Decision **2003-108**

ATCO Gas

2003 Gas Rate Unbundling

December 18, 2003

Alberta Energy and Utilities Board

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Decision 2003-108: ATCO Gas
2003 Gas Rate Unbundling
Application No. 1303682

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Alberta Energy and Utilities Board
640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

Web site: www.eub.gov.ab.ca

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1 INTRODUCTION

ATCO Gas, a division of ATCO Gas and Pipelines Ltd. (AGPL), filed an application (the Application) with the Alberta Energy and Utilities Board (the Board or EUB), by letter dated June 6, 2003, requesting approval of interim distribution rates as a result of the unbundling of existing distribution rates. ATCO Gas includes ATCO Gas South (AGS) and ATCO Gas North (AGN), each of which has its own service areas.

A Notice of Hearing dated June 16, 2003 was emailed to all interested parties registered in the ATCO Retail Sale Application (the Retail Sale) and published in the daily newspapers in ATCO Gas's service areas.

The public hearing was convened in Calgary on October 20, 2003 before Mr. B. T. McManus, Q.C. (Presiding Member), Mr. J. I. Douglas, FCA, Member and Mr. W. K. Taylor, Acting Member. The hearing was completed on October 22, 2003. Registered interveners were required to file argument and reply by October 31, 2003 and November 7, 2003 respectively.

The Board considers that the record for this proceeding closed on November 7, 2003.

In the Retail Sale Application, ATCO Electric Ltd (ATCO Electric) and ATCO Gas requested approval to transfer certain retail electricity and natural gas assets to Direct Energy Regulated Services (DERS), a business unit of Direct Energy Marketing Limited (DEML). The Retail Sale Application also requested approval for DERS to perform certain functions on behalf of ATCO Electric and ATCO Gas, including being the Regulated Rate Provider (RRP) and Default Supply Provider (DSP), providing a Regulated Rate Tariff (RRT) and Default Rate Tariff (DRT) for eligible electric and natural gas consumers respectively. DERS filed an application with the Board on May 20, 2003 (DERS Tariff Application) for approval of the RRT and DRT in the service territories of ATCO Electric and ATCO Gas.

In Decision 2003-098[1] the Board approved the assignment of the DSP function by ATCO Gas to DERS and the assignment of the RRP function by ATCO Electric to DERS.

[1] Decision 2003-098 – ATCO Electric Ltd., ATCO Gas North and ATCO Gas South, Both Operating Divisions of ATCO Gas and Pipelines Ltd., Transfer of Certain Retail Assets to Direct Energy Marketing Limited and Proposed Arrangements with Direct Energy Regulated Services to Perform Certain Regulated Retail Functions, dated December 4, 2003

2 PARTICULARS OF THE APPLICATION

Unbundling involves removing the costs of functions related to the sale of natural gas from the existing distribution rates and instead recovering these costs in a gas sales service rate, referred to as the Gas Cost Recovery Rate (GCRR) and identified in ATCO Gas' rates as Rider "F". The GCRR is a cost recovery rate on which ATCO Gas does not make a profit. ATCO Gas earns its profit through its distribution rates. The GCRR recovers gas commodity related costs on a monthly forecast basis. Forecast costs used to determine a GCRR are subsequently reconciled with actual costs incurred, through the Deferred Gas Account (DGA). Any over/under-recovery in one month is credited/charged to customers in the subsequent month. The gas supply and related customer care functions may be provided by a natural gas Retail Service Provider (RSP), or the regulated DSP.

ATCO Gas noted that it would effectively become a "pipes" only utility (a gas distributor or Pipe Service Provider (PSP)) on approval of the Retail Sale, as it would no longer provide gas sales and related customer care functions. However, ATCO Gas noted that it would still be required to retain certain customer care functions related to providing distribution service. ATCO Gas submitted that the objectives of the Application were to:

- Identify the impact of ATCO Gas no longer providing gas supply and customer care services.
- Develop new interim rates to be effective on the date of the approval of the Retail Sale.
- Provide a methodology for addressing impacts of the Retail Sale on the ATCO Gas 2003/2004 General Rate Application (GRA).

In the Application, ATCO Gas proposed a methodology for addressing impacts of the Retail Sale on the ATCO Gas revenue requirement, and noted that the unbundling of rates would be required even if the Retail Sale were not approved.

To facilitate the unbundling of its delivery rates, ATCO Gas stated that it had conducted an unbundling allocation study using the 2002 AGS revenue requirement, which was the most recently approved revenue requirement. The 2002 AGS revenue requirement for the asset-related costs was $80,708,000 and for the operating costs was $96,772,000, resulting in a total 2002 Base Rate Revenue Requirement of $177,480,000 as approved in Board Decision 2003-006[2].

ATCO Gas submitted that the services and associated unit costs impacted by the Retail Sale were similar for both AGS and AGN, and therefore considered it appropriate to use the AGS analysis as a surrogate for AGN, when assessing the impacts of the Retail Sale.

ATCO Gas examined each of the prime accounts and assessed whether the services charged to a prime account could be assigned directly to a function, or classified as an indirect cost if general in nature. ATCO Gas applied the allocation methodologies used in the 2002 Cost of Service Study (COSS) filed on February 18, 2003 to assign indirect costs to the various functions. ATCO

[2] Decision 2003-006 – ATCO Gas South, 2001/2002 General Rate Application, and Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues – Second Compliance Filing, dated January 21, 2003

noted that in Decision 2001-75[3], the Board identified 10 functions to be used in an unbundling study. In addition to these functions, ATCO Gas also included the functions of Distribution Mains and Services, Production and Gathering, Gas Supply and Administration in the unbundling study, for completeness of the analysis.

ATCO Gas reviewed the costs of each function costs to identify any related impact resulting from the Retail Sale and customer choice. Functions were analyzed to determine the costs of services that would no longer be provided by ATCO Gas. Indirect costs assigned to those functions were also reviewed in the same manner.

Costs were then assigned to either ATCO Gas, as the PSP, or to the gas supply function of the DSP or RSP. The results of the analysis were shown on Schedule 1 of the Application and are reproduced in Appendix C of this Decision.

ATCO Gas noted that interim rates were already in place for both AGS and AGN, and considered it appropriate to adjust the interim rates effective with the Retail Sale. ATCO Gas recommended an interim rate adjustment of $7,035,000, representing total cost reductions of $8,548,000 less late payment penalty revenue of $1,513,000. ATCO Gas recommended that the rate adjustment calculated for AGS should also be applicable to AGN. The interim, unbundled rates proposed by ATCO Gas are shown in Tables 1 and 2 below.

Table 1. Proposed Interim Rates – AGS

Rate	Fixed $/month	Variable $/GJ*	Demand $/GJ
1	12.70	1.058	----
3	263.45	0.284	3.35
5	19.08	0.876	----
13	283.72	0.154	5.47

*gigajoule

Table 2. Proposed Interim Rates – AGN

Rate	Fixed $/month	Variable $/GJ	Demand $/GJ
1	11.90	0.990	----
3	256.93	0.267	3.70
13	293.01	0.052	5.68

ATCO Gas's existing interim rates are included in Appendix D of this decision.

ATCO Gas proposed that the final rates for the 2003/2004 GRA test period would be determined once the Board had completed the 2003/2004 GRA Phase II proceeding.

