EUB Alberta Energy and Utilities Board

# DECISION 2001-96

# ATCO GAS SOUTH

# 2001/2002 GENERAL RATE APPLICATION PHASE I

# ATCO GAS SOUTH
# 2001/2002 GENERAL RATE APPLICATION
# PHASE I

## CONTENTS

**ALBERTA ENERGY AND UTILITIES BOARD**
**Calgary, Alberta**

| | |
|---|---|
| **ATCO GAS SOUTH** | **Decision 2001-96** |
| **2001/2002 GENERAL RATE APPLICATION** | **Application No. 2000350** |
| **PHASE I** | **File No. 1307-1** |

# 1 INTRODUCTION

By letter dated December 6, 2000, ATCO Gas filed Phase I of a 2001/2002 General Rate Application (GRA) for ATCO Gas South (ATCO, the Company or AGS), a division of ATCO Gas and Pipelines Ltd (AGPL).[1] In the Application, ATCO forecast that the revenue requirement for the test years would exceed revenue at existing rates by $23.8 million in 2001 and $24.0 million in 2002.

In correspondence dated April 2, 2001, ATCO requested that certain affiliate, pension and post employment transactions arising in the context of the GRA be deferred and heard as part of the ATCO affiliate Transactions and Pension proceedings scheduled to be heard in the Fall of 2001. By letter dated May 17, 2001, the Board, in the absence of objections from interested parties, accepted ATCO's proposal for deferral of the affiliate, pension and post employment benefit transactions.

Notice of Hearing for the GRA was mailed to all interested parties on January 4, 2001, and published on January 11, 2001.

The public hearing was convened in Edmonton on June 12, 2001 before Board members Dr. B. F. Bietz (Chair), Mr. G. J. Miller, and Ms. C. Dahl Rees. The hearing was completed on June 26, 2001. Registered interveners and the Company were required to file written argument and reply on August 3, 2001 and August 24, 2001 respectively.

The Board considers that the record for this proceeding and for the related proceeding of ATCO Pipelines South 2001/2002 GRA, Phase I and II, closed on September 14, 2001.

Those who appeared at the hearing and the abbreviations used in this report are listed in the following table.

[1] In the Application, ATCO Gas referred to the restructuring of Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, noting that on January 1, 2001, Northwestern Utilities Limited would be amalgamated into ATCO Gas and Pipelines Ltd (formerly Canadian Western Natural Gas Company Limited). ATCO Gas stated that ATCO Gas and Pipelines would then hold all assets for both of the former utilities, and that on an ongoing basis, two divisions of ATCO Gas and Pipelines Ltd. (ATCO Gas and ATCO Pipelines) will continue the operations of the distribution system and the transmission system respectively. In the hearing, ATCO Gas confirmed that these changes had taken place, and that this structure would continue at the present time with the operating and accounting functions being segregated into ATCO Gas North and ATCO Gas South, and ATCO Pipelines North and ATCO Pipelines South, in accordance with Decision U99102, dated November 1, 1999.

## THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| ATCO Gas South (ATCO, the Company or AGS) | |
| L. E. Smith | J. F. Engler |
| A. C. Wooley | D. A. Wilson |
| N. M. Gretener | B. R. Hahn |
| | G. S. Fraser-Steffler |
| | L. W. Clausen |
| | R. Trovato |
| | M. J. O'Brien |
| | K. C. McShane |
| | M. Chwalowski |
| The City of Calgary (Calgary) | |
| R. B. Brander | H. W. Johnson |
| P. L. Quinton-Campbell | J. Stephens |
| | L. E. Kennedy |
| | H. J. Vander Veen |
| | L. Booth |
| | M. Berkowitz |
| Alberta Irrigation Projects Association (AIPA) | |
| J. H. Unryn | |
| Consumers Coalition of Alberta (CCA) | |
| J. A. Wachowich | |
| Municipal Intervenors (MI) | |
| C. R. McCreary | |
| Public Institutional Consumers of Alberta (PICA) | |
| N. J. McKenzie | |
| R. T. Liddle | |
| Federation of Alberta Gas Co-ops Ltd and Gas Alberta Ltd. (FGA) | |
| T. D. Marriott | |

Tsuu T'ina, Siksika and Peigan Nations (TR7)
J. Graves
A. O. Ackroyd

Alberta Energy and Utilities Board staff
J. Hocking, Board Counsel
E. J. Gallagher
R. Armstrong
D. Popowich
M. McJannet

## 2 PROCEDURAL AND OTHER GENERAL MATTERS

There was considerable discussion in this Proceeding with respect to matters relating to the regulatory status of ATCO, the impact of restructuring of the ATCO Group and related accounting, and the quality and extent of evidence provided by ATCO in support of the Application. The positions of the parties with respect to these matters are summarized in the following paragraphs of this Section of the Decision.

### 2.1 Regulatory Status of ATCO Gas South

**Position of ATCO**

ATCO submitted that the regulatory status of ATCO Gas (South), is an issue that should have been identified much earlier, not just in this regulatory process but in the prior reorganization related proceedings. ATCO noted that the Board appears to consider that the point is academic at this stage of the regulatory process and submitted that the Board did provide approval for ATCO Gas and ATCO Pipelines to be regulated separately through the restructuring decision. ATCO referred specifically to Decision U99102,[2] dated November 1, 1999.

ATCO pointed out that the Board implicitly approved the distinct regulation of ATCO Gas separate from ATCO Pipelines, and that the one reason for suggesting the reorganization approval should be granted without a public hearing was that a detailed review of the affairs of each new entity would be conducted in their respective GRAs.

**Position of Calgary**

Calgary stated that approval of ATCO Gas and ATCO Pipelines to be regulated separately through the restructuring decision is predicated solely upon its interpretation of the language in Decision U99102. It fails to recognize that ATCO Gas is not AGS and that no approval for AGS was provided.

Calgary's submitted that, in public utility matters there should be nothing "implicit" about what entity is being regulated, and how the books are being kept. The public is entitled to certainty. The restructuring Application was brought forward at the insistence of the ATCO Group.

[2] Decision U99102 Canadian Utilities Limited, Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited, Application for Renewal of the Reorganization of NUL and

**Views of the Board**

The Board notes the comments of ATCO and Calgary regarding the regulatory status of AGS. The Board considers that it was appropriate for AGS and APS to file their GRAs separately in these proceedings.

In Section 2.2, the Board deals with the filing of annual reports by the business units of AGPL.

## 2.2 Completeness and Accuracy of Financial Data

**Position of ATCO**

ATCO noted that several of the Interveners have commented on the complexity of this Application, an issue, which the Company addressed in Argument and, at the risk of being repetitive, ATCO noted that with change comes uncertainty, and the requirement to find different ways of dealing with things. ATCO considered that it provided sufficient information in this proceeding to allow the Board to judge the reasonableness of the 2001/2002 forecast revenue requirement.

ATCO stated that, in 1999 and 2000, the regulated and legal entities were AGPL and Northwestern Utilities Limited (NUL), and separate accounts have been maintained by ATCO Gas and ATCO Pipelines to allow for proper accounting and reporting for those two entities, consistent with the Board's direction in Decision U99102. ATCO confirmed that ATCO Gas and ATCO Pipelines will continue to maintain this level of segregation between the south and the north as long as there is a requirement to do so.

ATCO indicated that the Company performed the utility calculations for the two utilities that were regulated in that time frame. Specifically, the 1999 AGPL Annual EUB filing was provided in Tab 17 of the Application, and the 2000 financial statements for AGPL were provided in the response to MI-ATCO GAS.1(b). ATCO indicated that the Company provided historical information for 1999 and 2000 for all relevant comparisons, including income statements.

ATCO rejected Calgary's allegation that insufficient information was provided by ATCO during the proceeding, and noted that additional information was provided in Rebuttal evidence on most of the matters referred to by Calgary. Regarding the fact that the forecast before the Board is not necessarily the same forecast approved by the Board of Directors through the normal planning process, ATCO discussed this process in testimony.

**Position of Calgary**

Calgary's submission on this issue was comprehensive and detailed. The main concerns are summarized below. Calgary submitted that:

- The Board must consider the actions of ATCO, and the ATCO group, in creating a circumstance in which Interveners and the Board, have been forced to deal with this GRA in a disjointed and incomplete fashion

- From the date of the filing in this proceeding Calgary has tried to understand the financial maze created by ATCO Gas and Pipelines ("AGPL") commencing with the restructuring in late 1998
- It is clear from the cross-examination of Company witnesses concerning CAL-AGS.116, that the financial data cannot be properly examined and the reasonableness of such financial data cannot be tested, without access to the whole picture, that is, all four sets of books/accounts
- It is only through a series of allocations and other techniques that the four sets of books/accounts for each of AGS, AGN, APS, and APN were developed
- The allocation factors vary from year to year and in some cases are less than or greater than 100%
- The failure of the AGPL Board of directors to recognize the business units is the point that Calgary has tried to identify throughout this hearing
- For the test periods, 2001 and 2002, AGPL is the legal entity, the legally regulated utility, and that AGS, AGN, APS and APN are trade names or, at best, best business units, the result of assignments and allocations of dollars, recorded to look like accounting records, which are not subject to examination in their totality
- There is no practical methodology available for either the Board or interveners to determine the relationship of the parts to the whole or the whole to the parts

**Views of the Board**

The Board agrees with intervener observations with respect to the complexity of this Application, recognizing in particular that this is the first application filed for two separate business units of ATCO Gas and Pipelines Ltd. The Board also agrees with concerns expressed that, without an extensive interrogatory process and cross-examination, it would have been extremely difficult to properly evaluate the test year forecasts. The Board is satisfied, however, that the additional information provided as a result of requests by the Board and interveners has provided a reasonable basis to evaluate the Application.

The Board does note that the latest annual report of finances and operations, filed as required by the Board for the year 2000, was for ATCO Gas and Pipelines Ltd. The Board expects that for the year 2001 and subsequently, ATCO will file a separate annual report for each of ATCO Gas South and ATCO Pipelines South, ATCO Gas North and ATCO Pipelines North.

## 2.2 Other Matters

A number of submissions were entered into evidence challenging ATCO's position with respect to:

- The quantification of benefits to customers resulting from restructuring, and the treatment of pension gains and other costs arising from restructuring
- The concept of prospectivity and adjustments for actual events arising subsequent to the filing of the Application
- The treatment of affiliate-related and pension-related transactions.

**Views of the Board**

The Board notes the comments and concerns raised by interveners and the responses by ATCO with respect to issues regarding the benefits of restructuring, and the concept of adjusting forecasts to recognize post-Application transactions and events. The Board considers that there is no need to reproduce the positions of the parties with respect to these matters in this section of the Decision, since the issues are addressed more fully in other sections. While the same comment applies to the issue of affiliate and pension-related transactions, the Board considers it worthwhile to highlight at the beginning of the Decision how affiliate and pension-related transactions in the Application will be dealt with.

On April 2, 2001, ATCO requested Board approval to transfer affiliate, pension and post employment benefit transactions from the General Rate Application to the ATCO Affiliate and Pension proceedings respectively. In the case of affiliate-related transactions, ATCO requested that all revenues and expenditures relating to transactions with non-regulated affiliates be dealt with in the Affiliate proceeding. Due to the complexities associated with isolating the revenue requirement impact of capital related affiliate transactions, ATCO proposed that capital costs associated with affiliate transactions continue to be reviewed in the General Rate Application.

On May 17, 2001, the Board accepted ATCO's proposal. Accordingly, the quantum and propriety of forecast revenues from services to affiliates, forecast expenditures relating to services provided by affiliates, and forecast expenditures relating to pension and post-employment benefits are not addressed in this Decision. The forecast amounts will be treated as "placeholders" in the revenue requirement for the test years and adjusted by ATCO on refiling, after the Board Decisions are issued on the Affiliate and Pension proceedings.

Capital costs associated with affiliate transactions have been reviewed in the General Rate Application, and will be addressed in this Decision. These transactions relate to expenditures on the new CIS system, and expenditures on improvements at Carbon.

# 3 RATE BASE

## 3.1 Capital Additions

ATCO assigned forecast capital additions for the test years to four main categories, namely, growth, replacement, improvement or supply. Total forecast capital expenditures were $51.56 million (2001) and $48.18 million (2002).

## 3.2 Growth-Related Expenditure

### Position of ATCO

ATCO indicated that growth-related expenditures are required for new or upgraded plant or equipment necessary to extend service to new customers, to generate additional revenues from existing customers, or protect revenues from existing customers. ATCO indicated that the bulk of the forecast expenditures in this category are required for extensions to distribution systems and installation of new urban service lines. The total forecast for these categories was $21.25 million (2001) and $21.33 million (2002), representing approximately 80% of growth-related expenditures. The balance of the forecasts related to expenditure for acquisition of new meters and metering equipment.

With respect to feeder mains, ATCO submitted that the need for these mains, while tied to growth, is not directly proportional to growth. ATCO noted that the MI was concerned that "not all specified projects proceed as anticipated". ATCO pointed out however, that its witness stated:

> There are always projects that come in, and some go out, but generally we get a pretty good handle on what the total is going to be.[3]

ATCO pointed out that a critical point to note is that some unanticipated projects will also proceed in a given year.

With regard to measurement facilities, ATCO noted that the MI questioned the validity of the forecast for new measurement facilities on the basis that the Company did not proceed with expenditure on stations forecast previously. ATCO indicated that the forecast is based on development planned in an area as indicated by the community and developers. The Company will not build a facility until it is actually needed and even then will consider all options. Further, the requirement for a new measurement facility can sometimes be offset by additions or improvements to the distribution feeder system depending on where the growth in the community occurs.

ATCO stated that the comparison of the costs of individual projects to costs of projects completed in the last three years would be invalid, since measurement facilities are built with a certain capacity, which, when reached, results in the requirement for a new facility. Furthermore, ATCO pointed out that the cost of the facility is dependent on its size, and that it is Company practice to install small temporary stations initially and replace them when they are no longer large enough. ATCO indicated that the facilities required in the test years are larger than those installed in 1998, 1999 and 2000, and that station costs can vary between $36,000 for a new farm tap unit to $650,000 for a full sized gate station. ATCO submitted that, based on the information provided, the forecast provided is reasonable.

With regard to meters, the Company stated that total replacements as a result of sampling, recall of failed groups, damaged meters and other causes are in the order of 24,000 meters per year, and not 3,000 as the MI implied. ATCO increased the number of meter purchases in the years 1999 and 2000 in excess of customer growth levels in those years and purchased more meters in each of those years than in the test years. ATCO indicated however, that even with increased purchases, the Company was unable to reach the level of inventory required to efficiently administer meter sampling and recalls.

With regard to meter inventory, ATCO stated that while the desired target inventory level is 4% of all installed meters, only a 3.2% level will be attained with the meter purchases planned in the test years.

ATCO considered that the meter purchases identified for 2001 and 2002 have been adequately justified and that the associated costs should be allowed.

[3] Tr. p.451

## Positions of the Interveners

### MI

The MI submitted that both the quantum and unit cost of urban feeder main additions in the test years far exceed historical experience. In the MI's view, the variance in the test years, together with ATCO's explanation of the variance, indicates that ATCO is building more extensions with less in-fills than in the past, or the forecast expenditures are overstated. The MI subscribed to the latter theory, suggesting that sooner or later, in-fills will start to catch up to new extensions.

The MI noted that the average cost per additional urban customer from 1996 through 2000 was $149, compared to ATCO's forecast of $261 per addition in the test years. The MI calculated that based on the average actual cost for 1999 and 2000 plus an escalation factor of 3%, the expenditure for urban feeders should be reduced by $700,000 in 2001 and $285,000 in 2002.

The MI pointed out that ATCO spent less than 40% of forecast amounts for measurement and regulating stations in the years 1998, 1999 and 2000. The MI also pointed out that identified projects represented only 54% of the total forecast in 2001, and that four out of the five projects identified 2002 were forecast at $140,000 each, compared to the maximum expenditure of $66,000 per gate station from 1998 to 2000. The MI speculated that these forecast items are more than likely to be deferred, cancelled or scaled back, as was the case for projects forecast for 1998 through 2000.

The MI considered that ATCO has failed to provide justification for the forecasts of $220,000 (2001) and $140,000 (2002) classified as unspecified projects, and submitted that, based on prior experience and the apparently very preliminary estimates, expenditures on measurement and regulating stations should be reduced by 50% to $240,000 in 2001 and $390,000 in 2002.

With regard to meter inventories, the MI noted that ATCO described the reasons for inventory levels to include the load levelling of meter shop and meter recalls of up to 3,000 units when a sample fails Measurement Canada testing. The MI expressed concern that ATCO had not adequately described why the forecast inventory levels for the test years had increased to 13,242 (2001) and 13,554 (2002), particularly if the 2000 level (10,141) was perceived to be adequate. The MI expressed concern that meter levels were only topped up in test years, and submitted that, absent adequate justification, the meter inventories should be set at 2000 levels, which would result in a reduction of $834,000 and $898,000 for 2001 and 2002 respectively.

## Views of the Board

While noting the submission of the MI that both the quantum and unit cost of urban feeder mains additions in the test years far exceed historical experience, the Board notes that percentage increases of actual expenditures in years between 1996 and 2000 have been significant, with a percentage increase in 2000 compared to the previous three years of 51%. The Board considers that the trend appears to support a higher level of increase than that proposed by the MI, noting that the increases in the test years are 32.6% (2001) and 18% (2002) over the year 2000 actual expenditure, considerably less than the historical averages.

The Board agrees with ATCO that, since the forecasts are based on known projects plus an estimate for unspecified projects, use of average costs per additional urban customer from 1996 through 2000 may not be an appropriate criterion for evaluation of the increase in test year forecasts.

The Board notes that the detailed analysis of forecast expenditures provided by ATCO in response to BR-ATCO.2(a) demonstrates that the level of reduction proposed by the MI would, in addition to reducing the forecast for known projects in 2001, eliminate the entire forecast for unspecified projects.

Based on the foregoing, the Board accepts ATCO's forecasts for expenditures on urban feeder mains.

With respect to forecast expenditure on measurement and regulating stations, the Board acknowledges ATCO's submission that comparison of the costs of individual projects in the test years to projects completed in the previous three years may be invalid, since these facilities are built with a certain capacity, which, when reached, results in the requirement for a new facility. In other words, the nature and required level of expenditures included in the forecasts do not necessarily correspond to the type of requirements in previous years. Nevertheless, the Board agrees with the MI that the test year forecasts are significantly in excess of actual expenditures for the previous three years, and that the Company spent less than 40% of forecast amounts in those years, giving weight to the MI's view that forecast items have the potential for deferral, cancellation or scaling back.

While, in agreement with the MI's proposal for a reduction in forecast expenditure, given ATCO's position as set out above, the Board does not consider that a reduction of 50% is warranted. The Board however, agrees with the MI that ATCO has failed to provide justification for the forecasts of unspecified projects. Accordingly, the Board directs ATCO to revise the forecasts for new measurement and regulating station facilities to reflect the amounts identified as known projects, thereby reducing forecast expenditures by $220,000 (2001) and $140,000 (2002).

The Board notes the MI's comments with respect to the test year forecasts for additions to meter inventories. However, the Board acknowledges ATCO's position that total replacements as a result of sampling, recall of failed groups, damaged meters and other causes are in the order of 24,000 meters per year, and not 3,000 as the MI implies. While noting the MI's observation that the forecast levels are unjustified, particularly if the 2000 inventory level was perceived to be adequate, the Board acknowledges ATCO's submission that the year 2000 level of 10,141 represented only 2.5% of installations, which would not be adequate to efficiently administer meter sampling and recalls.

The Board accepts ATCO's submission that the target meter inventory, based on experience, is 4% of all installed meters, and that a level of only 3.2% will be attained based on purchases in the test years. Accordingly, the Board rejects the MI's proposal for a reduction of test year forecasts to year 2000 levels, and accepts ATCO's forecasts of meter additions.

### 3.3 Replacement Expenditure

**Position of ATCO**

ATCO's expenditures in the replacement category are designed for replacement of plant and equipment, no longer suitable for service, while maintaining the existing capability of the plant or equipment. ATCO indicated that the bulk of the forecast expenditures in this category are required for replacement of bare and unprotected mains, and urban and rural mains replacements and relocations. The total forecast for these categories was $9.9 million (2001) and $8.4 million (2002), representing approximately 55% of the total replacement expenditure forecast in 2001, and 60% in 2002. The balance of the test year forecasts represents expenditures for installation and refurbishment of meters, acquisition of transportation, tools and work equipment and office furniture and equipment. The forecast for 2001 includes $3.3 million for replacement to the CIS system ($0.5 million in 2002).

ATCO referred to the alternate methodology suggested by the MI for developing the forecast for urban mains replacement based on 1998 and 1999 historical levels and addition of valve and vault replacements. ATCO submitted however, that the MI analysis fails to treat the Lethbridge LP-IP conversion project ($300,000 in 2001) in the same manner as the valve and vault replacements and exclude that cost from their base number. ATCO further submitted that the MI analysis has not adequately addressed inflation by failing to inflate the 1998 number before averaging it with the 1999 number and then inflating the average each year through 2001 and 2002. ATCO noted that, by correcting the MI analysis, the result is a forecast expenditure of $1,182,000 in 2001 and $896,000 in 2002, certainly not in line with the $300,000 reduction in each test year proposed by the MI. ATCO submitted that the differences between the Company forecast and the MI proposal, when calculated correctly, are insignificant.

ATCO considered the urban main replacement forecasts filed to be reasonable.

ATCO noted that the MI suggested that the forecast for contributions to urban mains relocations is too low. ATCO submitted that basing the argument on the 1998 and 1999 forecast numbers and the total contributions in 1999 and 2000, is not an appropriate way to look at this issue. Specifically, the 1999 actual expenditures for urban relocations were $1,242,000 and the contributions in that year were $407,000 (33% of expenditure). In 2000, the actual expenditures were $1,580,000 and contributions were $898,000 (56% of expenditure). ATCO pointed out that the relocations in 2000 had an unusually high level of contributions, approximately half due to work on the Deerfoot Trail Relocation that had an exceptionally high contribution level (50% plus an extra contribution to cover costs incurred by ATCO when the City of Calgary and the Province changed the scope of the project).

ATCO submitted that the contribution levels proposed by the MI of 47% in 2001 and 46% in 2002 are too high based on 1999 actual expenditure and the unusual level of contributions in 2000. Accordingly, ATCO considered the contribution levels forecast to be reflective of the contributions that were experienced in 1999 and appropriate for the test years.

ATCO referred to the MI claim that the forecasts for rural main replacements and relocations for the test years are high and should be maintained at the level of actual expenditures in 2000, noting that, in its argument, MI provided a table summarizing expenditures from 1996 to 2002.

ATCO pointed out that the table contains an error. Specifically, known projects total $270,000 in 2001, not $130,000 as indicated by MI. ATCO noted that the table clearly shows increasing expenditures over the period, which the MI has characterized as a 'step function.' Rather than a step function stabilizing at current levels as suggested by MI, ATCO submitted that the Company is forecasting expenditures to continue to increase, a factor largely driven by provincial and federal infrastructure grants that allow counties to complete road improvements. ATCO referred to the response to PICA-ATCO Gas.29(b), which shows that in addition to the work normally done in this category, there is $140,000 budgeted in each of the test years for graphics data conversion. ATCO indicated that this project is required to convert manual records to electronic format, and must be taken into consideration when comparing to previous years actual expenditure. ATCO considered that that the 2001 and 2002 forecasts are reasonable.

ATCO noted the MI claim that capital expenditures for moveable equipment have not been justified and should be limited to 1999 and 2000 actual levels. ATCO submitted that the expenditures identified in the 2001 and 2002 capital forecast are not based on historical information, rather they are determined from the costs for specific equipment that has been identified for purchase and replacement in the test years. ATCO referred to the response to CCA-ATCO Gas.6, where a list of all equipment, with a unit price of greater than $25,000, was provided and, in contrast to the MI claim, a description of each piece of equipment and the reason for its replacement has been provided. ATCO noted that the justification for replacement was not challenged in the hearing, and that historical levels do not drive these expenditures.

ATCO took issue with the MI claim that the practice to extend the mileage and operating hours of vehicles and heavy equipment beyond the levels used prior to 2000 has not flowed through to depreciation parameters or expense. ATCO pointed out that the response to CCA-ATCO Gas.6 demonstrates that the life of vehicles varies considerably, with very few reaching a ten-year life. ATCO submitted that it is not known if the impact of this change in practice will affect the average service life of the equipment, but it will be considered in the next depreciation study.

ATCO stated that, contrary to the implication of the MI that the extended use practice was not the basis of the 2001 and 2002 forecasts, the replacements in 2001 and 2002 are based on the extended use practice implemented in 2000.

**Positions of the Interveners**

**MI**

Referring to ATCO's statement that the estimated expenditure for urban mains replacement for the test years was based on actual experience for 1998 and 1999, the MI noted that this should suggest a forecast in the order of $850,000 per year, inclusive of $400,000 for vault and valve replacement in each test year. The MI submitted therefore that the expenditures for the test years should be reduced to 1998/99 levels, including a reduction of the 2002 forecast for valve and vault replacement, which the MI considered might not be fully justified, given the relatively recent vintage of units targeted for replacement. The MI submitted therefore, that forecast capital expenditures for each test year should be reduced by $300,000.

The MI noted that historically, contributions towards relocation of urban mains have been in the range of 46% to 50%, in contrast to contributions for the test years of 31% (2001) and 38%

(2002). Accordingly, the MI submitted that forecast contributions should be increased by $140,000 in 2001 and $55,000 in 2002 to more closely reflect historical experience.

The MI acknowledged ATCO's claim that the increase in rural main replacements is driven, in large part, by provincial and federal infrastructure grants, which counties are using to widen or relocate roads. However, the MI considered that the response to PICA-ATCO.29(b) indicated that expenditure for rural mains replacement in the years 1998-2000 represented a new level of expenditure rather than part of a trend. The MI submitted that, since there is no evidence to suggest that this category of expenditure will take another step upwards in 2001 and 2002, the forecasts for rural mains replacements and relocations should be reduced by $425,000 in 2001 and $348,000 in 2002, to maintain the forecasts at the 2000 level of $1,095,000.

Referring to variances in forecast and actual expenditures for moveable equipment, the MI acknowledged that a significant portion of the 12% variance in 1998 was due to a reduction in office furniture and equipment due to restructuring. However, the MI submitted that the variances for 1999 and 2000 of 21% and 17% respectively would have been significantly higher had it not been for unplanned expenditure on the SAIT Cogeneration Plant Compressor in 1999.

The MI argued that ATCO has failed to justify the reasons for the increase in expenditures for moveable equipment forecast for the test years compared to actual expenditures on a historical basis. Accordingly, the MI submitted that the test year forecasts should be reduced to 1999 and 2000 levels. The MI also indicated that it was unclear whether or not the test year forecasts reflected the impact of ATCO's change in policy for replacement of vehicles, which allows for extension of useful life before replacement.

**Calgary**

Referring to ATCO's comment that customers benefit through capitalization of meter refurbishment as a result of recovery of costs over many years, Calgary submitted that ATCO neglects to review the other side of the ledger. In particular, Calgary considered that a shift in meter refurbishment from Operating and Maintenance (O&M) to capital would have resulted in a decrease of O&M costs. Calgary noted however, that the opposite has occurred, in that ATCO's O&M costs are increasing, not decreasing.

**Views of the Board**

With respect to forecast expenditures on urban mains replacements, the Board notes the MI's submission that actual expenditures for 1998 and 1999, adjusted to incorporate the addition of $400,000 for valve and vault replacement in each test year, would suggest a forecast for each year of $850,000, compared to the Company's forecast of $1.37 million (2001) and $0.96 million (2002). The Board, however, agrees with ATCO that the MI's proposal for a reduction of the forecasts to the 1998/99 levels, does not incorporate an inflation factor, and fails to treat the Lethbridge LP-IP conversion ($300,000 in 2001) in the same manner as the valve and vault replacements.

The Board has reviewed ATCO's recalculation of the test year forecasts using the 1998/99 expenditures as a base, incorporating an inflation factor of 3%, and recognizing the Lethbridge LP-IP expenditure. The Board notes that ATCO's recalculation, on this basis, results in a forecast for the test years of $1.182 million (2001) and $0.896 million (2002), compared to the MI's proposal for a forecast of $850,000 in each test year.

The Board shares the MI's concern that a significant proportion of test year forecast expenditure represents expenditure on unspecified projects, and considers that the 1998/99 actual expenditures can be regarded as a reasonable basis for projecting test year expenditures. However, the Board considers that the revised forecasts, based on ATCO's recalculation, recognize the concerns of the MI while at the same time recognizing relevant issues raised by ATCO. Accordingly, the Board directs ATCO to reduce the test year forecasts for urban mains replacement to $1.182 million (2001) and $0.896 million (2002), being the amounts as determined in ATCO's recalculation. This adjustment represents reductions from ATCO's original forecasts of $150,000 (2001) and $61,000 (2002).

With respect to contributions for urban mains relocations, the Board notes the MI's proposal for an increase of forecast contributions to historical levels. Specifically, the MI recommends that contributions be increased by $140,000 (2001) and $55,000 (2002), bringing the forecasts to historical levels within the range of 46%-50% of capital costs, compared to a forecast level in the range of 31%-38%.

However, the Board accepts ATCO's position that contributions for 1999 represented 33% of expenditure, and that the level of contributions, at 56% for 2000, was abnormally high, due to specific circumstances relative to the work on the Deerfoot Trail Relocation. Accordingly, the Board agrees with ATCO's submission that contribution levels are reflective of experience in 1999 and 2000 and, therefore rejects the MI's proposal for an increase in contribution levels for the test years.

The Board agrees with ATCO that information provided for 1998-2000 on rural mains replacements and relocations shows increasing expenditures over the period rather than a "step increase" as suggested by the MI, and accepts ATCO's position that expenditures will continue to increase as a result of provincial and federal infrastructure grants that allow counties to complete road improvements. However, the Board agrees with the MI that the increased expenditure on rural mains replacements and relocations in the test year appears unusually high compared to historical actual expenditures. In particular, the Board notes the MI's observation that forecast expenditures for unspecified projects in the test years are higher than actual expenditures for combined specified and unspecified projects in the years 1998 through 2000.

Accordingly, the Board agrees with the MI's proposal for use of the year 2000 actual expenditure as a base, adjusted to recognize specified amounts of $270,000 in each test year, rather than the amount of $130,000 suggested by the MI. The Board agrees with ATCO that the forecast expenditure of $140,000 for graphics conversion in the test years also needs to be included as expenditure on identified projects. The Board therefore agrees with the MI that the expenditure forecasts should be calculated based on the actual 2000 expenditure of $1.095 million plus $270,000 to recognize specified amounts for the test years. The Board notes that expenditure forecasts, calculated on this basis will be $1.365 million for each test year, compared to ATCO's original forecasts of $1.520 million (2001) and $1.443 million (2002).

Accordingly, the Board directs ATCO to reduce the test year forecasts for rural mains replacements and relocations by $155,000 (2001) and $78,000 (2002).

With respect to forecasts for moveable equipment additions, the Board notes that the response to CCA-ATCO.6 shows actual expenditure on transportation equipment of between $2.1 million and $2.3 million in 1996, 1997 and 1998, whereas expenditure on transportation equipment in 1999 and 2000 ranged between only $198,000 and $895,000. The Board also notes that the response to CCA-ATCO.5 provided details of transportation equipment scheduled for replacement in the test years, indicating that the expenditure in this category will revert to pre-1999 levels.

While acknowledging ATCO's position that the forecasts are determined from the costs for specific equipment identified for purchase and replacement in the test years, and that historical experience has no bearing on forecasts, the Board notes the MI's submission that actual expenditures on moveable equipment have historically come in significantly below forecast. The Board agrees with the MI that ATCO has failed to fully justify the increase in expenditures for moveable equipment compared to historical levels, but the Board does not consider that a decrease to the unusually low 1999 levels is warranted. Accordingly, the Board directs ATCO to decrease forecast expenditures for moveable equipment by $217,000 (2001) and $215,000 (2002) representing 10% in each test year, which will reduce test year forecasts to 2000 levels.

## 3.4 Improvement Expenditure

### Position of ATCO

The improvement category includes expenditures incurred to alter or replace existing plant or equipment to meet new demands or improve operability. In the Application, expenditures totaling $3.3 million (2001) and $3.5 million (2002) on pipes and equipment to tie in additional Company operated and non-operated wells and additional storage capacity, expenditures to replace corroded piping, looping line relocation and improvements to owned or leased facilities represent approximately 55% of the 2001 forecast for this category and 47% in 2002. Of the remainder, $2.17 million (2001) and $3.65 million (2002) is earmarked for major software development, consisting mainly of expenditures on the OPS/MMS Replacement and Work Management Replacement projects.

ATCO noted that the MI questioned the forecast for regulating and measurement station improvements implying that the forecast should be based totally on historical expenditures. ATCO considered this inappropriate, pointing out that, while some forecasting in this category is based on historical expenditures, such as equipment failures and replacement of obsolete equipment, the main forecasting focus is expenditure requirement as a result of growth. ATCO referred to Company testimony and responses to information requests providing further detailed explanation.

ATCO submitted that the MI has misinterpreted the response to PICA-ATCO Gas.29, by incorrectly stating that the Company made no regulating and measurement station improvements since 1997. ATCO noted that, in fact, PICA-ATCO Gas.29 clearly shows increasing expenditures for 1997-2000. ATCO reiterated previous comments indicating that a comprehensive facility review has demonstrated that an increased level of expenditure is required in this category to improve and replace existing facilities. In addition, ATCO noted that the forecasts for the test years include work that was identified in previous years but has not yet been completed.

ATCO considered that the explanation provided for the higher expenditure levels for regulating and measurement station improvements is adequate to support the forecasts provided.

**Positions of the Interveners**

**MI**

Referring to ATCO's claim that significant growth has resulted in the need to replace and improve regulating and measurement station equipment that is undersized for current loads, the MI submitted that the Company has experienced high growth since 1997 without having made any improvements in this area.

In the MI's view, the forecasts of $1,231,000 (2001) and $1,408,000 (2002) for this expenditure category, are out of line with historical expenditure levels, including actual expenditure for 2000 of $560,000. Accordingly, the MI proposed a reduction of $290,000 in 2001 and $470,000 in 2002, representing an allocation of the difference of $760,000 between the average forecast for the test years of $1,320,000 and the actual expenditure of $560,000 for 2000.

**Views of the Board**

The Board acknowledges ATCO's submission that the response to PICA-ATCO.29 shows a steadily increasing trend in expenditures for replacement and improvement of measuring and regulating station equipment between 1996 and 2000, and that the increase should continue at a higher level during the test years due to the need to replace equipment that is either obsolete, or inadequate to meet capacity.

However, the Board notes that, while the increases historically were in the range of 26% and 37%, the increases in the test year forecasts compared to the year 2000 actual expenditure are approximately120% (2001) and 150% (2002). The Board also notes that the test year forecasts mainly represent expenditures on unspecified projects. The Board considers that, even allowing for an increase to deal with a higher level of replacement of obsolete and below capacity equipment, forecast expenditures are significantly out of line with historical levels. Accordingly, the Board finds that a reduction in forecast expenditure is warranted, and considers that the MI's calculated reduction in forecast expenditures will achieve a reasonable compromise which recognizes ATCO's position that increases should continue at a higher level than historically during the test years. Accordingly, the Board directs ATCO to reduce forecast expenditure for regulating and measurement station improvements by $290,000 (2001) and $470,000 (2002).

## 3.5 Appropriateness of Capital Forecasts

**Position of ATCO**

ATCO referred to evidence which illustrated the accuracy of previous capital expenditure forecasts, noting in particular that, in the Distribution category, which comprises 60%-70% of the total, actual expenditures exceeded approved expenditures by 5% in 1998 and exceeded forecast expenditures by 1% in 1999. ATCO indicated that the evidence on the record explains the forecasting process for customer growth, which includes discussions with developers and communities, and is based on a combination of known projects and unspecified amounts.

ATCO referred to the MI claim that the Company and its predecessor CWNG, have a history of over-forecasting capital expenditures in test years. ATCO considered that a review of previous year's forecasts, allowing for extraordinary items, demonstrates that previous forecasts have been reasonable. To illustrate the point, ATCO referred to the MI's comparison of 1999 forecasts versus actual, which ignored adjustment to the 1999 for removal of ATCO Pipelines expenditures, not included in the actual numbers. Once this correction has been made, ATCO noted that the difference between forecast and actual in 1999 is only 4.9%, not 7.0% as claimed by the MI.

ATCO submitted that overall capital forecasts have been accurate, pointing out that, in the Distribution category, which represents 65-70% of the total capital in 1998 and 1999, actual expenditures exceeded forecast, by as much as $1.7 million in 1998. ATCO stated that the following extraordinary items totaling $3,340,000 in 1998 and $900,000 in 1999 were identified and should be considered as a reduction to the forecast for comparative purposes, as there are no similar expenditures in 2001 or 2002:

- deferred crown royalty payments of $840,000 in 1998 and $900,000 in 1999;
- in 1998, $1,300,000 to purchase acreage protection at Carbon to prevent drainage;
- a new Transportation Information System, which is an ATCO Pipelines system, for $1,200,000 that was not required due to the restructuring of NUL and CWNG.

ATCO considered that, allowing for these adjustments, the Company has not significantly over-forecast in 1998 and 1999, since the under-expenditure of 4.3% in 1998 and 3.2% in 1999 are well within acceptable forecasting variability.

ATCO considered that responses to information requests demonstrate that there has been sufficient information provided to support the forecasts, and that capital forecasting has been accurate, particularly with respect to distribution projects, which represent 80% of the capital forecast. Referring to the MI's proposal for reduction of the Closing Balance of Property, Plant, and Equipment by $4.719 million based on a comparison of 2000 forecast to actual amounts, ATCO submitted that acceptance of this proposal by the Board, would undermine the fundamental principle of prospective ratemaking in the use of actual information as it becomes available subsequent to the filing. ATCO submitted that the MI proposal must be denied, on the grounds of inconsistency with the Board's stated position on prospective ratemaking, which the Company views as elemental to ratemaking in Alberta. ATCO argued that it should be further noted that the MI proposal ignores the fact that some of the 2000 capital expenditures would be in work-in-progress, and would therefore not impact the opening rate base for 2001.

### Positions of the Interveners

### MI

The MI expressed the view that CWNG, the predecessor of ATCO has a long history of over-forecasting capital expenditures in test years, and cited comments of interveners from the 1997/98 CWNG GRA, to support this view. To illustrate the extent to which this trend has continued, the MI provided a table demonstrating that the expenditures reflected in the

Application for 1998, 1999 and 2000 were in excess of actual expenditures subsequently filed for those years by 10%, 7% and 8.8% respectively.

The MI considered that this forecasting bias translates into an inflated rate base, and related return, taxes and depreciation, and suggested that ATCO had not met its burden of proof. Accordingly, the MI submitted that, based on the experience in recent test years, capital additions should be reduced by a minimum of 10% or $5 million in each test year. The MI pointed out that, as detailed on the table referred to above, actual expenditure for 2000 was $4.7 million less than forecast. The MI submitted therefore, that the opening balance of Property, Plant and Equipment for 2001 should be reduced by that amount.

The MI noted ATCO's assertion that the Company prepared accurate forecasts of the funds required for growth, replacements, and improvements to ensure safe, reliable and efficient facilities that meet the needs of existing and new customers and that generally, previous forecasts have been accurate. The MI also referred to ATCO's statement that actual expenditures in the Distribution category exceeded the approved capital expenditures by 5% in 1998 and 1% in 1999.

The MI submitted that ATCO is being very selective in identifying two of the few instances where actual capital exceeded forecasts. As already noted by the MI, actual capital expenditures for CWNG were 11% below filed for the 1989-1993 test years and for 1998-2000, actual capital expenditures, (excluding transmission), were 10.0%, 7.0% and 8.8% respectively below filed.[4] The MI reiterated the concern that the persistent and disturbing trend of over-forecasting capital expenditures has continued and that the reduction to capital additions to reflect that experience should be no less than 10% in each of 2001 and 2002 and that the 2000 closing balance should also be reduced by $4.7 million to reflect actual capital additions.

