Acting Member

Staff:
- B. McNulty, Board Counsel
- S. Wakil, Board Counsel
- D. Popowich, P.Eng.
- R. Armstrong, P.Eng.
- D. Weir, Esq.
- A. Laroiya
- R. Engelhardt

APPENDIX 2 – ABBREVIATIONS

AFUDC means Allowance for Funds Used During Construction
AE means ATCO Electric
AG means ATCO Gas
AGN means ATCO Gas North
AGS means ATCO Gas South
AIPA means Alberta Irrigation Projects Association
AP means ATCO Pipelines
AR 546/63 means Alberta Regulation 546/63 – General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas Utilities Under the Jurisdiction of the Public Utilities Board of the Provincial of Alberta
ARC means Athabascan Resource Company
Board or EUB means the Alberta Energy and Utilities Board
CAD means Computer Aided Dispatch
CCA means Capital Cost Allowance
CFIB means Canadian Federation of Independent Business
CG means Consumer Group
CIS means Customer Information System
CNRL means Canadian Natural Resources Limited
Code means Code of Conduct
COP means Company-Owned Production
COSRR means Company Owned Storage Rate Rider
CPI means Consumer Price Index
CPU means Central Processing Unit
CU means Canadian Utilities Ltd.
CWNG means Canadian Western Natural Gas Company Limited
DDR means Distributed Disaster Recovery
DERS means Direct Energy Regulated Services
DEML means Direct Energy Marketing Limited
FTEs means Full-Time Equivalents
GCC Decision means Generic Cost of Capital - Decision 2004-052
GCRR means Gas Cost Recovery Rate
GJ means Gigajoule
GRA means General Rate Application
GTA means General Tariff Application
GUA means Gas Utilities Act
GUO means Gas Utility Operator
GVW means Gross Vehicle Weight
HR means Human Resources
ITBS means ATCO-I-Tek Business Services
IRR means Internal Rate of Return
IT means Information Technology
IW means Information Workshop
MEID means Meter Shop, Electronics, Instrumentation and Distribution Centre (MEID) Relocation
MRRP means Meter Relocation and Replacement Program
MSA means Master Service Agreement
NPV means Net Present Value

NWC means Necessary Working Capital
O&M means Operating and Maintenance
PPE means Property, Plant and Equipment
PUB means Public Utilities Board Act
RID means Reserve for Injuries and Damages
ROE means Return on Equity
ROI means Return on Investment
TCO means Total Cost of Ownership
UCC means Undepreciated Capital Cost
UMR means Urban Mains Replacement
UOP means Unit of Production
VPP means Variable Pay Plan
WAN means Wide Area Network
WM means Work Management

APPENDIX 3 – BOARD DECISIONS/ORDERS REFERENCED

Decision E89091	TransAlta Utilities Corporation Decision E89091 – TransAlta Utilities Corporation, In the matter of a Filing by TransAlta Utilities Corporation, pursuant to a direction of the Public Utilities Board in Order C88027 dated November 14, 1988, for an Order or Orders fixing new rates, charges or schedules thereof for electric light, power or energy furnished by TransAlta Utilities Corporation to and for the public in Alberta during the years 1988, 1989 and 1990. dated December 15, 1989
Decision C90026	Canadian Western Natural Gas Company Limited Application pursuant to a direction of the Public Utilities Board in Order C89037 to determine a rate base and fix a fair return thereon for the years 1989, 1990, and 1991. dated July 27, 1990
Decision E93004	Canadian Western Natural Gas Company Limited 1992/1993 GRA Phase I dated February 8, 1993
Decision U96002	Centra Gas Alberta Approval of changes in the existing rates, tolls and charges for natural gas utility services supplied by Centra Gas Alberta Inc. to its customers within Alberta for the test years 1995 and 1996. dated January 5, 1996
Decision U97065	Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation, Grid Company of Alberta 1996 Electric Tariff Applications dated October 31, 1997
Decision 2000-9	ATCO Gas and Pipelines Ltd. (CWNG) 1997 Return on Common Equity and Capital Structure; 1998 GRA Phase I dated March 2, 2000
Decision 2001-75	GCRR Methodology and Gas Rate Unbundling Part A: Methodology and Unbundling Proceedings dated October 30, 2001
Decision 2001-96	ATCO Gas South 2001/2002 General Rate Application, Phase I dated December 12, 2001