3 Decision 2001-75 – GCRR Methodology and Gas Rate Unbundling, Part A: Methodology and Unbundling Proceeding, dated October 30, 2001

ATCO Gas also requested that, effective with the Retail Sale implementation, the Board approve a change, for all municipalities collecting franchise fees on Method B (franchise fee calculated on sales service rates). The change would be to Method C (distribution rate plus the deemed value for gas). ATCO Gas explained that as a result of the Retail Sale, a municipality using Method B would no longer collect any franchise fee, as ATCO Gas would no longer provide sales service. ATCO Gas indicated that Method C would result in collection of the same dollar value of franchise fee per customer as Method B.

ATCO Gas also requested approval to change the definition of "deemed value" utilized in Method C to the DSP's Rider "F" (the gas cost flow-through rate). ATCO Gas indicated that this definition would replace the ATCO Gas Rider "F" (the GCRR).

ATCO Gas also proposed the following:

1) Components identified as impacting the 2003/2004 GRA revenue requirements as a result of the Retail Sale would be approved as part of the Application. Any final adjustments to the 2003/2004 revenue requirements related to the Retail Sale would be made in a final application once all other placeholder[4] amounts had been determined.

2) As there would be an impact on rate base associated with the Royalty Fee for the Customer Information System (CIS) in an amount estimated at $1.1 million, there would be an increased contribution to rate base by that amount, which would impact the 2004 revenue requirement (excluding working capital) by a reduction of $459,000.

3) The gas supply expense and GST (goods and services tax) components related to gas purchases would be removed from the Necessary Working Capital (NWC). The gas supply expense related to production and storage would continue to be included in the NWC. As this cost was being recovered through the GCRR, this change would impact the revenue requirement, but it would not impact the revenue shortfall as there would be an offsetting adjustment to revenue. The NWC related to the gas supply expense for production and storage would be dealt with through the company-owned production (COP) and company-owned storage (COS) rate riders (COPRR and COSRR, respectively).

4) With respect to Operating and Maintenance (O&M) expenses, adjustments would be included for fringe benefits costs for changes to the labour forecast, the removal of bad debt expense and the removal of consulting fees related to gas supply in the amount of $21,000.

5) The gas management fee and the costs related to portfolio management would be removed from the forecast. As these costs were being recovered through the GCRR, this change would impact the revenue requirement, but it would not impact the revenue shortfall as there would be an offsetting adjustment to revenue.

6) The customer care costs from ATCO I-Tek Business Services (ITBS) would be adjusted based on the principles established in this proceeding. The impact on the 2003/2004 revenue requirement forecast would be determined through the same methodology used

[4] Certain values in the ATCO Gas 2003/2004 GRA revenue requirement to be determined in separate processes.

in the Application and would also incorporate the impact of decisions related to the GRA placeholder for this amount.

7) The impact of energy revenue would be removed from the allocation factor used to allocate the ATCO Ltd./Canadian Utilities Limited (ATCO/CU) corporate costs included in the 2004 forecast revenue requirement if the Retail Sale were approved. The impact of the change to revenue requirement was estimated to be a reduction of $1.137 million (not including any changes that might result from the GRA placeholder for Executive Compensation).

8) If the Retail Sale were approved, an adjustment to allocation of corporate aircraft charges would result in a decrease in the 2004 revenue requirement of $115,000.

9) The GCRR revenue and expense related to gas purchases would be removed from revenues. Forecast revenues related to the sale of COP and storage on the open market would be incorporated. The gas supply expense would continue to include amounts related to royalties on production and purchases with respect to storage. The net amount of revenue less gas supply expense would be the same as the market value adjustment that was included in the current GRA forecast with respect to the COPRR and COSRR. The NWC related to the gas supply expense for COP and storage would also be dealt with through the COPRR and COSRR. As a result, there would not be any impact on the revenue shortfall as a result of these changes.

10) The "Cost of Service Transferred to the DGA" revenue adjustment would be removed. Since ATCO Gas was also removing all of the costs related to this from the forecast, there would not be any impact on the revenue shortfall as a result of this change.

11) The "COP Market Adjustment" and "Storage Market Adjustment" would be removed, as these amounts would be replaced by the revenue and gas supply expense related to production and storage. There would not be any impact on the revenue shortfall as a result of these changes.

12) The penalty revenue forecast and the revenue related to Customer Requests and Dishonored Cheques would be removed, as ATCO Gas will no longer receive this revenue. The estimated reduction to the 2004 revenue forecast for the latter two was $6,000 and $70,000 respectively.

ATCO Gas also indicated that there might be further changes required associated with long term financing, Large Corporation Tax and income tax.

ATCO Gas requested that the Board provide separate direction with respect to interim rates in the event that the Retail Sale was approved prior to the Board issuing its decision with respect to the Application.

In the Application, ATCO Gas did not propose that all costs previously allocated to unbundled functions could be eliminated. ATCO Gas submitted that certain costs prudently incurred, which were otherwise allocated in part to those functions for rate-making purposes, must now be recovered in delivery rates.

In rebuttal evidence, submitted October 7, 2003, ATCO Gas proposed that costs associated with the Production and Storage functions should be transferred from delivery rates into the respective riders. Based on the 2002 COSS included in the Application, ATCO Gas calculated the reduction in delivery rates that would result if the total costs associated with Storage and Production were transferred to the respective riders. The respective rate adjustments are shown in Table 3 below.

Table 3. Proposed COPRR and COSRR Adjustments

	Reference	Costs $000	Throughput GJ	Rate Adjustment $/GJ
Production	COSS, page 28	3,198	108,487,000	0.029
Storage	COSS, page 29	11,608	108,487,000	0.107

ATCO Gas proposed to decrease interim rates by the amounts shown in Table 3 and increase the respective riders accordingly.

3 RELEVANCE OF DECISION 2001-75

In this section the Board will consider the views of parties as to the need for and timing of an analysis or study that would comply with Decision 2001-75, notably section 6. The Board will also consider views of parties as they pertain to specific areas considered for unbundling.

3.1 General

Views of the Interveners

AIPA

The Alberta Irrigation Projects Association (AIPA) expressed concern with ATCO Gas's premise that overhead and indirect costs that the regulator previously found prudent on the basis that these costs supported a combined distribution and retail function would remain prudent in perpetuity regardless of significantly changed circumstances. AIPA argued that there was no basis to support the view that the total of these costs should be allocated 100% to the functions that remained.

AIPA argued that the quantum of overhead and indirect costs must be justified on the basis of remaining functions. This process was no different than a utility requesting an increase in a GRA. If judged reasonable and prudent, the costs would be approved. Otherwise, they would be denied. AIPA agued that the Board needed to determine an appropriate allocation of overhead and indirect costs that were associated with the removed retail function. AIPA submitted that, if ATCO Gas subsequently determined that stranded costs existed, ATCO Gas could make an application to the Board for consideration at that time.

AltaGas

AltaGas Utilities Inc. (AltaGas) argued that Decision 2001-75 was still very relevant to the process of unbundling in Alberta and that the Board had set out various principles and examined various utility functions that should or should not be unbundled. AltaGas submitted that the Application should not be viewed as a forum for a party to re-litigate or review that Decision. AltaGas argued that Decision 2001-75 had been largely reaffirmed by the Government of

Alberta and given the force of legislation in new amendments to the *Gas Utilities Act*, R.S.A 2000 c. G-5 (GUA), the enactment of *Roles, Relationships and Responsibilities Regulation* AR 186/2003 (*R3 Regulation*), and the enactment of the *Default Gas Supply Regulation* AR 184/2003 (*DGS Regulation*), and various other regulations under the GUA.

AltaGas considered the approach proposed by ATCO Gas in the Application to be consistent with Regulations under the GUA and Decision 2001-75. AltaGas argued that ATCO Gas was in the best position to determine appropriate allocation principles for its own operations within this framework.