**CCA**

The CCA took little comfort from the fact that, in the distribution category, actual expenditures exceeded approved expenditures by 5% in 1998 and 1% in 1999,[5] noting that there is a direct correlation between revenue levels and distribution capital additions. The CCA submitted that the utility is motivated to minimize revenue forecasts in the form of additions and throughput per customer on a forecast basis, since higher actual returns will result if a lower forecast is accepted and approved by the Board. The CCA noted that, if revenues were under forecast in the form of lower customer additions then distribution capital additions would also be under forecast. The CCA considered that it is with the larger distribution projects that the greatest flexibility exists for capital deferral, noting that there was significant financial activity in 1998 and 1999 particularly in residential and commercial development in Alberta. The CCA stated that the fact remains that predecessor companies of ATCO have generally tended to over forecast capital expenditures in GRAs. Accordingly, the CCA considered it appropriate for the Board to make general reductions and reduce forecast capital additions to reflect previous GRA forecast to actual variances.

[4] MI Argument, pp. 2-3
[5] ATCO Argument, p.10

**Views of the Board**

The Board notes intervener submissions with respect to the Company's history of over forecasting, and the specific observations regarding the forecasts for 1998 –2000. However, the Board acknowledges ATCO's position, provided in response to MI-ATCO.13, that, in the Distribution category, which represents 65%-70% of total capital expenditure in 1998, actual expenditure exceeded forecast by as much as $1.7 million. The Board notes ATCO's explanation in that response, that expenditure variances for 1998 and 1999 in the remaining categories were due to the inclusion of extraordinary items in the forecasts.

The Board agrees with ATCO that, allowing for these adjustments, the Company has not significantly over-forecast capital expenditures in 1998 and 1999, and rejects the proposals of interveners for a general reduction of 10% or $5 million in the test year forecasts. In reaching this conclusion, the Board recognizes that a general reduction in forecasts would duplicate reductions already made for specific items in this Section of the Decision.

However, the Board agrees with the MI's observation that, since year 2000 actual expenditure was $4.7 million less than forecast, the opening balance of Property, Plant and Equipment for the 2001 test year should be reduced by that amount. In reaching this conclusion, the Board considered the findings in Decisions U97065[6] dated October 31, 1997 and E89091[7] dated December 15, 1998, where the forecasts of TransAlta Utilities Corporation and ATCO Electric were found to be deficient to the extent that actual information that became available during the course of the proceedings, was not used. In those Decisions, the Board concluded that the use of forecast data distorted the opening balances for the test period, when actual results were available.

Accordingly, the Board directs ATCO to reduce the 2001 test year opening balance of Property, Plant and Equipment by $4.7 million to recognize actual expenditure in the year 2000.

## 3.6 Capital Expenditure Policy

**Position of ATCO**

ATCO indicated that the Application incorporates a proposal to reduce customer contributions for service lines, beginning in 2002. Specifically, urban customers, currently contributing 65% of service line costs, would not be required to make a contribution for a service line construction costs, and rural customers, currently contributing $2,300 per service line, would receive a reduction of $600. ATCO submitted that the change in policy is proposed to ensure that the acceleration of convergence of electricity and gas will not present an impediment in future to provision of natural gas service to customer premises. ATCO noted that energy retailers are already offering both services to customers, and felt that an important fact to consider was that electrical service would always be required for new buildings.

---

[6] Decision U97065 Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation and Grid Company of Alberta, 1996 Electric Tariff Application

[7] 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

ATCO also indicated that the costs to repair meters and return them to service will be capitalized beginning in 2001. Noting that there was little by way of cross-examination of the issue of capitalizing meter repair during the hearing, ATCO indicated that meter repair costs increase the life of the meter and add value to the individual meter and meter pool, resulting in a benefit to customers through cost recovery over many years rather than in the year the cost is incurred. ATCO indicated that the policy revision results in a reduction of approximately $400 for the average urban customer, and a reduction of $600 in the connection charge for rural customers.

With regard to the proposal to reduce customer contributions, ATCO considered that a "wait and see" approach to attachment of new customers is a dangerous proposition, and must be proactive in meeting the needs of all existing customers served by the Company. Accordingly, ATCO considered it essential to remove any financial barriers to the provision of service to future customers. In ATCO's view, providing certainty that customers will continue, in the future, to request natural gas service, will result in benefits to all existing customers as the system continues to grow.

With reference to intervener argument that the Company has not adequately demonstrated the need for the change in policy, ATCO referred to testimony of Company witnesses indicating that the policy proposal is a proactive initiative by ATCO Gas to protect existing customers by ensuring future rates are kept as low as possible by achieving the highest possible saturation rate in securing new customer growth. ATCO noted that intervener arguments imply that there is a threshold number that has to be passed in terms of 'lost' customers before there would be sufficient evidence of a threat. ATCO considered that this view will damage existing customers, and may result in irreparable damage on an ongoing basis. In ATCO's view, the threat is clear and present, as evidenced by customers electing not to obtain natural gas service. ATCO submitted that, rather than sit by idly waiting to lose additional customers, the Company has taken a proactive position in proposing a revised service line contribution policy that will remove an existing obstacle to future customers obtaining natural gas service.

ATCO noted the MI's submission regarding the historical commodity price differential between gas and electricity. ATCO disagreed with the calculations set out by the MI, as based on an inappropriate comparison, and submitted that it is completely speculative to assume the historical price advantage of natural gas will continue into the future.

ATCO considered that there is no evidence to support the MI's statement that "Gas and electric prices have tended to move up or down in tandem", and submitted that in fact, the evidence supports the position that there is volatility in the energy commodity marketplace. ATCO submitted that, by reducing one of the obstacles to new customers obtaining natural gas service, the ATCO proposal will lessen the risk that this volatility will result in developers building "all electric" buildings.

ATCO submitted that the FGA's suggestion that the proposal is "anti-competitive" with electric utilities presupposes that convergence has in fact occurred and natural gas and electricity are in competition. ATCO stated that the FGA undermines the credibility of its argument by this contradiction, and re-emphasized the point that the proposal will reduce one of the obstacles to the installation of natural gas. ATCO submitted that the proposal is in no way "anti-competitive", but does ensure that natural gas remains competitive with electricity.

ATCO argued that the FGA's statement, introduced in argument, that "Other utilities providing rural gas service require contributions at a level much higher than that proposed by ATCO Gas", is inappropriate and not supported by the record in this proceeding. ATCO pointed out that it could very well turn out that the 'other utilities' may elect to introduce similar policy changes in the future as they see the same challenges that ATCO is currently experiencing. ATCO objected to the FGA's suggestion that this policy cannot be changed in isolation, but that any change should be made by all of the utilities in Alberta. ATCO considered that this would hinder the ability of ATCO to manage an external challenge that it sees today.

Contrary to PICA's suggestion that the proposal "will clearly be a policy which acts to reduce the future business risk of AG," ATCO suggested that implementation of the policy is an attempt to maintain its competitive position, not enhance it, as suggested by PICA.

Referring to intervener concerns that the Company did not consult with customers prior to putting forth this proposal, and that any change should be through a collaborative process with stakeholders with results brought forward in the 2003 application, ATCO considered that the time to take action with respect to this change is now. Considering that the 2003 Application will be filed early in 2002, ATCO submitted that it would be difficult to imagine that a collaborative process can occur prior to that filing.

Referring to the area of intervener argument dealing with discrimination against customer groups, ATCO noted that the argument falls into two areas; firstly either rural or urban customers will be discriminated against by the proposed change (both sides being argued by interveners); secondly, new customers will benefit to the detriment of existing customers.

ATCO pointed out that in reality, the historical investment level has been equivalent for both urban and rural customers, citing the MI argument and testimony by Mr. Engler in support of this contention. ATCO's objective is the same for both urban and rural customers in that the Company is "trying to remove that portion of the contribution that either of those customers would make to service lines." ATCO stated that the Company has been equitable in the past and the proposal would treat both urban and rural customers equitably in the future.

ATCO noted that, within the general argument of discrimination, the MI argued "this change in policy is discriminatory to existing customers who have paid for 65% of their service lines." ATCO considered this argument to have merit only in a narrow, short-term view. However, ATCO indicated that the Company takes a long term, broad approach to this issue, and by removing obstacles to the installation of natural gas, it will be able to maintain a high degree of saturation in new developments. This would have the advantage of maximizing growth and throughput and ultimately keeping rates as low as possible to the benefit of existing and future customers.

ATCO noted that the Company commenced capitalizing the cost and contributions for customer initiated service line alterations in the year 2000. As the intention of the contribution is to offset the cost of the expenditure, ATCO did not view this as an accounting change. ATCO also pointed out that it should be noted that there are also Company initiated service line alterations for which customer contributions are not recovered. ATCO submitted that the 2000 – 2002 forecasts have been treated consistent with this change, and that the Board should accept them.

### Positions of the Interveners

### MI

The MI expressed concern that the proposed change in contribution policy is unfair to existing customers, and that the Company investment for rural customers, which is currently higher than for urban customers, will be even higher in 2002, despite the fact that the rates are the same. The MI noted that the Company declined to provide any further support for the change in policy, and stated that electricity could not be considered an economic alternative to gas for space and water heating at the present time. With this in mind, the MI submitted that ATCO's policy revision was designed to do nothing more than increase rate base, noting that net plant in service would be some $4.8 million greater under the new policy.

The MI noted that, despite ATCO's implication that rising gas prices could encourage use of electricity as an economic alternative, the cost of electricity was 2.8 times higher than the relative cost of gas during the past year when gas prices were as high as $15 per GJ. The MI also pointed out that, at current gas prices of about $4 per GJ, the cost electricity is approximately 3.5 to 4 times higher. The MI submitted that such a large relative difference in energy costs would cause customers to demand the installation of natural gas to new homes.

The MI submitted that ATCO has not demonstrated that energy convergence justifies elimination or reduction of customer contributions for services. The MI pointed out that, furthermore, the policy change is discriminatory to the extent that new customers will avoid approximately $400 in the first year, or $5.50 per month, in contrast to existing customers who have paid for 65% of their service lines. The MI disagreed with ATCO's statement that the incremental cost would be spread over all customers, and submitted that the proposed change in policy should be denied at this time. The MI agreed with Calgary that the existing policy should only be modified if and when it can be demonstrated that natural gas service needs to be promoted.

The MI took issue with ATCO's assertion that Company investment for urban and rural systems would be in line if urban feeder mains were included in the calculation, noting that the record proves that rural investment ranges between $58 to $155 more than urban investment. Accordingly, the MI considered that the rural customer contribution should be increased by approximately $100 from existing levels.

The MI noted that ATCO began capitalizing expenditures on service line alterations and partial replacements in 2000, when expenditures of $394,000, net of contributions, were capitalized rather than expensed. The MI submitted that rates prevailing in 2000 reflected the policy in place prior to 2000, and that ATCO's change in policy had the effect of increasing ATCO's earnings before tax by $394,000. In the MI's view, such changes should not be allowed without the express approval of the Board in the context of a GRA. Accordingly, the MI submitted that the Board should direct ATCO to remove the net amount of $394,000 from the year 2000 closing balance.

The MI also noted ATCO's statement that any revenues received by the Company by way of contributions for line alterations were now treated as an offset to property, plant and equipment. The MI submitted that this constituted an accounting change in 2000, a non-test year. The MI submitted that, unless ATCO can demonstrate that plant in service has been reduced by at least

$600,000, which is the increase in service line replacements capitalized from 1999 to 2000, the 2001 opening plant in service balance should be reduced accordingly. Furthermore, the MI considered that ATCO should also demonstrate that revenues forecast for service line replacements in the test years should be treated as offsets to plant in service in those years.

**AIPA**

AIPA expressed concern with ATCO's proposal to alter its existing customer capital contribution policy, on the basis that the policy does not appear to result in fair treatment between urban and rural customers. AIPA noted that the evidence indicates that customer contributions for rural extensions and services are approximately 65% of forecast expenditures for 2001 and 55% for 2002, and in the case of urban extensions and services, contributions represent 61% of costs in 2001 and 0% in 2002.

AIPA submitted therefore, that the proposed policy causes inequities to the extent that urban customers will receive a disproportionate benefit in relation to rural customers, and this will result in a disproportionate increase in rate base, which will be shared by all customers. To restore balance and equity, AIPA recommended that ATCO should modify the proposal to target a 55% contribution for both urban and rural customers, and that the Company should not proceed with expenditure on urban extensions and service regardless of cost without a cap on expenditure.

AIPA also considered that the contribution policy, based on recovery of 3 times annual revenues indicated a bias towards urban customers, and that the urban policy encompasses the commercial classification where unit connection costs are substantially in excess of residential costs. AIPA submitted that it is unreasonable to treat such large commercial connection costs as system costs, which are shared by all customers. AIPA noted that, furthermore, since the rate of urban customer growth is significantly higher than rural customer growth, the change in policy will result in a disproportionate increase in rate base, which all customers must share.

In AIPA's view, another negative impact of the policy change is that it will remove any economic discipline from developers, and encourage urban sprawl.

**Calgary**

Calgary expressed concern that ATCO's proposed change in the policy with respect to contributions for new service lines appears to represent a strategy to increase rate base, and the rationale for the change is unsupported by facts or studies. In Calgary's view, to justify such a major change, ATCO should have been expected to provide cost benefit analyses demonstrating the relative costs of gas compared to electricity for space and water heating. Calgary submitted that, instead of filing information of this nature, ATCO merely provided some anecdotal evidence demonstrating that one or two buildings chose electricity over gas. Calgary also noted that ATCO's responses to intervener questions about incremental revenue and cost considerations with respect to contributions appeared less than definitive. Calgary submitted that awareness of these cost considerations puts some discipline on those requesting facilities.

Calgary submitted that ATCO has provided no evidence that any change is occurring in the market place, only speculation that a change may occur. Calgary considered that, if homeowners and builders are no longer having gas connected to new dwellings, or if existing customers are discontinuing gas service, ATCO should have data to provide to the Board, and suggested that, such a significant change should not be based on mere speculation.

**PICA**

Regarding the proposed change in policy for customer contributions, PICA noted there is little or no evidence to suggest that new customers are, in fact, opting for other heating fuel alternatives in any significant numbers. While ATCO lists a few customers who have installed electric, rather than gas, heating, PICA noted that ATCO provided no indication as to the date of those installations or evidence of any analysis to determine the reasons for the customers' choice. Accordingly, PICA submitted that, although it is possible that at some point in future gas and electricity may be directly competitive, there is no evidence to indicate that current market conditions in Alberta are creating any significant or notable customer movement from gas to electricity.

Notwithstanding the foregoing, if or when the Board considers a change appropriate, PICA recommended that the following qualifications be incorporated:

- There should be a maximum limitation on the level of company investment in new services. The level of company investment should not exceed the average service-related costs recovered through rates. In practical terms, a maximum limitation on the length of new urban service installed free of charge should be established. In this regard, no other jurisdiction in Canada offers completely free service. Accordingly, a maximum length of no greater than 30 metres is recommended.
- To the extent the Board agrees with the ATCO proposal, it will clearly be a policy which acts to reduce the future business risk of ATCO. Therefore, the Board must give weight to any change in the customer contribution policy when assessing the business risk of ATCO and setting an appropriate capital structure; and
- Any additional costs incurred by ATCO as a result of this change in policy should be allocated appropriately to the Customer Rate classes benefiting from the new policy.

**FGA**

The FGA stated that the net result of the change to the contribution/investment policy is that ATCO will invest approximately $500 more in rural services than in urban services. In other words, ATCO's proposal to treat urban and rural customers differently with respect to investment levels, should alert the Board that the new policy will not result in a "just and reasonable" rate. The FGA referred to ATCO's investment in rural services and related customer contribution, which has been determined on the basis of an estimate of three years of base revenue from the customer. The FGA submitted that ATCO would raise investment for new rural customers but questioned if ATCO intends to increase rates for rural service accordingly, or if rural customer consumption will increase accordingly. The FGA submitted that such rate and/or volume increases are unsupported by evidence, leading to the conclusion that ATCO has not followed its own 3-year revenue policy in initiating the new proposal.

The FGA expressed concern with this proposal for several reasons. First, the FGA considered that the proposal is based on an erroneous premise, in that the only competition in the deregulated electricity marketplace is among energy retailers. The FGA argued that other than a few anecdotal and poorly documented instances, there is no evidence to support ATCO's proposition that electricity is mandatory for a new building and natural gas optional.

The FGA's second area of concern was the fact that ATCO appeared to be initiating this proposal without stakeholder input, or without any consultation with other stakeholders in the natural gas industry. The FGA submitted that other regulated entities, such as the Transmission Administrator, ESBI Alberta Ltd., held extensive stakeholder meetings before proposing new contribution/investment policies.

The third issue of concern cited by the FGA is that ATCO's proposal is openly anti-competitive to both the electric utilities and other gas utilities in the Province, on the basis of its inconsistency with the policies of all other Alberta utilities. The FGA indicated that all of Alberta's electric utilities have a uniform level of investment per customer, whether urban or rural, consistent with the Board's policy with respect to locational decisions. The FGA also pointed out that other utilities providing rural gas service require customer contributions at a level much higher than proposed by ATCO. Further, The FGA considered that ATCO has ignored the following principles established by the Board in Decision 2000-1,[8] dated February 2, 2000 with respect to the Transmission Administrator:

> The Board considers that customer contributions are suitable in circumstances where service to a customer may impose costs on other customers for which they should not be responsible.[9]

The FGA submitted that finally, the proposal is inconsistent with ATCO's own corporate policies, to the extent that ATCO espouses a uniform level of investment for all customers in the same rate class, while the Company's evidence shows that the proposal results in higher levels of investment in rural customers.

### CCA

The CCA disagreed with ATCO's position that service line contributions should be reduced, on the basis that there is no evidence that the Alberta energy market is becoming more competitive. The CCA considered that the economics of home heating with electricity do not make sense when compared to the economics of heating with natural gas, and submitted that, what ATCO considers a removal of financial barriers to future customers requesting natural gas service is simply a movement of costs from new customers to existing customers. The CCA considered that cost causation demands that new customers be responsible for the same level of service line contributions as existing customers, and submitted that it is unfair for existing customer to subsidize gas service for new customers.

### Views of the Board

The Board notes that there is general consensus among the interveners that ATCO has failed to provide persuasive evidence supporting the proposal to reduce customer contributions for service lines beginning in 2002. The Board agrees with Calgary and others that the Company has

[8] Decision 2000-1 ESBI Alberta Ltd., 1999/2000 GRA – Phase I and II
[9] Decision 2000-1, p.276

provided no more than anecdotal evidence to support its position that current market conditions are creating a significant movement from gas to electricity, and that gas service is not in demand for new homes.

The Board agrees with ATCO that there is volatility in the energy commodity marketplace, and that there is no reason to assume that the current price differential between electricity and gas will continue into the future. However, ATCO has provided no data to support the claim that price volatility could lead to developers building “all electric” units.

The Board agrees with interveners that cost causation requires that new customers be responsible for the same level of service line contributions as existing customers. The Board also agrees that, all things being equal, existing customers will end up subsidizing gas service to new customers if new customers avoid the requirement to contribute to new service installations. On the other hand, the Board agrees with ATCO that, while new and existing customers would share equally in incremental changes to rate base resulting from the policy change, rate increases would be minimized due to maximization of growth and throughput. However, the Board is not persuaded that there is a need to change the existing policy to maintain a high degree of saturation in new developments.

In conclusion, on this issue the Board is not persuaded that there is sufficient evidence of market convergence at the present time to warrant a change in the customer contribution policy. Accordingly, the Board does not accept ATCO’s proposal for a reduction in urban and rural contributions commencing in the 2002 test year. However, as pointed out by PICA, the possibility exists that, at some point in the future, gas and electrical energy may be directly competitive and comparable. If, in future, market convergence occurs, the Board considers that, based on feedback from interveners, the following factors would be relevant with respect to any renewed proposal by ATCO for a change in the customer contribution policy:

- the appropriateness of investment levels in relation to the recovery of installation costs through rates
- the allocation of any additional costs incurred as a result of the change to the rate classes deriving benefit from the new policy
- evidence that any policy change will maintain an equitable investment policy between urban and rural customer groups.

The Board notes the submission of the MI with respect to the capitalization of service line alterations and replacements beginning in the year 2000, resulting in costs of $394,000, net of contributions, being excluded from expenditures in that year. The Board agrees with the MI’s observation that rates prevailing in the year 2000 reflected the policy in place prior to 2000, and the change in policy had the effect of increasing ATCO’s earnings before tax in that year by $394,000. The Board agrees with the MI that such changes in policy should be brought forward for approval in the context of a GRA, and that any changes made in non-test years should be filed with the Board for acknowledgement.

Accordingly, the Board agrees with the MI that the amount of the service line alterations capitalized in 2000 should be removed from the opening balance of Property, Plant and

Equipment for the 2001 test year. The Board therefore directs ATCO to reduce the 2001 opening balance of Property, Plant and Equipment by $394,000.

However, the Board accepts ATCO's proposal for capitalization of service line alterations commencing the 2001 test year.

### 3.7 Major Capital Projects

In the Application, ATCO provided background information on major capital projects forecast for the test years. The following is an analysis of the forecast expenditures:

| | **2001** ($000) | **2002** ($000) |
|---|---|---|
| Customer Information System | 3,349 | 500 |
| Bare and Unprotected Mains Replacement | 6,470 | 6,065 |
| Valve and Vault Replacement | 400 | 400 |
| Carbon Ultrasonic Flow Meter | 450 | 0 |
| Carbon Emergency Shutdown System | 0 | 500 |
| OPS/MMS Replacement | 531 | 1,029 |
| Work Management Replacement Project | 1,046 | 2,047 |
| GMS Replacement | 27 | 302 |
| Khalix Application | 162 | 0 |
| Barcode System | 142 | 0 |

**Position of ATCO**

ATCO referred to its testimony during the proceeding, indicating that, while all projects are formally justified, the complexity, volume and timing of the justification vary with the facts of the individual projects. ATCO submitted that appropriate justification includes the reason that action is required, alternatives investigated, the project costs and recommendation. In the case of the Work Management Replacement Project, ATCO stated that the feasibility report is typical of a larger, complex project, where the impact on the overall operations of the Company and the expenditure involved are substantial.

ATCO submitted that timing of a project justification and development of the test year forecast may not necessarily coincide, noting that detailed justifications have not been completed for all projects included in the test year forecasts. However, ATCO confirmed that only projects with a high certainty of proceeding based on preliminary justification are included in the forecast. ATCO referred to the OPS/MMS Replacement as an example of a project included in the test year forecasts, where the justification is currently underway.

ATCO submitted that the Company has properly addressed the Board's direction from Decision 2000-9,[10] dated March 2, 2000, in this proceeding, i.e. that for major capital projects the Company provide sufficient information to enable the Board and interveners to assess the need for the projects, noting that the focus of the direction was for "all major capital projects." ATCO

[10] Decision 2000-9 ATCO Gas and Pipelines Ltd. (CWNG) 1997 Return on Common Equity and Capital Structure 1998 GRA – Phase 1

pointed out that a detailed level of information with respect to major capital projects was provided in the Application, and throughout the proceeding. ATCO stated that in some instances, due to the timing of the project, a complete justification in the level of detail indicated by the Board was not available at the time the Application was put together. In addition, ATCO referred to projects driven primarily by safety concerns, such as the Bare and Unprotected Mains Replacement, Valve and Vault Replacement and the Carbon Emergency Shutdown System, where an economic justification would not be meaningful.

**Positions of the Interveners**

**CCA**

The CCA submitted that ATCO has failed to comply with the direction of the Board in Decision 2000-9 that, for major capital projects, the Company provide sufficient information to help the Board and interveners assess the need for the projects. In the CCA's view, by merely providing descriptive assessments of the need for the projects, without sufficient data to allow for meaningful analysis, the Company has failed to meet the onus of proving that the assets are used and useful and should be added to rate base.

The CCA considered that failure to provide the necessary information on major capital expenditures means that the Company has been unable to demonstrate that the project is needed and the expenditure prudent, and is sufficient to justify a general reduction of 15% in capital project expenditure. The CCA also expressed concern that absence of the detailed information in the Application results in deficiencies in the record and inefficiencies in the subsequent examination process.

The CCA did not consider that all capital projects were formally justified, noting ATCO's comments on the Board direction concerning what level of information is appropriate for capital addition justification. The CCA considered that ATCO has severely limited the information necessary to review the reasonableness of capital project additions, and submitted that the Board should take this into account in its determination of forecast capital additions and make reasonable reductions as deemed appropriate.

**Calgary**

Calgary submitted that ATCO has failed to comply with the direction of the Board in Decision 2000-9 that, for major capital projects, the Company provide sufficient information to help the Board and interveners assess the need for the projects. Noting that this concern applied to all major projects, Calgary considered that failure to provide the required information was particularly apparent with respect to the new CIS system and other software expenditures. Calgary submitted that the failure to adhere to the direction in Decision 2000-9 should be a factor considered by the Board in evaluating ATCO's forecast capital expenditures.

Referring to the Board's direction in Decision 2000-9, Calgary noted that, even after many information requests, and significant cross-examination, the record clearly shows that ATCO has failed to comply with the simple and straightforward directive from the Board. Calgary considered that ATCO has failed to provide complete justification for many of its IS projects, and, in the case of the CIS project, provided no justification at all.

Calgary considered that ATCO's suggestion that justification for some projects "may not coincide" with the timing of the development of test year forecasts is both incorrect and circular. By way of illustration, Calgary pointed out that the GRA Application was filed in December 2000, and all forecast spending in 2001 would have gone through the ATCO internal approval processes months before, and that expenditures for 2002 would already be under review. Additionally, the Board's directive in Decision 2000-9 was for ATCO to provide proper information. Calgary indicated that developing the processes to ensure the Board has the information it has directed is the responsibility of ATCO. Calgary submitted that it should not be acceptable to the Board for ATCO to fail to comply with a Board directive because it internally decided not to generate materials in time for the GRA.

**MI**

The MI agreed with Calgary and the CCA that ATCO has failed to provide the information stipulated by the Board pursuant to Decision 2000-9. Although ATCO refers to the Feasibility Report for the Work Management System[11] as typical of a larger sized complex project, the MI considered that it must be noted that this report was only filed as an undertaking late in the hearing process. The MI considered that the Board's direction resulted from concerns over the manner in which CWNG provided information to both customers and the Board in that proceeding in order to allow parties to effectively analyze projects and expenditures. The MI submitted that the Company's failure to provide the directed information makes it impossible to analyze expenditure levels or whether projects are used or useful, which means that historical forecasting accuracy becomes an important consideration in judging the level of capital additions.

**Views of the Board**

Interveners argued that, in order to comply with the direction in Decision 2000-9, ATCO should provide sufficient information regarding major capital projects to enable the Board and interveners to assess the need for the projects. In the Application, in response to Information Requests and in Undertakings, the Company did provide a description of the projects and related information. However, the Board considers that ATCO could have provided more detailed information with respect to detailed justification, cost breakdown, options considered and need for the projects.

The Board recognizes that in some instances, due to the timing of the project, a complete justification in the level of detail required by the Board may not have been available when the Application was filed, and that for projects driven solely by safety considerations, an economic justification would not be meaningful.

On balance, the Board considers that a general reduction of 15% in capital expenditure forecasts is not justified. However, although acknowledging that most large projects were subject to a significant degree of scrutiny during the proceedings, the Board will evaluate the justification provided for these projects on an individual basis in the following paragraphs of this section of the Decision.

[11] Exhibit 117

In future rate applications, the Board will require more detailed information from ATCO for all major capital projects, in accordance with the Board's direction in Decision 2000-9, as follows:

- 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.

### 3.8 CIS System

**Position of ATCO**

ATCO submitted that the costs associated with replacement of the old CIS with a new custom built CIS were prudently incurred and properly included in rate base, indicating that this GRA is not the first time that the Board has had to consider ATCO CIS. Referring specifically to the application by ATCO Electric for approval of $25.6 million in development costs for ATCO CIS, ATCO noted that, in Decision U97065, the Board found those expenditures to be reasonable in view of the magnitude and benefits of the project. Acknowledging that this finding is not determinative, ATCO considered that it supports that conclusion in this proceeding, that the decision to invest in ATCO CIS was also reasonable in view of the magnitude and benefits of the project.

ATCO submitted that there can be no doubt that the Company acted prudently in replacing the existing CIS using a proven platform approved by the Board, noting that the witness for the City of Calgary acknowledged that the Company "had to replace" the existing system given the move towards deregulation.

Furthermore, ATCO submitted that the decision to proceed with the project was made following a thorough and lengthy review process, which included the initial attempt by ATCO and ATCO Electric to work with other utilities to develop a CIS system. ATCO indicated that construction of the system in-house was taken after evaluation of options related to other billing systems, and the decision took into account the ability to control costs and obtain system functionality.

ATCO submitted that the development costs associated with ATCO CIS are reasonable when compared to the industry average, noting Dr. Chwalowski's testimony that development costs experienced by larger utilities would be in the range of $50 - $80 per customer and that less than $50 US per customer is "a good solid number" for development costs associated with a CIS system. Dr. Chwalowski noted that ATCO's CIS development cost was approximately $60 Canadian per customer, which translates to under $50 US. ATCO also referred to Dr. Chwalowski's statement that the development cost of ATCO's system "is not different than average cost for a North American utility." Referring to Calgary's suggestion that lower development costs would be more appropriate**,** ATCO noted that Calgary's witness acknowledged that he had filed evidence in the Enbridge Consumers Gas 2000 General Rate Application, indicating that regardless of the size of the utility, the expected project costs for a custom built CIS system were in the range of $30-$80 US per customer.

ATCO submitted that successful implementation of the CIS demonstrates the prudence of the Company's decision, noting that almost all of its customer accounts have been transferred to the

CIS. ATCO also referred to the major features of the CIS as documented in the Application, and the written testimony of Dr. Chwalowski detailing the capabilities of the system. ATCO noted that on the other hand, Calgary's witness testified that he did not "look…in particular" at the functionality of ATCO CIS.

ATCO noted that Calgary relied on a comparison of ATCO's "CIS Cost of Ownership" and "CIS Project Capital Cost per Customer" with that of other Canadian utilities to support the view that ATCO CIS development costs were too high. ATCO noted that the information supporting Calgary's position, contained in the Gartner Report (Charts 5 and 6) was obtained from regulatory filings made by the various utilities prior to the implementation of their new CIS systems. ATCO submitted that the reliability of those estimates is questionable, and should not be used as a basis for measuring the reasonableness of the costs related to ATCO CIS. By way of an example, ATCO referred to the testimony of Calgary's witness that, at the time of the Enbridge Consumers' Gas hearing, "there was some concern as to the scalability of both the BC Gas and the Enbridge Consumers' Gas systems from the number of customers served on a test run basis to the total customers of the utilities"

ATCO indicated that, furthermore, the information provided in the Gartner Report Charts 5 and 6 does not take into account the functionality of the customer information systems used by the other utilities relative to that of ATCO. In this regard, ATCO referred to Dr. Chwalowski's testimony, indicating that system functionality is an important factor in determining the reasonableness of system cost. ATCO submitted that the data in Charts 5 and 6 of the Gartner Report does not in and of itself, demonstrate that ATCO's CIS development costs were unreasonable, and referred to its previous comments that the development costs associated with ATCO CIS are just and reasonable, and have been found by this Board to be just and reasonable in the past.

**Positions of the Interveners**

**PICA**

PICA noted that development of the new CIS software is substantially complete and utilization of the software has commenced on the ATCO system. PICA also noted that, while the aggregate cost of the new system is approximately $75 million, shared between ATCO Gas (North and South) and ATCO Electric, the portion of costs allocated to the Company is $25.57 million, consisting of $24.571 million for CIS replacement and $1.0 million for CIS enhancements.

While in agreement that the requirements of each utility might be somewhat unique, PICA expressed support, in principle, for the recommendations made by the witness for Calgary, that ATCO's costs appeared out of line when compared to information on nine U.S. utilities contained in the Gartner cost survey, and to costs incurred by other Canadian utilities who have developed similar new customer information systems. Accordingly, PICA agreed that the costs incurred by AGS on its share of the total system development costs were unreasonably high, noting Calgary's testimony that a more economical approach would have been for ATCO to "buy" rather than "build" the system.

### CCA

The CCA referred to a letter dated March 6, 1995, filed as an attachment to Cal.ATCO.73, which documented the agreement between Canadian Western Natural Gas Company Ltd. (CWNG) and Alberta Power Limited (now ATCO Electric) with respect to the sharing of the costs of development of the CIS system. The CCA noted that, while the CIS system will be brought into rate base in the year 2000, ATCO's response to Cal.ATCO.126(c) indicated that no payments had been made to ATCO Electric.

The CCA took issue with ATCO's comments in rebuttal evidence, where the Company stated that changes in IS products and implementation products are only made when required by changes in the marketplace, existing products become unusable and there are clear benefits to customers. In the CCA's view, the only clear benefits to customers are lower rates, and the new IS system does not lead to lower rates, as the implementation costs of the system are much higher than the costs of the current system. In this regard, the CCA agreed with the findings of Calgary's witness that the costs of the new IS system are above industry benchmarking norms, and considered that such measurements of efficiency are important to ensure that customers receive value for the rates charged. The CCA noted that the level of IS charges have increased dramatically in this Application, and expressed support for each of the recommendations of Calgary's witness arising from the review of the information services and customer accounting functions.

### Calgary

Calgary agreed with recommendations made by Mr. Stephens with respect to expenditures forecast for the CIS and other software systems as documented in Section 6 of this Decision, and submitted that implementation of those recommendations would require a reduction of capital costs forecast for these systems.

Calgary considered that in the GRA, the issue is not that the Board approved the ATCO Electric forecast request for a new CIS system in Decision U97065, but whether the current ATCO request to have $25.6 million for a new CIS system added to rate base is prudent. Calgary cited information filed by Mr. Stephens from four Canadian gas utilities showing that ATCO's choice to continue to invest in the CIS system was a choice that not only cost too much to build and implement, but has operating costs that are too high.

Calgary submitted that, since ATCO did not provide a CIS feasibility study, the assumption is that the Company examined no alternatives, but instead chose to custom develop a solution using the ATCO CIS system as a base. While Mr. Stephens agreed that AGS needed to replace its CIS, in Calgary's view, that does not relieve the Company from the need to be prudent in evaluating options and replacing the system.

Calgary noted that, during the same time period (1995 – 2000), Enbridge Consumers Gas (ECG), was the only other single custom developed implementation in Canada, at a cost of $120 million, or $80 per customer, very little of which has been allowed into rates by the Ontario Energy Board. On the other hand, Calgary pointed out that the cost of the ATCO CIS implementation was approximately $75 million or $75 per customer ($25.6 million for each of AE, AGS, AGN or $156, $61, and $60 per customer respectively).

Noting that during the same time period, there have been several packaged implementations in Canada, Calgary stated that Union Gas and Centra Gas Manitoba systems were implemented using an outsourcing arrangement, and the BC Gas system was implemented as an in-house solution at a cost of $45 per customer.

Calgary stated that the approach of Mr. Stephens is much more definitive and applicable to the Canadian industry than that argued by ATCO's witness. Calgary noted that ATCO's witness suggested that "development costs of $US 50 - $US 80 per customer and operating costs for the relational database structure … requires significantly more computing power … and results in much higher computer charges." To contrast this, Calgary produced a chart developed from the Stephens Report, which compared in and out-sourced alternatives along with custom developed and packaged alternatives of Canadian CIS implementations designed to meet the needs of the Canadian deregulated natural gas distribution industry, using relational database technology, and currently in production. Calgary pointed out that the chart illustrated that the comparative annual costs of ownership are:

| Utility | Cost per Customer per Year ($) |
|---|---|
| ATCO Gas South | 23 |
| Union Gas | 16 |
| Centra Gas Manitoba | 19 |
| Enbridge Consumers Gas | 19 |
| BC Gas | 14 |

### AIPA

Referring to ATCO's comments in Argument,[12] AIPA considered that ATCO is attempting to substantiate CIS costs by referencing Decision U97065. However, AIPA noted that the reference is to expenditure of $25.6 million whereas the current estimate is a three-fold increase to $75 million. AIPA also noted that ATCO indicates that the expenditure was made as a result of "the move to deregulation" which justifies the CIS replacement. AIPA submitted that the deregulation justification supports the AIPA position that the CIS system will enhance the "value" of the retail business unit and therefore total CIS expenditures should not be recovered from only current and future customers. AIPA recommended that a significant amount should be placed in a deferral account for assessment and disposition at the time of the retail sale proceeding.

### Views of the Board

The Board notes the submissions of Calgary with respect to the level of development costs incurred by ATCO on the CIS system. Specifically, Calgary presented information developed from the Stephens Report, which compared costs of in-sourced and out-sourced development in Canada, and concluded that Enbridge Consumers Gas (ECG), the only custom developed system in Canada, was implemented at a cost of $80 per customer, and at the other extreme, the BC Gas system was implemented as an in-house solution at a cost of $45 per customer. Calgary noted

[12] Argument pp.13-14

that the development cost of the ATCO CIS system was $61 per customer, and pointed out that very little of the ECG system cost has been allowed into rates by the Ontario Energy Board.

On the other hand, the Board notes that ATCO's witness concluded that the Company's cost per customer of $61 was no different than the average costs for other North American utilities, and that $61 per customer is less than the average of $50 US.

The Board notes that, while ATCO supported its expenditure level with evidence regarding the capabilities and functionality of the CIS system, Calgary maintained that the functionality of CIS was not examined in making conclusions about cost comparisons.

The Board considers that both the Calgary and ATCO evidence indicates that the development costs per customer appear to be within an average range or development costs associated with such systems. The Board considers that, based on basic comparisons of costs per customer and limited substantive evidence on the record to challenge the development cost, it is difficult to make a conclusive determination on a precise quantum of CIS development cost that would represent a definitive prudent acquisition cost for such a system.

In evaluating ATCO's position, the Board recognizes that the CIS project has been ongoing for many years, and that the Board has already considered the prudence of the costs incurred by ATCO Electric relating to the CIS system. In this regard, the Board notes the information provided in response to CAL-ATCO.126. As ATCO points out, the Board has approved the costs incurred by ATCO Electric based on representations made in previous proceedings. The Board considers that the rationale presented by ATCO in this proceeding in support of the extension of the project to ATCO Gas South parallels that presented in earlier proceedings. Accordingly, the Board considers that there is no basis for a reduction in expenditure forecast for the ATCO Gas South portion of the investment in the CIS project.

## 3.9 Bare and Unprotected Mains

### Position of ATCO

Noting the significant level of intervener interest in the forecast expenditure for Bare and Unprotected Mains Replacement, ATCO submitted that the detail provided in evidence and testimony, which refers to the use of an analytical demerit evaluation program to justify and prioritize individual projects, provides sufficient assurance with respect to the prudence of the forecast expenditure. ATCO stated that this forecast expenditure is required to maintain a safe, reliable, and cost effective system and is fully supported by the documentation submitted and testimony in this proceeding.

ATCO referred to the description and expenditure justification provided for this forecast in the evidence, which indicated that these facilities have reached the end of their normal service life due to corrosion, and in some cases, the operability of the valves has been compromised and replacement is required. ATCO stated that the replacement facilities incorporate current industry design practices and materials to extend the life of the facilities and reduce operating costs in the future.

ATCO disagreed with the CCA claim that the Company has not provided enough information to justify the bare and unprotected mains replacement, and referred to the submission in Section 2 of the Application where the following objectives are stated:

> The replacement reduces the safety risks associated with the deteriorated mains and service lines, the costs that would otherwise be incurred to repair leaks on an unplanned basis as well as the amount of gas released in an uncontrolled fashion to atmosphere through leaks.