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
Decision 2002-034	ATCO Gas South GCRR Methodology and Gas Rate Unbundling - Compliance Filing dated March 21, 2002
Decision 2002-037	ATCO Gas and Pipelines Ltd. Disposition of Calgary Stores Block and Distribution of Net Proceeds – Part 2 dated March 21, 2002
Decision 2002-069	ATCO Group Affiliate Transactions and Code of Conduct Proceeding. Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues dated July 26, 2002
Decision 2002-072	ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Transfer of Carbon Storage Facilities Application 1237639 Released: July 30, 2002
Decision 2003-061	AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariffs for May 1, 2002 to April 30, 2004; TransAlta Utilities Corporation Transmission Tariffs for January 1, 2002 - April 30, 2002 dated August 3, 2003
Decision 2003-071	ATCO Electric Ltd. 2003-2004 General Tariff Application - Application 1275494 Rate Case Deferrals Application - Application 1275539 2001 Deferral Application - Application 1275540 dated October 2, 2003
Decision 2003-072	ATCO Gas 2003/2004 General Rate Application Phase I dated October 1, 2003
Decision 2003-100	ATCO Pipelines 2003/2004 General Rate Application – Phase I dated December 2, 2003

Decision 2003-106	Direct Energy Regulated Services Electric Regulated Rate Tariff and Gas Default Rate Tariff dated December 18, 2003
Decision 2004-036	ATCO Gas 2003/2004 General Rate Application Compliance Filing dated April 28, 2004
Decision 2004-047	ATCO Gas 2003/2004 General Rate Application Second Compliance Filing dated June 15, 2004
Decision 2004-052	Generic Cost of Capital dated July 2, 2004
Decision 2004-066	ENMAX Power Corporation 2004 Distribution Tariff Application Part B: 2004 Final Distribution Tariff dated August 13, 2004
Decision 2004-067	EPCOR Distribution Inc. 2004 Distribution Tariff Application Part B: 2004 Final Distribution Tariff dated August 13, 2004
Decision 2004-069	NOVA Gas Transmission Ltd. 2004 General Rate Application, Phase I dated August 24, 2004
Decision 2005-019	AltaLink Management Ltd. and TransAlta Utilities Corporation 2004-2007 General Tariff Application dated March 12, 2005
Decision 2005-119	ATCO Pipelines Salt Cavern Peaking Working Gas Deferral Account dated November 1, 2005
Decision 2005-036	ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Imbalance and Production Adjustments – Deferred Gas Account dated April 28, 2005
Decision 2005-039	ATCO Gas 2003/2004 GRA – Impact of the Retail Transfer and ITBS Volume Forecast dated May 3, 2005

Order U2004-423	Board Initiated Proceeding - 2005 Return on Equity dated November 30, 2004
Order U2005-133	ATCO Gas South 2005/2006 Carbon Storage Plan Interim Order dated March 23, 2005
Order U2005-410	Board Initiated Proceeding 2006 Generic Return on Equity Formula Result dated November 22, 2005

APPENDIX 4 – SUMMARY OF BOARD 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.

14. The Board observes that the HR Advisor complement of 21.6 in 2005 results in an HR FTEs/100 FTEs ratio of 1.09, equal to that in 2002. Any further additions during the test period would cause that ratio to be exceeded. Accordingly, the Board approves the HR Advisor addition for 2005, but not for the remaining test years and directs AG to make the necessary revisions to salaries and benefits in the Compliance filing. 57

15. The Board understands that the average of step increases will be influenced by the number of new hires and that new hires would tend to lower the average. Therefore, if the new hires include positions that are ultimately considered by the Board to be unacceptable for inclusion in determination of the revenue requirement, the Board will expect AG to reduce the overall average labour step increases accordingly, and to demonstrate such in the Compliance filing. Therefore, the Board directs AG to make any changes to the overall amounts of step labour increases that follow from the Board's determinations in other sections of this Decision..... 63

16. Accordingly, issues related to Pensions and Post Employment Expenses are to be dealt with in the Common Matters process. For purposes of establishing the revenue requirement in this proceeding, AG is directed to isolate, identify and provide the placeholder amounts in a Compliance filing.. 64

17. The Board has reviewed the forecast I-Tek Volumes shown in Tab 4.3 and has determined that the volumes are reasonable. However, the Board directs AG in its Compliance filing, to reduce its placeholder forecast I-Tek Operating Expenses by 7.5% in all applicable O&M schedules. 66