AUMA/EDM

The Alberta Urban Municipalities Association and the City of Edmonton (AUMA/EDM) noted that there were no objections to including the record from the Retail Sale and DERS Tariff proceedings in the Unbundling proceeding.[5]

AUMA/EDM considered that ATCO Gas had partially complied with the Board's expectation "that in conjunction with the Retail Sale application, ATCO Gas will file a proposal for unbundling those retail functions that would move to DERS from the distribution function, together with a methodology for dealing with test year cost implications and reductions to the distribution revenue requirement."[6] However, it appeared to AUMA/EDM that ATCO Gas had chosen to only include the most obvious, direct, first-order costs to be removed from the revenue requirement as a result of the Retail Sale and transfer.

AUMA/EDM argued that the ATCO Gas 2003/2004 GRA Phase II proceeding would likely provide the best opportunity to incorporate both the results from the outstanding modules and unresolved unbundling issues into a final proceeding.

Calgary

The City of Calgary (Calgary) argued that the issue with respect to Decision 2001-75 was not one of relevancy but rather was one of timing. Calgary argued that while the GUA amendments legislated certain responsibilities, with a view to embracing competition, these legislative changes were not prescriptive or limiting in defining or shaping the competitive marketplace. Calgary believed that the legislative changes described certain mandated functions and responsibilities, but did not purport in any way to discourage or prevent the Board from invoking other competitive enhancing measures under its general supervisory powers. Calgary argued that there was no legislative interdiction against unbundling under the *R3 Regulation* when the Board rendered Decision 2001-75, nor did the legislation purport to place a tether upon the Board in terms of the unbundling of rates.

Calgary argued that while the gas distributor might outsource any of the functions not specifically requiring Board approval, there was nothing in the legislation that stated the Board could not order such on its own initiative if, in the unbundling of functions, the Board determined that the rates charged for a particular function were not fair market value. Calgary argued that the Board was in a position to disallow such costs as being imprudent, thereby

5 Tr. pp. 9-11
6 Board letter dated January 29, 2003

effectively making the rates for a particular function competitive, or alternatively, to force the distributor to outsource the function.

Calgary argued that the parties had every reason to believe that what would be prepared and filed by ATCO Gas was not just an incremental costing study, hiving off those costs which ATCO Gas no longer considered would be required by a local distribution company (LDC), but a fully unbundled COSS as contemplated by the Board in past decisions.

Calgary stated that its position throughout the process had been founded on enhancing the competitive market place by allowing consumers, either through their own efforts or by alternative service providers on behalf of consumers, to participate in a more competitive marketplace for the provision of energy services. Calgary submitted that section 6.1.2 and Direction 12 of Decision 2001-75 provided a framework in which to evaluate rate and functional unbundling with the potential for enhancing the development of the competitive marketplace.

Calgary viewed ATCO Gas's concern with stranded costs and/or bypass as a clear indication that ATCO Gas considered that its costs were non-competitive and higher than fair market value. Calgary argued that if ATCO Gas's costs were fair market value or below there would be no ability for it to be bypassed or to have stranded costs.

Calgary submitted that the Board should order a fully unbundled COSS substantively along the same lines as contemplated by Decision 2001-75, the study to be prepared and filed along with the final replacement of 2003/2004 placeholders. Calgary submitted that this would enable parties to assess adequately the implications of the material as presented, prior to the ATCO Gas 2003/2004 GRA Phase II hearing.

FGA

The Federation of Alberta Gas Co-ops Ltd. and Gas Alberta, the Town of Redwater, and the Samson Band (FGA) noted that ATCO Gas's position was that the Board had relieved it from Direction 12 of Decision 2001-75 and directed it to provide an unbundling proposal related to the Retail Sale. The FGA also noted that Calgary's position was that ATCO Gas was given relief for only the 90-day filing requirement pertaining to Direction 12; thus ATCO Gas must still fully comply with Direction 12.

The FGA agreed with ATCO Gas's interpretation of the Board's comments in its letter dated January 29, 2003. The FGA also did not oppose ATCO Gas's use of the *R3 Regulation*, and the roles and responsibilities for distributors and retailers outlined therein, as a basis the Application. However, the FGA argued that ATCO Gas might be ignoring other comments in Decision 2001-75 based on the relief it received for Direction 12. For example, section 6.4.2 of Decision 2001-75 stated that storage costs not related to gas price management are not to be unbundled, yet ATCO Gas proposed to unbundle remaining storage costs to the storage rider because the *R3 Regulation* does not specifically enumerate storage as a distribution function.[7]

The FGA believed ATCO Gas's proposed unbundling methods were generally reasonable and that there was no need for the Board to act in any manner that would be inconsistent with legislation or regulation. The FGA submitted that ATCO Gas's method of adopting the *R3 Regulation* as a basis for developing the Application was reasonable.

[7] ATCO Gas Rebuttal Evidence, p. 6, lines 12-16

PICA/STMG

The Public Institutional Consumers of Alberta (PICA)/St. Michael's Extended Care Society (STMG) argued that certain functions, such as load balancing and load settlement costs, had not been unbundled by ATCO Gas. PICA/STMG suggested that a module to deal with the unbundling of the 2004 revenue requirement prior to the ATCO Gas 2003/2004 GRA Phase II proceeding would be fitting to ensure the Phase II cost allocations were appropriate.

Views of ATCO Gas

ATCO Gas argued that Decision 2001-75 was very relevant with respect to functional unbundling and clearly matched the government legislation enacted in June of 2003.

ATCO Gas argued that Calgary's intended use of a future COSS would be to develop unbundled rate schedules that would be used to evaluate which functions should be unbundled on the tariff sheet to provide the opportunity for enhanced development of the competitive market.[8] ATCO Gas argued that Calgary was attempting to reintroduce bypass of utility functions, and urged the Board to reject this position. ATCO Gas argued that the roles of distributors, the DSP and retailers were clearly defined and that it was not necessary to initiate additional studies and hearing processes to facilitate the bypass of functions, which were now clearly assigned to the utility by legislation.

ATCO Gas argued that the Board rejected the notion of eventual bypass of utility functions by "competitive service providers" when Calgary previously attempted such functional unbundling in the proceeding that led to Decision 2001-75. ATCO Gas further argued that the Board should order the undertaking of the further "unbundling" suggested by Calgary only if the Board supported bypass. ATCO Gas believed that there should be no stranded costs if the Application was approved as filed. ATCO Gas submitted that if the Board did not approve the Application, provision needed to be made for the recovery of stranded costs.

ATCO Gas disagreed with Calgary's jurisdictional assertion and argued that such assertion could not withstand a review of legislation, such as section 2(1) of the *R3 Regulation*, which required a gas distributor's authorization prior to having any of its listed functions performed by other persons. ATCO Gas argued that this provision was the antithesis of bypass and directly contradicted Calgary's related argument on legislation.

ATCO Gas noted that customer care and information technology (IT) functions would be tested through a benchmarking exercise, and that load settlement and load balancing would be reviewed through the Retailer Services and GUA Compliance Application (No. 1308709). ATCO Gas considered transmission costs to be very transparent as they are a single charge from ATCO Pipelines. ATCO Gas noted that Calgary had been an active participant in ATCO Pipelines' rate cases. ATCO Gas argued that what was left were the typical functions performed by a gas distributor, specifically installing and maintaining pipes and meters to ensure safe, reliable service.