ATCO also referred to additional information it provided for the bare and unprotected mains replacement which identified the projects scheduled for the test years. ATCO stated that information has been provided on each project with respect to the number of leaks experienced and the demerits used to prioritize the projects. The estimated cost, main length to be replaced and the number of services to be replaced was provided for each project. ATCO considered that, with this detailed level of information, the forecast certainly cannot be considered a "single-number forecast" as the CCA would have the Board believe.

ATCO also noted the CCA claim that, because historical data is not available, there is not enough information for the Board to determine the reasonableness of the forecasts. ATCO submitted that the CCA merely needs to review the response to CCA-ATCO Gas.3, where the historical information has been submitted for the program, including provision of a table clearly demonstrating that ATCO's forecasting of the bare and unprotected mains replacement projects has been extremely accurate. ATCO referred to the total over-expenditure of 0.3% compared to forecast for the entire period 1992 to 2000, and indicated that the Board has approved bare and unprotected mains replacement work in the test years 1991, 1992, 1993 and 1998, following extensive discussion with respect to the need and methodologies for carrying out this work in the related proceedings.

ATCO stated that the CCA's claim that the expenditure level in 2000 is somehow indicative of what the expenditures should be in 2001 and 2002 is completely erroneous for the bare and unprotected mains replacement. ATCO referred to the explanation provided in CCA-ATCO Gas.3 that expenditures are forecast on an individual project basis, and indicated that that each year's expenditure will depend on the actual projects identified for completion. ATCO stated that this work is not forecast based on historical expenditures for that category. For the reasons stated, ATCO considered that the forecast for bare and unprotected mains replacement is reasonable and that adequate information has been provided for the Board to approve the forecasts as submitted.

**Positions of the Interveners**

**CCA**

The CCA noted that ATCO's forecasts for replacement of bare and unprotected mains are expenditures that will be incurred on the culmination of a 10-year replacement program, and expressed concern that the information filed by ATCO in response to intervener requests during the proceedings failed to indicate the weighting relied upon by the Company to determine the need and timing of individual replacements. In the CCA's view, in providing a single-number forecast without a detailed cost justification, the Company had taken a "broad brush" approach to defining its forecast requirements for the test years. The CCA expressed concern, that despite the directions of the Board in Decision 2000-9 with respect to filing of detailed justification for major projects, there is insufficient information on the record to enable parties to properly assess the Company's specific requirements for the test years. The CCA also expressed concern that there is no long-term historical evidence on the record to assist the Board in determining the reasonableness of previously approved forecasts.

The CCA noted that actual expenditure for 2000 was almost $2 million less than the approved forecast for 1998 of $7.04 million, and submitted that it does not seem plausible that the forecasts for 2001 and 2002 should be respectively 23% and 15.3% higher than the actual expenditure for 2000. The CCA submitted therefore, that the test year forecasts should be no more than the actual cost incurred in 2000, adjusted for inflation. The CCA calculated that, with the addition of a 3% inflation adjustment to the actual expenditure for 2000, the reduction to the 2001 and 2002 forecasts would be $1.05 million and $0.49 million respectively.

**Views of the Board**

The CCA expressed concern that it is not plausible that test year forecasts for bare and unprotected mains replacement should be 23% (2001) and 15.3% (2002) higher than the year 2000 actual expenditure, and that ATCO has taken a "broad brush" approach to determining forecasts. On the other hand, ATCO made reference to total over-expenditure of 0.3% compared to forecast for the period 1992-2000, as calculated based on information provided in the response to CCA-ATCO.3. The Board accepts ATCO's position that forecasts are not based on historical expenditures, but determined on a project-by-project basis, dependent on the actual projects identified for completion. To support this claim, the Board notes that, in the response to CCA-ATCO.3, the Company provided a detailed analysis of projects included in the test year forecasts.

The Board acknowledges that this program is designed to replace facilities that have reached the end of useful life due to corrosion, and the expenditure is necessary to maintain safety and reliability. The Board is satisfied that the analytical demerit evaluation program used to justify and prioritize individual projects provides sufficient assurance with respect to prudence of forecast expenditure.

For these reasons, the Board accepts ATCO's test year forecasts for bare and unprotected mains replacement, and rejects the CCA's proposal for a reduction of test year forecasts to 2000 levels.

## 3.10 Carbon Ultrasonic Flow Meters

**Position of ATCO**

Referring to the issue of expenditure on Carbon Ultrasonic Flow Meters, ATCO considered that Calgary appeared to be of the opinion that measurement inaccuracies at the Carbon Storage facility are resulting in the flow of base gas to storage customers. ATCO submitted that this is not physically possible as all gas entering and leaving the Carbon facility is measured at the connection points to the TCPL and ATCO Pipelines systems. Storage customers deliver through one of these two connection points and withdraw through the same two connection points. ATCO stated that metering at these connection points is not in question, but that the issue to be addressed with respect to metering relates to the collective volumes from the individual wells beyond the plant itself, which are not used for custody transfer for storage customers. ATCO indicated that the differences in collective measurement at the well meters compared to the custody transfer meters do not impact the volume of gas that storage customers inject and withdraw. ATCO noted that the volumes of gas measured at all of the wells combined do not balance precisely with the results at custody transfer meters, and the differences being investigated relate to unidentified points between the wells and the custody transfer points at TCPL and ATCO Pipelines. ATCO indicated that the ultrasonic meter at the downstream side of the Carbon Plant will enable measurement differences to be further isolated to either the plant or the field lines and wells.

ATCO referred to the concern of the CCA that the Company waited until a test year to install ultrasonic measurement on the field side of the Carbon Plant, two years after a nearly identical project was installed on the inlet side of the plant. ATCO noted that the CCA wondered why the project could not have been done in 2000, and further asserted that ATCO has not provided any evidence that orifice meters are in fact providing inaccurate results. ATCO pointed out that Section 2 of the Application indicates that the installation of ultrasonic meters on the two field-side inlet pipelines to the Carbon plant will result in more accurate metering. ATCO stated that the present procedure requires the use of 31 different well site meters to determine the total inlet flow to the plant. ATCO also pointed out that, at the Carbon plant inlet, there is high variability in injection withdrawal volumes, meaning that the ultrasonic meters are an optimal choice to measure storage applications due to the bi-directional and high range capability of these meters. ATCO referred to the response to CAL-ATCO Gas.103, where the Company clearly explained the further advantages of ultrasonic measurement over orifice meters. ATCO indicated that these advantages include recorder accuracy and greater accuracy over wider flow variability. Other disadvantages of orifice metering include errors introduced as a result of manual integration of charts produced from orifice measurement and the averaging that takes place with orifice metering using chart recorders, compared to the real time integration of measurement factors such as super compressibility with ultrasonic metering.

ATCO submitted that installation of ultrasonic measurement on the field side of the Carbon plant at this time, was only reasonable given that the installation in 1999 represented the Company's first experience with ultrasonic meters. ATCO considered that the experience gained as a result of that project confirmed the appropriateness of proceeding with the current project. ATCO further noted that the proposal by CCA to reduce the allowed expenditures as if the project had been undertaken in 1999 is nonsensical. ATCO submitted that, based on this premise, customers should be required to pay for a full year of rate base on the project in the year 2001, which would result in higher costs.

### Positions of the Interveners

### CCA

The CCA had a number of concerns regarding the 2001 forecast expenditure of $450,000 for the Carbon Ultrasonic Flow Meters. Specifically, the CCA pointed out that, although the equipment was being acquired to facilitate validation of the results obtained from orifice meters, ATCO has not provided any evidence of orifice meter inaccuracies. The CCA also expressed concern that the Company waited until a test year to incur the proposed expenditure, noting that this project could have been undertaken in a non-test year, such as 1999 when the project could have been carried out in conjunction with the installation of similar-purpose equipment that year. The CCA submitted that concerns about accuracy of gas volume measurements are no more pronounced in 2001 than they were in 1999 or 2000. In addition, although ATCO also justified the acquisition as being required to fulfill regulatory reporting requirements, the CCA noted ATCO's confirmation that reporting requirements have not changed, but the new flow meter would help validate the accuracy of gas well injections and withdrawals.

The CCA considered that it would have made more sense for ATCO to have undertaken this project in conjunction with the installation of identical equipment on the inlet side in 1999, and submitted that the amount included in rate base should reflect the mid-year net book value (NBV) of the equipment assuming a 1999 installation. Assuming purchase of the equipment in 1999 at the forecast cost of $450,000 and application of depreciation for 1999 and 2000 at the rate of 4.15%, the addition to rate base in 2001 would be $413,038, resulting in a reduction of $36,962 to the 2001 forecast amount.

**Calgary**

Calgary considered that, with respect to ultrasonic meters, ATCO has provided no evidence to indicate that the meters add to the value of Carbon to ratepayers, or increase the revenue received for the services offered. In fact, Calgary considered that, given the ATCO application to transfer Carbon to ATCO MidStream, the Board should be very reluctant to approve expenditures at Carbon that do not have a clear, immediate, and demonstrated benefit to ratepayers.

**Views of the Board**

The Board notes the CCA's submission that the expenditure on Carbon Ultrasonic Flow Meters could have been undertaken in 1999 with the installation of similar equipment, and the recommendation for a reduction in the forecast amount assuming expenditure in that year. The Board however, accepts the Company's position that installation of the equipment in 2001 is reasonable given that the installation in 1999 represented the Company's first experience with ultrasonic meters, and the experience gained confirmed the appropriateness of proceeding with the current project.

The Board considers that ATCO has presented a reasonable case to support the benefits of this forecast expenditure and, in the absence of compelling evidence to refute the Company's representations, the Board accepts ATCO's forecasts of expenditure on Carbon Ultrasonic Flow Meters. The Board is also not persuaded that the ATCO application to transfer Carbon to ATCO MidStream justifies denial of the forecast expenditures.

## 3.11 Carbon Emergency Shutdown System

**Position of ATCO**

ATCO indicated that the forecast expenditures for the Emergency Shutdown (ESD) System project at Carbon represents expenditure for the final phase of a project started in 1997, and will enable the effective isolation and blow down of the Carbon Plant facilities under emergency conditions. ATCO stated that the project was completed in phases to coordinate the timing with other modifications being done at the plant over the period, and that the benefits included reduction in environmental damage caused by venting raw gas into the atmosphere.

ATCO submitted that the approach taken in determining the need for and in designing the ESD system was consistent with industry practice and isolation of the plant from the storage field and transmission systems and exhausting of the trapped gas was necessary for safety reasons. ATCO considered that completion of the ESD system will reduce the consequences of an incident at the plant caused by a rupture in the piping or an explosion at one of the compressors.

ATCO noted that the CCA claims that evidence indicates that there has never been a full plant ESD at Carbon and that there was no industry standard mandating design and construction of emergency shutdown systems that make an investment as proposed necessary. ATCO also noted the CCA's submission that, if the ESD project was necessary based on safety and environmental concerns, the project should have been undertaken earlier than 2002, and that, even if the project is beneficial, the existing ESD is sufficient to meet and may exceed current industry standards.

ATCO referred to Section 2 of the Application, where the Company notes that the proposed expenditures represent the final phase of modifications to the existing emergency shut down system to ensure depressurization of <u>all</u> plant compressors and associated piping to the new flare system installed in 2000. ATCO pointed out that the project is part of the ongoing review of the Carbon storage facilities, and follows current industry best practice with respect to emergency shutdown facilities. ATCO noted that in 1997, the first phase of the project was completed, which permitted isolation and containment of any problem within the plant, with the exception that plant piping would remain pressurized. Prior to starting the second phase, ATCO indicated that a number of piping modifications dealing with corrosion had to be completed since these modifications influenced the ESD system design. ATCO pointed out, that in 2000, the ESD system was augmented with the installation of valves and controls to depressurize the plant piping. ATCO noted that this results in a capability that will flare approximately 70% of the plant piping while the remaining piping and the compressors are vented to atmosphere. ATCO indicated that the final phase, as proposed in the Application, includes the installation of piping and valves and instrumentation that will allow 100% of the plant piping to be depressurized in the event of an emergency and flared at the new flare stack.

ATCO referred to the response to BR-ATCO Gas.11, where the Company further details the needs addressed as a result of the project. First and foremost, ATCO indicated that the project ensures the safety of company employees, nearby residents and of the plant itself. Second, by flaring gas, which would otherwise be vented to atmosphere, the system reduces greenhouse gas emissions. The Company confirmed its commitment to the objective of reducing greenhouse gas emissions and pointed out that, as stated in AEUB Guide 60, venting leads to higher carbon dioxide emissions and for that reason is discouraged. ATCO submitted that clearly customers benefit as a result of the completion of this project as it results in a safer facility reducing the potential injury to employees, nearby residents and damage to equipment that would otherwise need to be replaced in the event of some sort of emergency.

Dealing with the question of why the project wasn't completed earlier, ATCO stated that it seems obvious to the Company that proceeding in stages, ensuring each of the individual components of the process work effectively and efficiently, was the appropriate and prudent course of action.

With respect to CCA's assertion that such an emergency shut down system was not mandated, the Company submitted that a statement of this nature does not take into consideration the obligation of the Company, as reflected in legislation, to do its utmost to ensure worker, customer and public safety. ATCO stated that, particularly in the areas of health, safety and the environment, the Company views the legislated requirements as the minimum standards and does not feel that meeting these minimum standards necessarily meets its obligations to protect its employees and the public.

**Positions of the Interveners**

**CCA**

Referring to the forecast expenditure of $500,000 in 2002 on the Carbon Emergency Shutdown System, the CCA noted that the project, to modify the existing emergency system installed in 2000, was justified on the basis of safety and environmental issues. The CCA submitted that the evidence indicates that there never has been a full plant Emergency Shut Down (ESD), and that no clear industry standards exist to mandate or require construction of such a system.

The CCA questioned why the project was not undertaken earlier than 2002, particularly if the project was necessary on safety or environmental grounds, and noted that the response to BR-ATCO.11 indicates that the project could have been done in any year subsequent to 1997, when the first ESD enhancement was carried out. Acknowledging that the project may be beneficial, the CCA considered that the existing design of the ESD appeared sufficient to meet or exceed "current industry best practices." In addition to concerns expressed about ATCO's decision to target this expenditure for a test year, the CCA submitted that the Company had failed to present sufficient evidence to support the requirement for this project, either on grounds of need or environmental concerns.

Based on concerns identified, the CCA recommended a 50/50 sharing of the proposed project cost between customers and shareholders, on the basis that the customer portion recognizes the potentially beneficial aspects of the project, and the allocation to shareholders recognizes the concern about the proposed timing and lack of a clearly identified need for the project.

**Calgary**

Calgary considered that ATCO attempts to justify the Carbon Emergency Shutdown System on the basis of "consistency with industry standards." Calgary submitted that this was not the point, and indicated that "industry standards" cannot be used to justify specific expenditures. Instead, they must be justified with project specific analysis as required by Decision 2000-9, which Calgary claimed ATCO has failed to do. While the ATCO argument refers to BR-ATCO Gas.11, Calgary considered it clear from that response that there was no benefit to customers from this project, and that there is little documented justification. Furthermore, Calgary noted that, given the Carbon transfer application, the Board should be reluctant to approve Carbon specific expenditures absent very clear indications of ratepayer benefit.

**Views of the Board**

The Board notes the concern expressed by the CCA that the expenditure on the Carbon Emergency Shutdown project should have been undertaken earlier than 2002, and in fact could have been undertaken in any year subsequent to 1997 when the first Emergency Shutdown enhancement was carried out. On the other hand, the Board notes the submission of ATCO that the project is part of an ongoing review of the Carbon storage facilities and follows current industry best practices with respect to emergency shutdown facilities. The Board accepts the Company's representations in this regard, and considers it reasonable that proceeding in stages, ensuring that each individual component of the process works effectively and efficiently, is the appropriate course of action.

The Board considers that no compelling evidence has been presented to refute the representations of the Company with respect to the decision to incur the expenditure on the Carbon Emergency Shutdown project in the test years or to support the intervener proposal for a 50/50 sharing of costs with shareholders.

The Board considers that ATCO has presented a reasonable case to support the benefits of this forecast expenditure, and accepts ATCO's forecasts of expenditure on the Carbon Emergency Shutdown project. The Board is also not persuaded that the ATCO application to transfer Carbon to ATCO MidStream justifies denial of the forecast expenditures.

## 3.12 OPS/MMS Replacement

### Position of ATCO

Referring to the OPS/MMS system as the cornerstone of the Company's purchasing and materials management function, ATCO considered the system essential for the ongoing efficient operation of those functions. ATCO stated that replacement of the OPS/MMS system is necessary given the advanced age of some components of the existing system, which have become difficult to maintain over the years due to the evolution of computer system hardware, software and communications functions. ATCO anticipated that the Company will be able to purchase a packaged system with no or little customization.

### Positions of the Interveners

### MI

The MI acknowledged ATCO's submission that the OPS/MMS Replacement is forecast for completion in 2002 at a total cost of $1.6 million, but noted that the Company could not comment on a firm completion date until after completion of scoping and analysis, designed to provide details for the evaluation, selection, purchase installation and integration. The MI recognized that, although there may be a need to replace the existing system, there appeared to be some doubt as to whether or not the project would be complete by the end of 2002.

### Views of the Board

The Board acknowledges the concerns of the MI that there appeared to be some doubt as to whether or not the OPS/MMS project would be completed by the end of 2002.

While noting the submission of ATCO that the system expenditure is necessary given the advanced age or inefficient operation of existing system hardware and software, the Board is concerned that the Company has failed to present a comprehensive business case incorporating the benefits to customers and/or shareholders. Accordingly, the Board will not allow the inclusion of the forecast expenditure for the OPS/MMS project into rate base.

### 3.13 Work Management Replacement System

**Position of ATCO**

ATCO stated that the present CAD Work Management System is the key system in the operations of work based at customer premises and has proven over the years to be a cornerstone of these operations from which customers have benefited both in terms of cost savings and level of service. However, ATCO submitted that, since installation in 1991, the equipment and software have become obsolete, and the system has reached the end of its useful life. ATCO noted that the existing system has several key features, which must be present in the new system in order to retain the current cost and service level benefits, and a feasibility study indicated that none of the current "off the shelf" products on the market contain all of these essential features. Accordingly, ATCO stated that the most likely option would be customization of a commercially available product, with the degree of customization determined through an RFP process, which is about to commence.

**Positions of the Interveners**

**MI**

Noting that the Work Management System is forecast for completion in 2002 at a cost of $2.6 million, the MI expressed concern that, as in the case of the OMS/MMS System, the Company has been unable to provide the expected month of completion. The MI considered that there appeared to be some doubt as to whether or not the project would be completed in its entirety in 2002.

**Calgary**

Calgary submitted that the Work Management System expenditures should not be forecast to be included in rate base for 2001 or 2002, on the basis that ATCO has not developed the proposal enough for the project to be regarding as anything more than a general scoping. Calgary considered that this does not meet the requirements of Decision 2000-9 or the criteria of used and useful.

**Views of the Board**

The Board acknowledges the concerns of the MI that there appeared to be some doubt as to whether or not the Work Management System project would be complete by the end of 2002.

The Board notes the submission of ATCO that the system expenditure is necessary given the advanced age of existing system equipment and software, and the detailed information and options considered, as set out in the project feasibility report filed in exhibits during the proceedings and in the response to CCC-ATCO.8. Accordingly, while recognizing the concern of the MI regarding project completion, the Board is prepared to accept ATCO's forecast expenditure on the Work Management Replacement system.

### 3.14 GMS Replacement

**Position of ATCO**

Referring to the replacement of the existing Gas Management System (GMS), ATCO indicated that the expenditure in 2001 ($27,000) is forecast to complete a detailed analysis of scope and costs of the replacement, and the expenditure in 2002 ($302,000) is a high level estimate for the replacement of the system itself. ATCO noted that the existing system is approximately 16 years old and no longer capable of meeting the business needs of ATCO Gas.

**Positions of the Interveners**

**Calgary**

Calgary submitted that the GMS expenditures should not be forecast to be included in rate base for 2001 or 2002, on the basis that ATCO has not developed the proposal enough for the project to be regarded as anything more than a general scoping, which does not meet the requirements of Decision 2000-9 nor the criteria of used and useful.

**Views of the Board**

The Board notes ATCO's submission that the expenditures in the test years are fairly high level estimates, and agrees with Calgary that the Company has not developed the proposal enough for the project to be regarded as anything more than a general scoping, which does not meet the requirements set out in Decision 2000-9.

As ATCO has not provided a suitable business case in accordance with the directions in Decision 2000-9, the Board will not allow the inclusion of the forecast expenditure for the GMS project into rate base.

## 3.15 Khalix Application

**Position of ATCO**

Recognizing that current financial planning and regulatory reporting application (IFPS) no longer receives vendor Support, ATCO stated that, for several years, CWNG and NUL have been aware of the need for a replacement system. However, ATCO submitted that, since IFPS is a powerful but complex modeling language, the options for acquisition of a replacement in the marketplace are limited.

ATCO stated that the Khalix Application not only has the ability to replace IFPS, but also offers other benefits such as the ability to manage extensive levels of detailed information, perform different tasks and generate different reports. ATCO stated that continued use of the existing system would potentially result in the need to hire three or four additional staff. Referring to the information on the Business Case for Phase I of the Khalix Application (completed in 2000), as documented in response to PICA-ATCO GAS.28, ATCO indicated that this Phase consisted of the purchase of the license for Khalix, a one-time fee, and the development of the models required to allow the downloading and management of records from the Financial Information System. ATCO indicated that, while the forecast costs for Phases II and III of the Khalix application were based on information on the implementation costs from Phase I, a detailed business case has not been completed, as the scoping for these phases has not been completed.

ATCO indicated that the Company has the sole license to use the Khalix Application in the ATCO Group, and the costs of the application are shared equally between the south and the north, as both business units benefit from the use of the application. ATCO considered that a five-year amortization period was appropriate since software projects today typically have a short life given the rate of technological change. Given that the one-time capital costs and on-going operating costs associated with the Khalix Application are small, the IFPS system has a limited life span, and the Company has saved costs related to avoided staff increases, ATCO considered that the Board should approve the costs of the Khalix Application as reasonable and prudent.

**Positions of the Interveners**

**MI**

The MI also noted that ATCO had been unable to provide a definitive date for completion of the GMS Replacement in 2002, and Phases II and III of the Khalix System scheduled for completion in 2001.

The MI submitted that, under the circumstances, there appeared to be no more than a 50% probability that the Khalix System in 2001, and the OPS/MMS System, the Work Management System and GMS System in 2002. In the MI's view, historical experience with respect to the timing of replacement of software systems, indicates that a certain amount of discretion appears to apply to the completion dates of new system development.

The MI noted that, notwithstanding that the project justification for a number of proposed software development projects were not completed at the time of the development of the filing, ATCO argues that only projects with a high degree of certainty are included in the forecast. As already noted in Argument the MI indicated that ATCO was unable to provide firm completion dates for several software development projects that had been identified, and suggested that the forecast may well be nothing more than projects that have been identified for review. The MI referred to information provided in Argument demonstrating that the Company's software forecasts for the last three years have been overly optimistic and there is no evidence to suggest that will not be the case in 2001 and 2002.

**Views of the Board**

The Board notes that the test year forecast expenditure on the Khalix system represents costs for Phases II and III of the project, and is based on the information on the implementation costs from Phase I, already undertaken prior to the test years. The Board accepts ATCO's submission that since the scoping for these phases has not been completed, a detailed business case could not be provided. However, the Board notes ATCO's submission with respect to cost savings, which will be realized due to the avoidance of staff increases resulting from ongoing use of the IFPS system, which has a limited life span.

The Board notes that the project was already underway prior to the test years, and is expected to result in efficiency savings. The Board also notes the detailed business case provided in advance of the first phase of the project, in response to PICA-ATCO.28. Accordingly, the Board accepts ATCO's forecast expenditure on the Khalix Application.

### 3.16 Barcode System

In the Application, ATCO indicated that the Bar Code project will include the evaluation, selection, and purchase of new computer software/hardware to replace an outdated system. The Bar Code system consists of software resident on a workstation that communicates via telephone lines with portable data collection units used to capture daily inventory transactions. These transactions are transmitted to the materials management system for processing.

Forecast costs for the Bar Code system are $142,000 in the 2001 test year, which represent costs that will be paid to ATCO I-Tek to evaluate, select, purchase and implement a replacement system.

**Views of the Board**

The Board notes that the expenditures in the test years are fairly high level estimates, and agrees with Calgary that the Company has not developed the proposal enough for the project to be regarded as anything more than a general scoping, which does not meet the requirements of the directions set out in Decision 2000-9.

Accordingly, the Board will not allow the inclusion of the forecast expenditure on the Bar Code System project into rate base pending provision of a suitable business case in accordance with the directions of the Board in Decision 2000-9.

### 3.17 Summary of Board Adjustments and Approved Capital Additions

The following table sets out the Board adjustments described in this Section of the Decision made to the capital additions forecast by ATCO for the test years. As indicated in the table, the Board will approve capital additions of $49.837 million for 2001 and $45.886 million for 2002.

| | 2001 | 2002 |
|---|---|---|
| Forecasts as applied for | $51.569 | $48.181 |
| Less: Reductions in forecasts for: | | |
| New Measurement & Regulating facilities | $0.220 | $0.140 |
| Urban Mains Replacements | $0.150 | $0.061 |
| Rural Mains Replacements | $0.155 | $0.078 |
| Regulating & Measurement Station Improvements | $0.290 | $0.470 |
| Moveable Equipment | $0.217 | $0.215 |
| Major Projects disallowed: | | |
| OPS/MMS Replacement | $0.531 | $1.029 |
| GMS Replacement | $0.027 | $0.302 |
| Barcode System | $0.142 | |
| Total Reductions | $1.732 | $2.295 |
| Approved Capital Additions | $49.837 | $45.886 |

## 4 NECESSARY WORKING CAPITAL

In the Application, ATCO Gas forecast $64,279,000 and $27,458,000 for Necessary Working Capital (NWC) for the years 2001 and 2002 respectively. The Lead-Lag study supporting the cash expenses of necessary working capital was not updated. The results of the 1998 Study were used to determine the leads/lags for the cash expense components of NWC requested in this application.

### 4.1 Cash Expenses and Financial Items

**Position of ATCO**

ATCO Gas proposed the following three changes to the calculation of cash and financing expense components of NWC:

1) Applying the recovery lag for natural gas supply to the actual gas supply expense instead of applying the lag for Gas Cost Recovery amount used in the previous method;

2) Applying the lag to the lower of the current or prior year utility income tax payable rather than the utility income tax expense, and;

3) The treatment of common dividends in working capital. ATCO Gas requested the Board review its findings in Decision 2000-9 relating to the treatment of dividend lag. In Decision 2000-9, the Board directed CWNG to calculate NWC for common return by separating retained earnings and dividends into two components. Both components would continue to use the same revenue lag however, the retained earnings component would have a zero expense lag and the dividend component would have an expense lag equal to the preferred dividend lag. The Company requested that a zero expense lag be allowed on the dividend component thereby asking that dividends be treated the same as retained earnings.

In response to BR-ATCO GAS.17, the Company proposed that its shareholders were entitled to a return on their investment from the moment that service was provided, therefore the NWC was also applicable from the date service was provided. The Company stated that it was the shareholders option where their earnings were used whether retained within the Company or paid out as dividends. If dividends were held for some time within the Company before being paid out, the shareholders were entitled a NWC component with a zero expense lag.

**Positions of the Interveners**

**Calgary**

Calgary opposed ATCO's request to change the treatment of return on common equity from that approved by the Board in Decision 2000-9. Calgary also expressed concern with the apparent differential treatment between payments to affiliates and other expenses, and recommended that the lag days for affiliate payments should be adjusted to the same number of days as for other O&M expenses.

**CCA**

The CCA argued that the working capital component of NWC should reflect the actual costs required to provide safe and reliable service. The CCA expressed concern that it was important to take into account both gas cost recoveries and gas cost expenditures in the calculation of the NWC component for natural gas supply. The CCA observed that a gas cost recovery rate higher than actual gas supply costs would result in a working capital contribution whereas a rate lower than actual gas costs would result in a working capital requirement.

The CCA also considered that ATCO's request to change the treatment of common dividends and resulting working capital constituted a request to review and vary Decision 2000-9 and that ATCO had not met the standards for a review and variance process. The CCA considered that the reasons supplied in Decision 2000-9 were adequate for the ruling on the issue and should remain in place for this proceeding.

**Views of the Board**

The Board notes ATCO's proposal to change the natural gas supply impact on working capital, whereby the lag is applied to gas supply expenditures as opposed to gas cost recoveries as was the case previously. The Board notes the concern of the CCA that it is important to take into account both the expenditures and recoveries in the determination of the NWC component for gas supply. However, the Board agrees with ATCO that gas cost recoveries represent a cash inflow to the Company, and are therefore already incorporated in the revenue lag. As gas supply expenditures represent an actual cash outflow, the Board agrees that this is a more appropriate working capital determinant. Accordingly, the Board accepts ATCO's proposal to apply the lag to gas supply expenditures in the determination of the natural gas expense component of NWC.

The Board also agrees with ATCO's position that applying the lag to the lower of current or prior year utility income tax payable rather than utility income tax expense, properly accounts for the impact of deferred income taxes, and is an appropriate change from the previous method. The Board therefore accepts ATCO's proposal.

The Board notes ATCO's submission with respect to the NWC treatment of common dividends and retained earnings. Specifically, ATCO requested that the Board review its direction in Decision 2000-9, requiring the Company to apply a zero expense lag to the retained earnings component, and an expense lag for the common dividend component based on the methodology used to calculate the preferred dividend lag. The Board also notes Calgary's submission that the Company should comply with the requirements of Decision 2000-9.

The Board acknowledges ATCO's submission that the shareholder is entitled to a return on common equity from the moment service is provided and it is the option of the shareholder to decide if dividends will be paid or earnings retained within the Company. However, the Board continues to hold the view that assigning a zero expense lag to the common dividend component of common equity return fails to take into account the payment schedule that generally exists for the portion of equity return that may be paid out in dividends on a periodic basis throughout the year. As indicated in Decision U97065 with respect to ATCO Electric Ltd. (previously Alberta Power Limited), the Board considers it reasonable to make the assumption that the dividend component of common equity could be treated, for working capital purposes, in the same manner as preferred equity.

Accordingly, the Board repeats the direction made in Decision 2000-9 that ATCO apply a zero expense lag to the retained earnings component of common equity return and an expense lag for the common dividend component based on the methodology used to calculate the preferred dividend lag. The Board therefore directs ATCO to make the appropriate adjustment to its lead/lag study to comply with this requirement.

The Board acknowledges Calgary's concern with the different treatment between payments to affiliates and payments for other O&M expenses, noting that ATCO's proposed expense lag for affiliate payments is 17.41 days as opposed to 34.16 days for other O&M expenses. The Board agrees with Calgary that, for the purposes of calculating the NWC requirement, there is no reason why the expense lag for payments to affiliates should be any less than the lag relating to payments for arms length transactions. Accordingly, the Board directs ATCO to recalculate the NWC balance using a zero lag for transactions with ATCO Pipelines and an expense lag of 34.16 days for other affiliate payments.

## 4.2 Materials and Supplies

### Position of ATCO

ATCO forecast the Working Capital component for Materials and Supplies at $1,581,000 for 2001 and $1,600,000 for 2002. The requirement for Materials and Supplies was updated based upon the analysis of the 1999 ATCO Stock issues. As a result of the divesture of the Retail Services function, an adjustment for inventory held for retail purposes was not required in this application as was the practise in previous applications. Therefore, 37% of the total mid-year stock inventory has been included in NWC to support the operation and maintenance of the gas distribution system.

### Views of the Board

The Board notes that no concerns were expressed by interveners with respect to ATCO's working capital treatment of materials and supplies, and considers that the Company's proposal to include 37% of total mid year inventory is reasonable. Accordingly, the Board accepts ATCO's treatment of the working capital component for materials and supplies for the test years.

## 4.3 Natural Gas Stored

### Position of ATCO

ATCO forecast the mid-year balance of Natural Gas Stored at $21,709,000 for 2001 and $0 for 2002 for inclusion in NWC. This amount was consistent with the Carbon Storage Agreement to transfer the storage inventory to ATCO Midstream proposed in the Affiliate Application.

### Views of the Board

The Board notes that the treatment of this item is consistent with previous applications, with the only change made to recognize the transfer of stored gas to ATCO Midstream. The Board recognizes that the storage leasing arrangement with ATCO Midstream is being considered in the Affiliate proceeding. Accordingly, the Board will not address the quantum of the forecasts included in NWC for natural gas stored pending the outcome of the Affiliate proceeding.

The Board notes that ATCO adjusted its forecast of mid-year Natural Gas Stored as set out in the Amendments to ATCO Gas South Forecast, May 28, 2001, to reflect the results of the third party storage obtained by the Company for the period April 1, 2001 to March 31, 2002. The Board accepts ATCO's adjustments for the NWC component of mind-year value of gas in storage as filed in the May 28, 2001 Amendments.

## 4.4 Payment Equalization Plan (PEP)

**Position of ATCO**

ATCO forecast the NWC requirement for the PEP at $20,977,000 for 2001 and $18,246,000 in 2002. These forecasts reflected the changes in the PEP procedure whereby the customers have an October reconciliation date since 1999. The amounts were also affected by the significant increase in 2001 of increasing gas prices. As a consequence of the increase in gas prices and an expectation that the number of customers on PEP will increase significantly, ATCO Gas submitted that historical normalized average method was no longer appropriate in determining the NWC for PEP amounts. Instead, ATCO Gas proposed in this filing to use the actual average outstanding budget plan balance for each year when calculating the NWC component for PEP amounts.

**Views of the Board**

The Board notes that interveners did not address the treatment of PEP and related effect on NWC, and recognizes that the treatment reflects the change in procedure, approved in Decision 2000-9 and understands that all customers now have an October reconciliation date. The Board accepts ATCO's forecast for PEP included in NWC.

## 4.5 Deferred Pension, Supplemental Pension, Post Employment Benefits

**Position of ATCO**

In its working capital requirement, ATCO included $8,163,000 for 2001 and $5,930,000 for 2002 for Deferred Pension, Supplemental Pension, and Post Employment Benefits.

**Views of the Board**

The Board notes that the treatment of Deferred Pension and Benefits was not challenged by any of the interveners. The Board recognizes that the issue of deferred pensions and post employment benefits will be considered in the Pension proceeding. Accordingly, the Board will not address the quantum of the forecasts included in NWC for deferred pension, supplemental pension and post employment benefits pending the outcome of the Pension proceeding.

## 4.6 Deferred Storage Revenue

**Position of ATCO**

ATCO reduced the 2001 NWC by an amount equal to one half of the 2001 opening balance of deferred revenue associated with Carbon Compressor # 6.

As a result of the Carbon Storage Agreement filed in the Affiliate Application, the 2002 NWC has not been reduced for the Deferred Storage Revenue forecast from ATCO Midstream.

**Views of the Board**

The Board notes that the treatment of this item is consistent with previous applications, with the only change made to recognize the transfer of stored gas to ATCO Midstream. The Board recognizes that the storage leasing arrangement with ATCO Midstream is being considered in the Affiliate proceeding. Accordingly, the Board will not address the quantum of the forecasts included in NWC for deferred storage revenue pending the outcome of the Affiliate proceeding.

## 4.7 Deferred Hearing Costs

### Position of ATCO

ATCO indicated that the effect on NWC of Deferred Hearing Costs was forecast to be $1,225,000 in 2001 and $185,000 in 2002.

### Views of the Board

The Board notes that the treatment of deferred hearing costs in NWC was not challenged by any of the interveners. The Board is satisfied that the treatment of deferred hearing costs is consistent with the treatment of other deferred items, and accepts ATCO's treatment of these items in the NWC balance.

## 4.8 Goods and Services Tax

### Position of ATCO

ATCO included amounts for Goods and Services Tax (GST) at $1,218,000 for 2001 and $864,000 for 2002 as a component of NWC. These amounts were calculated on the GST affected sales and purchases when applying the appropriate lag day working capital ratios.

In this application, the forecast GST working capital impact incorporated a change from Decision 2000-9, and related to the franchise fee expense on which ATCO Gas is able to claim a GST input credit. The change related to franchise fees that are remitted to communities on the last day of the month whereas the associated GST is recovered as a reduction to the GST remittance made at the end of the following month, therefore, resulting in a one-month lag.

### Views of the Board

The Board notes that the treatment of GST in NWC was not challenged by any of the interveners. The Board is satisfied that the treatment of GST is reasonable and accepts ATCO's treatment of these items in the NWC balance.

## 4.9 Crown Royalty Deposit

### Position of ATCO

As a change from the previous NWC, ATCO added an amount of $25,000 to provide for the mid-year balances to the Crown Royalty Deposit account. The previous lead/lag study incorporated the delay in Crown Royalty payments but did not incorporate the impact of the requirement to keep two months payments on deposit in the account.

### Views of the Board

The Board notes that the treatment of Crown Royalty Deposits in NWC was not challenged by any of the interveners. The Board is satisfied that the treatment of Crown Royalty Deposits is reasonable and accepts ATCO's treatment of this item in the NWC balance.

## 4.10 Deferred Restructuring Costs

### Position of ATCO

ATCO provided amounts of $428,000 in 2001 and $149,000 in 2002 in NWC for the mid-year effect of unamortized deferred restructuring costs. These amounts were calculated assuming equal sharing of total restructuring costs between ATCO Gas South and ATCO Gas North.

### Positions of the Interveners

Intervener comments are included in Section 6 of this Decision addressing the prudence of the costs.

### Views of the Board

The Board notes that the treatment of deferred restructuring costs in NWC was not challenged by any of the interveners. The Board is satisfied that the treatment of deferred restructuring costs is consistent with the treatment of other deferred items, and accepts ATCO's treatment of these items in the NWC balance.

## 4.11 Computer Reserve Deficiency Account

### Position of ATCO

ATCO forecast $3,269,000 in 2001 and $1,963,000 in 2002 as amounts for NWC for the unamortized Computer Reserve Deficiency account resulting from the sale of the computer assets to ATCO I-Tek on January 1, 1999 at a price less than the net book value.

### Positions of the Interveners

The Interveners challenged the sales transaction of the computer equipment to ATCO I-Tek. Calgary disagreed with ATCO Gas' proposal to amortize $1.3M to recover the loss on the sale of computer equipment to ATCO I-Tek. Calgary proposed that the sales value be adjusted to the NBV less the unamortized portion of accumulated depreciation variance determined in Decision 2000-9.

### Views of the Board

While satisfied with the treatment of the unamortized portion of the computer reserve deficiency account in Necessary Working Capital, the Board recognizes that the issue with respect to the accounting for the loss on sale of computer equipment to I-Tek is being considered in the Affiliate proceeding. Accordingly, the Board will not address the quantum of the forecasts included in NWC for the unamortized computer reserve deficiency account pending the outcome of the Affiliate proceeding.

# 5 FAIR RETURN ON RATE BASE

## 5.1 Treatment of ATCO Gas South (AGS) and ATCO Pipelines South (APS) as Separate or Merged Entities

### Background

ATCO applied for separate treatment of AGS' and APS' rate of return and capital structure. In the most recent GRA for ATCO, the 1998 CWNG GRA, the two divisions were treated as one entity, CWNG. The capital structure and rate of return for CWNG was established based on risks facing that integrated entity.

### Position of ATCO

ATCO stated that it was appropriate to consider the capital structures and allowed rate of return on equity separately for AGS and APS. The principle put forward by ATCO was that the entities should be considered on a stand-alone basis. However, ATCO also stated that no premium had been added to its requested return above what was required for the two divisions to contribute to the overall maintenance of the CU Inc. credit rating.

ATCO stated that it met its financing requirements with a combination of internally and externally generated funds. Long-term external financing was obtained through CU Inc. Upon completion of a debenture, preferred share, or common share issue by CU Inc. in the capital markets, ATCO received its required portion of the proceeds by issuing a similar financing instrument to CU Inc. Based on this financing process, ATCO received the funds necessary to meet the funding requirements of its capital expenditure programs and to balance its capital structure. In its Application, ATCO stated that using CU Inc. as a long-term financing vehicle for its three utility subsidiaries optimized the size of public financing, and reduced the cost of market access.