18. The Board directs AG to confirm its forecast amounts for the Sales and Transportation Promotion function expenses to the Board approved amounts in the Compliance filing....... 70

19. The Board notes that it is not clear how each item within Account 721 is affected by Carbon. AG is directed to provide this detail in its Compliance filing. 72

20. The Board notes that no issues were raised during the hearing. Further, the Board notes that in its correspondence with respect to Application No. 1411635, dated December 22, 2005, the Board scheduled an oral hearing in June 2006 to deal with the first two modules of five modules. It is clear that that process will not be completed until well after June. Consequently, AG is directed to indicate the amount of any placeholder related to gas balancing for revenue requirement purposes in the Compliance filing 82

21. The Board acknowledges that, while some cost of removal is expected, and although 1% appears to be a small percentage, there was no substantiation, either from history or from quotes for future work, as to a reasonable estimate of time or cost expected for ATCO I-Tek to remove the software. The Board considers that the provision of -1% net salvage is premature at this time since there is insufficient history available to justify that percentage. Therefore, the Board denies the inclusion of -1% net salvage to provide for the removal of software programs and directs AG in the Compliance filing to make all the adjustment necessary to the financial schedules to reflect this direction. 85

22. In addition, the Board approves an adjustment the asset contribution accounts for a one time contribution adjustment amount of $10.6 million in 2005. The Board directs AG in the Compliance filing to show the account entries and the related amounts. 86

23. The Board notes that AG discovered an error in its UOP calculation BR-AG-43(a, b) Attachment 2. AG submitted that the change was minimal and AG would reflect this change in the Compliance filing. In addition, the Board notes AG's correction in TAB 5.5, for AGS

APPENDIX 5 – SUMMARY OF KEY FINDINGS AND APPROVALS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

regarding Carbon, has determined that AG's forecast appears to have been prepared in a reasonable manner and approves the forecast for other revenue as filed. 90

9. The Board notes that no evidence was filed by interveners with respect to capital costs and operating expenses, and no concerns were raised with respect to the Carbon capital and operating cost forecasts. Accordingly, the Board approves the content of the capital costs and the operating expenses filed in the Application. 93

10. The Board notes that by recognizing the refund in 2006, the extent to which customer rates will be increasing in 2006 is minimized. The Board agrees that AG's proposal to offset the deferred income tax refund for the North in the amount of $5.981 million is appropriate and shall be used to offset one-time adjustments in 2006 to determine the one-time rider for the North. 97

11. With respect to the request by AG for a one-time recovery of hearing costs in 2006 of $4.35 million for AGN and $4.45 million for AGS, the Board notes that this request is consistent with past practices. The Board further notes that no parties objected to this one-time recovery. The Board approves the requested one-time recovery of hearing costs in 2006 of $4.35 million for AGN and $4.45 million for AGS. 102

12. In addition, the Board approves the one-time refund to be reflected in 2006 to bring the RID to a total of $600,000, which is a refund of $413,000 for the North and $370,000 for the South. The Board also finds that the balance in the RID of $600,000 continues to be appropriate. 103

13. While the Board considers that it is AG that has the responsibility to set performance levels, the Board would see an advantage to working with interested parties to develop performance standards in order to reduce potentially contentious items The Board notes that AG has been previously willing to discuss performance levels during negotiated settlements. Although the Board encourages, the Board will not compel AG to collaborate with others. 113

14. The Board finds AG's request for the proposed new deferral accounts listed above is reasonable as they cover amounts that are difficult to forecast and that are largely beyond the control of AG. Therefore, the Board approves the addition of the deferral accounts in the Application. The Board also considers that the necessity to continue to use the specified deferral accounts should be reviewed periodically as circumstances surrounding the related expenses can change over time. 114

15. In addition, the Board approves the continuation of the deferral account for collection of abandonment and removal costs for the North Production facilities. 114

16. In view of AG's requirement to respond to third party's schedules with the provision of natural gas service to their developments, the Board finds that AG may have little control over the variability in expenditures. In these circumstances, the Board accepts the three-year average method as reasonable for forecasting urban and rural main projects capital expenditures and, therefore, approves the forecasts as submitted in the Application. 116

17. The Board notes that interveners did not comment on the results of the temperature study. The Board has examined the results of AG's analysis and is satisfied at this time that using six temperature zones to forecast normalized throughput would not significantly improve the precision of the forecast. Therefore, the Board approves the use of two temperature zones to forecast the sales is approved for the test years. 118