[8] Tr. p. 391, lines 17-25; p. 392, lines 1-12

Views of the Board

The Board considers that the Application has generally fulfilled the Board's expectation with respect to complying with Decision 2001-75. The Board notes that the *R3 Regulation* is substantially in accord with Decision 2001-75, and that ATCO Gas has presented its analysis to comply with the *R3 Regulation*.

The Board will address the appropriateness of further unbundling of the distribution tariff in section 5 of this Decision.

3.2 Transmission (Upstream Capacity)

Views of the Interveners

AIPA

AIPA argued that there was a problem with the concept of assigning transmission capacity at this time. AIPA argued that the issue of stranded costs remained a concern. If a retailer opted to secure its own transmission service capacity then the remaining customers would be responsible for the relinquished capacity and costs.

AIPA also argued that the issue of multiple delivery points had not been addressed. AIPA considered that where a distribution system was connected to major transmission system with relatively few interconnects then the concept of assignment was more easily applied. However, in the case of ATCO Gas and ATCO Pipelines with multiple delivery points, the concept of assignment was more complex, especially if certain retailers use only particular sections of the transmission system.

AIPA also argued that there would be other issues, such as liability and credit requirements, if specific retailers were assigned a share of the transmission system.

AIPA argued that the capacity assignment proposal was premature and did not provide any enhancement over the existing process and appeared to be an unnecessary intermediate step if the ultimate goal was to have retailers contract for their upstream transmission capacity. AIPA submitted that the current proposal of assigning upstream transmission appeared to leave too many questions unanswered for the Board to accept the proposal at this time.

AltaGas

AltaGas argued that it was clear that subsection (c) of section 4(1) of the *R3 Regulation* obligated the gas distributor to contract for upstream transmission capacity. AltaGas argued that this was exactly what was contemplated by Decision 2001-75 with respect to transmission. AltaGas believed it was also clear from the GUA and the *R3 Regulation* that the gas distribution company was ultimately responsible for all of its roles and obligations under the *R3 Regulation*, even if these duties were assigned. AltaGas argued that since the gas distributor had the responsibility and liability for getting the job done, it must have the tools to get the job done and thus must retain upstream transmission capacity.

AltaGas noted that problems might develop in the capacity assignment scenario if there were a disagreement between the LDC and the retailer on whether "a failure of supply " was occurring or likely to occur. AltaGas was concerned that it would be impractical for the LDC to monitor retailers as to whether or not a failure of gas supply was imminent. AltaGas argued that, since reliability of the system and the regulations demanded that the gas distributor retain the responsibility and liability to ultimately provide upstream capacity and deliver gas, the gas distributor should hold that capacity. Any other result would saddle the distributor with liability without adequate control.

AUMA/EDM

The AUMA/EDM noted that in the 2001 Unbundling Proceeding the Municipal Intervenors/Urban Municipalities, an intervener group in which the AUMA was a participant, took the position that, although transmission was a candidate for unbundling, it should be subject to determining, quantifying and addressing the potential stranded costs before a final decision on unbundling was made.[9] The AUMA/EDM noted also that in Decision 2001-75 the Board directed that transmission costs remain as part of bundled delivery rates.[10] AUMA/EDM argued that it was appropriate to include the costs associated with this function with the PSP at this time.

The AUMA/EDM submitted that any unbundling of the transmission function should await the outcome of the process dealing with inter-pipeline competition issues as suggested by PICA/STMG[11] or alternatively, at the time of a bypass application as suggested by ATCO Gas.[12]

The AUMA/EDM did not consider it appropriate for the Board to accept capacity assignment pages from the tariff sheets of other pipelines as suggested in Calgary's Argument,[13] since the mechanics of how these capacity assignments work cannot be properly tested.

Calgary

Calgary repeated its argument that there was no legislative impediment to authorizing a DSP/RSP to manage upstream transmission capacity.

Calgary believed that there were two fundamental issues requiring evaluation regarding upstream transmission capacity. The first issue was who should manage and control the daily use of upstream capacity, the distributor or the DSP and/or RSPs. The second issue results from the decision on the first issue. Calgary argued that if the distributor managed and controlled upstream capacity, even though it was not the shipper, then the issue was one of rate unbundling. However, if the DSP and/or RSPs managed and controlled upstream capacity, then the issue of rate unbundling ceased to exist as the upstream capacity would be managed and controlled by the DSP and/or RSPs under assignment. Calgary stated that it did not dispute that the distributor was required to "arrange" for upstream capacity; however, Calgary's position was that the daily management and control of this capacity should be in the hands of the party best situated to actively manage the capacity and be provided the incentive to enhance the competitive market.[14]

Calgary's position was that, based upon implementation of the ATCO Gas sale to DEML, the competitive marketplace could be enhanced by assignment of the upstream capacity to the entities which actually would ship gas on ATCO Pipelines for ultimate delivery to consumers,

9 Decision 2001-75, p. 92; MI/UM Argument p. 29
10 Decision 2001-75, p. 92
11 PICA/STMG Argument, p. 2
12 ATCO Gas Argument, p. 6
13 Calgary Argument, p. 14
14 Tr. p. 418, lines 8-18

the DSP and/or RSPs. Calgary argued that these entities would have an incentive to actively manage the capacity on a day-to-day basis.

Calgary argued that the assignment of the capacity to DSP and RSPs placed standalone capacity in the hands of both regulated and unregulated suppliers, which should also serve to provide additional opportunities to enhance the competitive market. Calgary submitted that the assignment process provided the protection required to provide assurance to the distributor that the capacity would revert to it in the event of default of the DSP or RSP in providing service.[15] Calgary believed that this assurance not only protected the distributor, but also provided a seamless transfer for the end use consumer. Since the end-user relied on the DSP or other RSP to provide the commodity, the distributor, in event of default, would not only take over the capacity under the assignment, but must arrange concurrently for the gas supply, thus creating a seamless transition.[16] However, until default occurred, the DSP or RSP remained the gas supplier, was in the best position to manage and control the daily upstream capacity and had the requisite incentive to do so in a competitive manner.[17]

Calgary considered that the issue of unbundling and upstream capacity was one of efficiency and cost transparency. If the pooled capacity was allocated pro-rata there was no difference before or after assignment except that the parties would have an incentive to utilize the capacity more effectively. Calgary argued that ATCO Gas had no incentive to manage that capacity effectively, since the ATCO Group potentially benefited from the status quo.

Calgary submitted that stranded costs could not and did not need to be evaluated in a vacuum. Calgary argued that stranded costs should be addressed only when they were a reality. Calgary indicated that the steps to be taken then would be elimination of the stranded costs, mitigation, and finally, the method of collecting what was left.

Calgary argued that opponents to the unbundling of upstream transmission capacity failed to recognize the difference between unbundling and assignment. Calgary submitted that, absent an assignment and the retention of day-to-day capacity management and control by ATCO Gas, the cost of upstream capacity should be unbundled in the tariff sheet (not on the bill) as a standalone charge.

Calgary argued that it was not trying to promote a breach of the agreement between ATCO Gas and ATCO Pipelines (although it has not been approved for regulatory purposes), but rather was promoting that the operational control and management incentive should be placed in the hands of the shipper.

Calgary submitted that efforts achieved in Decision 2001-75 should be refined to develop an environment which exposed all elements of ATCO Gas's various functions to regulatory scrutiny for determining the extent to which functions could either be performed by others or by ATCO Gas in a more cost efficient (fair market value) manner.