ATCO noted that both the Canadian Bond Rating Service (CBRS) and Dominion Bond Rating Service (DBRS) had downgraded the debt ratings of CU Inc. CBRS had downgraded CU Inc. debt from AA to AA-, in response to increased industry risk. DBRS had downgraded CU Inc. debt from AA(low) to A(high). DBRS specifically referenced changes in the Alberta regulatory climate that have arisen in connection with deregulation, and stated that "gas utility…operations continue to be subject to an unfavourable regulatory environment."[13]

### Positions of the Interveners

### Calgary

Calgary submitted in evidence that reshuffling the assets of CWNG into AGS and APS should have no impact on either the appropriate overall capital structure or allowed rate of return. It stated that, however, the business risk of AGS may not be the same as APS, so that the allowed equity range should differ between the two. It stated that the critical issue was not to "over-compensate" for business risk differences by unintentionally adjusting both the allowed return and the common equity ratio.

[13] AGS Application, S:3.1, p.4

**Views of the Board**

The Board agrees with Calgary that it is not appropriate to change the assessment of the relative risk facing ATCO merely on the basis that it has restructured its business into two divisions. The Board is of the view that the most important issue with respect to these divisions is whether or not the business risks facing the still legally integrated entity have changed relative to previous GRA applications.

However, having reviewed the risks of the company as a whole, the Board also agrees with Calgary that it is appropriate to look to allocate the allowed return on equity between the divisions on the basis of their relative risk. This is consistent with the past practice of the Board in other cases involving the notional separation of previously integrated utility functions into separate divisions. The Board is of the view that a similar approach would be appropriate in this case.

## 5.2 Appropriate Return on Equity for AGS and APS

**Position of ATCO**

For AGS, based on common equity financing rate base of 37.4% in 2001 and 39.4% in 2002, ATCO requested a return on common equity of 11.5% for both 2001 and 2002.

For APS, based on common equity financing rate base of 45.4% in 2001 and 50.1% in 2002, ATCO requested a return on common equity of 12.0% for both 2001 and 2002.

ATCO presented estimates of fair rate of return on common equity for 2001 and 2002 based on an application of equity risk premium tests, discounted cash flow tests, and comparable earnings tests. In support of its requests, evidence was filed by Ms. McShane, Senior Vice President of Foster Associates Inc., who recommended a fair rate of return on common giving primary weight to the equity risk premium and discounted cash flow tests, but also with significant weight to the comparable earnings test.

Since AGPL is not a publicly traded company, Ms. McShane stated that its cost of equity could not be estimated directly from capital markets, and since it does not have its own debt rating, there was no independent market assessment of its business and financial risk. Therefore, the determination of a fair return was made by reference to proxies that do have market data. Ms. McShane used available market data available for a sample of publicly traded utilities including data from U.S. utilities in her evaluations.

Ms McShane stated that the standards that set the parameters of fair return on equity necessary to induce investment in public utility assets must provide the opportunity to attract capital on reasonable terms; maintain its financial integrity; and earn a return on the value of its property commensurate with that of comparable risk enterprises. She noted that during the past decade in Canada, the comparable earnings test has effectively been replaced by the cost of attracting capital test. Factors noted to contribute to this change were the sharp decline in inflation in 1992, industrial restructuring, and severe recession in the early 1990's which resulted in a significant decline in earnings. Ms. McShane stated that these lowered earnings were unrepresentative of future earnings, and unreliable indicators of investor expectations for future returns. On this basis, Ms. McShane stated that the results of the comparable earnings test were of limited reliability. She stated that the same factors had a similar effect on the discounted cash flow test.

Ms. McShane stated that with the shift in reliance onto the equity risk premium test, the approved returns of utilities in Canada were tied almost exclusively to interest rates, which had declined between 1992 and 1999. Approved returns can be broken into the real cost of capital, compensation for inflation and equity risk premium components. The effective risk premium declined by close to 2% since the risk premium test become the sole methodology relied upon in the mid-90's. She noted that with declining inflation and interest rates, and a strong economy, earnings of competitive firms have rebounded from the early 1990's to a point where in unregulated industries, the gap between the comparable earnings test and approved returns has widened considerably. She stated the opportunity cost (the return foregone) by investing in utility assets rather than the next best alternative has also widened. Ms. McShane stated that the comparable earnings standard provides a measure of such an opportunity cost and should be given weight. The equity risk premium test estimates a return expected or required on the market value of the investment. Ms. McShane stated that, for utilities, replacement cost is higher than book value, thus the market value of utility shares should be higher than book value.

The comparable earnings test recognizes return as applied to an original cost rate base. Ms. McShane recommended that weight be given to both the cost of attracting capital (through the application of both the equity risk premium and discounted cash flow tests) and the comparable earnings standard.

***Equity Risk Premium Test***

Ms. McShane stated that the equity risk premium test is a measure of the market-related cost of attracting capital. She noted that an equity investment in a utility is more risky than a bond investment and requires a higher return. As utility assets are long-lived and are committed to public use over the life of the asset, long-term Government of Canada bond yield becomes the basis for applying the risk premium test. Ms. McShane stated that the risk premium required by investors tends to widen and narrow with factors such as inflation, productivity, profitability and investors' willingness to take risks. In addition, she stated that it was a prospective concept that reflects investors' requirements to compensate for risk on a future basis.

The starting point of applying the risk premium test is to project the expected nominal long Canada yield, which serves as a proxy for the "risk free rate." Ms. McShane used a forecast of long Canada yield at 6.25%. Her estimation of required market risk premium resulted from analyzing U.S. and Canadian data from 1947 to 1999, which showed that risk premiums varied in the range of 6.3% to 6.9% (adjusted for exchange rates and impact of annual data based on a weighted average of 70% and 30% Canadian and U.S. stock and bond returns respectively). On a forward looking basis, Ms. McShane's analysis of the expected market returns over the past 10 years in relation to bond yields (weighted at 70% - 30% for Canadian and U. S forward-looking premiums respectively) resulted in a risk premium in the range of 8.25% - 8.75%. Her estimate of the current market risk premium based upon historic premiums was 6.5%. She noted that this premium needed to be adjusted to reflect the risk of utilities relative to the market risk premium. Using several models and regression analyses, Ms. McShane recommended 65% of market risk premium as the "bare bones" utility risk premium above long Canada bonds. Her adjusted equity risk premium for typical Canadian electric/gas utilities was approximately 4.25%.

Ms. McShane conducted a review of the historic risk premiums for the Canadian and U.S utilities for the period of 1947–1999, giving primary weight to the Canadian data. She found that, using arithmetic averages, a compound risk premium was achieved in the range of 4.0% - 5.8%.

Ms. McShane also conducted an analysis of investor growth expectations for a sample of U.S. gas distributors for the period from 1993 to 2000 with similar investment risk to typical Canadian gas/electric utilities. She stated that this indicated an average risk premium of 4.8%.

The results of the three approaches studied by Ms McShane indicated an equity risk premium for a typical Canadian utility of 4.25% - 4.5%, above a long Canada yield of 6.25%. Her estimate of the resulting cost of equity was in the range of 10.5% - 10.75%, before any adjustment for financial flexibility.

***Discounted Cash Flow Test***

The discounted cash flow (DCF) test proposes that the price of a common stock is the present value of the future expected cash flows discounted at a rate reflecting risk of the cash flows.

Ms. McShane applied the DCF test to a sample of eight LDC's. She found the average and median expectations of long-term earnings growth were both 5.8%. The average and median adjusted dividend yields were 5.2% for both. She stated that adding the adjusted dividend yield to the expected growth rate results in an estimated required return on common equity of 11.0% unadjusted for financial flexibility for AGS. Applying the discounted cash flow test to APS led Ms. McShane to recommend a 11.0-11.5% return, without adjustment for financing flexibility.

***Comparable Earnings Test***

The comparable earnings test measures a fair return based on the concept that invested capital should earn a return commensurate with alternative ventures of comparable risk.
The application of the comparable earnings test requires the selection of industrials of reasonably comparable risk to regulated firms, selection of an appropriate time period over which returns are to be measured to estimate prospective returns and the determination of relative risk of the industrials as compared to regulated firms.

Ms. McShane selected 17 companies from 95 Canadian industrial firms that met certain selection criteria. The earnings for the selected low risk industrials were evaluated over the most recent business cycle from 1991 to 1999. She found that the average annual returns for the selected sample of low risk industrials were 12.8%.

Ms. McShane noted that the business risks of industrials were typically higher than of regulated firms. She stated that the purpose of the analysis of relative risk of selected industrials was to determine to what extent the differences in risk should result in a risk adjustment to the industrial returns. She stated that statistical measures of risk for six major publicly traded Canadian gas/electric utilities suggested that these utilities are in about the same risk class as the typical low risk industrial sample, and that the data indicated that the gas/electric utilities have experienced greater book and market return stability than the low risk industrials. She argued that, therefore, a quantification of the risk differences on the return requirements was appropriate. This adjustment was made using the Capital Asset Pricing Model (CAPM), using an adjusted beta,[14] giving 2/3 weight to the raw beta and 1/3 weight to the market beta, applied to the comparable earnings test for Canadian industrials. Ms. McShane stated that this would indicate an appropriate return of 12.5% - 12.75%.

Ms. McShane considered the returns of U.S. industrials as a relevant input to the comparable earnings test due to the relatively low number of low risk consumer-oriented industrials in Canada, and the contrast of returns for low risk U.S. industrials as compared to low risk Canadian industrials for the most recent business cycle. Adjusting for corporate tax differences and differential risk with Canadian utilities, Ms. McShane determined that the applicable return was in the range of 12.5% - 13.0%

Ms. McShane gave primary weight to the Canadian results. Based upon the comparable earnings test and before adjustment for financial flexibility, she stated that the fair return would be in the range of 12.5% – 12.75%.

***Financial Flexibility***

Ms. McShane stated that to avoid equity dilution, the "bare bones" cost of equity derived from the risk premium test should be adjusted upward to maintain financial flexibility and integrity. She stated that the adjustment should include an amount for administrative expenses related to equity issues; an amount for market pressure to avoid the tendency for the price of the stock to fall as an additional supply of stock is issued; and an additional margin to cover unforeseen events such as a sharp rise in interest rates. She stated that financing costs for high-grade Canadian firms are in the range of 4% - 5% corresponding to and after tax rate of approximately 2.5%. The allowance for market pressure was evaluated in the range of 4% - 5%. Her sum of financing costs and market pressure costs was 7%. Adding a minimal increment for unforeseen events results in a flotation cost allowance of approximately 10%. Ms. McShane stated that the flotation cost adjustment was approximately 45–50 basis points for a 7% floatation cost, and was approximately 65–70 basis points for a 10% flotation cost.

ATCO rejected Drs. Booth and Berkowitz recommended rate of return on equity as being inadequate to reflect a sufficient premium over the cost of long-term debt. It stated that the tests applied by Calgary relied on the past, and did not take in to account investors' current expectations.

**Positions the of Interveners**

**Calgary**

In support of its position on rate of return on equity, Calgary submitted evidence from its witnesses Dr. Booth and Dr. Berkowitz.

[14] In the CAPM model "beta" is the measure of the variance of a given stock or portfolio relative to that of the overall market. It is defined as the covariance of the stock or portfolio with the overall market, divided by the variance of the market. A beta equal to 1 implies that the stock in question has the same variance (is as volatile) as the market as a whole. A beta equal to 0.5 implies that the stock in question is 50% as volatile as the market. The theory behind the CAPM model is that stocks with a smaller beta require less return to attract investors.

Drs. Booth and Berkowitz stated that the foundations for fair rate of return on equity were:

1) A regulated utility should be allowed to earn a fair return on the actual capital invested in the enterprise that should be equivalent to what the stockholders could get if they took their book value and invested it elsewhere.
2) The rate of return should be sufficient to attract new capital without impairing the existing investments.
3) The rate of return should be sufficient to maintain its financial integrity at a level that attracts capital at reasonable terms.

Drs. Booth and Berkowitz calculated the fair rate of return in relation to the market risk or beta and the risk free rate compared to long Canada bond yields. They forecast the long Canada bond yield rate at 5.75% over the next two years. Drs. Booth and Berkowitz studied two risk premium models. The CAPM estimate based upon the historic average market risk premium, adjusted for the changing risk profile of long Canada bond showed a fair return on equity in the range of 8.00% - 8.16%. A newer, multi-factor model showed a fair rate of return on equity in the range of 7.68% - 8.13%. Drs. Booth and Berkowitz recommended a "bare bones" rate of return of 8.00% based on the results of their tests.

Adjusted for flotation costs, Drs. Booth and Berkowitz recommended a fair rate of return on equity at 8.25% for both 2001 and 2002, on a 35% common equity capitalization ratio for AGS and 34% for APS. This rate of return was judged as sufficient to maintain the financial integrity of a gas LDC and would be broadly consistent with the NEB awards for class 1 pipelines.

In their evidence, Drs. Booth and Berkowitz criticized Ms. McShane's use of the comparable earnings test due to the accounting practices and relative risk of the sample firms studied, the time period of the study, the screening method to select the sample of firms studied, and an inability of the comparable earnings test to measure opportunity cost. Calgary disagreed with ATCO's method of arriving at market risk premium using the arithmetic rate of return versus the geometric rate of return method, and the weighting of U. S. data used in arriving at the recommendation. Furthermore, Calgary disagreed with the adjustment of 50 basis points to the risk premium for financial flexibility.

In rebuttal evidence, Calgary evaluated the difference between the recommendations of AGS and Calgary. In its view, the difference was attributable to several adjustments used by AGS' witness, all tending to increase the rate of return requested by AGS.

Calgary criticized Ms. McShane's comparable earnings test stating that the sample used did not eliminate those firms that exhibit market power, thus violating the premise that regulation is a surrogate for competition. Calgary submitted that the comparable earnings test did not provide an insight into what earnings investors require in the future, and results in an upward bias of the risk premium, and therefore should be given no weight by the Board. Furthermore, Calgary submitted that the Board should reject Ms. McShane's result of the DCF model on the grounds that it relied heavily on U.S. data and was biased upward as a result of reliance on IBES analysts' forecasts, which could be optimistic.

Calgary submitted that Ms. McShane's Market Risk Premium test was biased upward due to her selection of data from the Canadian Institute of Actuaries and her disregard of the data from the Task Force on Retirement Income and the Canadian Stocks, Bonds and Inflation. Similarly, Calgary criticized Ms. McShane's selection of the Blume report and her disregard of the study by Gombola and Kahl, which Calgary suggested resulted in an upward bias to the recommended rate of return on equity.

Calgary submitted that Ms. McShane's addition of 50 basis points for financial flexibility was unwarranted since no evidence was provided that CU Inc. experienced any market pressure when raising common equity on behalf of AGS. Calgary agreed with the result of using Canadian data to measure market risk premium as presented in the evidence of Ms. McShane. Calgary was critical of the weight given by Ms. McShane to U.S. data and recommended that the Board reject the reliance on U.S. data and base AGS' allowed return on Canadian data.

**AIPA**

AIPA considered that AGS overstated the risk free rate in comparison to the average of the 10-year Canada Consensus forecast of 5.6%. AIPA submitted that a risk free rate of 5.7% would be appropriate for the test years of 2001 and 2002.

**CCA**

The CCA supported Calgary's recommendation of 8.25% return on equity for ATCO.

**FGA**

The FGA did not support the use of data from U.S. markets to evaluate investor's perceptions about raising capital in Canada. As a consequence, FGA recommended that the Board should consider 50 points as an adjustment to the risk premium for financial flexibility.

**MI**

The MI were critical of AGS' request for 11.5% and 12.0% return on equity for AGS and APS, respectively. The MI agreed with Calgary regarding the equity risk premium and the adjustment for financial flexibility and supported Calgary in recommending a fair return on equity of 8.25% for 2001 and 2002.

**Views of the Board**

As noted in the previous section, the Board is of the view that it is appropriate to consider the rate of return on common equity for AGS and APS as a combined entity, and then look to the relative risks of AGS and APS in establishing their respective allowed capitalization ratios.

The Board has reviewed the evidence of Ms. McShane for ATCO, and Drs. Booth and Berkowitz for Calgary. The Board is concerned that, despite its volume, the nature of the expert evidence provided is ultimately of little probative value to the Board in establishing this important determinant of the utility's revenue requirement.

In particular the Board notes the effect that the application of professional judgement has on the outcome of the equity risk premium test. This test has been noted to be the mainstay of this

Board and other Canadian regulatory boards over recent periods, and is also the one test undertaken by both parties. Ms. McShane provides an estimate of adjusted beta for the CAPM of .65 as being appropriate for ATCO, resulting in an equity risk premium of 425 basis points. Drs. Booth and Berkowitz criticize Ms. McShane's conclusions regarding this adjustment and note:

> The beta estimate used by Ms. McShane in this hearing is too high. To raise her estimated beta of .45 to a level of .65, she applies Blume's (1975) finding that in the long run, U.S. equities in general tend to regress toward the market. … If we now repeat Blume's analysis using the 1994-98 and 1989-93 periods…these results suggest an overall regression tendency towards an overall beta of .582 [using data from 16 Canadian utilities].[15]

This beta estimate of .582 is further averaged with other data on current market utility betas to arrive at an adjusted beta of .50. This is compared to another direct estimate of beta in the range of 52-56%.[16] In the final analysis, the value for beta used by Drs. Booth and Berkowitz is .50, associated with a return on equity of 8.00%, adjusted for the changing risk profile of long Canada bonds (an adjustment of 50 basis points).

Although the Board is of the view that Calgary's criticism of Ms. McShane's beta adjustment has merit, it finds that the further adjustments made by Calgary present their own difficulties. It is evident that the range of professional judgement that can be applied to this one aspect of one of the tests can account for a substantial difference in the estimated required return. This one difference accounts for nearly 100 basis points on return on equity, or approximately $1.5 million per year, between Ms. McShane's beta estimate of .65 and Drs. Booth and Berkowitz' estimate of .50. The Board has examined the other evidence brought forward by parties on the issue of rate of return and has found that parties' views are similarly far apart in every instance.

The Board notes Calgary's submission that the adjustments made by Ms. McShane all increase the requests for rate of return for ATCO. However, the Board also notes that on the same page in its evidence where Calgary makes a recommendation of 250 basis points as being adequate for a risk premium for ATCO, Calgary also notes that comparable recent awards in other Canadian utility jurisdictions have ranged from 300-387.5 basis points.[17] The Board considers that the application of professional judgement to rate of return evidence is not a "one way street". The Board is of the view that the requests by ATCO for between 525 and 550 basis points above their long Canada bond forecast and the Calgary request for 250 basis points above their long Canada bond forecast are both outside what the Board would consider to be reasonable. Further, these estimates are far enough apart that the underlying evidence is of little value to the Board in establishing an accurate and well justified estimate of the utility rate of return required to maintain the financial integrity of the utility in the eyes of investors and the market. Subsequently, the Board must rely on an examination of past awards to CWNG to determine if there is a requirement for adjustments to those awards. The Board is also of the view that alternative methods of determining appropriate utility return may need to be examined for use in future rate cases.

[15] Calgary Evidence, Appendix B. pp.11-12
[16] Calgary Evidence, pp.51-52
[17] Calgary Evidence, p.68

In Decision 2000-9, the Board awarded a risk premium of 375 basis points above the forecast long Canada rate for 1998. This was inclusive of an amount for financing flexibility. The Board notes that this is near the upper end of the range of current awards noted by Calgary. The Board has no reason to believe that investors or the market would see a need for ATCO to receive a risk premium that would be above these other awards, based on either the business or regulatory climate in Alberta. Therefore, lacking evidence that would suggest a measured adjustment up or down, the Board is satisfied that this previous risk premium award is reasonable and may be used for AGS and APS for 2001 and 2002.

The Board notes that the estimates provided by parties for long Canada bond rates are relatively close together. Calgary has forecast 5.75% and ATCO has forecast 6.25%. The Board also notes that both estimates involved the use of judgement by the expert witnesses to account for various recent financial trends. The Board finds that it is reasonable to average these estimates in order to establish a forecast long Canada bond rate of 6.0% for the test period.

The Board therefore determines that a rate of return on common equity of 9.75% is reasonable for both AGS and APS for the period of 2001/2002.

## 5.3 Appropriate Capital Structure for AGS and APS

### Position of ATCO

ATCO applied for approval of its forecast capital structure for 2001 and 2002 in comparison to the capital structure approved in Decision 2000-9. The proposed capital structure as consolidated by the Board (exclusive of no-cost capital) is as follows:

| | Forecast 2001 | Forecast 2002 | Decision 2000-9 |
|---|---|---|---|
| Debt | 53.8% | 51.1% | 45 - 50% |
| Preferred Equity | 6.5% | 6.5% | 12 - 17% |
| No Cost Capital | 0.5% | 0.4% | |
| Common Equity | 39.2% | 42.0% | 32 - 37% |

Ms. McShane testified that a capital structure with a common equity ratio of 40% and a preferred share component in the 5-10% range, AGS would contribute its fair share to the creditworthiness of CU Inc. She testified that a capital structure with a common equity ratio of 50% and a preferred share component of approximately 5% would be appropriate for APS.

AGS requested approval for a target 40% common equity component financing rate base; however, AGS claimed it was unable to achieve a mid-year ratio of 40% due to the effect of Decision 2000-45,[18] dated July 4, 2000, on retained earnings in 2000.

[18] Decision 2000-45 ATCO Gas and Pipelines Ltd. (CWNG), 1997 Return on Common Equity and Capital Structure and 1998 GRA – Second Refiling

In its application, ATCO proposed a significantly lower preferred equity ratio than approved in Decision 2000-9. The changes in ATCO' capital structure reflected the changes in tax laws and accounting treatment of preferred shares. It stated that there was no market for true preferred shares and an unpredictable market of equity-like preferred shares, therefore, it was prudent and cost effective to maintain a capital structure with a lower preferred ratio and higher common equity and debt ratios.

In support of its requested capital structure, ATCO submitted evidence from Ms. McShane. Ms. McShane provided evidence on capital structure for 2001 and 2002 for AGS and APS.

Ms. McShane stated that the major elements of business risk for AGS were:

- Market risks related to the concentration of its load among a few cyclical industries, the relatively small number of residential heating customers whose usage is subject to variations in temperature and conservation;
- The Alberta utilities face higher forecasting risks than the typical Canadian LDC due to lack of deferral mechanisms for weather and usage variations, fewer deferral accounts for unusual expenses;
- Generally longer intervals between rate cases;
- The introduction of full retail competition and the unbundling of various services being competitively supplied;
- Anticipation of significant changes in the market place raises the prospect that municipalities will not renew franchise agreements;
- Exposure of gas utilities to competition resulting from the restructuring of the gas industry.

Ms. McShane stated that the major business risks for APS were:

- Competitive pressure from other, larger pipeline companies, particularly NGTL.
- No direct access to ex-Alberta markets.
- A highly concentrated industrial sector, where the ten largest customers account for 85% of industrial throughput.
- Declining deliverability from the western sedimentary basin.

Financial risk relates to the use of leverage in terms of capital structure and coverage ratios. Ms. McShane noted that ATCO common equity ratios are slightly higher than the average ratio of its peers. The debt rating of CU Inc. by CBRS was AA-. CBRS states a range of 45–55% debt ratio for AA ratings. Ms. McShane stated that ATCO endeavors to maintain a capital ratio consistent with ratings maintained by CU Inc.

Ms. McShane noted that AGS' proposed capital structure, marginal tax rate of 43.5% and return on equity of 11.5% indicated a pre-tax coverage ratio of 2.8 times for 2001 and 3.2 times for 2002. Ms. McShane noted that the 2002 coverage would be toward the lower end of the CBRS range of 3.0–4.0 times for AA rating, but at the upper end of the 2.0–3.2 times range for A rating. She also noted that the average for all rated gas/electric distributors was 2.5 times. With respect to APS, Ms. McShane stated that near term interest coverage ratios should be in the range of 3.5 times, rising to 4 times as embedded debt costs fall.

ATCO stated that AGS was requesting virtually the same common equity ratio which had been proposed for CWNG in 1998, but with a significantly lower preferred stock ratio and a higher debt ratio. With the elimination of the *Public Utilities Income Tax Transfer Act* (PUITTA), it argued that preferred shares have become less cost efficient and are being replaced with debt and common equity. It stated that, effectively, the 18.0 % decline in the preferred component has been replaced 80% with debt and 20% with common equity.

Ms. McShane stated that it was necessary to consider all three components of capital structure to determine if a particular structure is compatible with the business risk and retain the objective of maintaining financial integrity of the utility. In the comparison of a proposed capital structure with capital structures in effect prior to the elimination of PUITTA, she stated that it was important to consider that preferred shares had been used in place of common equity in prior capitalization ratios.

Ms. McShane stated that the following factors should be taken into account when determining whether the proposed capital structures are reasonable in comparison to capital structures maintained before the elimination of PUITTA, as follows:

- An expectation to contribute fairly to the creditworthiness of the parent company that issues capital on behalf of the regulated subsidiaries.
- The remaining preferred shares are a hybrid security with elements of both debt and equity, not a direct substitute for debt.
- The relative costs of the three main components of capitalization and unreliability of the preferred market.
- The findings of the Board with respect to reasonable capital structures for other utilities.

Ms. McShane agreed that business risk is the key determinant of capital structure. Ms. McShane concluded that ATCO' proposed 2001 and 2002 capital structure was compatible with its business risk representing an average business risk relative to its peers and would provide an ability to maintain a degree of financial integrity consistent with CU Inc. However, with the unfavorable market for preferred shares, Ms. McShane stated it was prudent and cost effective for ATCO to maintain a capital structure with a lower preferred ratio and higher common equity and debt ratios.

Ms. McShane noted that in a 1996 Decision, the Board permitted TransAlta to increase its regulated common equity ratio from 35.5% to 40.0%. Ms. McShane stated that since AGS had a relatively similar level of business risk and a lower preferred stock ratio than TransAlta, there is no reason that ATCO' common equity ratio would be lower than that approved for TransAlta in 1996. Furthermore, she noted that ATCO's forecast coverage ratios were almost identical to those determined reasonable for TransAlta in 1996.

ATCO noted that its request to transfer debt from APS to APN arose from the need to increase the common equity of APS in response to increased competitive risks. ATCO submitted that APS customers would not be treated unfairly by transferring debt that was secured post 1995. It stated that fairness would dictate that debt should be transferred at a rate similar to that in place at the time of the transfer.

In argument, ATCO rejected Drs. Booth and Berkowitz statement that AGS had "very, very low risk" and concluded that Drs. Booth and Berkowitz were not sufficiently familiar with risks faced by natural gas utilities in Alberta. ATCO agreed with Drs. Booth and Berkowitz acknowledgement during cross-examination that the relative difference in business risk between gas distribution and electric transmission companies was 5%.

ATCO noted several instances wherein Drs. Booth and Berkowitz were unable to discuss or identify key business risks facing the company. ATCO also noted that its submission was virtually identical to a submission made by TransCanada Pipelines Ltd. before the National Energy Board. In reply argument (APS), ATCO stated that interveners had understated the actual risks facing the company.

**Position of the Interveners**

**Calgary**

In support of its position on capital structure, Calgary submitted evidence from its witnesses Dr. Booth and Dr. Berkowitz.

Drs. Booth and Berkowitz agreed that it was appropriate to set capital structure to address the overall risk facing the Company. The sources of risk faced by investors in utilities are business, financial, investment, and regulatory risk.

Calgary stated that ATCO's business risks were affected by:

- The company's large residential sales component greatly reduces its exposure to changes in the business cycle.
- The ability of the company to recover almost all of its costs through fixed demand charges.
- Limited competition from alternate energy sources.
- Volatility of gas costs resulting from price and volume changes is shielded through the effects of the Deferred Gas Account (DGA) process.
- The ability to raise capital through CU Inc.

On the basis of their analysis, Drs. Booth and Berkowitz concluded that the overall business risk of ATCO remains relatively low and stable and similar to high grade low risk LDC's.

Drs. Booth and Berkowitz stated that regulated utilities have the lowest business risk of any sector and therefore should have the highest debt ratios. The reasons for this assertion were stated as:

- A full cost-of-service regulated utility has no variation in its operating income.
- In the unanticipated events can be recovered through rate relief from the regulator.
- The tax advantages of debt are offset by the low risk of bankruptcy.
- The asset base consists largely of tangible assets that provide security to lenders.

In comparison to a typical competitive firm, Drs. Booth and Berkowitz evaluated that the regulated utility was about 50% as risky when compared to overall market risk.

In argument, Calgary submitted that AGS should be compared with high quality companies in their peer group such as Consumers, Union, and B.C. Gas.

Drs. Booth and Berkowitz reviewed the common equity ratios for seven natural gas LDC's in Canada. On the basis of their analysis, Drs. Booth and Berkowitz recommended a common equity ratio of 35% for AGS.

Since the elimination of PUITTA, preferred share financing is no longer tax efficient and was recommended by Drs. Booth and Berkowitz to be eliminated as a source of financing. One exception could be in times when regulated utilities have problems meeting interest coverage tests, and retaining their access to reasonable debt financing. In such a time, a five-year preferred issue would circumvent a temporary financing problem.

Calgary observed that in its Annual Information form, CU Inc. stated that its operations were subject to the normal risks faced by regulated companies, and that in its list of other than normal business risks, there were no material gas and pipeline risks other than those mentioned in the broad definition of regulated operations.

In argument, Calgary stated that the critical issue for assessing business risk of AGS was that 95% of AGS' throughput and 98% of AGS' revenues come from the residential and commercial sector. It further assessed that rate unbundling and/or GCRR methodology would likely have a negligible impact on AGS. Drs. Booth and Berkowitz evaluated AGS as a high quality local gas distribution company, having extremely low business risk. They noted that Ms. McShane had classified AGS in the same low risk group as Union, Enbridge, Consumers and B.C. Gas. Drs. Booth and Berkowitz argued that the capital structure for AGS should be related to those companies, which have a common equity ratio of 33 – 35%.

Calgary also noted that the risk facing APS was greatly affected by the low risk of AGS, in that 60% of its revenue is derived from AGS. It noted that there was relatively little risk of major bypass to serve Calgary, and that the Industrial/Producer Settlements and Gas Alberta Memorandum of understanding would see any shortfall in revenues being passed on to AGS.

Calgary argued that CU Inc. and CUL do not have enough common equity to support AGPL's common equity ratio and therefore, AGS would be engaging in "double leverage". In reply argument, Calgary referred to Exhibit 127, wherein a calculation was provided supporting its proposition that there was a lack of common equity underpinning the AGS requested common ratio. To determine the existence of common equity for which a return is requested in the regulated entity, Calgary requested the Board to direct AGPL, in future proceedings, to provide pro forma financial statements showing the allocation of its capitalization between each of its four regulated business units and to provide pro forma financial statements showing the allocation of the capital structure of CU Inc. between that portion financing AGPL and that portion financing other regulated entities as well as the portion financing unregulated entities. Calgary submitted that this information was required to determine whether there is any cross-subsidization between regulated entities or between regulated and unregulated entities as a result of capital structures that may be inappropriate for the relative risks involved.

### AIPA

AIPA expressed concern that the proposed transfer of debt from APS to APN would increase the weighted cost of APS debt capital above 8.5%.

### CCA

The CCA stated that it was not appropriate for the Board to determine a range for capital structure and then use the maximum end of the range, as had been done in Decision 2000-9. The CCA supported the use of a deemed capital structure for ATCO.

The CCA stated that it considered that there had been an improvement in the business risks facing ATCO since its previous GRA, as displayed in the significant increase in producer revenues.

### MI

The MI were critical of AGS' request of 40% common equity ratio. It was MI's position that the risk to AGS had not increased since the last GRA, and had been reduced through certain elements of reorganization such as removal of the pipeline function and pending sale of the retail business unit. MI supported Calgary's recommended common equity ratio of 35%. The MI did not agree that business risks had increased for APS, and supported the evidence of Calgary.

The MI were also critical of APS' proposal to transfer debt issues to APN and recommended that any debt transfer occur at APS' embedded cost of debt.

### Views of the Board

The Board has examined the overall risk of ATCO compared with the business and regulatory conditions prevalent at the time of 1998 CWNG GRA. The Board is of the view that there is a slight increase in the business risk facing ATCO since that time. The Board notes two factors that particularly affect APS, in turn affecting the Board's assessment of business risk for ATCO. These are

- Decision 2000-6,[19] dated February 4, 2000, had the effect of lowering prices for NOVA transmission in the APS service territory, increasing competitive pressure on the company.
- Recent swings in gas prices, both up and down, have provided a new basis for the assessment of the risk facing APS. High gas prices have the effect of increasing costs to APS for compressor gas. Low gas prices have the effect of reducing producer volumes on the APS system.

The Board is of the view that there have been no significant changes in the business risks facing AGS. In particular, the Board has examined the effects of Decision 2001-75,[20] Methodology for

[19] Decision 2000-6 NOVA Gas Transmission Ltd., 1999 Products and Pricing

[20] Decision 2001-75 Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding, Part A: GCRR Methodology and Gas Rate Unbundling

Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding (Unbundling Decision), dated October 30, 2001. The Board notes that those areas that were considered to have a potential effect on the risks facing the Company have either not been affected by the Unbundling Decision or have been specifically addressed by the inclusion of deferral accounts to collect any potential stranded costs.

On the basis of the slight increase in risk seen to be faced by ATCO, the Board is of the view that the overall common equity ratio may be reasonably increased from 37% on an integrated basis to 39% on an integrated basis. The Board is satisfied with ATCO's forecast levels of preferred share equity. The overall level of deemed long-term debt will be determined as the remaining portion of the capital structure, after accounting for common and preferred equity, and no cost capital.

Addressing the share of the overall equity deemed appropriate for the integrated entity that should be allocated to AGS and APS, the Board is of the view that it is appropriate for APS to have a higher common equity ratio than AGS. As noted above, the Board is of the view that the noted increases in business risk have affected APS. The Board has determined that a common equity ratio of 37% should be maintained for AGS, particularly in light of the appropriate reduction in preferred equity. APS will be allowed to have 45.5% common equity in its capital structure.

## 5.4 Preferred Share Cost

### Position of ATCO

AGS forecast a mid-year cost rate on preferred Shares of 5.517% for 2001 and 6.146% for 2002. This represented the embedded cost of AGS' preferred shares based on a mid-year balance of $29.130 million for 2001 and $30.503 million for 2002.

There were no preferred share issues or retirements forecast in 2001 or 2002. As per the conditions of share issue, the dividend rate for the Series U and V non-retractable preferred shares will be re-negotiated. The forecast negotiated rate for each of these series was 7.0%.

### Position of the Interveners

Calgary argued that no information was presented justifying the reasonableness of the requested rate for the preferred Series U and V. On the argument that ATCO Ltd. was issuing preferred shares of a lower quality and lower rate than forecast by AGS, Calgary recommended a rate of 5.75%.

### Views of the Board

The Board is of the view that ATCO's forecast preferred equity cost should be reasonably accurate. This is based on there being no forecast issues and redemptions. The forecast rate for renegotiations of the Series U and V shares appears to be reasonable.

## 5.5 Debt Cost

### Position of ATCO

AGS forecast a mid-year cost rate on long-term debt of 8.306 % for 2001 and 8.163 % for 2002. This represented the embedded cost of AGS' long-term debt based on forecast mid-year balances of $247.621 million for 2001 and $234.939 million for 2002.

The was no long term debt financing forecast for 2001; however, a 9.85% debenture and a 10.25% debenture are forecast to be redeemed prior to their stated maturity date. The 2002 long term financing requirements were forecast to be met with a $35 million debenture issue at a coupon rate of 7.05%. In addition, a $26.8 million 5.42% debenture and a $19.1 million 12.00% debenture were forecast to be redeemed prior to maturity date.

### Positions of the Interveners

### Calgary

Calgary was critical of ATCO's request to include a debenture issue for 30 years at a nominal cost rate of 7.05% given the track record of ATCO in forecasting the type and yields of bonds. Calgary argued that ATCO has not provided information that justifies the reasonableness of the forecast cost.

### MI

The MI observed that ATCO has not issued any long-term debt within the past 10 years. The MI suggested that ATCO should obtain 10-year financing rather than 30 years and that the coupon rate should be 6.43% to 6.63% versus the 7.05% forecast by ATCO in the application.

### Views of the Board

The Board notes that if ATCO were to alter its proposed debt issue, as suggested by the MI, this change would arise in a GRA well before the end of the debt issue. The Board is comfortable that this provides a reasonable incentive for ATCO to try to be accurate in its forecast debt issues.

For the purposes of this Decision, the Board is concerned with the long-term debt cost rate appropriate for the deemed capital structures of AGS and APS. The Board accepts that ATCO has an incentive to reasonably forecast debt costs, and therefore accepts its forecast debt cost rates. The overall debt level deemed to be appropriate for ATCO is noted below.

## Approved Capital Structure and Cost Rates for AGS and APS

| 2001 | AGS | | | APS | | |
|---|---|---|---|---|---|---|
| | Ratios | Cost Rate | Return Components | Ratios | Cost Rate | Return Components |
| Debt | 55.90% | 8.31% | 4.64% | 48.06% | 8.49% | 4.08% |
| Preferred | 6.50% | 5.52% | 0.36% | 6.44% | 5.94% | 0.38% |
| No-Cost | 0.60% | | 0.00% | 0.00% | | 0.00% |
| Equity | 37.00% | 9.75% | 3.61% | 45.50% | 9.75% | 4.44% |
| Total | 100.00% | | 8.61% | 100.00% | | 8.90% |
| **2002** | | | | | | |
| Debt | 55.90% | 8.16% | 4.56% | 48.30% | 8.34% | 4.03% |
| Preferred | 6.60% | 6.15% | 0.41% | 6.20% | 6.23% | 0.39% |
| No-Cost | 0.50% | | 0.00% | 0.00% | | 0.00% |
| Equity | 37.00% | 9.75% | 3.61% | 45.50% | 9.75% | 4.44% |
| Total | 100.00% | | 8.58% | 100.00% | | 8.85% |

## Approved Capital Structure and Cost Rates for ATCO

| 2001 | AGPL | | |
|---|---|---|---|
| | Ratios | Cost Rate | Return Components |
| Debt | 54.11% | 8.34% | 4.51% |
| Preferred | 6.49% | 5.61% | 0.36% |
| No-Cost | 0.46% | 0.00% | 0.00% |
| Equity | 38.94% | 9.75% | 3.80% |
| Total | 100.00% | | 8.68% |
| **2002** | | | |
| Debt | 54.05% | 8.20% | 4.43% |
| Preferred | 6.50% | 6.16% | 0.40% |
| No-Cost | 0.38% | 0.00% | 0.00% |
| Equity | 39.08% | 9.75% | 3.81% |
| Total | 100.00% | | 8.64% |

## 5.6 Treatment of Short Term Debt

### Position of ATCO

In Decision 2000-9, the Board directed the Company to include short-term debt in its capital structure on a go-forward basis by calculating a deemed amount to balance the rate base and capitalization. AGS has not included short-term debt in its forecast capital structure on the assertion that Decision 2000-9 did not direct the Company on how to perform the calculations nor did the Decision instruct how a short-term investment position would be included in the calculation. Furthermore, the Company purported that determining the effective annual cost of short-term debt would create a significant administrative cost in comparison to the immateriality of the amount of short-term debt.

In argument, and Exhibit 134, AGS calculated the difference between rate base and capital structure in 2002 as 0.5% of total investment and argued that this amount was small in comparison to the total rate base and therefore, no balancing adjustment should be necessary as ordered in Decision 2000-45. It also noted that it would be in substantial net investment positions with respect to short term capital at each year end.