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15 Tr. p. 358, lines 1-8
16 Tr. p. 420, lines 5-13
17 Tr. p..418, lines 10-18

CCA

The Consumers Coalition of Alberta (CCA) was concerned about the stranding of costs associated with transmission if it was unbundled and upstream capacity assigned as Calgary suggested. The CCA argued that ATCO Gas was a captive customer of ATCO Pipelines and that Calgary appeared to be the most likely major core market customer that could bypass ATCO Pipelines due to the proximity of Calgary to major NOVA Gas Transmission Ltd. lines. The CCA noted that ATCO Gas and Calgary did not have a contractual franchise agreement. The franchise agreement is by means of a Calgary Bylaw. The CCA submitted that ATCO Gas was allocated an excessive amount of ATCO Pipelines transmission costs and consequently, if the Board considered that upstream transmission capacity was to be unbundled or capacity assigned, the issue of stranded and reassigned costs must be fully explored.

EnCana

EnCana Corporation (EnCana) argued that ATCO Pipelines had effectively been granted a franchise to deliver gas to the ATCO Gas distribution system, and that customer choice had therefore been precluded. EnCana also argued that the issue of concern was whether or not the development of upstream transmission alternatives was permissible, or if the Board countenanced the exclusive right that had been conferred on ATCO Pipelines by ATCO Gas. EnCana requested that the Board address this issue in its decision.

FGA

The FGA noted that, pursuant to section 28.1 (2) of the GUA, the responsibility for the transmission function would remain with the distributor even if that task were assigned to another entity. The FGA submitted that since AGPL was the owner of the transmission facilities and was responsible for the provision of transmission service, (see also section 4(1)(c) of the *R3 Regulation*) it must be the decision solely of ATCO Gas as to who will carry out the task of providing proper transmission service to customers.

With regard to the definition of the word “arrange” as it pertained to transmission service, the FGA submitted that Calgary was hair-splitting. The FGA noted that nowhere in the section 5(1) of the *R3 Regulation* did it state that retailers were responsible for any transmission costs.

The FGA supported ATCO Gas’s proposal not to unbundle the transmission function. The FGA submitted that the transmission function failed both of the Boards’ qualitative tests for unbundling and that ATCO Gas’s proposal was consistent with the Board’s direction that transmission costs remain part of bundled delivery rates (Decision 2001-75, section 6.3.2). The FGA was also of the view that ATCO Gas’s proposal was consistent with the *R3 Regulation*.

PICA/STMG

PICA/STMG submitted that transparency of transmission costs, as well as management of transmission capacity by the users of that capacity, would likely be most beneficial if the retailers/customers ultimately had the choice of selecting another provider of transmission service. PICA/STMG argued that this option did not appear to be viable at present. PICA/STMG considered that firstly, there was no level playing field among different pipelines providing transmission service within Alberta. PICA/STMG noted the Board was contemplating a process for dealing with inter-pipeline competition issues for intra-Alberta service. PICA/STMG argued that any unbundling and choice issues would need to be evaluated in light of the outcome of that process.

Secondly, PICA/STMG argued that the issue of the treatment of stranded costs, if any, arising from choice in transmission service must be examined.

PICA/STMG was not opposed to further investigation of the issues raised by Calgary in a comprehensive unbundling module following the Board process dealing with the inter-pipelines competition issues.

Views of ATCO Gas

ATCO Gas argued that it was clear that arranging for upstream transmission capacity was the responsibility of the gas distributor and therefore, no costs related to this function would be shed in the determination of interim rates or reduced from the AGS 2003/04 forecast revenue requirement.

ATCO Gas argued that it was the bundled transmission capacity provided by ATCO Pipelines that gave ATCO Gas the ability to provide safe, reliable and efficient distribution service to all its markets on a "pool to pool" basis. This bundled arrangement allowed RSPs and the DSP to obtain supply from wherever they chose. Once they delivered their supply to ATCO Gas's account on the ATCO Pipelines system, they had unrestricted access to any market within ATCO Gas's service area (subject to North and South differentiation). ATCO Gas argued that it was the connectivity provided by bundled transmission that allowed the "integration" of distribution service. ATCO Gas submitted that this was the foundation upon which competitive retailer service rested.[18]

ATCO Gas argued that the legislation obligated the utility to "arrange" which according to the Concise Oxford Dictionary (7th Edition) at page 47, means, *inter alia,* "come to agreement (with person, about thing)."

With respect to Calgary's position regarding assignment of the transmission capacity, ATCO Gas argued that:

1) an assignment assumes that ATCO Gas must contract with ATCO Pipelines in the first place, which was inconsistent with Calgary's position.

2) the assignment of capacity appeared inconsistent with the new roles of the RSPs, the DSP and distribution companies set forth in the GUA and in the *R3 Regulation*. The RSPs and the DSP were expected to arrange for transmission only to the point of receipt specified by the distributor.[19] In the present case, ATCO Gas's receipt point was into its account on the ATCO Pipelines system. Hence the RSPs' and the DSP's roles with respect to upstream transmission ended at the ATCO Pipelines receipt point. From that point on, the role of the LDC clearly envisaged the utility contracting for upstream transmission

[18] Retailer Service and GUA Compliance Application filed July 25, 2003
[19] *Gas Utilities Statutes Amendment Act*, section 28 (i)(ii)(D)

capacity for the purposes enumerated in the *R3 Regulation*,[20] the prudent costs of which were properly included in its delivery rates.[21]

3) Calgary had made clear that its preference over the long term was that the RSPs and the DSP would be expected to contract for all transmission capacity upstream of the distribution system itself.[22] This would prevent the integration of ATCO Gas's distribution markets and force the RSPs and the DSP to point-to-point service, which would limit the RSPs' and the DSP's interests in serving "isolated" customers, if for no other reason than because of the associated administrative burden.

4) Calgary's simple assignment proposal suffered from a fatal lack of definition. There was no evidence tendered with respect to how insolvencies, bankruptcies or receiverships might affect the respective rights and obligations and with it the ability of the utility to ensure the availability of adequate upstream capacity for safe, reliable and economic service.

ATCO Gas also noted that if the assignment option was to be adopted, extensive revisions to the RSP and DSP service terms and conditions would be required since assignment, bypass and avoidance of potential stranded cost, were not discussed in the Retailer Service and GUA Compliance Application.

ATCO Gas argued that Calgary provided no discussion of the related costs of bypass pretending that none would arise since ATCO Gas indicated that no stranded costs would accompany its application.[23] If Calgary's bypass recommendations were accepted, stranded costs would arise. ATCO Gas argued that Calgary also failed to provide any discussion of how ATCO Gas would recover the costs if capacity reverted to it from failed RSPs or a failed DSP. ATCO Gas pointed out that those costs would have been stripped out of the ATCO Gas delivery rates.

ATCO Gas argued that if its proposal was approved, there should be no stranded upstream transmission costs, since ATCO Gas would have ensured use of the related facilities as part of its arrangement to ensure safe, reliable and economic distribution service. ATCO Gas's approach would be in accord with the new legislative scheme whereas Calgary's proposition that "…there is no legislative impediment to authorizing a DSP/Retailer to manage upstream transmission capacity" was directly contradicted by the same legislation (section 2(1) *R3 Regulation*).

With respect to Calgary's submissions on the contractual arrangement between ATCO Gas and ATCO Pipelines, ATCO Gas submitted that the arrangement was found acceptable prior to the introduction of the new legislation, which now obliged the gas distribution to make such arrangements to ensure safe, reliable and economic gas distribution service.

ATCO Gas stated that it was not possible to mask these fundamental disagreements in collaborative processes or negotiated settlements. The starting points were simply too far apart and would belie any chance of a successive negotiation. Calgary's ideology of bypass also would frustrate potential collaboration in connection with the Retailer Service and GUA Compliance

[20] *R3 Regulation*, section 4(1)(b) and (c)
[21] *R3 Regulation*, section 4(3)
[22] Tr. pp. 418-419
[23] Information response AG-CAL-3 g

Application since none of the proposed terms and conditions have been prepared in anticipation of pervasive bypass of utility functions. ATCO Gas requested the Board's guidance on this critical philosophical issue.

Views of the Board

The Board considers that any issues regarding stranded assets could be addressed when an application was made that would produce such stranded assets.

In response to EnCana's concern that ATCO Gas appears to have given exclusivity to ATCO Pipelines for 10 years, the Board is of the view that any party can apply to construct a new pipeline required to deliver gas to a market served by ATCO Gas provided the construction was not in violation of an existing franchise arrangement. The Board would assess any such application in the ordinary course.

With respect to the unbundling of transmission costs, the Board considers that ATCO Gas is in the best position to forecast the requirements for upstream transmission capacity. The Board further considers that in order to arrange for adequate upstream capacity, it is appropriate for the PSP to contract for any required upstream capacity. The Board also considers the fact that the ATCO Gas distribution system is not integrated presents a significant level of complexity that would potentially make Calgary's suggestion of capacity assignment unnecessarily complex or even unworkable.

The Board also notes that the transmission costs that are paid by ATCO Gas are flowed through, and that the costs incurred are all subject to regulation by the Board.

Therefore, unless otherwise approved by the Board, the Board accepts that ATCO Gas should make arrangements for and pay for all upstream transmission capacity, and recover the related Board-approved costs in its distribution delivery rates.

3.3 Production

Views of the Interveners

AUMA/EDM

AUMA/EDM argued that, given that COP costs and the benefits of COP are effectively allocated to all customers on the basis of commodity, it was appropriate to retain COP costs with the PSP, at this time.

AUMA/EDM agreed that moving the COP and COS costs out of the distribution rates would not have any impact on customers' net bills. However, AUMA/EDM agreed with Calgary that the most logical place to address this proposal was in the forthcoming ATCO Gas 2003/2004 GRA Phase II proceeding.[24]

Calgary

Calgary submitted that issues surrounding COP were twofold: rate unbundling, and the transfer of the currently bundled costs related to COP from the distribution rates to the COPRR. Calgary noted that ATCO Gas alleged that this cost shift was based upon a recommendation submitted by

[24] Calgary Argument, p. 15

Calgary in Table 1 attached to Information Response BR-CAL-3. However, Calgary submitted that the referenced table was nothing more than an illustrative example of rate unbundling. Calgary argued that ATCO Gas did not provide any historical or forecast data of the customer impact of this cost shift, nor did it provide a foundation as to why the findings in Decision 2001-075, which implemented the COPRR, should be modified.

Calgary submitted that the COP proposal had the potential to move the collection of costs from fixed to variable. Calgary submitted that the COP issue could be fully evaluated in the forthcoming ATCO Gas 2003/2004 GRA Phase II proceeding, where cost allocation and rate design concepts would be evaluated in an unbundled setting. In the course of that proceeding, evaluation of the ATCO Gas proposal to move COP and COS costs out of the distribution rates, including customer impacts, could be evaluated and the merits of the ATCO Gas proposal could be assessed in comparison to the current operation of the COPRR. Therefore, Calgary submitted that the request for approval of separate riders for COP and COS costs should be denied in this proceeding and tabled in the next appropriate proceeding.

CCA

The CCA supported the unbundling of this function, but argued that it was preferable that residential bills did not have separate rates or riders for energy, COP and COS. The CCA believed that one rate, with all energy rates combined, was preferred to minimize customer confusion. The CCA argued that numerous rates and tariffs on residential customer bills did not promote economic efficiency, but would increase customer confusion and call centre activity. The CCA agreed with the comments of Mr. Vander Veen[25] where he distinguished between tariffs and rates. The CCA submitted that residential rates should be as simple as possible.

FGA

The FGA noted that the Application proposed no unbundling with regard to the COP costs remaining in revenue requirement, but that ATCO Gas changed its position on this matter in its rebuttal evidence. The FGA noted that ATCO Gas proposed to transfer $3,198,000 of “direct asset”, “direct cash” and “assigned” production expenses[26] from delivery rates to the COPRR. The FGA argued that ATCO Gas proposed to unbundle COP costs remaining in revenue requirement without explicit direction from the Board or from legislation. The FGA submitted therefore that ATCO Gas’s proposed unbundling of the COP function was unnecessary and inconsistent with the spirit of the existing COPRR and that the COP related costs of $3,128,000 should remain in distribution rates.

The FGA submitted that the lack of specific reference in legislation, that the production function was the responsibility of the gas distributor, did not imply that the function should be unbundled.

The FGA submitted that there was no compelling reason offered by ATCO Gas for its proposed unbundling of COP costs. The FGA argued that the purpose of the COPRR was to preserve the semblance of a pure market rate for natural gas supply.

[25] Tr. pp. 367-368
[26] 2002 COSS, p. 28

The FGA argued that since COP could not be unbundled or given to any other party, there was no need to unbundle this function at this time. The FGA submitted that any unbundling of this function should take place when these assets were sold.

The FGA further argued that, should ATCO Gas's proposal be approved, risk would be transferred from ATCO Gas to its customers because the customer would pay prospective costs as if those costs were actual. The FGA argued that ATCO Gas's proposal was for a monthly deferral account, which was designed to operate using actual market-based costs, to collect prospective costs based on rate base, rate of return, depreciation and taxes. The latter did not lend itself to the monthly flow-through accounting utilized by the former because "cost of service" costs might vary monthly, but the drivers of those costs were updated only through a GRA. For example, the FGA noted that between GRAs ATCO Gas might buy or sell production assets or otherwise alter the $3,198,000 of prospective "direct asset", "direct cash" and "assigned" production expenses used to calculate the proposed $0.029 rate adjustment. The FGA argued that such changes must be approved in a GRA, so the proposed rate adjustment would remain unchanged until the time of the next GRA, which could be several years away.

Views of ATCO Gas

ATCO Gas stated that it now recognized that gas supply and storage are functions assigned specifically to RSPs and the DSP. ATCO Gas argued that withdrawal of the COS and the COP costs from the gas distribution delivery rates was fully consistent with the new legislation.

ATCO Gas submitted that the COPRR and COSRR were not an extremely complicated billing process, and that despite the variability in inter-seasonal gas costs and benefits, optionality gains and losses, and uncontracted capacity revenues, the existing rider mechanism would continue to offer the net credit/debit to delivery rates originally intended. The only change was that, as proposed, the costs would be included as part of the riders themselves.

ATCO Gas argued that it was proposing to complete the picture with respect to the COPRR by including the costs associated with the COP assets that are included in distribution rates in the COPRR. By doing so, the distribution rates would reflect the services that were defined in the *R3 Regulation* for a gas distributor. ATCO Gas disagreed with the FGA's submission that risk would be transferred from ATCO Gas to its customers. The cost of service rate that ATCO Gas had determined to be 2.9 cents per GJ was derived from the approved 2002 AGS revenue requirement. ATCO Gas was simply proposing that this rate be removed from distribution rates and included in the COPRR. This rate would remain in place until the Board approves a new rate. ATCO Gas argued the impact on customers would be the same and would not affect the FGA.