In argument, ATCO submitted that differences between rate base and capital structure must exist and are appropriate. It stated that the difference between capital structure and rate base for AGS and 2001 was greater than in 2002, and that this was due to the impact of reflecting four years of regulatory decisions in the year 2000. It noted two issues: the decisions with respect to refunds and rate reductions in 2000 were approximately $51 million; and the original Application had assumed that ATCO would no longer be in the storage business, with the result that the $43 million invested in storage inventory at the end of 2000 could be reinvested in other expenditures. ATCO submitted that time was required to properly address this impact on capital structure, however, the capital structure and rate base were aligned with each other over the forecast period.

**Positions of the Interveners**

### Calgary

Calgary noted that AGS requested an 11.5% return on common equity deemed to finance rate base whereas the financial return on mid-year value of common equity was forecast at 13.25%. Calgary submitted that this difference was caused primarily from the difference between rate base and capitalization and was probably understated due to the effects of construction work-in-progress and non-rate base assets on financial return. Calgary argued that AGS should be required to comply with Decision 2000-9 to balance rate base and capitalization, plus or minus $500,000, with the inclusion of a deemed amount of short term debt. Calgary prepared Exhibit 136 showing the application of adopting Board Decision 2000-9.

### MI

The MI also observed that AGS did not include short-term debt in its capital structure for regulatory purposes. MI recommended that short-term debt be included as a component of financing at a rate of 4.75%.

### Views of the Board

The Board notes that the difference between capitalization and rate base cannot be characterized as insignificant. The Board has calculated the difference between mid-year capitalization and rate base to be $21.0 million for 2001 and $7.2 million for 2002. The difference in 2001 is substantially larger than the difference that existed at the time of Decision 2000-9, wherein the Board ordered ATCO to include short-term debt in its capitalization for the purposes of determining Utility Income. The Board notes the ATCO argument that it will be in a surplus position at its year-ends. However the Board is not convinced that the year-end short-term position should necessarily influence its findings with respect to the inclusion of short-term debt in capitalization. Were the Board to accept ATCO's argument in this regard, it could also be argued that the Board should also utilize a balance sheet approach to determine NWC.

The Board notes that rate base is not strictly determined using the year-end amounts on the balance sheet, but rather includes a component that is determined based on a lead/lag study. The Board's determination, as per 2000-9 is similarly not strictly determined using the year-end amounts on the balance sheet. While the Board is not convinced by ATCO's suggestion that there 'must' be a difference between rate base and capitalization, the Board agrees that there would likely be a difference if no adjustment was made to the Company's capitalization to reflect a deemed short-term component. The Board considers that a non-balance sheet approach to determine NWC and short-term debt is a reasonable way to address the difference between rate base and capitalization that could otherwise exist.

The Board has considered the arguments of ATCO that it would be administratively difficult to determine a precise value for short-term debt costs. The Board does not accept this argument, as the primary application of the approved methodology is done on a forecast basis. The Company is only expected to apply a forecast short-term cost rate to a deemed amount of short-term debt. The Board acknowledges that there may be some added complexities with respect to the determination of actual Utility Income and actual Utility Capitalization, however as previously stated the primary reason for including short-term debt in the Company's capitalization is for ratemaking purposes on a forecast basis.

The Board has reviewed the proposal by the MI to deem the short-term cost rate to be 4.75% and finds that this cost rate is reasonable.

The Board is not prepared to reverse its findings from Decision 2000-9 with respect to the inclusion of short-term debt in ATCO's capitalization for the purposes of determining Utility Income. Therefore the Board directs that ATCO include sufficient deemed short-term debt in the capital structure of AGS in both 2001 and 2002 to balance capitalization and rate base within $500,000 on a mid-year basis, as directed in Decision 2000-9 and Decision 2000-45, at a deemed cost rate of 4.75%.

# 6 UTILITY REVENUE REQUIREMENT

## 6.1 Operation and Maintenance (O&M)

### Position of ATCO

ATCO indicated that utilities in the Alberta marketplace are now operating in a deregulated and highly competitive environment. The convergence of gas and electricity, along with the transition to deregulation has led to greater customer concerns, higher gas costs and increased uncollectible account values, which have all resulted in higher O&M costs. These higher costs have impacted sales per customer, as various consumer classes attempt to mitigate costs.

ATCO stated that while the cost of gas has increased by 260% since 1993, the cost of service component is lower today, despite a 22% increase in the number of customers over that same period. Using the 2002 revenue requirement as a barometer for comparison, ATCO observed that the non-gas portion of the residential customer bill has only increased by 3.1% since 1993.

The ATCO Group has responded to these new realities by restructuring CWNG and NUL into distribution and transmission business units. The ATCO Gas utilities are now more focused on functional activities, possibly creating a more responsive mechanism to competitive challenges. ATCO produced the following table which compares the 1995 operation and maintenance expense adjusted for the impact of customer growth and inflation, to the 2002 forecast O&M expense.

| Efficiency Savings since 1995 | ($000) |
|---|---|
| 1995 ATCO Gas (South) utility O&M | 71,141 |
| Impact of Customer Growth | 15,651 |
| Impact of Inflation | 9,960 |
| Impact of Accounting Change | 2,900 |
| Impact of Asset Cost Shift | 3,300 |
| Comparable 1995 O&M Expense | **102,952** |
| | |
| 2002 ATCO Gas (South) utility O&M | 110,666 |
| Less Transmission and Production on Charge | (23,795) |
| Less Revenues from Pipelines | (1,140) |
| Comparable 2002 O&M Expense | **85,731** |
| Accumulated Efficiency Savings since 1995 | **17,221** |

ATCO indicated that a number of assumptions were made which impacted comparative values, and the resulting cost savings to customers of $17 million. The bulk of the cost savings had been credited to the restructuring of the organization and the sharing of services between south and north business units.

ATCO expressed concern that interveners expect that the recovery of restructuring costs can only be justified by the quantification of rate reductions or other benefits to ratepayers, and indicated that the Company has demonstrated significant benefits to ratepayers in an environment of increased change, significant growth, increasing costs and inflation. ATCO submitted that the pace and scope of the structural change in the Alberta natural gas marketplace alone should warrant full recovery of these costs. ATCO indicated that the Company must be permitted to restructure and re-position in response to changes in its business environment, and that the costs of doing so are a normal cost of doing business in both the regulated and competitive world.

In response to the submission of the Calgary and the MI, ATCO stated that neither severance costs nor the pension gain would have been recognized if the Gas/Pipelines restructuring had not occurred.

O&M expenses are forecast to be $113,983,000 for 2001 and $110,666,000 for 2002 and are set out in the following table.

**Operation & Maintenance**
**($000)**

| | 1999 Actual | 2000 Actual | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Labour | 26,153 | 25,916 | 27,521 | 28,457 |
| Supplies | 66,549 | 69,097 | 86,462 | 82,209 |
| **Labour & Supplies** | 92,702 | 95,013 | 113,983 | 110,666 |

ATCO estimated that approximately $4.2 million of increased costs could be attributed to rising energy prices and argued that the significant increase in gas costs over the forecast period would result in higher operating costs due to the requirement to address the impact on customers (customer contact costs) as well as on the Company's own operating costs.

ATCO submitted that growth on the system as well as the impact of rapid, significant changes were also placing pressure on the Company's ability to keep costs flat over the forecast period.

ATCO noted that on a per customer basis operating costs were forecast to increase by 10% over the period 1999 – 2002, which resulted in an inflation factor of a little over 3% per year. ATCO submitted that when the impact of the pressures on cost (reorganization, staff levels, hearings) were taken into consideration, it was clear that the Company had built the efficiency savings into the forecast, and that the forecast costs were reasonable.

ATCO argued that Calgary's evidence, which noted that the 2000 operating costs per customer remained flat over 1999, overlooked various factors that contributed to this, some of which were not relevant for purposes of reviewing the 2001 and 2002 forecast operating costs. ATCO pointed out that some of these factors were:

- Actual bad debt expense was understated by an estimated $300,000 in the year 2000 due to a programming problem and resource constraints as a result of the impact that rising energy prices had on the Call and Credit Centres. As a result, these costs would be incurred in the year 2001.
- Lower ATCO CIS processing costs than forecast in 2000 reflected the fact that customer conversions were smooth and uneventful, resulting in lower operating costs. This, however, had no impact on the forecast processing costs.
- A number of activities were lower than forecast, particularly leaks and meter recalls (Tr. Pg. 758, Line 15 to Pg. 761, Line 4). In addition to a reduction in operating costs directly related to those activities, other associated costs such as overtime, standby pay and vehicle maintenance and fuel costs were also reduced as a result. These reductions were not consistent with longer-term trends (Exhibit 125) and were therefore not relevant when reviewing the 2001/2002 forecasts.

ATCO argued that the 2000 forecast was the more appropriate comparison base for the 2001/2002 forecast operating costs, as it ignored the impact of anomalies that occurred in 2000 which should not be taken into consideration in the review of the forecast.

ATCO stated that the significant cost drivers that were impeding the Company's ability to keep costs flat over the forecast period did not, as indicated by Calgary in their Argument, represent a disregard of cost containment. Rather, it reflected the fact that the Company's ability to continue to find significant efficiencies had been reduced as a result of the impact of previous restructuring activities, which had reduced staff to a "bare bones" level. The Company stated it had built efficiencies into the forecast, as could be seen by the fact that labour and general supplies costs were only increasing by inflation, although the Company was experiencing average customer growth of 2.7% per year over the 1999 – 2002 time frame.

ATCO argued that Calgary's approach of a 3.0% increase (net of productivity) being appropriate to use in determining the forecast O&M ignores circumstances which fall outside of the norm, such as the extent of customer growth, the significant increase in energy costs and the continuing impact of change and deregulation on customers. ATCO strongly disagreed with this approach, which it claimed ignored the indisputable facts confronted by the utility. ATCO noted that the average annual increase in operating cost per customer for the period 1999 – 2002 was approximately 3%, which was reasonable given the impact of inflation and also the other mitigating factors discussed above.

Regarding the information in Table 4 of Calgary's Argument, ATCO noted that the 1998 information was not comparable to the other years, as it was on an AGPL basis (including transmission related costs), and it ignored the changes that had occurred since 1998 – most significantly the contracting of services from ATCO I-Tek which shifted capital related costs to O&M. Furthermore, it ignored the fact that ATCO Gas was providing services to ATCO Pipelines, which was reflected in the operating costs of the Company, but had offsetting revenues. Finally, ATCO argued that it had indicated additional reasons as to why 1998 was not an appropriate year against which to make comparisons.

ATCO noted that AIPA made similar comparisons to 1998 with respect to the distribution function. ATCO argued that it should be noted that as a result of the accounting change which resulted in revenues no longer being netted against operating expenses, distribution O&M had increased by $1.2 million (with offsetting revenues) associated with jobbing and third party repairs. In addition, work performed on behalf of ATCO Pipelines would also result in an increase in distribution costs, once again offset by revenues. In 2001, $668,000 of revenue from Pipelines had been forecast for operations services. As a result of these two items, ATCO indicated that there had been an increase in distribution operating costs of almost $2 million, with offsetting revenues, since 1998. ATCO submitted that if the 1998 estimated distribution O&M of $19.7 million was increased by $2 million (to be more comparable to future years), distribution operating expenses had increased by only 7.9% over the period 1998 – 2002, an average of 2% per year, which was clearly well lower than the impact of growth and inflation. ATCO suggested that if AIPA adjusted its calculation of distribution expenses for the same $2 million, their forecast for 2002 would become $23.6 million versus the Company's forecast of $23.4 million. ATCO pointed out that it should be further noted that the AIPA calculation assumed an inflation rate of 2%, which the Company did not view as indicative of what was actually happening in the marketplace over the time frame.

ATCO also stated that a similar comparison made by Calgary of the 1999 actual Administration and General costs to forecast was not appropriate, as the 1999 actual amount was an AGS number, while the 1999 forecast appeared to be an AGPL number (AGS did not provide a 1999 forecast).

With respect to the treatment of the one-time costs, ATCO stated that rates would be set based on the second test year (2002 in this instance), not the first. It is for this reason that ATCO has included these costs in the year 2001, rather than 2002, so that they would not be reflected in rates on a going forward basis.

ATCO opposed PICA's view with respect to the use of deferral accounts for costs arising from the cost of gas. ATCO stated that they were not consistent with prospective ratemaking, and removed the incentive of the Company to find efficiencies that would benefit customers. Obviously some aspect of control would still appear to be in the hands of the Company, but it was a function for which there was no potential upside, but significant potential downside. ATCO submitted that it would be ironic if the use of deferral accounts, even where appropriate, were to increase the investor's perception of risk rather than provide the degree of protection that was their intention.

ATCO stated in reply that the following cost drivers were impacting the Administration and General expense in the forecast period:

- higher fringe benefit costs for employees;
- higher pension costs as a result of the change in accounting treatment, which would be reviewed in the Pension proceeding;
- higher bad debt expense as a result of increasing gas prices. ATCO Gas noted that Table 4 of the City's Argument did not incorporate the reduced bad debt forecast by approximately $300,000 in each of the forecast years, nor did it take into account the understatement of the 2000 actual bad debt expense;
- increased hearing costs as a result of an increase in regulatory activity;
- increased system costs from ATCO I-Tek, which would be reviewed in the Affiliate proceeding;
- the inclusion of charitable donations in utility operating expense.

ATCO referred to the evidence of Dr. Chwalowski explaining the reasons why the processing costs of the CIS will be higher than the costs of the existing system. Specifically Dr. Chwalowski explained that the relational data base structure used by CIS (and required to provide the necessary functionality in today's marketplace) requires significantly more computer power than a hierarchical database, and results in much higher computer charges.

ATCO submitted that, while the processing costs associated with CIS are relevant for determining the prudence of ATCO's investment in that system, it must also be remembered that CIS is still in the implementation phase. In this regard, ATCO noted that Calgary's witness acknowledged that the implementation of a new CIS system can be challenging, and referred to Dr. Chwalowski's testimony suggesting that it may be appropriate for the Board to review the performance of ATCO CIS in two years.

Noting the five recommendations with respect to IT spending contained in the written evidence of Calgary's witness, ATCO indicated that some of those recommendations address ATCO's relationship with its affiliates and will be addressed in the Affiliate Proceeding. Nevertheless, ATCO submitted that generally, those recommendations are based on doubtful evidence and should be disregarded.

ATCO noted that Calgary's witness relied on ratios of IT spending to revenue contained in the Gartner Report to support the view that ATCO had spent too much on IT, recommending that ATCO should be allowed to recover no more than the Gartner Report's industry average ratio of IT spending to revenue of 1.7% plus or minus 20%. In ATCO's view, the Gartner Report provides no basis for imposing such a limit on the Company, and that using the report for this purpose would arbitrarily limit ATCO IT spending without properly and accurately addressing the issue of reasonableness.

ATCO pointed out that Calgary's witness acknowledged that he had did not know the statistical methodology used by the Gartner Report and was unable to identify the standard deviation of that study. ATCO also pointed out that the witness acknowledged that he had no information on the specific data on utilities included in the Gartner Report and could not comment on how many of those utilities in fact had a spending to revenue ratio within 20% of the 1.7% industry average. ATCO also noted in this respect, that in a previous proceeding in another jurisdiction, only three of seven relevant data points in similar evidence filed by Calgary's witness came within 20% of the industry average in that report or 20% of the average identified in this proceeding.

Furthermore, ATCO pointed out that Calgary did not provide the Board with any information with respect to the operations or nature of business of the companies included in the Gartner Report, while at the same time acknowledging the importance of understanding the business of the companies used for comparison purposes. Furthermore, ATCO noted that, while Dr. Chwalowski stated that expenditure on a new CIS system "significantly changes the ratios", Calgary's witness was unable to determine whether any of the companies in the Gartner Report had replaced their CIS system during the time in which the study was conducted.

As a final observation about the evidence of Calgary's witness, ATCO noted that the evidence of Dr. Chwalowski indicated that the nine utilities in the Gartner Report had average revenues of $3.5 billion U.S., which is seven times larger than the revenues of ATCO Gas. ATCO also noted that, in testimony, Calgary's witness stated that companies enjoy economies of scope and scale with respect to IT spending but asserted that the companies in the Gartner Report would not enjoy such economies of scope and scale.

ATCO submitted that, given the uncertainty which exists with respect to the Gartner Report methodology, the limited information about the companies used to generate the industry "average" in that report, the very real possibility that only a minority of those companies themselves had IT spending to revenue ratios within 20% of the industry average, and the significant size difference between those companies and ATCO Gas, the Gartner Report should not be used as a basis to arbitrarily limit ATCO's IT spending. ATCO noted in this respect that the Gartner Report rejects the use of its own research for this purpose, stating:

> … each enterprise should assess its own situation carefully and should not arbitrarily change to conform to the survey results, which do not represent norms or best practices. By itself, IT spending as a percentage of revenue does not provide valid comparative information that should be used to allocate IT or business resources. IT spending statistics alone do not measure IT effectiveness and are not a gauge of successful business and IT fusion.[21]

ATCO noted that Calgary's witness agreed that the Board should take this statement into account when considering the Gartner Report.

**Positions of the Interveners**

**AIPA**

AIPA noted that ATCO had indicated that the retail business unit was for sale in conjunction with the other ATCO companies' retail business units. AIPA submitted that the restructuring costs incurred had probably enhanced the potential selling price of the retail businesses. Under such circumstance AIPA believed that restructuring costs could not be considered in the limited context of sharing between existing customers and ATCO for revenue requirement determination in the GRA proceeding.

AIPA submitted that, as a matter of principle, restructuring costs (or a significant portion thereof) should remain in a deferral asset account to be considered at the time of a future application for the sale of the retail businesses. AIPA argued that it was only in that way the costs of restructuring would be analyzed and allocated appropriately to the parties that benefit from such restructuring.

AIPA noted that ATCO estimated 1998 O&M actual expenses as $59.036 million[22] where this estimate excluded transmission costs.

AIPA referred to R–ATCO GAS.29, which provided O&M actuals for 1999 and 2000 and forecasts for 2001 and 2002. AIPA submitted that if transmission costs were excluded the following summary resulted ($000s):

[21] Gartner Report, p.13
[22] BR-ATCO GAS.37, p.2

($000)

| | 1998 Actual | 1999 Actual | 2000 Actual | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|---|
| | | | | | |
| Dev and Acquisition | 19 | 2 | 1 | 10 | 11 |
| Production | 703 | 647 | 803 | 1,049 | 824 |
| Gas Management | 1,510 | 629 | 628 | 631 | 635 |
| Underground storage | 3,139 | 4,027 | 4,078 | 5,940 | 5,432 |
| Distribution | 19,655 | 22,546 | 21,289 | 22,749 | 23,373 |
| General | 1,757 | 1,500 | 1,891 | 2,385 | 2,379 |
| Sales and Transp Promo | 1,550 | 1,661 | 1,811 | 1,961 | 2,031 |
| Customer Accting | 14,235 | 16,534 | 19,152 | 24,525 | 24,914 |
| Admin and General | 16,468 | 22,779 | 23,061 | 31,445 | 27,380 |
| | | | | | |
| Total | 59,036 | 70,325 | 72,714 | 90,695 | 86,979 |

AIPA noted that the Customer Accounting and Administration and General functions showed inordinate increases but these issues were deferred to the Affiliate and Pension proceedings so were only placeholders in the GRA proceeding.

AIPA noted that the above table showed a disproportionate increase in distribution costs in spite of decreases in staffing complements in 1998. AIPA pointed out that from 1998A to 1999A there was an increase of approximately 15% and from 1998A to 2002F an increase of 19%. AIPA submitted that the increases were a concern to customers.

AIPA submitted it was reasonable for distribution costs to track the increases in sales throughput over the relevant periods with an allowance for inflation. AIPA explained that for 1998 AGS had a sales throughput of 95,377 TJ[23] and that the forecast sales throughput for 2002 was 96,948 TJ, an increase of 1.7% from 1998A. AIPA argued that with inflation estimate of 2% per year the distribution function budget for 2001 should be $21.2 million[24] and for 2002 should be $21.6 million.[25]

## Calgary

Calgary submitted that the actual total O&M expense for 1999 on a per customer basis was $236.00 per year and the forecast for 2001 amounts to $275.00 per customer and for 2002 the amount is $260.00. In Calgary's view, this level of escalation was tantamount to a total disregard of cost containment by AGS, particularly when in 2000 the actual costs were the same on a per customer basis as in 1999.

Calgary stated that the O&M increases in Administrative and General (A&G) and Customer Accounting stood out in the AGS Application.

Calgary noted that in 1999, actual A&G costs amounted to $57.97 per customer, but over a two-year period to 2001, the forecast for A&G increased to $75.88 an increase of 30.9 percent

[23] Application, Tab 17, Schedule 2, Line 20
[24] 19,655 * (100% + 6% + 1.7%)
[25] 19,655 * (100% + 8% + 1.7%)

(14.4% compounded). In Calgary's opinion this level of increase far exceeded reasonable rates of inflation and exhibited a lack of cost control on the part of AGS. Calgary presented the following table, based upon the response to BR-AGS.29, which compared A&G labour and supplies expense for the 1998 through 2000 actual and forecast 2001 and 2002. Calgary argued that the slight reductions in labour costs were more than offset by large and increasing supplies costs.

**Table 4**
**($000)**

| Year | Labour | Supplies | TOTAL |
|---|---|---|---|
| 1998 | 5,098 | 14,749 | 19,847 |
| 1999 | 4,080 | 18,699 | 22,779 |
| 2000 | 4,069 | 18,992 | 23,061 |
| Forecast | | | |
| 2001 | 4,283 | 27,162 | 31,445 |
| 2002 | 4,445 | 22,935 | 27,380 |

Calgary submitted that while ATCO might argue that part of the 2001 increase was due to the recovery of past regulatory costs, the Board must recognize the nature of one-time costs. Calgary argued that one-time costs should not be built into the revenue requirement and resulting rates. To do so would reward the utility with the recovery of the costs each and every year the rates are in effect. It was Calgary's position that even the so-called one-time costs did not explain the almost 19% increase between 2000 and 2002, a year that supposedly did not have the one time costs included.

Calgary argued that it should also be noted that the forecasting of A&G expense varies from actual. For example the 1998 actual was $19.487 million versus a forecast of $25.305 million for a difference of $5.8 million dollars. For 1999 the actual was $22.779 million versus a forecast of $28.106 million for a difference of $5.3 million dollars.[26]

Calgary submitted that the Board must recognize both the forecasting margins in the historical numbers as well as the unconstrained growth in costs for customer accounting and A&G costs in reaching its decisions in this proceeding. Calgary believed that the expectation should be that customer accounting and A&G costs would increase, at most, by the inflation rate i.e. in the order of 3% per year, from 1999 to 2002 less a factor for productivity. Calgary stated that anything greater should be unacceptable to the Board and to ratepayers.

Calgary stated that in its evidence,[27] it had recommended that O&M costs should be reduced by over $15.5 million dollars for 2001 and over $9.3 million for 2002.

With respect to IS function Calgary submitted that the Board should accept the conclusions of Mr. Stephens, which were as follows:

[26] Exhibit 45, Table 1
[27] Exhibit 45, p.15

- IS costs of AGS were outside the bounds of reasonableness, resulting in a 20% increase in 1999 over 1998, due in large measure to the 'insourcing' with I-Tek and the fact that the IS budget in 2002 was forecast to be approximately 100% higher than the 1998 IS budget.[28] In determining that increase, Mr. Stephens had included the owning and operating costs of the new CIS application, which was included in the rate base of AGS.[29]
- The CIS solution cost of ownership (CIS O&M plus amortization plus cost of capital plus taxes) was \$5 – \$9 per customer higher than the other Canadian gas utilities (27% – 64% higher than other Canadian gas utilities).[30]
- The 2002 IS budget as a percentage of 1999 revenue was approximately double the average level found in the Gartner survey, and as a cost per employee (assuming a flat 1,000 employees), approximately 50% above the Gartner gas utilities survey results.[31] (The use of actual number of employees would increase the IS cost per employee to more than 100% of the Gartner Survey).[32]

Calgary submitted that the information provided in the Stephens report and the cross-examination of Mr. Stephens, indicated that the IS budgets were too high and needed to be reduced.[33]

With respect to the customer accounting function Calgary submitted that the Board should accept the conclusions of Mr. Stephens, which were as follows:

- The CIS solution annual cost of ownership was too high because the ATCO CIS solution not only cost too much to build and implement, but its operating costs were too high.
- The Customer Accounting direct costs less meter reading and bad debt including Singlepoint charges for billing, payment processing and call and credit services, together with the CIS costs including charges from I-Tek together with the owning and operating costs of the new CIS when compared on a per customer per year basis were \$8 – \$18 per customer above what Mr. Stephens considered to be fair market value.[34] This represented amounts of 16% – 45% above fair market value.

Calgary submitted that based on the information from Union Gas, Centra Gas Manitoba, Enbridge Consumers Gas and BC Gas, it was clear that the new ATCO CIS cost was unreasonably high.[35]

Calgary submitted that the Board should:

1) Allow AGS to recover annual IS spending in 2001 and 2002 in an amount no more than 1.4 to 2.0%[36] of 1999 AGS revenue or approximately \$6.5 million to \$9.3 million. At

[28] Exhibit 45, SCL 2001 Report - Chart 8
[29] Exhibit 45, SCL 2001 Report – Chart 8
[30] Exhibit 45, SCL 2001 Report – Chart 5
[31] Exhibit45, SCL 2001 Report – Chart 5
[32] Exhibit 45, SCL 2001 Report – Chart 9 and Chart 11
[33] Exhibit 45, SCL 2001 Report and AGS Volume 10, pp.1674-1765
[34] Exhibit 45, SCL 2001 Report – Chart 4 --- \$40 to \$50
[35] Exhibit 45, SCL 2001 Report – Chart 5
[36] Exhibit 45, SCL Report – p. 5 of 32 – 1.7% plus or minus 20%

$9.3 million this was still approximately a 33 percent increase over 1998 spending (when AP was removed from the combined budget).

2) Allow AGS to recover no more than $16.8 million to $21.0 million for Customer Accounting in 2001 and 2002, which represented a range of $40 to $50 per customer per year,

3) Indicate the reasons for reducing IS and Customer Accounting costs included the jump in costs of approximately 20% when I-Tek started providing services to AGS in 1999 and the 27% – 64% higher ownership costs for the CIS solution than those at other Canadian gas utilities.

4) Direct AGS to hire an independent director of Information Services, and order that AGS develop a formal procurement process to examine the insourcing and potential for outsourcing. (Calgary noted that APS, a smaller organization had a part-time IS person).[37]

5) Require AGS to provide annual information filings for Information Services and Customer Accounting, showing all direct and indirect costs in similar detail to that provided in a class cost of service study.

Calgary pointed out that, in making his recommendations regarding IS spending, Mr. Stephens considered benchmark information from the 2000 Gartner Report, benchmark information from the 1997 G2R Canadian Utilities Industry Study, benchmark information from the 1998 G2R United States Utilities Industry Study, and his professional experience.

Calgary noted that IS spending is forecast to double from 1998 to 2002, and as a percentage of 1999 revenue will also be almost double the Gartner gas utilities average in 2002.

Calgary indicated that, while ATCO argues that Mr. Stephens had no knowledge of the statistical methods used in the Gartner Report and that the seven relative points in the G2R report varied significantly from the average without the knowledge of which utilities were gas and which were electric, the Company provided no comparative information to show the Board that the level of IS spending was reasonable. Calgary submitted that, instead, ATCO asked the Board to allow the following application projects to be funded by their customers:

| Project | Forecast Cost ($ million) |
|---|---|
| CIS | 25.6 |
| OPS/MMS | 1.5 |
| WMS | 3.6 |
| GMS | 0.3 |
| Khalix | 0.4 |

[37] APS Volume 2, p.290

Calgary submitted that, by approving IS spending to within 20 percent of the Gartner gas utilities average, as recommended by Calgary, ATCO will be forced to improve IS strategies, evaluate options more critically, plan application upgrades or changes more effectively, and select outsourcing suppliers that are more cost effective. Calgary considered that ATCO's alternative to adopting the Calgary recommendation is to suffer an impact to their bottom line, as one would expect in an unregulated, competitive industry.

Calgary argued that the exclusive transportation agreement with APS was not in the public interest of ratepayers and that ATCO acknowledged the proposed service agreement was anti-competitive.

Calgary opposed the inclusion of any restructuring costs in ATCO's 2001/2002 revenue requirement. Calgary's opposition was based on a number of factors, but primarily the inappropriateness of using pension gain to reduce the restructuring costs, the lack of benefit to customers from the restructuring, and the failure of ATCO to comply with Decision U99102.

Calgary argued that notwithstanding ATCO's comments to the contrary,[38] the evidence indicated that there had been no benefits from the restructuring.

Calgary submitted that pages 1 and 2 of Exhibit 122 clearly demonstrated the lack of efficiencies and showed that a $32 to $47 million difference had resulted from the restructuring. Calgary argued that the Board should reject the attempt to justify the approximate $47 million increase.[39]

Calgary indicated that the significant increase in O&M costs of ATCO Gas and Pipelines combined in 1999 and 2000 compared to 1998 actuals is not indicative of benefits from restructuring. Calgary submitted that ATCO should have provided a concise trail from the amounts approved in Decision 2000-9 to the current applications by ATCO Gas South and ATCO Pipelines South.

Calgary argued that even on a per customer basis,[40] the cost increases greatly exceeded inflation over that period, let alone inflation less a productivity or positive restructuring factor. Calgary stated that its evidence, had indicated that a 3.0% increase (net of productivity) would be appropriate to use for ATCO' O&M on a total dollar basis, since such an increase would compensate in part for the potential for customer growth to result in increases greater than inflation. Calgary submitted that, on a per customer basis, the cost increases should be less than inflation and certainly less than 3%.

Calgary submitted that in Decision 2000-9 the Board found that it was appropriate to base forecasts on "the most current data available at the time of the proceeding."[41] Calgary noted that ATCO had proposed approximately $4.2 million of increased cost based on its forecast of "high" gas prices.[42] ATCO noted in its Argument that gas prices in its forecast were considerably below the prices seen in the winter of 2000/2001. Calgary submitted that the forecast prices were

[38] Exhibit 122 and volume 8, pp.1414 and following
[39] Exhibit 122, p.3
[40] 1998- 167.952 million/373,716; 2001 216.226 million/424,704; 13.3% over 3 years
[41] Decision 2000-9, p.65
[42] AGS Argument, pp.39-40

considerably above real prices experienced since March of 2001 and future prices for the upcoming winter.[43] Gas prices had tumbled since the forecast was made, and had continued to fall over the summer of 2001. High gas prices had dropped from the front page of the newspapers. Customer outrage over gas prices during the 2000/2001 winter had subsided. Calgary also noted that since the start of the proceeding, ATCO had twice reduced its GCRR. Calgary requested the Board to further reduce the GCRR due to the continuing decline in gas costs.

Calgary submitted that a one time run up in gas costs did not provide a foundation for millions of dollars of increased costs to be embedded in utility rates. Calgary believed that while forecast and prospective ratemaking were to be respected, practical and actual realities must also be acknowledged.

Calgary was of the view that when actual and test period forecasts of labour and supplies cost were compared, costs were escalating at rates well above the ATCO forecast percentages. In particular, supplies costs were escalating at imponderable rates of increase.

Notwithstanding that ATCO continued to advance its position that O&M expenses were escalating in the 3 to 4 percent range, Calgary believed this was not the case and it remained extremely concerned with the increases in O&M expense forecast by ATCO for the 2001 and 2002 test years. Calgary noted that AGPL came into existence on January 1, 1999,[44] with the name change of CWNG to AGPL. AGPL was established with two divisions, AG and AP. As the north assets of NUL were not brought into AGPL until January 1, 2001, AGPL was AGS and APS (i.e. the equivalent of CWNG) for the years 1999 and 2000. As pre-1999 data is only available for CWNG, Calgary's view was that the organizational restructuring meant that Intervenors and the Board were limited in their ability to conduct comparisons of "actual" to "forecast" for ATCO to the period starting in 1999. It was Calgary's position that even with the limited data available, the data contained in Table 1 attached to Calgary's Evidence could be used to make numerous comparisons to the rapidly escalating O&M included in the 2001 and 2002 forecasts. Calgary argued that the total O&M expense forecast for 2001 was 23% higher than 1999, and the forecast 2002 O&M was 19.4% higher than 1999.

In reply, Calgary argued that the issue of forecast expenditures versus actual expenditures must also be addressed. Table 1 attached to the Calgary Evidence provided a comparison of forecast O&M expense versus actual for the years 1998 – 2000. Calgary argued that in every year forecast expenditures exceeded actual expenditures.

With respect to Customer Accounting, Calgary noted that costs were forecast to increase by 40.6% on a per customer basis for 2001 over 1999 and 39.3% for 2002 over 1999. Calgary was of the view that, to a great extent, customer accounting costs were being driven by charges from affiliates, which compounded the degree of concern. Calgary argued that rising costs from affiliates, which drive cost increases beyond reasonable levels of inflation required substantially more documentation that ATCO had provided. Calgary also argued that ATCO had not met the burden of proof to demonstrate the need for increases in excess of 39% over a two and three year period.

[43] August 17, 2001 letter to Board re: GCRR
[44] AGS Tr. p.215

Calgary also expressed concern with significant increases in Affiliate costs incurred by ATCO. Exhibit 96 showed the following levels of "Forecast" costs incurred by ATCO from Affiliates:

| Year | Amount |
|---|---|
| 2000 | $26,112 |
| 2001 | $33,717 |
| 2002 | $32,179 |

Calgary argued that increases in costs of over $6 million in one year between Affiliates should be viewed with extreme caution. Ratepayers should not be expected to absorb cost increases of this magnitude between regulated and non-regulated Affiliates.

**CCA**

Given the introduction of government rebates and lower natural gas prices the CCA considered that the forecast for call centre costs were excessive for the test period. The CCA submitted that a more reasonable estimate is increasing 1999 actuals by 3% for 2000, 2001, 2002. A fixed amount can be added for the increased activity, which occurred in January and February of 2001. The CCA stated that the amount could be calculated using an increase of 10 persons over two months, plus incremental overheads.

The CCA again noted that in the early winter of 2000/2001 there was significant concern with the effects of high gas costs and the ability of customers to keep their accounts up to date. However, with the significant reduction in gas costs from their winter highs and the introduction of very significant government rebates, there is no reason to forecast high credit and collection costs for the years 2001 and 2002. The CCA considered that 2001 credit and collection costs should in fact be significantly lower than 1999 actual because of the level of rebates will actually cause lower bills than in previous years. The CCA also considered that the new ATCO billing capabilities should also lower credit and collection costs. It would be unfair to customers to charge customers higher costs for increased computer capabilities than higher operations and maintenance costs associated with credit and collection costs. The CCA recommended therefore, that the AEUB adopt the 1999 actuals for credit and collection expense, as a reasonable forecast for 2001 and 2002.

The CCA noted that ATCO had indicated that increases in gas costs over the forecast period would result in higher operating costs due to increased customer contact costs. The CCA considered that this might have happened when gas costs increased sharply and before the implementation of natural gas rebates. Rebate programs should reduce the level of customer contact costs in the future. The CCA noted that gas costs had dropped considerably, and ATCO could further reduce natural gas price volatility in its DGA by adjusting its natural gas portfolio, and thus reduce customer contact costs. The CCA also noted that payment equalization plan customers had significantly over paid gas costs as significant surpluses had been built up in the accounts of these customers. This was impacted by reduced natural gas prices and natural gas rebates. The CCA believed that system growth costs should be offset by increased investments in labour saving technologies, such as increased computer related expenditures.

The CCA did not consider that the economy was heating up, but that, in fact, the opposite was likely true, since overall growth was expected to slow and thus inflation rates had been over forecast by AGS for the test years.

**MI**

The MI submitted it would be helpful to review the Company's past forecasting record and provided the following table ($ thousands):

| | | | ($000) | |
|---|---|---|---|---|
| | **Filed** | **Allowed** | **Actual** | **References** |
| 1989 | 65,103 | 64,472 | 65,353 | C90026, 1992/93 GRA |
| 1990 | 69,560 | 68,534 | 67,167 | C90026, 1992/93 GRA |
| 1991 | 73,613 | 72,147 | 72,972 | C90029, 1992/93 GRA |
| 1992 | 79,936 | 78,295 | 76,282 | E93004, Report/Finances |
| 1993 | 84,634 | 80,359 | 78,462 | E93004, Report/Finances |
| 1998 | 73,004 | 70,112 | 66,401 | BR-29, 1998 Refiling, GRA |
| 2000 | 97,856 | - | 95,013 | BR-29, 2001/02 GRA |
| Average | 77,672 | - | 74,520 | - |
| Vs. Filed | - | - | (4.2%) | - |

The MI argued that similar to the capital expenditures forecast, the O&M forecast also continued to display a persistent and disturbing trend of over-forecasting. The MI stated that even the 2000 forecast, which presumably was the basis for the 2001 and 2002 forecasts, had the benefit of actual results up to September and yet came in $2.84 million or 2.9% below forecast. The MI noted that the bulk of the reductions were attributable to less meter recalls, less leak repairs, lower CIS costs and lower I-Tek costs than forecast.[45] The MI submitted that it was difficult to understand how these variances would have not been known in September and most certainly by December, when the application was filed. The MI further noted that those reductions translated to about $1.6 million after tax or 92 basis points on equity.

The MI submitted that the persistent bias towards over-forecasting required a minimum downward adjustment of 3% to the forecast O&M expenses for 2001 and 2002.

The MI agreed with Calgary that this may have been one of the most complex GRA's that the Board has had to deal with for any utility. The MI stated that it appeared that everyone, including the Board, struggled to understand the flow of costs through the transition from CWNG to ATCO Gas South. In addition to the restructuring of CWNG and NUL, the MI noted that operating costs were forecast to increase by some $33 million since 1998 and costs that were previously labour costs, had been transformed into supplies costs with the creation of ATCO I-Tek and ATCO Singlepoint.[46]

[45] Tr. pp.1031-1033
[46] BR-ATCO.29, p.3

The MI had several concerns with Exhibit 122 (submitted by ATCO at the request of the Board) and in particular the alternate comparison. The MI noted that ATCO started with the 1998 approved revenue requirement for CWNG and factored O&M and asset-related costs up for inflation and growth, to reconcile to the 2001 revenue requirements. AGS used 5% for inflation and growth which it indicated could be "2 ½ and 2 ½ " or "3 and 2".[47] While growth in customers has been close to 2 ½% per year during this period, core throughput has actually decreased by 2 ½% per year. The MI also noted that CWNG's 1998 Cost of Service Study had indicated that approximately 74% of costs were related to number of customers. Therefore, the MI considered that 2 to 2 ½% for growth was overstated and that it should be closer to 1% to 1 ½%. The MI believed that while inflation in 2000 was approaching 3%, it was around 1% in 1998. The MI argued that it appeared that inflation over the 1998-2000 period should have been closer to 2% and therefore, it appeared that the Board's inflation factor of 3% as reflected in Exhibit 122 was reasonable.

The MI believed that the $11.18 million of so-called incremental costs included several items that were already partially captured by the growth and inflation factor. The MI submitted that those items included the impact of rising energy prices on the call center, bad debts, carbon fuel and corporate communication, plus the impact of CIS processing and maintenance costs and ATCO Corporate Services.

The MI argued that based on the 3% factor for growth and inflation and the double counting of incremental costs, it appeared that there had been no benefits for customers as a result of the restructuring. However, the MI noted, the customer service functions had been moved to a deregulated ATCO affiliate in preparation for a future competitive market.

Notwithstanding the reputed efficiencies identified in Exhibit 122, the MI noted that a 15½% increase in Cost of Service rates was forecasted.[48]

The MI submitted that it also appeared that there was a significant increase in costs for most distribution functions in both 2001 and 2002,[49] and that the increases would be even more noticeable if the graphs had been adjusted to reflect the $2.84 million reduction for 2000 actual operating costs. The MI submitted that there appeared to be an upward bias in the forecast 2001 and 2002 test year O&M expenses.