ATCO Gas argued that the AUMA/EDM's only reason for not accepting this change was that the costs and benefits of COP were currently allocated effectively to all customers on the basis of commodity. ATCO Gas's proposal did not change that. The COPRR was also allocated to all customers on the basis of commodity. ATCO Gas similarly indicated that PICA/STMG concern was unfounded.

With respect to Calgary's claim, ATCO Gas replied that the change was not a cost shift, but rather a rate design issue of where the costs should be recovered. Instead of paying the 2.9 cents per GJ in the delivery rates, the same customers would be paying the 2.9 cents per GJ in the COPRR.

ATCO Gas believed that this amendment to the COPRR would combine costs and revenues with respect to COP and allow distribution rates to match the services provided by gas distributors as defined by legislation**.**

Views of the Board

The Board notes that interveners disagreed with the proposal by ATCO Gas to unbundle the COP costs and include them in the COPRR. However, it was suggested that the proposal could be further dealt with as part of ATCO Gas 2003/2004 GRA Phase II.

The Board is concerned that the issue of moving prospectively established revenue requirements into a rate rider that is adjusted monthly was not adequately addressed in this proceeding. The Board notes that if such costs were to be moved, it might be appropriate to establish a separate rate rider, not subject to deferral account treatment.

Therefore, the Board denies approval to unbundle the COP costs as proposed by ATCO Gas at this time, but the Board is prepared to further consider any such proposal as part of the ATCO Gas 2003/2004 GRA Phase II.

3.4 Storage

Views of the Interveners

AUMA/EDM

The AUMA/EDM argued that given that COS costs and benefits were effectively allocated to all customers on the basis of commodity it would be appropriate to retain COS costs within the PSP, at this time.

Calgary

Calgary noted that ATCO Gas had stated that Carbon storage would no longer be used as a source of gas supply for its customers if the sale to DEML were implemented. In conjunction with this position, Calgary noted that ATCO Gas proposed to continue the operation of the COSRR, which was established in Decision 2001-075, and in its rebuttal evidence in this proceeding had proposed to move the cost of storage from the distribution rates to the COSRR. Calgary also noted that DERS had stated that it did not plan to use storage in providing DSP service.[27] Calgary further observed that the Board had an application before it for the 2004/2005 Carbon Storage Plan.

Calgary argued that the ATCO Gas proposal to move the cost of COS from the distribution rates to the COSRR based upon an alleged recommendation set forth by Calgary was not supported on the record. Calgary noted that ATCO Gas stated that it relied upon Calgary Table 1 attached in response to BR-CAL-3. Calgary submitted that the referenced table was an illustrative example of unbundled rates.

[27] DERS Tariff Application, information response CAL-DERS-19(e)

Calgary argued that there were two opportunities to address the cost shift proposed by ATCO Gas: the 2004/2005 Carbon Storage Plan and the ATCO Gas 2003/2004 GRA Phase II. As with COP, Calgary submitted that the most logical place to address the cost shifting proposal was in the GRA Phase II proceeding where cost allocation and rate design will be fully evaluated, and where customer impacts and the merits of the ATCO Gas proposal could be evaluated as compared to the current operation of the COSRR.

CCA

The CCA was concerned with the issue of residential rate confusion, similar to its concerns with respect to COP.

FGA

The FGA assumed that in making the reference to storage as not being enumerated as a gas distribution function, ATCO Gas meant storage that was not associated with the provision and delivery of gas. The FGA equated the storage referred to in section 28(i)(ii)(E) of the GUA to storage related to gas price management.

The FGA submitted that, in light of ATCO Gas's position that the costs of the transmission function should not be unbundled, consistency would suggest that the COS costs should not be unbundled either. The FGA argued that, for the same reasons it stated in section 3.3, it was not appropriate for ATCO Gas to collect prospective COS costs through a monthly deferral account.

The FGA argued that, for the reasons stated above, the COS costs should not be unbundled as proposed by ATCO Gas and that COS related costs should remain in distribution rates.

Views of ATCO Gas

ATCO Gas replied that what was being proposed for the COSRR was identical to the proposal with respect to the COPRR and that the same arguments applied to COS.

ATCO Gas submitted that the Board should allow this simple rate change. ATCO Gas stated it was simply moving 10.7 cents per GJ from the distribution rates to the COSRR and that the impact on customers did not change.

Views of the Board

For the same reasons as provided with respect to the proposal to unbundle COP costs, the Board denies the proposal to unbundle COS costs at this time, but the Board is prepared to further consider any such proposal as part of the ATCO Gas 2003/2004 GRA Phase II.

3.5 Customer Care

Views of the Interveners

AIPA

AIPA argued that, while the Board indicated in Decision 2001-75 that utility customer information costs were unlikely to decrease substantially due to increased retail competition, the circumstances of the Application were different. AIPA submitted that the context of the Board's decision was that ATCO Gas would be the DSP and that there would be a number of RSPs. AIPA noted that, in the Application, ATCO Gas was assigning its function as a DSP to DERS and totally exiting the retail function. With this changed circumstance AIPA submitted that the relevance of Decision 2001-75 with respect to CIS costs in the distribution function was lessened.

AIPA noted that the customer care function was an important consideration for customers because of the apparent duplication of services between the distributor and the retailer. AIPA argued that further unbundling of the customer care components would provide the transparency that Calgary suggested and would serve to better address the potential areas of duplication of services.

AltaGas

AltaGas argued that Decision 2001-75 was still relevant with respect to the unbundling of customer care costs. AltaGas noted that the items identified by the Board in that decision for customer care include: billing, CIS, call centers, and credit and collections. AltaGas submitted that these services were still appropriate. AltaGas stated that it anticipated that costs related to the customer care function would continue for the gas distributor, as contemplated by the Board in Decision 2001-75. AltaGas noted for example, that the *R3 Regulation* sets out the following responsibilities of the gas distributor:

> **4(1)** A gas distributor must do the following:
>
> …
>
> (e) carry out gas distribution tariff billing for gas distribution service under the gas distributor's approved gas distribution tariff;
>
> (f) connect and disconnect customers in accordance with the gas distributor's approved gas distribution tariff;
>
> (h) maintain information systems relating to the consumption of gas by customers;
>
> (k) distribute public safety information;
>
> (n) respond to inquiries and complaints from customers respecting gas distribution service;
>
> (o) if a customer makes an inquiry related to the functions of retailers or default supply providers, direct the customer to the customer's retailer or default supply provider;

AltaGas argued it was clear that the above duties involved customer care functions for which the Government of Alberta believed gas distributors should retain some responsibility. AltaGas considered that, to the extent that the gas distributor was required to perform these functions, costs associated with providing these services would still be incurred by the utility and should be recoverable in distribution rates.

AUMA/EDM

AUMA/EDM argued that the emphasis of the Application with respect to customer care costs had shifted from one of unbundling to one of "cost shedding" or "cost peeling."

Calgary

Calgary submitted that the issue surrounding customer care was rate unbundling, not cost shifting or bill unbundling. Calgary stated that if the rate for customer billing was unbundled, then alternative service providers could determine their opportunity to provide the same service for, say, $1 rather than say $5 charged by the utility.[28] Calgary submitted that, if the $5 was bundled into the distribution rate, no such comparison by third party providers could be conducted. Calgary noted that when the rate was unbundled, the value was listed on the tariff sheet for all to see and evaluate.