The MI noted that, as part of its restructuring costs, ATCO had included severance costs of $8.9 million representing approximately 25% of the reduction of 469 full time equivalents (FTEs) since 1995.[50] The MI submitted that, as noted by the Board,[51] staff reductions should be offset by lower payroll costs. The MI argued that, given that ATCO chose to withdraw its 1999 GRA and chose not to file a 2000 GRA, it was inappropriate for ATCO to request that customers be requested to be responsible for a portion of those costs in 2001 and 2002.

[47] Tr. p.1419
[48] BR-ATCO.31 (b)
[49] Volume 2, Tab 4
[50] Tr. p.509
[51] Decision U99102, p.12

The MI submitted that with respect to the pension gain that was offset against the other restructuring costs, it should have been noted that the resulting pension gain, and the severance costs, would have resulted absent the restructuring, and therefore should not necessarily form part of the restructuring costs. The pension gain could have been used to offset the Supplemental Pension Costs and Post Employment Benefits and should, the MI submitted, have been deferred to the Pension Proceeding.

The MI agreed with Calgary that it was premature to include any amount for restructuring costs in the 2001 and 2002 revenue requirements before benefits to customers had been demonstrated.

The MI noted that, of the $4.4 million increase in customer accounting from 2000 to 2001, $3.8 million is attributable to increased charges by ATCO Singlepoint.[52] Tab 7 provides the forecast billing units, unit rates and total charges for ATCO Singlepoint services. The MI indicated a number of concerns with the forecast provided in Tab 7.

The MI noted that ATCO attributed approximately $4.2 million of increased O&M in 2001 to increased gas prices.[53] Notwithstanding that ATCO noted that the Government rebate program mitigated the impact on customer bills "somewhat", the MI countered that the rebates effectively reduced the cost of gas to customers in 2001 by $4 per GJ from approximately $7.48 per GJ, assuming the existing GCRR continued to year-end.[54] The MI stated that ATCO went on to note that the rebate program resulted in increased customer contact costs. In the MI's opinion it was apparent that ATCO was attempting to create the impression that the relatively short-term anomaly that occurred in early 2001 would continue throughout 2001 and 2002. That was simply not true, and not substantiated by the evidence in the MI's view. The MI noted that gas prices had fallen to 2000 levels, the rebate program was over and more than likely, the increased customer contact costs would have fallen accordingly.

The MI submitted that the cost reductions which they proposed[55] were reasonable and not unlike those proposed by PICA.[56] The MI agreed with PICA that the impacts from high gas prices were unlikely to continue throughout the balance of the two-year test period.

The MI noted ATCO's assertion that the 2000 forecast of O&M expense was more appropriate than the 2000 actual expenses because it ignored the anomalies of that occurred in 2000.[57] The MI argued that there was no evidence on the record to suggest that the actual number of leaks or meter recalls and associated overtime, standby pay and vehicle expenses in 2000 were an anomaly as opposed to persistent over-forecasting of O&M as shown at page 30 of the MI Argument. Contrary to the Company's suggestion that the 2000 actual O&M expenses should be ignored in reviewing the 2001 and 2002 forecasts, the MI submitted that 2000 actual O&M costs should represent an appropriate base for determining 2001 and 2002 O&M expenses.

[52] Volume 2, Tab 7
[53] AGS Argument, p.40
[54] MI Argument, p.39
[55] MI Argument, pp.36 to 38
[56] PICA Argument, p.11
[57] AGS Argument, p.42

### PICA

PICA noted that significant increases in O&M related to $4.2 million attributable to increasing energy prices, and that, in particular, this increase was attributed to the impact of higher gas prices on the Call Centre, bad debt expense, carbon fuel costs, and corporate communications cost. [58]

It was PICA's submission that costs arising out of factors such as gas prices, over which ATCO had no control, were more properly dealt with through a deferral account. PICA noted that for many years, the commodity price of gas purchases incurred by ATCO flowed through the Deferred Gas Account (DGA), which had left ATCO neutral with respect to changes in gas costs. PICA believed a similar approach was also warranted for any other costs driven by changes in gas costs since ATCO had little, or no, control over the level of these costs. PICA submitted that ATCO should neither profit nor lose in relation to what would effectively be, forecast gambles on the level of such costs.

Should the Board decline to treat such costs through a deferral mechanism, PICA submitted that the allowance for additional costs caused by high gas prices should be reduced to $1 million, from the $4 million claimed by ATCO. PICA stated this would recognize that, while there had been some impacts from high gas prices in the first part of the 2001 test year, those impacts were unlikely to continue or occur throughout the balance of the two-year test period.

In reply, PICA noted that ATCO took the position that the 2000 actual O&M costs should not be used as a comparison for forecast 2001/2002 O&M costs because of various events ATCO claims were anomalous in the year 2000. PICA noted that, in justifying its O&M forecast for 2001 and 2002, ATCO used forecast high gas prices as the basis for an increase of costs totaling $4.2 million. PICA stated that arguably, sustaining such high gas prices over the full 2 year forecast period would also have to be regarded as anomalous compared to the historical record. Consequently, PICA questioned the selective reasoning of ATCO, particularly when anomalous behaviour was only to be considered when favorable to ATCO.

### Views of the Board

The Board notes the significant discussion with respect to the escalation in expenditures forecast for the test years compared to 1999, and acknowledges that the bulk of the increase relates to expenditures for services provided by affiliates in the areas of Customer Services and Information Systems. The Board also recognizes that forecast expenditures related to pension and post employment benefits contribute to the increase. As indicated in other Sections of this Decision, the forecast expenditures for these Affiliate and Pension-related expenditures will be held as “placeholders” in the test year revenue requirements and the quantum and propriety of the amounts will be addressed in the Affiliate and Pension proceedings.

The Board also acknowledges the concerns expressed by interveners with respect to increases in O&M expenditure forecasts resulting from factors affecting expenditure categories that are neither Affiliate nor Pension related. In particular, the Board notes the significant concern expressed regarding expenditure categories where ATCO has indicated that increases are driven by high gas prices. The Board agrees that there is merit in the arguments of PICA and the MI that

[58] BR.ATCOGAS-33, p.3

the impact of unusually high gas prices in the first part of the winter 2000/2001, and accordingly the 2001 test year are unlikely to continue throughout the balance of the two-year test period. The Board notes PICA's recommendation that the additional costs resulting from the impact of high gas prices should be held at $1 million in each test year. The Board agrees that the long term impact of high gas prices is speculative and is persuaded that an adjustment should be made to the forecast to reduce the additional costs attributed to high gas prices. Accordingly, the Board directs ATCO to reduce the additional costs of $4 million claimed by ATCO in each test year by $2 million.

To determine the extent of the increases in forecast expenditures for all remaining expenditure categories (i.e. excluding costs relating to affiliate and pension transactions, high gas prices, donations and hearing costs), the Board has prepared the following table, based on information presented in the Application:

**($000)**

| Category | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|
| Total O&M Expense per ATCO filing | 92,702 | 95,013 | 113,983 | 110,666 |
| less Affiliate and Pension related | 18,288 | 21,291 | 28,581 | 28,180 |
| less Bad Debt/Carbon Fuel | 2,156 | 2,690 | 5,002 | 4,145 |
| less Hearing Costs | 524 | 524 | 4,500 | 1,000 |
| less Donations | 0 | 0 | 217 | 217 |
| less Transmission Charge | 22,377 | 22,299 | 23,288 | 23,687 |
| Remaining Expenditures | 49,357 | 48,209 | 52,084 | 53,100 |
| Percentage Increase from 1999 | | | 5.5% | 7.6% |
| Percentage Increase from 2000 | | | 8.0% | 10.2% |
| Remaining Expenditures based on 3% each year since 2000 | | | 49,655 | 51,145 |
| Difference | | | 2,429 | 1,955 |

As indicated in the chart, the increases in 2001 and 2002 O&M, when compared to 1999 represent less than 3% per year. However when the forecasts are compared to 2000 the increases are substantially more than 3% per year. The Board is not persuaded by ATCO's evidence that an increase of this magnitude can be justified. Accordingly, the Board considers that there is sufficient justification for reductions in the O&M expenditures for the test years, in addition to the $2 million adjustment for high gas prices discussed above. The Board is of the view that a 3% annual increase since 2000 is appropriate, is more in line with inflation, and will include an allowance for efficiencies achieved as a result of reorganization. On this basis, the total reduction in test year forecasts is set as:

| | 2001 | 2002 |
|---|---|---|
| Adjustment for High Gas Prices | $2.000 million | $2.000 million |
| 3% Inflation and Efficiency | $2.429 million | $1.955 million |

The Board notes that Calgary takes issue with ATCO's submission that costs in 2002 are forecast to actually be $17 million lower than the 1995 level as a result of proactive restructuring initiatives. The Board agrees with Calgary that there appears to be no reasonable justification for

ATCO not to provide a similar comparison with 1998 results, but also considers that precise quantification of the savings from restructuring is not fundamental to addressing the issue of whether or not the costs of restructuring should or should not be included in test year forecasts.

The Board notes ATCO's submission that the Company must be permitted to restructure and reposition in response to changes in its business environment. The Board accepts ATCO's position that the costs of restructuring are a normal cost of conducting business, and as such, should be considered an appropriate item for inclusion in regulated rates without the need for additional justification. Contrary to the comments of the MI that severance costs and pension gain would have occurred despite the restructuring, the Board agrees with ATCO that neither of these amounts would likely have been recognized if restructuring had not occurred. The Board is also prepared to accept ATCO's representations that it is difficult to quantify benefits to ratepayers associated with restructuring activities, and is not persuaded that compelling evidence has been presented to support any reduction in restructuring costs included in the test year forecasts.

### 6.1.1 Labour

**Position of ATCO**

ATCO indicated that labour has been significantly affected by corporate restructuring of the distribution business of CWNG and NUL. ATCO Gas South utilized temporary and contract workers to offset resignation and retirements in an effort to maintain a streamlined organization. As AGS' workforce ages, efforts to recruit new staff and maintain current employees will lead to higher salary costs. Supervisory employee salaries are expected to rise 4%, while other employees can expect a 3% increase.

ATCO noted that O&M labour costs were forecast to increase by 3.4% in 2001 and 2002, and argued that given the strong economy, competitive labour market, and growth in customers, this was a conservative forecast. ATCO submitted that the wage increases were determined after extensive surveying of the labour market, and in the case of the occupational increase, ratified in collective bargaining and resulted in a forecast 3% wage increase for occupational employees and a 4% increase for supervisory employees.

ATCO argued that, given the annual forecast increase in labour costs only incorporated the impact of wage increases, the forecast included the absorption of growth by assuming efficiency gains.

ATCO stated that in order to allow the Company to attract and retain qualified employees, the outdated employee benefits program was modified in July 2000 to a Flex Benefit program and although the new program had increased costs, it was an important necessity in maintaining a stable and productive workforce, and remaining competitive in a tight labour market. ATCO argued that although fringe benefit costs were forecast to increase, there had been reductions in benefit costs as a result of the restructuring the gas utilities had undergone.

ATCO noted that a rate increase of 14.3% by the Workers Compensation Board was also contributing to higher costs.

ATCO submitted that total O&M labour cost could not be directly correlated with the total number of FTEs in the Company and that labour costs must be judged on the reasonableness of the forecast.

ATCO submitted that FTE positions were a measure of the size of the company -- a management tool to determine space requirements, parking needs, equipment, benefits, etc. ATCO stated that the tracking of FTEs included all permanent positions, whether they were ultimately charged to O&M or to capital, and that the size of the company (number of FTEs) had diminished considerably as a result of restructuring and that a reduction was also forecast on a go-forward basis. ATCO stated that other savings had resulted, most noticeably the reduction in office space required, as was evidenced by the four floors of head office space which had been removed from utility costs.

ATCO stated it had not changed the way that the Company and its predecessor companies historically budgeted labour costs with respect to capital projects. Capital expenditure forecasts were developed using different procedures, which do not require the identification of a forecast labour component. ATCO indicated that the capital expenditure program in any year for the Company might rely heavily on the use of temporary and contract labour, depending on the level and timing of the work required. The amount of capital related work that is contracted out in any year varies as well and therefore attempting to forecast the amount and mix of the various alternatives available in the completion of a capital program would be an onerous burden, without necessarily adding any value to the process. ATCO indicated that instead, the Company has developed time proven techniques for forecasting the costs of different capital projects, such as projects related to customer growth. ATCO stated that a total labour cost forecast was not required to determine the reasonableness of either the operating expenditures or capital expenditures forecast.

**Positions of the Interveners**

**AIPA**

AIPA submitted that irrespective of whether the budget was developed from the bottom up or the top down there had to be an overall labour budget that was then identified as between operating requirements and capital projects. AIPA submitted that the ATCO approach to FTEs did not provide the necessary information for customers' evaluation.

AIPA argued that there was a concern with labour costs, staff reductions, and severance liabilities in test years and non-test years. AIPA stated that when rates were based on test year labour estimates, labour costs were subsequently reduced with staff reductions the utility stood to gain in the test year, but customers could be harmed if the associated severance liabilities carried over to subsequent test years and became embedded in rates.

AIPA argued that it was difficult to comprehend the ATCO position that total O&M labour costs could not be correlated with FTEs. AIPA suggested that the ATCO budgeting process was seriously lacking and the capital estimates were suspect.

AIPA stated that by not segmenting total labour costs between O&M and capital, the confusion into the future would be perpetuated and that the next GRA should require historical data on labour costs that were attributable to O&M requirements and the amount of labour costs that were capitalized to provide for meaningful evaluations.

### CCA

The CCA noted that ATCO indicated that FTEs were a management tool to determine space requirement, parking needs, equipment, benefits and other issues. The CCA agreed with this assessment and considered that FTEs would be a useful tool for the Board to provide a level of regulatory control of ATCO in future years. The CCA considered that ATCO should be directed to track FTEs for both operational and capital positions. Recording of FTEs should also include permanent, part time and contract positions. The CCA argued that the use of FTEs would allow interveners better understanding and give the Board greater control over a significant portion of the revenue requirement. This would be achieved by having a more reasonable understanding of the number of employees required to maintain the operations of ATCO.

### Views of the Board

The following table, based on information submitted in the Application, summarizes the labour expenses and percentage variances.

**Labour Expense ($000)**

| | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|
| Total Labour as filed | 26,153 | 25,916 | 27,521 | 28,457 |
| % increase since 1999 | | | 5.2 | 8.8 |
| % increase since 2000 | | | 6.2 | 9.8 |

Based on the results calculated in the chart set out in the above paragraph, the Board considers that the escalation in labour costs since 1999 has been held at a reasonable level, but when compared to 2000 the increases appear to be excessive. As indicated in the table above, the two-year increase from 1999 is 5.2%, whereas the one-year increase from 2000 is 6.2%. However, the Board is not persuaded that there is sufficient justification for a specific reduction in forecast expenditures, but rather has chosen to make an adjustment to O&M expenses on an overall basis, as provided for in the adjustment discussed previously in the Board's Views in Section 6.1.

The Board notes the significant level of discussion and concern expressed with respect to the interpretation of the FTE information presented in the Application. The Board acknowledges the comments of AIPA that the Company's approach to FTEs does not provide the information necessary for customers' evaluation purposes. However, the Board also agrees with ATCO that the use of FTE positions is primarily a measure of the size of the company, and primarily a useful management tool to determine space requirements, equipment, benefits and other operational needs. The Board also notes ATCO's submission that the tracking of FTE's includes all permanent positions, whether or not ultimately charged to O&M expense.

In the Board's view, a consistent definition and interpretation of FTE data would still help the Board and interveners evaluate comparative expenditure levels. The Board considers that, as a first step, such a common interpretation would be beneficial in annual financial filings required by the Board. Accordingly, the Board encourages ATCO to provide the Board with a proposal for a definition and interpretation of FTE for annual reporting purposes in ATCO's next GRA application.

### 6.1.2 Supplies

**Position of ATCO**

ATCO observed that the supply costs had increased at a much greater rate than labour costs and provided a comprehensive breakdown of supply costs in the Application, using an inflation rate of 3% in 2001 and 2002. ATCO noted that while the impacts of Affiliate matters were briefly addressed in the Application, the bulk of these costs will be assessed in the affiliate hearings, along with elements of pension expenses.

ATCO stated that 1999 supply expenses were adjusted upward by $212,000 to reflect the EUB Decision 2000-45 due to deferred hearing expense, the EUB assessment, the Reserve for Injuries and Damages, and Pension Expense.

#### 6.1.2.1 Bad Debt Expense

**Position of ATCO**

ATCO forecast that bad debt expenses are expected to increase in 2001 and moderate slightly in 2002. The unpredictability of bad debt expense led ATCO to not adjust bad debt write-offs, using historical levels from 1999 and 2000 instead for write-off's and recoveries.

ATCO submitted that the increased forecast in bad debt expense was solely attributable to the forecast increase in gas prices. ATCO argued that the forecast bad debt expense for 2001 and 2002 fell within the average percentage of 0.2% of total revenue, indicating the reasonability of the forecast. ATCO noted that the actual bad debt expense in the year 2000, which was understated by an estimated $300,000 due to a programming problem and resource constraints, had not been reflected in the forecast for 2001, and should be taken into consideration when reviewing what had happened to bad debt expense historically in comparison to the test years.

**Positions of the Interveners**

**CCA**

The CCA stated in reply that it was concerned that bad debt expense had been over forecast by AGS. The CCA considered that because of reduced natural gas prices and natural gas rebates, bad debts should be significantly reduced from prior years. Further, with unemployment in Alberta being at the lowest level in a number of years, the CCA submitted that the bad debt expense experience of the utility should be improved.

**Calgary**

Calgary opposed the view of ATCO that the forecast increase in bad debt expense was solely attributable to the forecast increase in gas prices. Calgary stated that gas prices were not at the level forecast by ATCO and the increase should be denied. Calgary argued that the Board should deny the cost adjustments proposed by ATCO due to its perception of high gas prices, as they were based upon one-time aberrations in the market place and should not be permanently imbedded into customer rates.

### MI

The MI noted it was ATCO's assertion that the increase in bad debts was attributed to an increase in customer bills due to higher gas prices,[59] and that the forecast of revenues and related bad debts was based on a considerably lower level of gas costs than customers actually experienced in 2001, and did not take into account either higher gas prices or the impact of the rebate program.[60]

The MI submitted that items outside the control of the Company, for example income tax rates, should be revised to reflect any changes, and although the federal and provincial changes to tax rates had not been enacted at the time of the application, there is an expectation that such changes would be flowed through to customers when they had been enacted. The MI did not see the natural gas rebates to residential and commercial customers being treated any differently and, as a matter of fact, the Company was required to flow the rebates through to end customers. The MI argued that the Company had forecast gas costs,[61] for purposes of bad debts, working capital, etc. prior to the announcement of the natural gas rebates and presumably this was part of the risk for which the Company was compensated.

The MI submitted that the gross bad debt expense should be reduced to reflect the rebates received from the government in 2001. The MI stated that based on sales of 96,315,000 GJ in 2001, rebates would have been approximately $385 million reducing forecast gross revenues to $415 million. The MI also stated that flowing these changes through Exhibit 82 resulted in a reduction of $917,000 to bad debt expense in 2001 and even if the increased gas costs were to be offset against the rebates, ATCO gross revenues, for purposes of bad debts, were still overstated by $275 million. The MI submitted that 2001 bad debts expense should be reduced to $832,000 to reflect natural gas rebates received by customers.

In response to ATCO, which indicated that the forecast bad debt expense for 2001 and 2002 was reasonable because it fell within the 0.2% of total revenues, the MI noted that the forecast revenues fail to reflect the approximately $385 million of rebates received by customers which were netted from the gross bill, and should therefore have been excluded from the calculation of bad debts.[62] The MI stated that the amount would be offset by increased gas costs of some $110 million. The MI submitted that 2001 bad debts expense should be adjusted, to reflect the net of natural gas rebates received by customers less higher natural gas costs.

### Views of the Board

The Board notes the reduction made by ATCO to its forecast of bad debts in the amounts of $311,000 and $337,000 for 2001 and 2002 respectively.[63]

The Board notes the submission of Calgary that ATCO's forecast increase in bad debt expense was based on a perception of high gas prices resulting from a one-time aberration in the marketplace. The Board agrees with this comment and does not consider it reasonable that

[59] Section 4.3, p.12
[60] Tr. p.1055
[61] CAL-ATCO.144
[62] MI Argument, p.39
[63] Exhibit 82

increases resulting from a likely one-time event should be embedded in rates on a going forward basis. In this regard, the Board considers that there is also considerable merit in the observation of the MI that, since the escalation in gas prices was offset by the impact of the Government's rebate program, the amount of the rebates should also be taken into account in determination of bad debt expenses.

The Board recognizes that, while the rebate program was not announced until 2001, it is appropriate to address the fact that the amount received should serve to mitigate the one-time impact of the high gas prices on which the bad debt forecasts were based. The Board is satisfied that the necessary reduction to bad debt expense is already allowed for in the overall reduction of $2 million (2001) and $2 million (2002) to the higher gas cost component of the test year forecasts, as discussed in Section 6.1 of the Decision.

#### 6.1.2.2 Carbon Fuel Costs

ATCO indicated that fuel is utilized in the operation and maintenance of compressors in the injection or withdrawal of natural gas from the Carbon storage reservoir. The higher carbon fuel costs reflect the higher cost of natural gas.

**Positions of the Interveners**

**PICA**

PICA noted with respect to Carbon Storage fuel costs that ATCO's estimate was based on a forecast of the forward market price of gas and an assumption that the full capacity of the storage facility would be cycled. PICA did not understand how ATCO could possibly make a realistic estimate of fuel use at Carbon when it had no say in how the storage reservoir would be utilized by ATCO Midstream. PICA argued that it continued to believe this cost should be recorded in a deferral account, since it clearly met the traditional test justifying a deferral account arising from a lack of control over the cost item.

**Views of the Board**

With respect to PICA's proposal for use of a deferral account for Carbon fuel costs, the Board is of the view that, despite the transfer of Carbon to Midstream, ATCO has sufficient historical operating experience to make a realistic estimate, at this time, of fuel use at Carbon. Accordingly, the Board rejects PICA's recommendation for use of a deferral account, and accepts ATCO's forecast of Carbon fuel costs for the test years, recognizing that any reduction necessary to account for the effect of high gas prices is already allowed for in the overall reduction of $2 million in each test year as discussed in Section 6.1 of this Decision

#### 6.1.2.3 Compressor Costs

**Position of ATCO**

ATCO pointed out that normal operating costs associated with compressors are the operation and maintenance of compressors for withdrawal or injection of natural gas from the carbon storage reservoir, along with the production of virgin gas. ATCO conducts routine inspections, parts replacements, lubrication, overhaul, and general maintenance of compressors to maintain industry and manufacturer standards for compressors.

ATCO stated that the two compressor overhauls at Carbon drove an increase over the 1999 and 2000 actuals for compressor maintenance. ATCO argued that the compressor at Well 6-32 was necessary to maintain company owned production from Well 6-32, while compressor #4 at the plant site was necessary to maintain company owned production from the South Carbon Field. ATCO suggested that should these units fail in service, the Company Owned Production (COP) would not be available to ATCO Gas South customers. ATCO noted that current accounting policy reflects compressor overhauls being expensed in the year they occur.

**Positions of the Interveners**

**CCA**

The CCA noted that ATCO argued that two compressors at Carbon should be overhauled and expensed in 2001. The CCA was concerned that with the application filed by ATCO to remove the Carbon storage facility from regulated service, customers might be funding expenses which were not related to the provision of utility service in the future. The CCA considered that it was appropriate that costs for COP be included in consumer rates, but not costs associated with future activities that might be deemed in the future to be non-utility. The CCA considered that the COP associated with the compressor overhauls should not be expensed but rather capitalized and assigned to the period where the benefits occur.

**Views of the Board**

The Board notes that the CCA expressed concern that the transfer of Carbon from regulation could result in utility customers funding expenses for items such as compressor overhaul, which will not be related to the provision of utility service in the future. While the Board accepts the forecasts of compressor fuel costs as adjusted, the Board agrees with the CCA that, if the transfer to ATCO Midstream is approved, the costs of compressor overhaul in the test years should be treated as costs to be recovered from ATCO Midstream.

#### 6.1.2.4 Corporate Communications

ATCO maintained that corporate communication costs have risen due to natural gas price increases, higher marketing costs from competition, renewed interest in energy conservation, electricity deregulation's impact on natural gas prices, promotion of a new billing system, and corporate promotions and community events. The need to harvest-customer loyalty in an increasingly competitive marketplace has also led to greater sponsorship, and subsequent signage costs.

**Views of the Board**

The Board notes that ATCO's rationale for the increase in corporate communications expense includes the impact of high gas prices. Since the Board has reflected an adjustment for the effect of high gas prices in the overall reduction of $2 million referenced previously in this Section, a reduction specific to this category of expense is unnecessary.

#### 6.1.2.5 Donations

**Position of ATCO**

ATCO stated that it is committed to help meet the social needs of the community through corporate donations. ATCO argued that these investments are a cost of doing business and should be included as a business expense in its utility revenue requirement, citing the 1995 NGTL Board Decision U96001,[64] dated January 4, 1996.

ATCO believed that corporate donations were an important cost of doing business, and should therefore be recovered from customers. ATCO considered that the cost of corporate donations was taken into consideration in the pricing of services by non-regulated companies, such as EPCOR and ENMAX, and if the intent of regulation was to imitate competition, then it was not appropriate to treat ATCO differently.

ATCO noted that several interveners suggested that charitable donations were generally made at the cost of shareholders, even in non-regulated companies. ATCO believed it was far more likely that the cost of corporate donations were factored into the pricing of services in competitive companies. ATCO submitted that charitable donations had been explicitly factored into the pricing of NGTL services for a number of years, with the full support of the Board. The basis upon which ATCO had applied for inclusion of these costs in its revenue requirement was exactly the same as the basis upon which the Board approved for NGTL, which had been in effect for a number of years.

**Positions of the Interveners**

**CCA**

The CCA stated that it does not support the inclusion of charitable donations in the revenue requirement. The CCA argued that by including donations in the revenue requirement the AEUB was forcing customers to make charitable contributions.

With respect to the comparison of ENMAX and EPCOR by ATCO, the CCA argued that any charitable donation made by those companies directly reduced earnings available to the shareholder.

The CCA also noted that there were significant differences between NGTL and ATCO. The CCA observed that approximately 83% of the volume of natural gas shipped on NGTL is exported out of Alberta, and therefore Alberta receives a net benefit.

The CCA considered that donations should continue to be excluded from the revenue requirement for regulatory purposes, and submitted that ATCO shareholders through its elected board of directors had the choice over which charity to support and how much to give. The CCA argued that customers, particularity low income residential, should not be forced to make contributions indirectly through their utility rates.

[64] Decision U96001 NOVA Gas Transmission Ltd. 1995 GRA – Phase I

### Calgary

Calgary stated that ATCO's request for donations was an example of the Company seeking a cost plus return after tax. Calgary considered that the cost of corporate donations was appropriately borne by the shareholders who receive the benefits. Calgary submitted that the Board should not depart from its long-standing practice of not allowing the inclusion of donations in the revenue requirement.

### FGA

The FGA did not recommend that ATCO, the ATCO Group or its employees should cease making charitable donations. The FGA commended ATCO and its employees for its public responsibility by jointly funding a program of charitable donations. However, the FGA noted that donations should be voluntary, and made to the organization of choice and not involuntarily by consumers through their gas bill.

The FGA noted that the Board had treated donations as a non-utility expense in Decision 2000-9, and submitted that the treatment was proper then and for the future. The FGA noted that shippers that were party to the proceeding that led to Decision U96001 did not object to NGTL continuing to include charitable donations in their rates whereas the majority of the customers of ATCO did object.

The FGA noted that some interveners had observed that that a customer loses the tax advantage associated with a charitable deduction when the utility included the donation as part of revenue requirement.[65] The FGA also noted that not only did the customer lose the tax deduction, but was further taxed on that portion of revenue requirement going to corporate donations via GST and municipal franchise taxes, where the latter were assessed on revenues. The FGA argued that not only would the customer lose the tax advantage, should the Board accept ATCO's proposal, but the customer would be further taxed and penalized. The FGA believed it appeared to be a most inefficient way for a customer to support community projects, and stated that this bad idea looked even worse when all costs were taken into account.

The FGA submitted that ATCO's proposal to include charitable donations in revenue requirement should be denied, but that the current program for employee initiatives on charitable donations should be continued as is.

### MI

The MI argued that charitable donations ought not be included in ATCO's revenue requirement for the following reasons:

- It was not really "the Company supporting the programs in the community" since it would be funded by customers.

- No rational explanation could be given by AGS as to why there should be a different treatment from electric utilities.[66] The MI stated that AGS seemed to rely on NGTL's

[65] MI argument, p.40
[66] Tr. p.1200

treatment of charitable donations, recognizing that ATCO Pipelines South has not included any such donations in its revenue requirement.[67]

- The Board in U97065 considered “that neither charitable donations nor political donations should be included in revenue requirement.”[68]

- Since it was being funded with customer money through the revenue requirement, many customers were precluded from any tax benefits associated with write-offs for charitable donations. The MI stated that for many customers, rates are paid with after tax dollars through their disposable income and that the customer not only had no say in what charity the money should be used for, but would not get the tax saving.

The MI submitted that the historical treatment for charitable donations should not change and should continue to be treated as “non-utility.” Therefore, the MI stated, the donations should be removed from the revenue requirement.

In response to ATCO’s suggestion that corporate donations were a cost of doing business and since non-regulated companies such as ENMAX and EPCOR make such donations, the MI stated that if the shareholders of ATCO Gas and Pipelines Ltd. want to pay for the corporate donations (be they charitable or political) the shareholders could certainly do so, but ought not to pay them out of what was disposable income to many of ATCO’s customers.

**PICA**

PICA agreed that it was appropriate for ATCO to make charitable contributions within the communities where it operates, and it was a generally accepted business practice for corporations, whether regulated or operating in the private domain. However, PICA considered that it was also generally recognized such donations come from the profits of the corporation, which, in the case of a regulated enterprise, would imply the return.

PICA stated that its position remains unchanged, i.e. that charitable donations should not be included in a utility’s revenue requirement. PICA submitted it was entirely inappropriate and unreasonable to require customers to pay, as part of their utility bill, an amount in relation to charitable contributions. PICA argued that ATCO would be receiving corporate recognition for charitable giving, even though it would have been fully funded on a non-discretionary basis by their customers, and the customers would receive no direct benefit.

PICA stated that it would not support ATCO’s proposal, but should the Board agree to the proposal, PICA recommended that as a condition of including charitable contributions in the revenue requirement, ATCO be required to match, as a minimum, any such contributions from its shareholder account on an annual basis.

PICA clarified its position that while it is appropriate to explore possible alternative treatments where reasonable, in this instance there was no basis to support the change requested by ATCO.

[67] Tr. p.1200
[68] Decision U97065, p.520

Specifically, PICA recommended that charitable donations continue to be excluded from the revenue requirement, leaving the responsibility for such contributions to the ATCO shareholders.

**Views of the Board**

The Board notes that ATCO's proposal to include donations as a business expense in utility revenue requirement was the subject of considerable discussion in the hearing and in argument, and was ultimately opposed by all interveners. The Board agrees with intervener concerns with respect to the Company's proposal, noting that ATCO has provided no rational explanation as to why the Board should approve a different treatment from that allowed for Electric Utilities. In this regard, the MI refers to Decision U97065 where the Board disallowed the inclusion of charitable or political donations in revenue requirement for Electric Utilities. The Board also agrees with intervener observations that NGTL has a completely different customer profile than ATCO.

Accordingly, the Board does not accept ATCO's proposal for inclusion of donations in the determination of revenue requirement for the test years, and directs the company to reduce revenue requirement by the amount of donations forecast for the test years.

#### 6.1.2.6 Fleet Expense

**Position of ATCO**

Fleet expenses involve the maintenance and operation (parts, fuel, tires, labour, etc.) of all vehicles allocated to the Company under the corporate restructuring. ATCO forecast that fuel costs would constitute over 35% of the total fleet costs.

ATCO stated that the 2001 and 2002 forecasts of fleet expense were based on normal projected levels of activity, and did not reflect the impact of increased fuel costs. ATCO argued that the 19% increase in fleet expenses from 2000 actual to 2001 forecast was as a result of abnormally low expenses in 2000, due to less O&M work being required on the distribution system. With regard to items such as leak repairs, meter recalls and hit lines ATCO submitted that the low expenditure in 2000 was an anomaly.

**Views of the Board**

While acknowledging ATCO's submission that the 19% increase in the 2001 test year forecast for fleet expense compared to 2000 was due to the abnormally low level of expenses in the year 2000, the Board is not persuaded that the increase in fuel costs in 2001 would lead to an increase of the magnitude requested. The Board is satisfied, however, that the resulting reduction to fleet expense is already allowed for in the overall reduction in O&M for each test year, as discussed in Section 6.1 of this Decision.

#### 6.1.2.7 Deferred Hearing Cost

ATCO stated that there was an under-recovery in its deferred hearing account of $2.3 million at the end of 2000, resulting from the actual regulatory costs since 1999 overrunning approved hearing expenses from Board Decision 2000-45. In 2001, ATCO predicted an additional $1.9 million in hearing costs arising from the following proceedings: Affiliate application, Pension application, 2001/2002 ATCO General Rate Application-Phase 1, Gas Cost Recovery Rate, Deferred Gas Unbundling process, and negotiations involved in the above proceedings.

In addition, ATCO forecasts $392,000 of regulatory costs from the 1999 CWNG filing, and $126,000 resulting from the corporate restructuring of CWNG and NUL. Based on Decision 2000-45, which approved a hearing expense for ATCO of $524,000, the Company would face an under-recovery of $4.7 million. ATCO is requesting a one-time recovery charge of $4.5 million. The 2002 hearing expense is forecast to be $1 million to recover the costs of the Phase 2 filing of the 2001/2002 GRA and the Gas Cost Recovery Rate proceeding. Based on Decision 2000-9, ATCO will no longer use a deferral account for hearing expenses.

ATCO noted that the CCA's proposal to base the level of hearing expense on an average of prior year actuals did not take into consideration the level of regulatory activity that the gas utilities have undergone, nor the fact that the historical level of approved hearing expense had not been sufficient to keep the deferred hearing cost account at a reasonable level. ATCO submitted that although it was compensated for the hearing cost balance through working capital, if the payments each year continued to exceed the expense, the receivable balance would continue to grow. Once the Company was outside of the forecast period, the cost of financing the growth was at shareholders' expense.

ATCO argued that the one time adjustment to hearing expense as forecast by the Company in 2001 would address this situation, and bring the hearing account balance to a more reasonable level. Given the significant reductions enjoyed by customers as a result of the 1998 GRA, ATCO believed it was appropriate that the costs be recovered from customers of the day, not spread out to be collected from customers of the future.

Regarding the FGA assertions with respect to the allocation of hearing costs between AGS and APS, ATCO noted that the 2001 revenue requirement calculation made by FGA was incorrect, resulting in too high a suggested allocation to AGS.

**Positions of the Interveners**

**CCA**

The CCA considered that it was appropriate to set up separate deferred cost hearing accounts for both AGS and APS. The CCA also considered it appropriate that hearings costs be allocated on the basis of 1999 opening net plant balances.

The CCA stated that it was concerned with the amount that ATCO was forecasting for payment in 2001. The CCA considered that it was unlikely that the hearings heard in the summer and fall of 2001 would actually be paid by ATCO in 2001 because the Board would generally wait for the substantive decision to be issued before processing cost claims and the cost payment is not issued concurrent with the Board cost order. The CCA noted that there is a significant increase in the level of regulatory activity associated with ATCO, but believed that the deferred cost amounts must be more even to ensure reasonable rate stability. The CCA recommended that ATCO hearing cost expense amount be increased to the average of the last ten years of actual payments but not to the level proposed by the Company.

### FGA

The FGA agreed with ATCO that it would be fair to allocate the cost of the reorganization hearing as between AGS and APS on the basis of assets, since the purpose was to segregate and reallocate the assets and staff belonging to the transmission and distribution sides of the utility business. The FGA did not propose a change to the allocation of reorganization hearing costs.

The FGA did not agree that every hearing subsequent to the reorganization hearing should be allocated on the basis of assets. The FGA submitted that in a Phase 1 hearing, the issue was revenue requirement where all customers benefit only to the extent of the revenue requirement that was allocated to their rates. The FGA argued that the Board should allocate hearing costs on the same principles it uses in a Phase 2 hearing. The FGA submitted that the costs of the 1997/1998 CWNG Phase 1 hearing should be allocated between AGS and APS on the basis of the filed revenue requirement of the two entities. The FGA argued that the aborted 1999 GRA was directed towards Phase 1 issues and therefore should be treated as a Phase 1, and the approved costs should be allocated on the same basis as the 1997/1998 Phase 1 proceeding.

The FGA submitted that, for a Phase 2 hearing, every intervener pursues the issues which affect the rate class that the intervener represents and therefore the costs should be shared in proportion to the intervener’s participation To illustrate its point the FGA submitted a table to demonstrate its proposal to allocate the CWNG 1998 Phase 2 costs approved by Cost Order 2000-42. The table showed that ATCO customers would be allocated 82.68% and APS customers 17.32%.

The FGA submitted that hearing costs between AGS and APS should be revised on a hearing by hearing basis.

The FGA noted that other customers of ATCO had not taken issue with the FGA’s initiative to examine hearing cost allocation. The FGA believed that customers of ATCO should be relatively neutral as to where these costs lie, as ATCO Pipelines’ costs ultimately flowed through to ATCO via ATCO Pipelines’ transmission rates. The FGA considered that it would be an issue to the customers of ATCO Pipelines if their service provider was assigned more costs than was fair and reasonable for that company.

The FGA argued that the only fair allocation of hearing costs was that proposed by the Federation and Gas Alberta.

### Views of the Board

The Board notes that the forecast for hearing costs in each test year represents one of the main factors contributing to the increase in expenditures from non-affiliate or pension sources. The Board agrees with ATCO that the level of regulatory activity in recent years should preclude the use of prior year actual expenditures as a forecasting base as suggested by the CCA. The Board also agrees with ATCO that a one time adjustment to hearing expense is appropriate and recognizes that customers who have shared in the benefits of rate refunds arising from the Company’s recent heavy regulatory schedule, should bear the related costs, rather than having those costs spread out for collection by future customers.

However, the Board is of the view that for the test years, the historical level of $524,000 is, on a forecast basis, more appropriate and should be maintained. Accordingly, the Board directs ATCO to reduce the 2001 and 2002 forecast by $3.976 million, and $476,000, respectively.

The Board also accepts ATCO's proposal for a one-time recovery of these costs. The Board directs ATCO to collect $4.452 million in regulatory costs for the 2001 and 2002 test years by means of a rate rider. The Board expects that the balance of hearing cost expense will be reconciled through the deferred account.

With respect to the FGA proposal for allocation of Phase I hearing costs between AGS and APS, the Board agrees with ATCO that this proposal ignores the fact that all customer groups contributed to the setting of the CWNG revenue requirement from which the rates were determined.

#### 6.1.2.8 Pension Expense

ATCO Gas South is part of a pension application proceeding filed by NUL, AGPL and ATCO Electric on November 15, 2000, regarding appropriate treatment of pension and post employment benefit expenses in the utility requirement. The application is still under review with the EUB at the time of this filing.

**Views of the Board**

The Board acknowledges ATCO's forecasts of pension expense, recognizing that all pension related matters will be considered in the context of the Pension proceeding filed by NUL, AGPL and AE. Accordingly, the Board will not make a determination with respect to the quantum or propriety of pension expense in this Decision, recognizing that the amounts included in the test year forecasts are subject to revision pending the outcome of the Pension proceeding.

#### 6.1.2.9 Reserve for Injuries and Damages

**Position of ATCO**

Based on Board Decision 2000-9, ATCO is required to maintain a reserve balance of $300,000 for injuries and damages. ATCO indicated that the Company disagrees with this decision, as in its view, it fails to reflect the magnitude of potential payments. ATCO requested the Board revisit Decision 2000-9 and adjust the expense level for the injuries and damages reserve to $175,000. In its Application, ATCO provided an in depth break down of expenses related to Reserve for Injuries and Damages.

**Views of the Board**

Based on an evaluation of the information provided in Section 4.3 of the Application, the Board considers that ATCO's request for an adjustment to the expense level for the injuries and damages reserve to $175,000 is reasonable. Accordingly, the Board accepts ATCO's proposal to revise the balance in the Reserve for Injuries and Damages.

However, to provide the Board with sufficient information to evaluate the ongoing appropriateness of the reserve balance, the Board directs ATCO, at the next GRA, to provide a more detailed accounting of the Reserve for Injuries and Damages. This should include details of amounts required for major and minor damages, claims history, and the extent to which the reduction in reserve is offset by increases in insurance premiums.

### 6.1.2.10 Transmission Charge

**Position of ATCO**

ATCO Pipelines South provides transmission delivery service to ATCO Gas South through an affiliate agreement. ATCO forecast the transmission charge rate at $1.85 per GJ passing this charge on a flow through basis, while awaiting the ATCO Pipelines South 2001/2002 GRA decision.

ATCO noted that the transmission rate for the Company approved by the Board in the ATCO Pipelines (South) proceeding would be flowed through to ATCO.

**Positions of the Interveners**

**Calgary**

Calgary submitted that before the Board accepts any service agreement between affiliates for transmission service, let alone a 10-year exclusive agreement, ATCO should be compelled to demonstrate that competitive services cannot be obtained from third parties for all or part of this service. Calgary believed that ATCO, in order to meet its fiduciary obligations to its ratepayers, must consider and seek the possibility of alternatives in the competitive market in order to assure the Board and its ratepayers that it had achieved the best deal the marketplace had to offer.

It was Calgary's understanding that a utility could not provide service without an appropriate Board approved tariff. It was also Calgary's understanding that this condition applied to affiliate, as well as non-affiliated service provisions. Calgary noted that APS has been providing transmission service to ATCO since January 1, 1999 under a "rate" which was developed internally. Calgary submitted that the rate had never been filed with the Board, there was no associated Board approved tariff, and there was no explanation of the genesis of the charge. Calgary urged the Board to consider the relationship between the affiliates, APS and AGS as well as with their non-regulated affiliates before approving any cost for transmission service so as to assure ratepayers of ATCO that the affiliate transactions met the just and reasonable standard.

**Views of the Board**

In Decision 2001-97, issued concurrently with this Decision, the Board directed APS to re-file its 2001-2002 GRA including its COS Studies for the test years. The Board directed APS to determine the rates for transmission service to AGS for the test years based on the results of the refiled COS Studies. Recognizing the lead time required by ATCO to reflect the changes to the revenue requirement after receipt of the rates for transmission service resulting from the ATCO Pipelines South refiling, the Board expects ATCO Gas South to continue to use the transmission charge as filed in the Application on an interim basis. The Board also expects that the rates resulting from the refiled COS will also continue to be applied on an interim basis, pending final determination of the revenue requirements, once the effects of the ATCO Affiliates and ATCO pension proceedings have been incorporated.

#### 6.1.2.11 Other Specific Supplies Items

***Fringe Benefits***

ATCO maintained that fringe benefits for its employees have lagged behind industry average. As a result, the rise in costs is a reflection of upgrading the past system, and implementation of a new flex benefits program.

***Head Office Rents***

AGS allocates its head office space between North and South on a shared service basis. The 2001 increase is a result of increased head office requirements in Edmonton. This is more than offset by revenue generated from leased space to ATCO Frontec in the Calgary Office. ATCO's head office space is forecast to decline to $16 per square foot in October of 2002.

**Views of the Board**

The Board notes that none of the interveners took issue with the increases forecast for Fringe Benefits expense, or Head Office Rents, and accepts the forecasts for these items as filed.

#### 6.1.2.12 Affiliate Supplies Items

***ATCO I-Tek***

ATCO indicated that costs associated with ATCO I-Tek will be addressed in the affiliate proceeding. Essentially, I-Tek houses the computer hardware system previously owned by ATCO Gas providing the computer functions necessary to run ATCO Gas CIS and ATCO Singlepoint call centre and billing system.

In the Application, ATCO pointed out that computer-aided dispatch (CAD) is the system and hardware that dispatches servicemen throughout the province, and will incur an increase in costs for processing of $371,000 in 2001 to interface with the new ATCO-CIS. Smaller projects will increase costs by $145,000 in 2001, while the termination of the ATCO Pipelines Corporate Services and Financial Services Service Level Agreement result in computer related expense forecasted to decline by $122,000 in 2001, and by $155,000 in 2002.

***ATCO Singlepoint***

ATCO indicated that ATCO Singlepoint is an affiliate company that manages the billing system and call centre for AGS. The charges from Singlepoint to AGS are driven by processing time, volume of customer bills, billing inquiries, volumes of customer payments, credit calls, and computer maintenance costs. Singlepoint costs rose in 2001 largely from customer inquiries regarding the new billing system, higher gas prices and costs, and increased volumes of credit and collection accounts.

Costs associated with ATCO Singlepoint will be addressed in the affiliate proceeding, and will be incorporated into the findings of this application.

**Views of the Board**

With respect to expenditures resulting from payments for services provided by ATCO-I-Tek and ATCO Singlepoint, the Board recognizes that these expenditures will be considered in the context of the Affiliate proceeding. Accordingly, for the purposes of this Decision, the Board accepts the forecast expenditures for payments to ATCO I-Tek and ATCO Singlepoint as filed, recognizing the potential for subsequent adjustment after issue of a Board decision on the ATCO Affiliate proceeding.

#### 6.1.2.13 Affiliate Agreements

ATCO provided details on services provided to affiliates and from affiliates in its Application.

**Views of the Board**

The Board recognizes that all affiliate related matters will be considered in the context of the Affiliate proceeding. Accordingly, the Board will not make a determination with respect to the quantum or propriety of affiliate expenditures in this Decision, recognizing that the amounts included in the test year forecasts are subject to revision after issue of a Board decision on the ATCO Affiliate proceeding

The following table summarizes the adjustments made to calculate the total O&M expenses approved by the Board.

**O&M Expenses ($000)**

| | 2001 | 2002 |
|---|---|---|
| Total O&M Expenses as filed | 113,983 | 110,666 |
| less Bad Debt adjustment per ATCO | 311 | 337 |
| less Donations (Board adjustment) | 217 | 217 |
| less one time Hearing costs (Board adjustment)* | 3,976 | 476 |
| less adjustment for gas prices (Board adjustment) | 2,000 | 2,000 |
| less adjustment for inflation and efficiency (Board adjustment) | 2,429 | 1,955 |
| Total O&M Expenses after Board Adjustments | 105,050 | 105,681 |

* The Hearing Costs (currently forecast at $4,452,000) are to be collected in a one-time rate rider.

### 6.2 Taxes Other Than Income Taxes

Property taxes forecasted in the application by ATCO are consistent with historical norms. In 1999, ATCO was forced to pay $59,000 in late penalties on property taxes. Additionally, municipal franchise fees are forecast at $69,210,000 in 2001 and $60,423,000 in 2002, recovered through Rider A.

**Views of the Board**

The Board notes that none of the interveners took issue with the forecasts for taxes other than income taxes, and accepts the forecasts for this item as filed.

## 6.3 Depreciation

ATCO forecast depreciation and amortization expense at $27,964,000 for 2001 and $29,661,000 for 2002 in its filed evidence as revised on May 28, 2001.[69]

Overall, the Company submitted that the composite depreciation rate would decrease from the present composite rate of 3.890% to 3.664% in 2001 and from 3.796% to 3.772% in 2002

ATCO indicated that fixed assets are depreciated or amortized using one of the following four methods:

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

During 1999, ATCO conducted a new depreciation study using data to the end of 1998. All study accounts were analyzed using the straight-line method and equal life procedure, as approved by the Board.

New rates and annual reserve amortization amounts were calculated based on plant balances as of December 1999, taking into account the restructuring of ATCO Gas and ACTO Pipelines, the sale of assets that occurred in 1999, and the impact of Decision 2000-9.

In summary, the recommendations of the latest study would result in a reduction in net annual depreciation expense for 2001 of $1,475 000 as compared to the depreciation expense for 2001 using the existing rates.

ATCO requested approval of the following changes and adjustments to its depreciation methodology:

a) ATCO historically used the unit of production method to depreciate the production and gathering assets and certain storage field assets. ATCO proposed that the storage asset accounts should be separated from the production and gathering assets and be depreciated using alternate methods, rather than continuing to use the unit of production method. The Company submitted that the functionality of Carbon Storage has expanded to include non-utility functions and, as a result, the rate of withdrawal from the production gas fields to meet utility customer demand is no longer an appropriate standard to use in future for depreciating the storage investment. ATCO proposed to discontinue the practice of depreciating five storage asset accounts using the UOP method and change the methods and rates as follows:

   447 Gas Leaseholds - Fixed amortization rate of 1.0%.
   448 Gas Rights – Fixed amortization rate of 2.5%.
   451 Land Rights – Study asset depreciation rate of 1.36%.
   453 Wells – Study asset depreciation rate of 2.29%.
   454 Well Equipment – Study asset depreciation rate of 3.98%.

[69] Volume 2 Tab 9 Rev May 28, 2001

Furthermore, ATCO proposed to discontinue the 1½ % fixed component of UOP depreciation used for production and gathering assets, and discontinue the practice of including storage base gas reserves in the UOP calculation.

As a result of the proposed changes listed above, each group of assets (production and storage) would be depreciated independently.

The forecast future net salvage for Production and Gathering assets would remain as approved in Decision 2000-9.

b) Contract life depreciation applies to assets whose service life is related to a contract with a specified term. For ATCO this only applies to leasehold improvements.

c) In conjunction with the agreement with ATCO I-Tek regarding the contracting of information system services, Canadian Western Natural Gas sold its general-purpose computer equipment to ATCO I-Tek effective January 1, 1999. ATCO's share of proceeds was $2,041,000.

   After all retirements and proceeds from the sale had been applied to the accumulated depreciation reserve as of January 1, 1999, there was a resulting terminal reserve deficit of $6,537,000. ATCO commenced amortizing this terminal reserve deficit in 1999 over a five-year period, the minimum period for amortizing depreciation reserve variances, as approved in Board Decision 2000-9. The annual amortization expense is proposed at $1,307,000.

d) ATCO costs relating to the restructuring of Canadian Western and Northwestern were accumulated in a deferred asset account, with a proposed amortization period of four years commencing in 1999. Charges to the deferred account were allocated equally between ATCO Gas South and ATCO Gas North for costs directly associated with the restructuring, offset by pension gains in 1998 and 1999 and the associated tax benefits. ATCO submitted that since the reduction in operating costs resulting from restructuring was estimated to be $16 million in 2001 compared to 1998, it was appropriate to defer the costs of restructuring to future years and amortize the amount over the next four years to better balance the costs with the future benefit.

e) ATCO also requested changes to the depreciation rates for many accounts based on the analysis of the Company's historical database, review of procedures, site visits, and discussion with company professional staff. For a few new and/or smaller accounts where there was limited retirement history, the Company requested advice from Mr. Earl Robinson of AUS Consultants, or developed retirement projections by referring to industry statistics.

ATCO defended its recommendation for the change in methodology to depreciate the Carbon Storage assets and claimed that a geological report supporting the current balances of the production and storage reservoirs was not necessary, since ATCO and CWNG were very familiar with the performance of the reservoirs based upon their operational experience for over four decades. ATCO observed that Calgary did not file any reports supporting its position and only referenced a Sproule report related to the Methodology hearing, which confirmed ATCO's position that drainage is not occurring from the storage reservoir. Furthermore, ATCO reiterated that its proposed change to the calculation of depreciation expense related to Carbon storage assets was simply to remove all storage assets (well site facilities and cushion gas reservoir) from the UOP calculation, so the storage assets can be depreciated based on the expected service life of the storage operation.

ATCO rejected Calgary's proposal to use the equal life group (ELG) method with truncation to calculate depreciation expense for the small individual production and gathering accounts, and stated that the proposal by Calgary would ignore both variations in annual gas withdrawals and future viability or economic life of the production gas reservoirs. ATCO recommended the Board approve the continued use of the UOP method, since it would track various production scenarios and was self-correcting.

**Positions of the Interveners**

### Calgary

Calgary submitted evidence through its expert witness, Mr. L. E. Kennedy on certain aspects of the depreciation expense requested by ATCO Gas.

Calgary confirmed that the change to the ELG procedure would be appropriate for the Carbon Storage Assets; however, Calgary did not agree with the methods used by ATCO to implement the change. Calgary argued that ATCO did not provide evidence to indicate that the levels of gas reserves used in the UOP calculation were appropriate. Mr. Kennedy stated that ATCO production assets do not demonstrate the characteristics of assets where the UOP method is appropriate. Furthermore, in Decision 2000-9, the Board accepted ATCO's proposal to group the cushion gas and production gas for the purposes of UOP calculations for depreciation applicable to production assets and certain storage assets. Calgary considered that, since ATCO has not provided a study that identified its reserves of storage cushion gas separate from production gas, the change in method of calculating depreciation as requested by ATCO should not be allowed. In the absence of reservoir and production information justifying the UOP method for production assets, Mr. Kennedy recommended that gas production assets be depreciated using the ELG procedure.

Calgary submitted that there were no benefits resulting from the restructuring of CWNG and that to the contrary, costs for regulatory proceedings were increased from what they would otherwise have been before the restructuring. Therefore, the overall costs for operations had increased. Calgary opposed the inclusion of any restructuring costs in the revenue requirement based primarily upon the inappropriateness of using pension gain to reduce the restructuring costs, the lack of benefit to the customers and non-compliance with Decision U99102. Calgary therefore opposed the amortization of restructuring costs.

### MI

The MI argued that it was inappropriate for ATCO Gas to request that customers be responsible for a portion of restructuring costs in 2001 and 2002 that were incurred in 1999 and 2000 when ATCO Gas incurred the costs. The MI submitted that it was premature to include any amount for restructuring costs in 2001 and 2002 revenue requirements before benefits to customers have been demonstrated.

**AIPA**

AIPA submitted that restructuring costs should remain in a deferral account to be considered at the time of a future application for the sale of the retail business, and at that time, the costs would be analyzed and allocated appropriately to the parties that benefit from the restructuring.

**Views of the Board**

The Board acknowledges ATCO's submission that Carbon storage has expanded to include non-utility functions, with the result that the rate of withdrawal from the production gas fields to meet utility customer demand may no longer be an appropriate standard for use in depreciating the storage investment. The Board also notes that, while Calgary agrees that the change to the use of the ELG procedure rather than the UOP procedure for Carbon storage assets is appropriate, Calgary expressed concern that there were significant shortcomings in the methodology adopted by ATCO to implement the change. Specifically, Calgary pointed out that the Company had not provided a study that differentiated volumes of storage cushion gas versus production gas, resulting in the potential for errors in the determination of new rates. Calgary also expressed concern that without such a study, it is difficult to determine the appropriate base for use of the UOP method.

The Board however also notes ATCO's submission that a geological report was unnecessary, given the Company's long historical operational experience with the performance of the reservoirs. In this case, the Board considers that the magnitude of errors that may be inherent in depreciation expense using the revised approach is unlikely to be significant, and can be corrected by a more extensive study prepared and filed at the next GRA.

Accordingly, the Board accepts the method adopted by ATCO for depreciation of production and storage assets, but directs ATCO to perform a detailed study for filing at the next GRA, to separately identify storage cushion gas volumes and other production volumes to support the ELG and UOP rates used in the depreciation calculation.

The Board notes Calgary's concerns with respect to the calculation of the loss on sale of computer equipment to I-Tek. However, the Board believes that the issue with respect to the accounting for the loss on sale of computer equipment to I-Tek is being considered in the Affiliate proceeding. Accordingly, while the Board is satisfied with ATCO's amortization of the loss on sale of the computer equipment to I-Tek, the Board will not address the quantum of the amount amortized pending the outcome of the Affiliate proceeding.

### 6.3.1 Amortization of Deferred Restructuring Costs

Restructuring costs for CWNG and NUL were $16.76 million and were offset by a $14.0 million pension gain leaving a net $2.76 million recorded in a deferred account. On the basis of each division's equity percentages, the net amount was split between ATCO Gas and ATCO Pipelines. ATCO Gas was deemed responsible for $1.866 of which $.933 million (50%) was assigned to the ATCO Gas South. ATCO proposed to amortize this amount over four years, 1999–2002 in the amounts of $297,000 for 2001 and 2002 to complete the amortization.

**Views of the Board**

The Board considers that ATCO's proposal for amortization of restructuring costs is reasonable, and therefore accepts ATCO's calculation of amortization of the restructuring cost balance.

## 6.4 Income Tax

**Position of ATCO**

In the Application ATCO forecast utility income tax expense of $12.85 million (2001) and $19.81 million (2002), indicating that the forecast is based on flow through taxes both federally and provincially. However, deferred taxes have been determined for the following items: Gas Cost Over/Under-recoveries, Deferred Pension, Supplemental Pension and Post Employment Benefits, Deferred Rate Hearing Costs, Reserve for Injuries and Damages and Deferred Restructuring Costs.

ATCO indicated that the Board has approved this treatment for all of these items, with the exception of Deferred Restructuring Costs and Post Employment Benefits. ATCO's treatment of Restructuring costs is designed to provide better matching of the related tax reduction, and the years that those costs are being amortized. In the case of Post Employment Benefits, the deferral is proposed on the basis that the expense is similar in nature to Deferred Pension expense.

ATCO indicated that, after receipt of Decision 2000-9, CWNG reduced the income tax over-provision to $2.0 million from $2.3 million. The reduction is reflected in the test year forecast. ATCO also indicated that the forecast increase in income tax expense for 2002 is partially attributable to the loss of the tax write-off associated with the ATCO CIS system. ATCO noted that, as software is written off over a very short time frame for tax purposes, the tax pools associated with the cost of the CIS system will be basically depleted by 2002, resulting in an increase in income tax expense.

ATCO indicated that the tax rates used to determine the forecasts are the current legislated rates, noting that potential rate reductions, although announced, have not been enacted at the time of filing the Application. However, during the hearing ATCO indicated that, both the Federal income tax rate reductions to the year 2004 and the Provincial rate reduction for 2001 have now been passed into legislation. ATCO noted that the Federal tax rate reduction is subject to the level of resource allowance that will be recognized by AGPL. Specifically, the higher the resource allowance reduction, the lower the impact of the reduction in Federal income tax rates. Noting that the proposed Provincial rate reduction for 2002 has not been passed into legislation, ATCO submitted that, given the uncertainty, the Board should not require ATCO to modify its revenue requirement for 2001 and 2002. In this regard, ATCO referred specifically to the Federal rate reduction, and the potential 2002 Provincial rate reduction. As neither has not been passed into law, ATCO submitted that the Company should not be placed at risk with respect to such reductions, the impacts of which are uncertain.

In the response to BR-ATCO Gas.46 (b), ATCO identified the tax deductions for "indirect overhead costs" associated with the Canderel Ltd. (*Canderel)* decision, which do result in savings to customers in the forecast period. ATCO noted that the impact of the related Rainbow Pipe Line Company Ltd. (*Rainbow Pipelines)* decision was addressed in an information response.

ATCO indicated that AGPL has deferred the income tax deduction associated with the restructuring costs since 1998, so that there is a proper matching of the amortization of these costs and the income tax deduction. ATCO advised that the deferred income tax will be written off at the same time as the restructuring costs, and therefore will be gone by the end of 2002, underlining the short-term nature of the tax. ATCO pointed out that the purposes of deferring the income taxes referred to in the Application is that they are short term in nature, and have the ability to change dramatically year over year. ATCO noted that, while it is possible to forecast the level of hearing expense to be recognized in a year, the actual level of hearing costs is unpredictable. ATCO submitted therefore, that inclusion of these costs as no-cost capital, as suggested by Calgary, would result in year over year fluctuations in the capital structure, and could result in negative no-cost capital.

ATCO indicated that, nowhere in this proceeding has the Company suggested that the reduction in income tax rates be viewed as an efficiency gain. ATCO's concern with respect to the reduction in rates is that the Federal rate reduction is subject to the level of resource allowance claimed in any given year, and the 2002 Provincial rate reduction is not passed into law at this time. ATCO noted the concern of Calgary that these reductions not accrue to the benefit of the Company, and pointed out that the Company has a similar concern that the shareholders not be placed at risk for reductions that may not occur.

**Positions of Interveners**

### TR7

The TR7 stated that, as far as Natives are concerned, a service given on an Indian Reserve is not taxable. The TR7 considered that, if consumers living on Indian Reserves were treated as a distinct and unique component of the ATCO system it may be doubtful that income tax component of Revenue Requirement would be applicable. The TR7 suggested that this question might be dealt with in determining rates.

### Calgary

Calgary referred to the issue, discussed in its evidence, of tax deductions available as a result of the *Rainbow Pipelines* decision, which relied on the *Canderel* decision. Calgary noted that ATCO indicated that with respect to AGPL, the change in assessing practice arising out of these decisions resulted in tax savings of $1.9 million in 1998 and $2.1 million in 1999. Calgary pointed out that these saving obviously went to the shareholders in those non-test years, and referred to the fact that other utilities (e.g. Enbridge Consumers Gas and AltaGas) have specifically documented how the savings arising out of these decisions have been passed on to customers. Calgary remained concerned with ATCO's failure to provide specific documentation of how these decisions have benefited customers in the test years.

In addition, Calgary addressed the concern regarding whether or not customers had received the benefits of certain tax deductions associated with restructuring and other costs deducted in prior years for income tax purposes. Specifically, Calgary noted that ATCO had deducted the expense for restructuring and rate hearing costs in a prior year, and recorded deferred taxes on the amounts. Calgary submitted that if the deferred taxes were recorded in 1999 and 2000, they would not fall into the category of deferred taxes referred to in Decision 2000-9. In Calgary's view, these deferred taxes relate to items that are able to be forecast, and should be reflected as zero cost capital by ATCO.

In Calgary's view, the ATCO treatment of tax rates borders on disdain for the interests of customers, particularly in light of the changes in tax rates proposed by both the Alberta and Federal Governments. ATCO considered that, given the sizable majorities and recent mandates of both Governments, it is virtually inconceivable that these changes to income tax rates will not come to fruition, yet ATCO has used the existing rates in its Application.

Calgary referred to ATCO's response to BR-ATCO.45, which indicated that ATCO's view, the criteria of section 3465.56 of the CICA handbook did not apply to the Company. However, Calgary noted that ATCO agreed that the federal tax reductions have been approved for both of the test years, as has the first portion of the provincial reductions. As previously discussed, given the overwhelming majority that the Alberta Government has, Calgary submitted that it is unreasonable to suggest that the proposed change in income tax rates incorporated in the Alberta Government's budget will not take place. Calgary submitted that the Board should direct ATCO to use the federal income tax rates approved[70] and the provincial income tax rate approved for April 2001 to March 31, 2002,[71] as well as the forecast reduction for April 2002 to March 2003. Calgary considered that, furthermore, to the extent that ATCO does not have an application for change in rates in 2003, the Board should direct that any savings associated with the changing income tax rates should be placed in a deferral account for the benefit of customers. Calgary submitted that it is ludicrous to suggest that a change in income tax rates is an "efficiency" achieved by ATCO.

Calgary noted the inconsistency between ATCO's proposed treatment of income tax rate reductions and increase in WCB premiums, which incidentally, was not mentioned when ATCO was cross-examined on tax rates. In the latter case, Calgary noted that ATCO does not hesitate to include the proposed increase and seek to recover it from customers, as opposed to the former case, where ATCO objects to passing the decreases on to customers, apparently on the grounds that the Company has not recalculated the impact of the resource allowance.

Calgary submitted that the benefits of the proposed tax rate changes should be passed on to customers of ATCO, as tax rate changes are not the result of any effort by the Company and should not accrue to the benefit of shareholders. Calgary considered that, if the Board has any doubt about passing the benefit to customers, at the very least, a deferral account should be established so that customers not shareholders, benefit from the income tax rate changes. Calgary suggested that this will remove the risk that ATCO appears to be worried about, and submitted that the reduction in risk should also be considered in setting the rate of return on common equity.

**Views of the Board**

The Board notes Calgary's observation regarding the change in assessing practice arising out of the *Rainbow Pipelines* decision, which relied on the *Canderel* decision, resulted in tax savings of $1.9 million (1998) and $2.1 million (1999) to shareholders of AGPL. While acknowledging Calgary's concern that other utilities have documented how customers have benefited from the

[70] APS BR.APS.21, AGS Tr. p.1464
[71] APS Tr. p.1058

savings arising from those decisions, the Board considers that ATCO's method of accounting for these savings is consistent with past practice with respect to this jurisdiction. Specifically, in Decision E95106,[72] dated April 12, 1996 and Order U96033,[73] dated April 12, 1996, the Board confirmed that that regulatory principles generally preclude the deferral of cost savings arising from isolated transactions occurring outside of a test year.

The Board also notes ATCO's response to BR-ATCO.46(b) demonstrating that, pursuant to those decisions, indirect overhead costs have been deducted in determining income tax expense tax for the test years.

The Board notes Calgary's concern that ATCO's deferral of costs associated with restructuring and other costs in prior years did not fit the definition of deferred taxes referred to in Decision 2000-9. In this regard, the Board acknowledges ATCO's submission that the treatment of restructuring costs is designed to achieve better matching of the tax deduction with the related amortization, and that the treatment of post employment benefits is proposed on the basis that the expense is similar in nature to pension expense. The Board agrees with ATCO that the deferral of rate hearing costs is appropriate, given their short-term nature and the unpredictability in the level of costs attributable to particular years. The Board accepts ATCO's proposal for deferral of these items, on the basis that the expenditures can be considered in the same category as the deferred items referred to in Decision 2000-9.

The Board notes that Section 3465 of the CICA Handbook specifies that income tax assets and liabilities be measured using the income tax laws and rates that are expected to apply when the asset is realized or liability settled. Section 3465 states that it would be appropriate to use a substantively enacted rate that the Government is able and committed to enacting in the foreseeable future. The Board notes that Clause 112 of the March 2001 *Income Tax Act*, indicates that the rates in effect for 2001 will be reduced by 1% from previously prevailing rates, and by 2% for 2002.

The Board agrees with Calgary's submission that, in determining income tax expense and liabilities for the test years, ATCO should use the federal income tax rates as set out in the 2001 *Income Tax Act*, and the provincial income tax rates announced by the Alberta Government applicable for periods from April 2001 to March 2003. Accordingly, the Board directs ATCO to recalculate income tax expense and liabilities for the test years using those rates announced or substantively enacted by the federal and provincial governments for those years.

## 6.5 Unaccounted for Gas (UFG)

### Position of ATCO

Historically, ATCO determined UFG as the difference between the total receipt and total delivery categories using total delivery as the denominator in the calculation of percentage UFG. The UFG percentage was identified through a Rider D, based on the rolling average of actual

[72] Decision E95106 Canadian Western Natural Gas Company Limited, 1995/96 Winter and 1996 Summer GCRR

[73] Order U96033 Canadian Western Natural Gas Company Limited – Sale of Assets

UFG for the preceding three years, and collected in kind or through rates from the sales, industrial and producer transportation customers.

A revised UFG recovery formula was established in the Industrial/Producer Negotiated Settlement Process (NSP). The NSP formula provided for the removal of UFG from Producer Transportation customers and inclusion of compressor fuel quantity to be recovered in kind.

ATCO proposed to implement a more rigorous UFG management program that requires the installation of metering equipment between ATCO Pipelines and ATCO Gas interconnection points, and the installation of additional custody transfer quality measurement equipment to further segment the distribution system. Upon installation of the metering equipment, the Company proposed to calculate the quantity of UFG as the difference between the gas received and the gas delivered out of the distribution system, and to calculate the UFG percentage by taking the difference and dividing by gas delivered from the distribution system.

ATCO noted that during the course of the hearing, some questions arose concerning the methodology used to determine the UFG percentage, and indicated that, as discussed by the Company, the change in the methodology to determine the UFG percentage arose in the Industrial/Producer NSP. ATCO pointed out that, prior to those agreements, the Company included all receipts into the system and all deliveries from the system to calculate the percentage, which resulted in a particular gigajoule receiving the equivalence of two treatments of UFG as it passed from a receipt point on the system to a delivery point on the system. ATCO stated that, to address this unfairness, parties agreed that the UFG percentage would be determined by taking into account only physical deliveries off the system. ATCO noted that, while this resulted in an increase in the percentage for UFG, the gross amount for UFG remained the same, in essence, being the difference between the receipts on to the system and the deliveries from the system. ATCO submitted that this is a more fair system and a more accurate method to measure the percentage of gas unaccounted for on the transmission and distribution systems.

ATCO also noted that the Company supports the proposed investment by ATCO Pipelines related to the installation of meters at exchange points between the transmission and the distribution systems, and considered that this change would be required regardless of whether or not the reorganization of the gas utilities had occurred. ATCO pointed out that with high prices of natural gas, UFG percentages become quite important for large transmission customers.

**Positions of the Interveners**

**AIPA**

AIPA stated its concern that the percentage of UFG should be based upon receipts into the system to ensure that volumes delivered to interchange points, storage or backhauls receive an appropriate share of UFG.

**CCA**

The CCA considered that the agreement between APS and industrial/producer customers resulted in significant harm for the customers of ATCO. The CCA considered this but one example where the use of negotiations in the determination of rates has not produced a satisfactory result, particularly since the core customers did not agree, and were unable to negotiate on this issue. CCA suggested that the Industrial/Producer settlement agreement should be given little weight in the determination of the change of UFG methodology as requested by ATCO.

### Calgary

Calgary submitted that the section of the ATCO argument on UFG[74] is a clear indication of the pure fiction of the separation between ATCO Gas and ATCO Pipelines. Calgary noted ATCO's statement that "it supports the proposed investment by [APS] related to the installation of meters …", and considered it hard to imagine a comparable situation where any company "supports" a supplier spending money so it can increase the rates which the supplier charges. Calgary pointed out that, further, the proposed expenditure and increased cost is another example of the cost associated with the restructuring. Calgary submitted that, if AltaGas has a UFG percentage[75] almost half that of AGS/APS, there is a problem for both AGS/APS. Calgary submitted that ATCO's ratepayers should not bear the full cost.

### MI

The MI noted that ATCO concurs with the ATCO Pipelines proposal for UFG, and indicated that the MI and all other core customer groups have opposed that treatment in the ATCO Pipelines proceeding. In the MI's view, it appeared that ATCO has chosen to support its affiliate rather than those core customers that it serves, another example of self-dealing with affiliates in the absence of a code of conduct.

### Views of the Board

The Board notes AIPA's concern that the percentage of UFG should be based on receipts into the system. However, the Board acknowledges ATCO's submission that, to address the unfairness that previously prevailed due to inclusion of all receipts and deliveries on the system in the calculation of UFG, parties agreed that the UFG percentage would be determined by taking into account only physical deliveries off the system. The Board therefore accepts ATCO's methodology for the test years.

The Board notes Calgary's submission with respect to the difference between the prevailing rate on the ATCO system compared to the AltaGas rate. The Board acknowledges that UFG can vary widely from year to year, and that the existing rate is based on the averaging of three years experience. Since no information has been presented in this proceeding to identify the basis for calculation of the AltaGas rate, the Board is not inclined to accept Calgary's position on this issue.

[74] AGS Argument, pp.55-56
[75] Tr. p.1061

# 7 UTILITY REVENUES

## 7.1 General

ATCO forecast its utility revenue for 2001 and 2002 at $841,700,000 and $739,028,000 respectively. The forecasts were based on the sales and transportation rates in effect at September 1, 2000 and approved by the Board in Decision 2000-61,[76] August 30, 2000.

ATCO stated that it undertook a survey to determine the reaction of customers to the unprecedented high cost of natural gas and to quantify an expected reduction in consumption. ATCO noted that as of October 31, 2000, approximately 12,000 customers were purchasing natural gas from an alternative supplier and that the forecast includes a reduction of gas supply requirements for 38,000 customers by the end of the forecast period.

## 7.2 Sales Forecast Methodology

In accordance with the directions given in Decision 2000-9, ATCO provided a variety of methodologies for developing a forecast. ATCO noted that it had developed and utilized the following alternative methodologies to develop the sales forecast:

- Average Trend
- Vintage Model
- Efficiency Model
- Seasonal Line Slope Analysis
- Individual Customer Analysis
- Analysis of Impact of High Natural Gas Prices.

ATCO provided greater detail and descriptions in the Application, and noted that the historical data had been normalized using the average temperatures for the period 1980-99.

## 7.3 Customer Growth

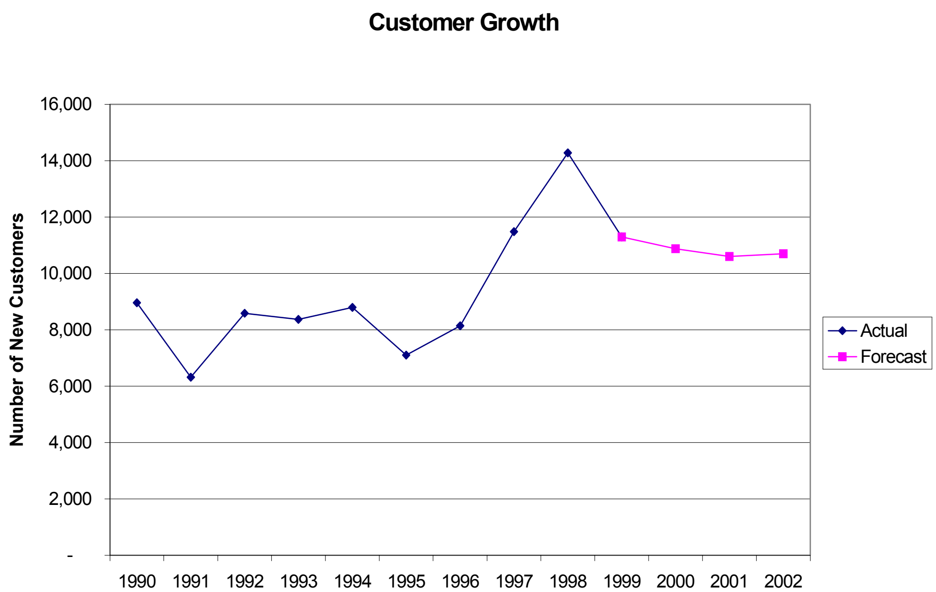
### Position of ATCO

ATCO provided a forecast of customer growth by rate class, based on a review of data collected from agency staff and historical and projected population and housing start data gathered from a variety of sources including Central Mortgage and Housing Corporation (CMHC) as follows:

[76] Decision 2000-61 Canadian Western Natural Gas Company Limited, 1998 GRA Phase II – Compliance Filing

## Customer Growth Forecast

| Customers | 1999 YEAR END | 1999 ACTUAL | FORECAST ADDITIONS 2000 FORECAST | 2001 FORECAST | 2002 FORECAST |
|---|---|---|---|---|---|
| **SALES** | | | | | |
| **Residential** | 361,744 | 10,604 | 10,355 | 10,070 | 10,165 |
| **Commercial** | | | | | |
| Small Apartments | 2,520 | 33 | 12 | 20 | 20 |
| Large Apartments | 107 | 5 | 13 | 5 | 5 |
| Small Commercial | 27,775 | 641 | 397 | 490 | 495 |
| Large Commercial | 562 | 13 | 102 | 15 | 15 |
| **Total – Commercial** | **30,964** | **692** | **524** | **530** | **535** |
| **Industrial** | | | | | |
| Small Industrial | 59 | (4) | (2) | - | - |
| Large Industrial | 106 | 6 | (12) | - | - |
| **Total – Industrial** | **165** | **2** | **(14)** | - | - |
| **Irrigation** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** |
| **Transportation** | | | | | |
| Commercial | 6 | 1 | 9 | - | - |
| Industrial | 39 | 5 | 8 | - | - |
| **Total – Transportation** | 45 | 6 | 17 | | |
| **TOTAL CUSTOMERS /Growth in number of customers 1999-2002** | **392,918** | **11,304** | **10,882** | **10,600** | **10,700** |



## 7.4 Forecast Sensitivity

### Position of ATCO

Based on existing rates the annualized impact on the forecast for 2002 of ±1,000 residential customers would be:

| | | |
|---|---|---|
| Fixed Charge: | 1,000 x $13.00/month x 12 = | $156,000 |
| Variable Charge: | 1,000 x 137.5 GJ/customer x $.952/GJ = | $130,900 |
| | | $286,900 |

ATCO submitted that the forecast customer additions are reasonable and should be approved as filed.

### Views of the Board

The Board notes that none of the interveners expressed any concern with the ATCO forecast of customer growth for the test years, and considers that the methodology adopted by the Company is reasonable. Accordingly, the Board accepts ATCO's forecasts of customer growth for the test years.

## 7.5 Residential Sales

### Position of ATCO

Residential Sales comprise customers from single family and multi-family dwellings that use 8 TJ's or less annually, representing 90% of AGS customers. These customers are temperature sensitive, and their consumption varies based on a variety of factors: efficiency improvements, new housing construction, price of natural gas, and individual household consumption habits. ATCO provided the following Residential Sales forecast:

**Residential Sales Forecast**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Sales per Customer (GJ) | 146.2 | 142.0 | 140.0 | 137.5 |
| **Change** | | 4.2 | -2.0 | -2.5 |
| **Throughput (TJ)** | 52,068 | 52,050 | 52,696 | 53,181 |

The above forecast factored in the high cost of gas, along with incorporating the following methodologies: Average Trend, Vintage Model, Efficiency model and Seasonal Line Slope Analysis. The results of these various methods utilized by ATCO are provided below.

**Annual Residential Sales per Customer Forecasts**
**(GJ)**

| FORECAST METHODOLOGY | 2000 | 2001 | 2002 |
|---|---|---|---|
| Average Trend | 143.1 | 142.0 | 141.0 |
| Vintage Model | 142.7 | 141.7 | 140.7 |
| Efficiency Model | 142.2 | 141.2 | 140.0 |
| Seasonal Line Slope Analysis | 142.8 | 141.6 | 140.4 |
| **RECOMMENDATION (Excl Price)** | 142.5 | 141.5 | 140.5 |
| **Impact of High Gas Prices 2000** | -0.5 | -0.5 | -0.5 |
| **Impact of High Gas Prices 2001** | | -1.0 | -1.0 |
| **Impact of High Gas Prices 2002** | | | -.15 |
| **FINAL RECOMMENDATION** | 142.0 | 140.0 | 137.5 |

Sales per customer are predicted to decline from the replacement or retirement of old furnaces and water heaters with mid and high efficiency units, greater energy conservation, improved housing, and the high price of gas. Essentially, all methodologies forecast a decline in consumption per customer.

ATCO indicated that it would "live or die" by its forecast in its Application, and submitted that it was conservative in its analysis and that the results of 2000 support that claim. ATCO took issue with interveners who suggested the downturn in gas prices should be used to refute its study, which was prepared to quantify the impact of high gas prices on residential consumption. ATCO submitted that the facts of the case show that this criticism is unfounded, pointing out that the GCRR at the time of the survey was at $6.496/GJ, which was not significantly higher than the existing level of annualized gas costs. In addition ATCO indicated that the Government had announced that future Government rebates would not be implemented unless gas costs approached the $6.00/GJ level, a level consistent with the forecast used in the filing.

ATCO argued that the Board should reject such claims outright as the merits of the Application should be based on the information available at the time of preparing the Application. ATCO believed that related information on actual customer conservation would be favorable to the Company, however, the prospectivity principle required the Company to maintain its filed forecasts.

ATCO argued that the study prepared by it was comprehensive, conservative in its estimate and should be accepted by the Board. ATCO pointed out that, as noted during the hearing, the actual sales per customer for 2000 was 139.5 GJ, well below the forecast figure of 142.0 GJ. ATCO also noted that this downward trend has continued in 2001.

ATCO rejected the MI's interpretation of its survey results and stated that the survey was conducted at the time when higher gas prices were in the news but the impact on gas bills had not been experienced. The ATCO analysis assumed a certain level of energy conservation measures would take place in 2001 based on the survey results. ATCO indicated that the analysis also assumed that conservation measures by other customers motivated by the experience of winter 2001 bills would drive them into action. The impact of any changes they would make would impact 2002 consumption.

ATCO went on to state that its use of Natural Resources Canada's 2% estimate of savings related to thermostat turndown was a reasonable estimate from an impartial organization. ATCO believed that the three discounting factors[77] used to develop the analysis provided a high level of conservatism.

ATCO argued that the MI claim that the 2000 actual results appeared anomalous was not logical. ATCO stated that as shown in its filing and based on the 2000 actual figure, 1999 was the year that one would reasonably identify as the year, if any, that was anomalous. ATCO stated that the 2001 actual experience was consistent with the 2000 actual results.

ATCO rejected the MI's claim that more weighting should be given to the Average Trend because the Efficiency Model was in the development stages and that the Vintage and Seasonal Slope Models utilized untested normalization techniques. ATCO stated that a significant quantity of information was provided in the Application, information requests and under cross-examination to test the appropriateness of each model. In the case of the residential sales per customer forecast the results from each model were comparable and support the forecast recommendations.

ATCO submitted that the arguments of the CCA with regard to sales per customer were unsubstantiated.

ATCO noted that Calgary attempted to refute the forecast by pointing to the results of the trend analysis provided in Exhibit 100 that extended the trends to the year 2015. ATCO stated that as the Company had pointed out in testimony, that the trend analysis was an appropriate tool to develop short-term (1-2 years) forecasts. ATCO pointed out that, under cross-examination it had shown the actual results for 2000 and the existing experience for 2001 were far below the forecast figures in the Application.

### Calgary

Calgary expressed concerns with respect to ATCO's continued use of regression analyses to forecast residential and commercial consumption. Calgary argued that, notwithstanding the addition of other regressions, as shown by Exhibit 100 and discussed in Calgary's[78] evidence, there were definite problems with some of the regression data and analyses. Further, Calgary noted, based on the chart filed as Exhibit 100 Residential Average Trend Model, ATCO's recommendation was significantly lower and would provide significantly lower consumption than any of the other regression lines, and would therefore result in the highest rates.

Calgary stated that the Exhibit 100 Residential Average Trend Model also showed that there appears to be a break-point at 1994, with 1995-1999, 1996-1999, providing almost identical results, and 1997-1999 providing fairly consistent results to those other two trend lines in the two test years. Calgary submitted that it was clear that ATCO's recommended residential trend line was significantly below anything that can reasonably be expected and should not be accepted. It

[77] Volume 2, Tab 13, Section 1, p.3
[78] Exhibit 45 p.9

was Calgary's opinion that if the Board found some merit in the use in a regression analyses then the 1995-1999 and 1996-1999 regressions should be used.

Calgary submitted that the adjustment for "higher prices" proposed by ATCO which projected additional reduction in consumption of 1.5 GJ in 2001 and 3.0 GJ in 2002, were totally inappropriate. Calgary stated that its evidence showed there was virtually no relationship between consumption and price, i.e. natural gas consumption was extremely inelastic. Calgary believed that this view was consistent with those noted by the NEB in its Annual Report.[79] In Calgary's submission it was inappropriate to make significant adjustments to revenue forecasts based on a single unprecedented spike in gas prices in the winter of 2000/2001.

Calgary noted that the conservatism referenced by ATCO could result in customers being asked to pay more because, in an effort to reduce its risk, ATCO had overstated the reductions in throughput for residential and commercial customers.

**CCA**

The CCA noted that in Decision E93004,[80] dated February 8, 1993, the Board made the following statement with respect to sales per residential and commercial customer:

> The Board agrees with CWNG that it is arbitrary to select a historical period and expect that it will reflect future consumption patterns. However, the Board notes that the factors used to temper the historical trend line are judgmental and their influence is subject to interpretation. The Board views that CWNG's forecast to decrease residential sales per customer may be accelerated.[81]

The CCA expressed concern that ATCO was accelerating the decline in sales per residential customer. The CCA believed that by under forecasting per customer sales, ATCO was attempting to improve its rate of return on an actual basis.

The CCA submitted that over several years heating efficiency had risen from 55% to 80% for standard house construction and that high efficiency furnaces were at 90%. The CCA believed that the use of linear regressions was suspect in over forecasting sales per customer declines. The CCA stated that gains that are made moving from a lower than 50% or 55% efficient furnace to 80% did not exist as in the past as a significant number of furnaces were replaced. Also the stock of houses using the higher efficiency furnaces were of a greater percentage of total housing therefore large reductions in sales per residential sales per customer would not occur in the future. The CCA stated that linear regression assumes that changes in the future will occur at the same rate as the past. The CCA stated that this assumption was simply not true with respect to per customer sale forecasts. The CCA argued that the trend line with a linear regression would assume in the same period that furnace efficiency moved from 55% to 80%, would assume that furnace efficiency would move from 80% to 105% for the same percentage of the housing stock. The CCA stated that this will simply not be the case. The CCA stated that the linear regression line was excessively tilted and did not provide adequate estimates of future per customer sales. The CCA also considered that sales per commercial customer had been accelerated. The CCA

[79] Exhibit 45 p.10
[80] Decision E93004 Canadian Western Natural Gas Company Limited, 1992/1993 GRA Phase I
[81] Decision E93004, p.327

submitted that actual 1999 sales per customer for both residential and commercial should be used for 2001 and 2002 forecast purposes.

**MI**

The MI considered that one of the reasons the 2000 normalized sales might have been so low was shown in Tab 13[82] where the graph showed that some of the January results were skewed. The MI believed that this appeared to be confirmed again under the discussion of the Seasonal Slope Analysis whereby the Company intended to correct for deviations in estimates prepared in the 4th quarter each year and with respect to unbilled sales at year-end.[83] The MI submitted that the 2000 normalized sales might be skewed by the 1999 results.[84]

The MI noted that the Company's recommendation was actually less than the average of the four methods used by ATCO to study use per customer. The MI submitted that given that the Average Trend had been tested and approved in the previous several proceedings, it should be given greatest weight. The MI went on to say that since the Efficiency Model was still in the development stage it should be given no weight. The MI was of the view that since the Vintage and Seasonal Slope Methods were based on the approved methods but utilized untested normalization techniques a reasonable weighting would be 50%, 25% and 25% on the Average Trend, Vintage and Seasonal Slope methods respectively. The MI stated that this resulted in normalized residential sales of 141.8 GJ and 140.8 GJ in 2001 and 2002 respectively

The MI had a number of concerns with the methods and assumptions used to derive the estimated reductions in gas consumption.

The MI stated that the major flaw in the analysis was that the GPC Survey failed to determine the incremental percentage of respondents who planned to implement measures to reduce gas consumption. The MI noted that ATCO agreed that the purpose of the survey was to determine the incremental reductions,[85] however, the specific question as to whether such measures were incremental or not, was not asked.[86] The MI submitted that surveys are often influenced by the questions asked.

The MI noted that in the GPC Survey,[87] a significant number of new furnaces and hot water heaters had already been installed which suggested that change outs were already occurring absent high gas prices. The MI believed those change outs would already be built into the Average Trend and to ignore them would constitute double counting. The MI submitted that there should be another discount factor to account for the fact that the percentages of respondents intending to take actions were not incremental In the absence of any evidence to support any incremental measures due to high gas prices, it was submitted by the MI that the discount factor should be 50% or less.

[82] Section 3, Appendix A
[83] Section 5.2, p.3
[84] Section 5.4, p.3
[85] Tr. p.1080
[86] Tr. p.1082
[87] CAL-ATCO.203 p.9 and 23

The MI stated that the second major flaw in the analysis was the assumption that an equal number of respondents, plus 20%, would take measures in 2002 to reduce gas consumption. The MI explained that this implicitly assumed that the respondents indicated that they did not plan to change out their furnace or water heater according to the October 2000 Survey, but would, for some unexplained reason, decide to do so in 2002. The MI submitted that was a totally unreasonable assumption and that there was no substantiation for any further increases in 2002 relative to the Average Trend.

Thirdly, the MI noted that ATCO chose the Natural Resources Canada estimate of a 2% savings in energy per degree of thermostat turndown and ignored the Union Gas and TransAlta estimates of 1%, because ATCO "felt" that Union and TransAlta had been deliberately conservative to ensure customers would not have high expectations. The MI argued that there was no evidence to support that position and it certainly was not a conservative assumption that ATCO claims the entire exercise was meant to be. The MI submitted that the use of the Union and TransAlta estimates are not unreasonable and would have reduced the estimated savings by 25%.

The MI submitted that an 80% follow through of intentions was highly optimistic in light of the rebates that had been provided, the announcement of Bill 1 and the fact that the exiting gas prices had dropped below $4 per GJ.

The MI noted that the Average Trend, Vintage Model and Seasonal Line Slope Model were utilized for residential, small and large apartments and small and large commercial classes while the Efficiency Model was utilized only for the residential class. Individual large apartment and commercial customers were also individual analyzed. As noted in Argument,[88] the MI submitted that the Efficiency Model was still in the development stage and therefore should be given no weight. The MI argued that the Average Trend model had long been approved by the Board and should receive 50% weighting with 25% weighting to the Vintage and Seasonal Line Slope Models.

The MI agreed with Calgary,[89] that there appeared to be a definite break-point in the normalized residential annual sales per customer in 1994 and accordingly greater weight should be given to the 1995-1999, 1996-1999 and 1997-1999 data.

The MI concurred with PICA that the impact of high gas prices might have been a factor in early 2001 but had been subsequently mitigated by Government rebates, a legislated price protection program and falling gas prices,[90] all of which suggested that the reductions should be significantly reduced. The MI also agreed with Calgary's submission that it was inappropriate to make significant adjustments to revenue forecasts based on a single, unprecedented spike in gas prices during the winter of 2000/2001.[91] As noted by the National Energy Board in its 2000 Annual Report, "…customers need to perceive price changes as permanent before they will significantly reduce consumption."[92]

[88] MI Argument, p.42
[89] Calgary Argument, p.44
[90] PICA Argument, p.11 and 12
[91] Calgary Argument, pp.44-45
[92] Exhibit 45, p.10

### PICA

PICA submitted that the combination of the Alberta Government gas rebates program during the winter of 2000/2001, the more permanent price protection program announced by the Government and the falling prices in the existing gas market meant it was very unlikely the additional costs projected by ATCO would actually be realized. PICA noted that while these factors might not have been known at the date of the original filing on December 6, 2000, parties were certainly aware of them by the time of the hearing, only a short time into the initial 2001 test-year.

PICA submitted that the impact of high gas prices was likely to be only a fraction of that projected by ATCO. Specifically, PICA recommended that only 25% of the portion of reductions projected for the various customer classes by ATCO attributed to higher gas prices be included by the Board in its approval of unit customer consumption rates. In effect PICA argued, that would recognize there have been some impacts from high gas prices in the first part of the 2001 test year, but those impacts were unlikely to continue or occur throughout the balance of the two-year test period. PICA believed that this was particularly true given the Alberta Government had legislated a price protection program mitigating the impact of high gas prices on Alberta consumers.

### Views of the Board

The Board acknowledges interveners concerns with respect to ATCO's continued use of regression analysis to forecast residential and commercial consumption, noting that both Calgary and the MI submitted data to indicate that ATCO's trend line, and resultant customer consumption, is below a reasonable level. The Board notes Calgary's proposal for use of alternative base years, and the MI's recommendation for revision to the weighting used in the regression models. The Board also notes the CCA's concern that regression analysis is not a reliable forecasting tool, and its recommendation that the test year forecasts should be based on 1999 actual data.

The Board also agrees with ATCO that a significant quantity of information was provided in the Application, and ATCO's models were subjected to a considerable degree of scrutiny during the proceedings.

In the Board's view, all of the models used in ATCO's analysis have attributes worthy of consideration. The Board recognizes that, while the regression analysis does not necessarily predict the future, the methodology has proved its value in the past. The Board considers that the forecast consumption is based on the results of a wider range of different models than was the case in the past and recognizes ATCO's efforts and initiative taken in introducing new methods into the regression methodology. The Board considers that the methodology used by ATCO is reasonable and accepts the Company's forecast consumption based on the regression methodology used. However, while satisfied with the weighting given to each model used in the analysis, the Board intends to further evaluate the appropriateness of equal weighting at the next GRA. Accordingly, the Board directs ATCO to provide a discussion and clear rationale to support the weighting methodology at the next GRA.

The Board notes the concerns of interveners with respect to the Company's adjustment for high gas prices, and agrees that the evidence that customers will use significantly less gas in the near term as a result of higher prices is speculative. The Board considers that the regression analysis already recognizes some effects of price increases from the recent past, and will to a degree, project the related impact into the forecasts. Therefore, since the Board is not persuaded that there is a need, at this time, to adjust the consumption forecasts to reflect the effect of higher gas prices, the Board directs ATCO to recalculate forecast consumption without including an adjustment for the effect of higher gas prices.

## 7.6 Commercial Sales

Commercial Sales are made up of small apartment, large apartment, small commercial, and large commercial customers. Each customer group has its own forecast taking into consideration their different load profiles. The large apartment and large commercial categories (Rate 3 / Rate13) include customers with annual consumption in excess of 8TJ'S, while small commercial and small apartment categories (Rate 1 / Rate 11) consume less than 8TJ's annually.

### 7.6.1 Small Apartments

ATCO classifies small apartments as blocks with more than four units, with an annual consumption of up to 8 TJ's. Apartment load consumption is dictated by efficiency improvements, vacancy rates, the price of natural gas, new apartment construction, and economic activity. The following two tables provide ATCO's small apartment sales forecast and small apartment sales forecast per customer.

**Small Apartment Annual Sales Forecast**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Sales per Customer (GJ) | 1,488.3 | 1,460 | 1,455 | 1,450 |
| **Change** | | -28.3 | -5 | -5 |
| **Throughput (TJ)** | 3,804 | 3,692 | 3,697 | 3,716 |

**Small Apartment Annual Sales per Customer Forecasts (GJs)**

| FORECAST METHODOLOGY | 2000 | 2001 | 2002 |
|---|---|---|---|
| Average Trend | 1,478.5 | 1,496.0 | 1,513.6 |
| Vintage Model | 1,427.1 | 1,430.4 | 1,433.7 |
| Seasonal Line Slope Analysis | 1,455.2 | 1,463.6 | 1,471.9 |
| **RECOMMENDATION (Excl Price)** | 1,460 | 1,460 | 1,460 |
| **Impact of High Gas Prices** | 0 | -5 | -10 |
| **FINAL RECOMMENDATION** | 1,460 | 1,455 | 1,450 |

The high cost of gas combined with a change in threshold for the group from 10 TJ's to 8 TJ's is predicted to put downward pressure on consumption.

ATCO submitted that at the time the forecast was prepared, the rolling twelve month sales per customer for the small apartment customer group supported the forecast recommendation. In addition, ATCO stated that it was reasonable to expect that high natural gas prices would have some impact and a small adjustment was made to recognize that fact.

### 7.6.2 Large Apartment

This customer group includes apartments with four or more units that have an annual consumption of more than 8TJ's. Consumption is impacted by the same factors that influence the load profile of small apartment customers.

**Large Apartment Annual Sales Forecast (GJs)**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Sales per Customer | 15,261 | 15,800 | 15,350 | 14,4900 |
| **Change** | | +539 | -450 | -450 |
| **Throughput (TJ)** | 1,605 | 1,735 | 1,862 | 1,882 |

* All Sales per Customer figures have been re-stated to reflect the current customers in the rate class after all transfers between rate classes.

Forecasts were prepared using the following methods: Average Trend, Vintage Model, Seasonal Line Slope Analysis and Individual Customer Analysis. The results of those forecasts are summarized in the following table.

**Large Apartment Sales per Customer Forecasts**

| FORECAST METHODOLOGY | 2000 | 2001 | 2002 |
|---|---|---|---|
| Average Trend | 14,753 | 14,294 | 13,836 |
| Vintage Model | 15,714 | 15,725 | 15,736 |
| Seasonal Line Slope Analysis | 14,781 | 14,324 | 13,866 |
| Individual Customer Analysis | 15,890 | 15,862 | 15,883 |
| **RECOMMENDATION (Excl Price)** | 15,800 | 15,400 | 15,000 |
| **Impact of High Gas Prices** | 0 | -50 | -100 |
| **FINAL RECOMMENDATION** | 15,800 | 15,350 | 14,900 |

Based on the threshold change from 10TJ's to 8TJ's, eight customers were transferred from Rate 1 to Rate 3. This resulted in a decline in consumption per customer compared to historical norms. Natural gas prices are expected to accelerate this decline in 2002.

### 7.6.3 Small Commercial

Small Commercial customers are non-apartment businesses with consumption of 8TJ's or less, with gas consumption affected by the following factors: the price of natural gas, efficiency improvements of older buildings, new commercial construction and local economic activity. The following table incorporates the methodologies and findings used to provide ATCO's forecast for small commercial sales per customer:

**Small Commercial Annual Sales per Customer Forecasts**
**(GJ)**

| FORECAST METHODOLOGY | 2000 | 2001 | 2002 |
|---|---|---|---|
| Average Trend | 763.0 | 762.1 | 761.1 |
| Vintage Model | 747.3 | 747.4 | 747.6 |
| Seasonal Line Slope Analysis | 753.6 | 748.9 | 744.2 |
| **RECOMMENDATION (Excl Price)** | 760.0 | 757.5 | 755.0 |
| **Impact of High Gas Prices** | 0 | -2.5 | -5.0 |
| **FINAL RECOMMENDATION** | 760.0 | 755.0 | 750.0 |

Overall sales per customer are estimated to decline, as newly constructed commercial buildings become a higher percentage of sector sales.

ATCO submitted that at the time the forecast was prepared, the rolling twelve month sales per customer for the Small Commercial customer group supported the forecast recommendation. In addition, ATCO stated that it was reasonable to expect that high natural gas prices would have some impact and a small adjustment was made to recognize that fact.

### 7.6.4 Large Commercial

Large commercial customers consume 8TJ's or more, with gas consumption affected by efficiency improvements, natural gas prices, economic activity and new commercial construction. The forecast used the methodologies which are reflected in the following table:

**Large Commercial Sales per Customer Forecasts**
**(GJ)**

| FORECAST METHODOLOGY | 2000 | 2001 | 2002 |
|---|---|---|---|
| Average Trend | 18,882 | 17,463 | 16,044 |
| Vintage Model | 19,781 | 19,765 | 19,749 |
| Seasonal Line Slope Analysis | 18,948 | 17,513 | 16,029 |
| Individual Customer Analysis | 19,878 | 19,873 | 19,842 |
| **RECOMMENDATION (Excl Price)** | 19,800 | 19,250 | 18,700 |
| **Impact of High Gas Prices** | 0 | -50 | -100 |
| **FINAL RECOMMENDATION** | 19,800 | 19,200 | 18,600 |

Any customer additions or transfers can have a significant impact on sales per customer trends, as these customers are generally large in nature. Average sales per customer are expected to fall as new customers are transferred from Rate 1 (smaller customers) to Rate 13.

ATCO noted that Calgary claimed that the data for small apartments and large apartments were inconsistent because the short-term trend for small apartments was flat and the trend for large apartments showed a decline. ATCO stated that the facts of the case were that the small apartment group (Rate 1) was comprised of some 2,500 customers with little growth over the years resulting in a very stable consumption figure. The large apartment group (Rate 3) was comprised of only 100 customers. ATCO further noted that the Application indicated the change of the breakpoint between Rate 1 and Rate 3 from 10,000 GJ to 8,000 GJ resulted in a transfer of eight customers to Rate 3 from Rate 1, which would reduce the average usage per customer in the large apartment group since these customers would be at the lower end for consumption for Rate 3 customers.

ATCO argued that Calgary's claim that the small apartment group and the residential group are comparable was not supported by the facts of the case and should be disregarded.

**Positions of the Interveners**

**Calgary**

Calgary submitted that both of the average and seasonal slopes trend lines for Large Commercials produced negative results by the year 2014 and 2015.[93] Calgary believed that such a result was unrealistic, and brought into question any of the forecasts using that same data for the test years 2001 and 2002.

Furthermore Calgary stated that the data was totally inconsistent with respect to Small and Large Apartment buildings. In Exhibit 100, prepared by Calgary, the Large Apartment buildings were showing a significant reduction in consumption, while the Small Apartment buildings were showing an increase in consumption. Calgary's view was that to the extent Small Apartment buildings showed an increase in consumption, one would expect that Residential consumption would also follow a similar trend, since construction techniques for Residential housing and Small Apartments tended to be similar.

**MI**

The MI submitted that the same weighting factors that it recommended for the forecast methodologies in respect of the residential category should be applied to the forecast methodologies in respect of the commercial sales categories.

**Views of the Board**

The Board notes Calgary's submission that, based on the results of its analysis, filed as Exhibit 100, the average and seasonal slope models for Commercial customers and Apartment buildings produced unrealistic and inconsistent data. While recognizing that, in the near term, actual experience will modify the slopes for these models, the Board notes that, in ATCO's analysis, these models were only used to modify the average derived from the vintage and individual analysis models, which formed the basis of the consumption forecasts. The Board considers it reasonable that ATCO applied some judgment to the results produced by the regression models to recognize non-homogeneous categories. For example, the Board notes that application of equal weighting to the models in the case of small commercial buildings would have produced a lower consumption than that recommended by the Company.

The Board considers that the methodology used by ATCO to forecast consumption for Commercial Sales is reasonable and accepts the Company's forecast consumption based on the regression methodology used. However, the Board notes that ATCO's explanation of the assumptions used and conclusions reached in evaluating the regression results was unclear. The

[93] Exhibit 100

Board therefore expects ATCO to continue to evaluate the ongoing appropriateness of the methodology used to forecast consumption in this category, and to provide, at the next GRA, a more detailed analysis and explanation of the assumptions used and conclusions reached in evaluating the data.

The Board notes the concerns of interveners with respect to the Company's adjustment for high gas prices, and agrees that the evidence that customers will use significantly less gas in the near term as a result of higher prices is speculative. The Board considers that the regression analysis already recognizes some effects of price increase from the recent past, and will project the related impact into the forecasts. Since the Board is not persuaded that there is need, at this time, to adjust the consumption forecasts to reflect the effect of higher gas prices, the Board directs ATCO to recalculate forecast consumption without including an adjustment for the effect of higher gas prices.

## 7.7 Industrial Sales

### Position of ATCO

In this sector, ATCO uses consumption rates of 8TJ's per annum as the break point between large and small industrials. Industrial customers are generally not sensitive to temperature fluctuations, although annual throughput tends to vary seasonally. The following sales forecast is for both small and large industrial customers, with no adjustment being made for transfers from Rate 3 to Rate 13.

**Small Industrial Sales Forecast**
**Year End Customers and Annual Throughput**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Year End Customers | 59 | 57 | 57 | 57 |
| Throughput (TJ) | 303 | 178 | 172 | 172 |

**Large Industrial Sales Forecast**
**Year End Customers and Annual Throughput**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Year End Customers | 106 | 94 | 94 | 94 |
| Throughput (TJ) | 3,269 | 3,100 | 3,008 | 3,008 |

### Views of the Board

The Board notes that interveners expressed no concerns with respect to the consumption forecasts in the Industrial Sales category. The Board accepts the forecasts as filed.

## 7.8 Irrigation Sales

### Position of ATCO

ATCO noted that irrigation throughput is not temperature sensitive, but rather varies from year to year based on precipitation levels. The table below provides a forecast for irrigation sales:

**Irrigation Sales Forecast**
**Average and Peak Customers and Annual Throughput**

| | 1996 Actual | 1997 Actual | 1998 Actual | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|---|---|---|
| **Average Customers** | 698 | 700 | 702 | 700 | 707 | 700 | 700 |
| **Peak Customers** | 1,640 | 1,607 | 1,627 | 1,624 | 1,632 | 1,624 | 1,624 |
| **Throughput (TJ)** | 958 | 777 | 592 | 634 | 1,003 | 781 | 781 |

### Views of the Board

The Board notes that interveners expressed no concerns with respect to the consumption forecasts in the Irrigation Sales category. The Board accepts the forecasts as filed.

## 7.9 Distribution Transportation

The Distribution Transportation category includes both Commercial and Industrial Rate 13 customers with an annual consumption of 8TJ's or more. This customer group is comprised of customers transferred from Rate 3 sales service to Rate 13 transportation service, effective November 2000. Furthermore, Rate 13 has been demand based since September 1, 2000, thus eliminating the necessity to forecast throughput for 2001 and 2002. Contract demand is based on nominal demand, representing maximum gas flow in a 24-hour period, with a demand charge for any month which equals the maximum measured gas flow subject to a minimum amount of 90% of the nominated demand, and a maximum of 110%.

**Commercial Transportation Service Forecast**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Year End Customers | 6 | 15 | 15 | 15 |
| Throughput (TJ) | 1,842 | 1,805 | n/a | n/a |
| Annual Contract Demand (TJ) | | 48 | 156 | 156 |

* For 2000, the throughput total for Jan-Aug is shown in addition to the demand for Sept-Dec.

**Industrial Transportation Service Forecast**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Year End Customers | 39 | 47 | 47 | 47 |
| Throughput (TJ) | 6,567 | 4,551 | n/a | n/a |
| Annual Contract Demand (TJ) | | 100 | 312 | 312 |

* In 2000, the throughput total for Jan-Aug is shown in addition to the demand for Sept-Dec.

### Views of the Board

The Board notes that interveners expressed no concerns with respect to the consumption forecasts in the Distribution Transportation category. The Board accepts the forecasts as filed.

## 7.10 Other Revenue

### Position of ATCO

ATCO provided the following table to summarize its forecast for Other Revenue.

**Other Revenue Forecast
($000)**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Storage Revenue | 5,680 | 7,103 | 12,300 | 13,920 |
| Service Charges and Other Misc Revenue | 4,642 | 5,347 | 6,730 | 6,397 |
| Affiliate Support Services Revenue | 4,500 | 3,443 | 2,808 | 2,582 |
| Production Related Revenue | 687 | 382 | 432 | 381 |
| **Total Other Revenue** | **15,509** | **16,275** | **22,270** | **23,280** |

ATCO stated that the forecast was consistent with the Carbon Storage Agreement proposed in the Affiliate Application wherein AGS was proposing to lease the working capacity of the field (43.5PJ's) to ATCO Midstream for a 10-year period effective April 1, 2001 (corrected to January 1, 2000 during the hearing).

ATCO claimed that the proposed treatment of Carbon provided a positive impact of $9,621,000 to customer rates as was detailed in its application.

### Views of the Board

The Board notes that subsequent to filing of the Application the Company has made application to determine a procedure to transfer Carbon Storage to ATCO Midstream. This is the subject of a separate proceeding.

### 7.10.1 Service Charges and Other Miscellaneous Revenue

**Position of ATCO**

ATCO provided the following summary of revenues in this category:

**Service Charges and Other Miscellaneous Revenue**
**($000)**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Late Payment Penalty | 2,815 | 3,697 | 4,865 | 4,262 |
| Reconnect Fee | 196 | 235 | 236 | 341 |
| Dishonored Cheques | 82 | 85 | 88 | 173 |
| Mains and Services Repair | 299 | 274 | 297 | 305 |
| Jobbing | 626 | 575 | 840 | 863 |
| Other | 624 | 481 | 404 | 453 |
| **Total Service Charges** | **4,642** | **5,347** | **6,730** | **6,397** |

ATCO stated that the Late Payment Penalty revenue forecast was based on a review of the last three years of actual sales and penalty revenue information. The approved late payment penalty charge is 5%. Higher sales revenues tend to result in higher late payment penalties.

ATCO provided a Reconnect Fee revenue forecast for 2001 and 2002 based on a forecast of reconnect units of 5,250 for each year. ATCO stated that rising gas costs resulted in increases in the numbers of disconnections by the company for non-payment and therefore used a proposed rate of $65 per reconnect in the 2002 revenue forecast, up from the current rate of $45. ATCO noted that the $45 rate had been in effect since 1991 and the increase to $65 reflected increases in field labour, credit and collections and administrative support.

ATCO noted that there was an existing $15 fee charged to customers for processing of dishonored cheques. In its application ATCO used a rate of $20 for the year 2002 claiming that the increase was required to offset the increase in costs for processing dishonored cheques.

Jobbing revenue is expected to increase in 2001 and 2002 due to the parts replacement program introduced in 2000.

**Views of the Board**

The Board notes that interveners expressed no concerns with respect to the test year forecasts for Service Charges and Other Miscellaneous Revenue. The Board considers ATCO's forecasts in this revenue category are reasonable. The Board is not persuaded, however, that a 33% increase in the rate charged for processing dishonored cheques, justifies an increase of 109% in revenues forecast for 2002 compared to the year 2000. Accordingly, the Board directs ATCO to reduce the 2002 test year forecast to $113,000, which represents an increase in revenue proportionate to the increase in the fee.

### 7.10.2 Affiliate Revenue

**Position of ATCO**

ATCO receives revenue from affiliates for rental and support services, which will be dealt with in the Affiliate proceeding. The forecast revenue from affiliates for ATCO is $3,443,000, $2,808,000, and $2,582,000 for 2000, 2001, and 2002 respectively.

**Views of the Board**

The Board recognizes that the test year forecasts for Affiliate Support Services Revenue represent amounts which are being considered in the Affiliate proceeding. Accordingly the Board will not address the quantum or propriety of forecast revenues for Affiliate Support Services in this Decision.

### 7.10.3 Production Related Revenue

**Position of ATCO**

ATCO provided the following table with respect to this revenue category:

**Production Related Revenue**
**($000)**

| | 1999 Actual | 2000 Forecast | 2001 Forecast | 2002 Forecast |
|---|---|---|---|---|
| Net Condensate Revenue | 631 | 277 | 277 | 277 |
| Other Revenue | 56 | 105 | 155 | 104 |
| **Total** | **687** | **382** | **432** | **381** |

ATCO stated that the forecast condensate revenue for 2001 and 2002 was based on the expected level of revenue for 2000 which was $277,000.

Other revenues, which included overriding royalties derived from farmed out lands where ATCO owned or leased the mineral rights and joint venture recoveries, were forecast to be $105,000, $155,000 and $104,000 for 2000, 2001 and 2002 respectively.

**Positions of the Interveners**

**Calgary**

Calgary submitted that the cost of Carbon storage was included in the proposed revenue requirements set forth by ATCO in the proceeding. Calgary stated that its position was simple - Carbon storage offered and provided benefits to ratepayers and should continue to provide service.

Calgary was of the opinion that Carbon storage could not be simply plucked from the GRA proceeding and moved to the Affiliate proceeding. Calgary submitted that there appeared to be a shortfall in the forecast revenue from Carbon in the Application, and noted that in Decision

2000-9[94] the Board deemed approximately $3 million in additional revenues to be applicable to storage operations. Calgary stated that ATCO appeared to have downgraded this amount to $1.6 million, ignoring the additional deemed revenues related to Compressor 6, providing no explanation of the reduction and providing no evidence to support the exclusion of approximately $1.4 of Board ordered deemed revenue.

Calgary argued that the net costs of operating the Carbon storage field were overstated as a result of the capacity, previously used by NUL, becoming available to ATCO Midstream, resulting in a loss of revenues credited to the overall cost of the Carbon storage operation. Calgary noted that ATCO had purportedly contracted the full Carbon storage field to an affiliate, ATCO Midstream, as of April 1, 2001, and that the Company was no longer providing service to ratepayers from the Carbon facility, a rate base asset. Calgary submitted that this action raised the question of the ATCO proposal to include several million dollars of O&M expense for Carbon in its revenue requirement. Calgary observed that part of the O&M expense was fuel costs, which are driven by the manner in which an operator manages the storage facility. Calgary believed that more cycles produced greater revenues to the operator, but at a higher fuel cost. Calgary argued that since ATCO Midstream was the operator of the Carbon facility, it should be held totally responsible for the fuel costs, not ATCO ratepayers. As with the fuel, Calgary stated that there was no justification as to why ATCO ratepayers should be held accountable for the O&M costs other than what was appropriately included in a charge for storage service.

Calgary submitted that the revenues which ATCO Midstream earned from the operation of the Carbon facility must also be considered in this Application. Calgary stated that its evidence in the GCRR proceeding indicated the value of the flexibility alone in the winter of 2000/2001 was at least $8.9 million.[95] Calgary viewed that under the contract with its affiliate, ATCO did not have storage rights for 2001/2002 in the Carbon facility and as such the existing ratepayers were paying for the use of Carbon in their rates. Calgary stated that due to the arrangement with an affiliate, customers had to request ATCO contract for third party storage for the 2001/2002 storage season and consequently, ratepayers were paying for O&M, return, depreciation and taxes on a rate base asset from which they derived no service or benefits in 2001. Calgary argued that these costs, as well as the benefits of savings arising from the optionality, liquidity and seasonal savings, were not reflected in the Application for 2001 and 2002.

Calgary recommended that the Board find and order that:

- The Board recognize the value of Carbon storage field to utility ratepayers.
- The Board find that the contract between AGS and its Affiliate ATCO Midstream is not in the public interest and is not approved.
- ATCO be ordered to manage Carbon for the benefit of ratepayers including the appropriate use of Carbon, and the flexibility being paid for by ratepayers, to reduce service costs and maximize the revenues to be achieved from surplus storage; and
- ATCO be ordered to recognize and account for all costs including lost revenue arising from its decision to change storage management practices and those related to its contract with its affiliate ATCO Midstream, and to credit those revenues to the 2001/2002 revenue requirement.

[94] Decision 2000-9, Section 6.6, Directions 55 and 56
[95] GCRR Inquiry, Exhibit 81

**Views of the Board**

The Board recognizes that the test year forecasts for Carbon Storage Revenue represent amounts recoverable under the arrangement with ATCO Midstream, which will be considered in a separate proceeding. Accordingly, the Board will not address the quantum or propriety of forecast storage revenue in this Decision.

The Board considers that test year forecasts for Production Related Revenue are reasonable and accepts ATCO's forecasts as filed.

## 8 SUMMARY OF 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 report, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board directs ATCO to revise the forecasts for new measurement and regulating station facilities to reflect the amounts identified as known projects, thereby reducing forecast expenditures by $220,000 (2001) and $140,000 (2002). ........................ 9

2. Accordingly, the Board directs ATCO to reduce the test year forecasts for urban mains replacement to $1.182 million (2001) and $0.896 million (2002), being the amounts as determined in ATCO's recalculation. This adjustment represents reductions from ATCO's original forecasts of $150,000 (2001) and $61,000 (2002)................................ 13

3. Accordingly, the Board directs ATCO to reduce the test year forecasts for rural mains replacements and relocations by $155,000 (2001) and $78,000 (2002)........................... 14

4. Accordingly, the Board directs ATCO to decrease forecast expenditures for moveable equipment by $217,000 (2001) and $215,000 (2002) representing 10% in each test year, which will reduce test year forecasts to 2000 levels........................................................ 14

5. Accordingly, the Board directs ATCO to reduce forecast expenditure for regulating and measurement station improvements by $290,000 (2001) and $470,000 (2002)............... 15

6. Accordingly, the Board directs ATCO to reduce the 2001 test year opening balance of Property, Plant and Equipment by $4.7 million to recognize actual expenditure in the year 2000........................................................................................................................ 18

7. Accordingly, the Board agrees with the MI that the amount of the service line alterations capitalized in 2000 should be removed from the opening balance of Property, Plant and Equipment for the 2001 test year. The Board therefore directs ATCO to reduce the 2001 opening balance of Property, Plant and Equipment by $394,000..................................... 25

8. Accordingly, the Board repeats the direction made in Decision 2000-9 that ATCO apply a zero expense lag to the retained earnings component of common equity return and an expense lag for the common dividend component based on the methodology used to

calculate the preferred dividend lag. The Board therefore directs ATCO to make the appropriate adjustment to its lead/lag study to comply with this requirement. ................ 46

9. Accordingly, the Board directs ATCO to recalculate the NWC balance using a zero lag for transactions with ATCO Pipelines and an expense lag of 34.16 days for other affiliate payments. ........................................................................................................... 47

10. The Board is not prepared to reverse its findings from Decision 2000-9 with respect to the inclusion of short-term debt in ATCO's capitalization for the purposes of determining Utility Income. Therefore the Board directs that ATCO include sufficient deemed short-term debt in the capital structure of AGS in both 2001 and 2002 to balance capitalization and rate base within $500,000 on a mid-year basis, as directed in Decision 2000-9 and Decision 2000-45, at a deemed cost rate of 4.75%......................................................... 69

11. The Board agrees that the long term impact of high gas prices is speculative and is persuaded that an adjustment should be made to the forecast to reduce the additional costs attributed to high gas prices. Accordingly the Board directs ATCO to reduce the additional costs of $4 million claimed by ATCO in each test year by $2 million........... 86

12. Accordingly, the Board does not accept ATCO's proposal for inclusion of donations in the determination of revenue requirement for the test years, and directs the company to reduce revenue requirement by the amount of donations forecast for the test years....... 98

13. However, the Board is of the view that for the test years, the historical level of $524,000 is, on a forecast basis, more appropriate and should be maintained. Accordingly, the Board directs ATCO to reduce the 2001 and 2002 forecast by $3.976 million, and $476,000, respectively. ......................................................................................... 101

14. The Board also accepts that ATCO's proposal for a one-time recovery of these costs. The Board directs ATCO to collect $4.452 million in regulatory costs for the 2001 and 2002 test years by means of a rate rider. The Board expects that the balance of hearing cost expense will be reconciled through the deferred account............................................. 101

15. However, to provide the Board with sufficient information to evaluate the ongoing appropriateness of the reserve balance, the Board directs ATCO, at the next GRA, to provide a more detailed accounting of the Reserve for Injuries and Damages. This should include details of amounts required for major and minor damages, claims history, and the extent to which the reduction in reserve is offset by increases in insurance premiums. 101

16. Accordingly, the Board accepts the method adopted by ATCO for depreciation of production and storage assets, but directs ATCO to perform a detailed study for filing at the next GRA, to separately identify storage cushion gas volumes and other production volumes to support the ELG and UOP rates used in the depreciation calculation. ........ 108

17. Accordingly, the Board directs ATCO to recalculate income tax expense and liabilities for the test years using those rates announced or substantively enacted by the federal and provincial governments for those years. ....................................................................... 112

## 9 ORDER

THEREFORE, IT IS ORDERED THAT:

1) ATCO Gas South shall refile its 2001/2002 GRA, on or before February 15, 2002 incorporating the findings of the Board in this Decision.

2) ATCO Gas South, in its refiling, shall include all of the supporting schedules necessary for the Board to make its final determination respecting ATCO's 2001/2002 revenue requirement. The refilling shall be at a level of detail sufficient to reconcile with the original filing and demonstrate compliance with the Board's findings.

3) With respect to transactions with Affiliates and transactions related to pension and post employment benefits, ATCO Gas South shall include in the revenue requirement for the test years, the related expenditures and revenues as filed in the General Rate Application, pending final determination of these amounts in the ATCO Affiliates and ATCO Pension proceedings. ATCO will be required to adjust the amounts, included as "placeholders" in the revenue requirement for the test years, will be adjusted after the Board issues decisions on the ATCO Affiliates and ATCO Pension proceedings.

4) ATCO Gas South shall propose a method for collection of the 2001 revenue shortfall on an interim basis pending final determination of the revenue requirement for the test years upon receipt of Board decisions with respect to the ATCO Affiliates and ATCO Pension proceedings.

Dated in Calgary, Alberta on December 12, 2001

**ALBERTA ENERGY AND UTILITIES BOARD.**

*(original signed by)*

B. F. Bietz, Ph.D.
Presiding Member

*(original signed by)*

Gordon J. Miller
Member

*(original signed by)*

C. Dahl Rees
Acting Member