Calgary submitted that following the unbundling of the rates for customer care costs, evaluations could be conducted to determine those cost centres which should remain unbundled in the tariff to provide opportunity for alternative service providers to evaluate the offering of like services at lower prices; be it to the utility, the DSP or Retailer commodity suppliers. Calgary argued that it could not be over emphasized that rate unbundling was not bill unbundling. Calgary noted that rate unbundling was a more comprehensive exercise than bill unbundling. Rate unbundling was unbundling the tariff sheet in order to provide transparency to third party service providers.[29]

Calgary submitted that there was the ample opportunity to continue to peruse the plan laid out by the Board in Decision 2001-75 between the decision in this proceeding and the ATCO Gas 2003/2004 GRA Phase II.

Calgary emphasized that, although ATCO Gas has outsourced its customer care functions except for metering, the rates for services inherent in the outsourcing arrangement had not been unbundled to determine whether such functions as billing, credit and collection, CIS and call centre are competitive.[30]

Calgary submitted that ATCO Gas's position with respect to the unbundling of this item was inconsistent with its position in the proceeding that led to Decision 2000-10.[31] In that proceeding ATCO Gas argued that there were many suppliers of these services and as such ATCO Gas was not a monopoly utility service.[32] Calgary argued that the concept behind unbundling was to provide transparency and accountability. Calgary submitted that it was essential that the customer care costs be unbundled for that reason alone. Calgary considered that the first order of business was to establish what the costs are for each of the functions so that a fair market value could be determined. Calgary observed that by outsourcing most of this function to ATCO I-Tek and ITBS, ATCO Gas had already taken the step of choosing another company to perform the function or delegating its responsibilities.

CCA

CCA noted that in Decision 2001-75 the Board provided the following direction with respect to customer information costs.

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28 Tr. p. 416, lines 1-20

29 Tr. p. 427, line 25 to p. 428, line 5

30 Tr. p. 430, lines 24-25, pp. 431-432

31 Decision 2000-10 – Apollo Gas Inc., Complaint – NUL and ATCO Gas re Termination of Billing Services, dated February 28, 2000

32 Decision 2000-10, p. 4

> The Board directs the utilities to provide information on the anticipated effect of increased retail competition on their expected customer information system costs at the time they file the unbundling allocation study directed in section 6.1.2 of this Decision, as part of the Board's direction to examine the customer information system function's operations and requirements.[33]

The CCA considered that customer care was better offered with the LDC as it appeared to be the most cost efficient structure. The CCA considered that customer care should not be unbundled.

FGA

The FGA noted that in Decision 2001-75, section 6.2.2, the Board referred to the CIS function as a "customer care" function but ATCO Gas's unbundling study classified the CIS function as a "distribution" function and 100% of costs were allocated to PSP as a result. The FGA expressed concern that ATCO Gas was not being consistent in its selective reliance upon Decision 2001-75. However, the FGA submitted that, in light of the *R3 Regulation's* specific statement that the CIS function was the responsibility of the distributor, it did not oppose ATCO Gas's allocation of 100% of CIS costs to PSP.

The FGA noted ATCO Gas's method in respect of the credit and collection function was to first calculate the costs it would be losing (those costs allocated to RSP), then subtract those costs from the total costs of the function to determine the costs allocated to PSP. The FGA noted that the method used to calculate the allocation between PSP and RSP seemed to have been in reverse as compared to the "incremental" method.[34]

The FGA was concerned that ATCO Gas was not consistent in adhering to its "incremental" method for determining unbundled costs. However, the FGA noted that the level of credit and collection costs allocated to PSP seemed to be directionally correct, given the comments from the Board in Decision 2001-75, section 6.9.2.

The FGA did not oppose ATCO Gas's proposed unbundling of customer care functions: billing, call centre and credit and collections and the respective allocations between PSP and RSP.

Views of ATCO Gas

ATCO Gas argued that the shedding of the customer care functions subsequent to the sale to DEML, together with the proposed benchmarking, fully satisfied the unbundling requirement. ATCO Gas stated that section 3 of the *R3 Regulation* made it clear that a gas distribution company may not perform the functions specified for a RSP or a DSP except under certain limited conditions. ATCO Gas noted that, conversely, section 2 of the *R3 Regulation* made it clear that no other person, including the RSP or the DSP, may perform the functions specifically assigned to the gas distributor unless the gas distributor specifically authorized it to do so.

ATCO Gas stated that there was no need for any additional functional or rate unbundling, as Calgary suggested. ATCO Gas argued that Calgary's recommendation was misplaced since it was in furtherance of an objective rejected by the Board in Decision 2001-75. ATCO submitted that the bypass of utility functions contemplated by Calgary's functional unbundling proposal

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33 Decision 2001-75, p. 101
34 Information response CAL-AG-13

was also inconsistent with the legislation, which did not permit other persons to perform a gas distribution company's function without the utility's specific consent.

Views of the Board

The Board notes that the FGA generally supported the level of the customer care costs being allocated to the PSP. The Board finds no compelling reason to alter ATCO Gas's customer care cost allocations, including CIS, for the purpose of setting interim rates.

The Board will address the appropriateness of further unbundling of the distribution tariff in section 5 of this Decision.

3.6 Other

Views of the Interveners

AltaGas

AltaGas noted that reference was made to whether the cost of meters should be unbundled.[35] AltaGas submitted that unbundling of meter ownership was previously addressed by the Board in Decision 2001-75.[36] Most parties noted that these functions were not candidates for unbundling in the near term. AltaGas argued that this view was reaffirmed in the *R3 Regulation*, where the following was set out:

> **4(1)** A gas distributor must do the following:
>
> g) perform metering, including verifying meter readings and verifying accuracy of meters;

AltaGas was concerned that the concept of bypass of the utility for meters, or otherwise, that might result in stranded costs for the utility represented an increase in risk to the utility, which must be compensated for. Accordingly, AltaGas submitted that the Board should not endorse such a position.

Calgary

Calgary submitted that whether the cost of meters should be unbundled was only an illustration of how certain costs could be displayed in the tariff as opposed to on a bill. Calgary stated that the primary purpose of the example discussed by Mr. Vander Veen was to indicate that there might be benefits of transparency and accountability of having the cost of meters and the cost of meter reading shown separately in the tariff. Calgary stated that it was not a specific recommendation at this time.

Views of the Board

The Board agrees with AltaGas that all metering activities are the responsibility of the gas distributor, and that the related costs are to be recovered in the distribution rates.

The Board will address the appropriateness of further unbundling of the distribution tariff in section 5 of this Decision.

[35] Tr. pp. 425-426
[36] Decision 2001-75, p. 97

4 INTERIM RATES

In this section the Board will consider the views of parties as to the appropriateness of the proposed unbundling of existing rates and the applicability of using AGS costs as a surrogate for AGN.

4.1 General

Views of the Interveners

Calgary

Calgary noted that the Application had been prepared based on the assumption the Retail Sale was approved, but also noted that in an exchange during the hearing ATCO Gas acknowledged the following:

> Q. But if I understand the application correctly, the
> interim rates you've proposed do not include, at least in
> total, the impacts of the retail sale as set out in section
> 5; is that fair?
> A. Yes, that's fair.
> …
>
> A. MR. BECKETT: Sir, I think I've figured this out.
> We prepared the application; we looked at some things that
> we would not have otherwise looked at if the retail sale
> wasn't on the horizon; but in the end, the proposal for the
> unbundled rates is not based on any significant impacts from
> the retail side.[37]

Calgary argued that the proposed interim rates did not include the impacts of the Retail Sale as set out in section 5 of the Application. As a result Calgary argued that the Application was of limited benefit in selecting an appropriate level of interim rates.

CCA

COSS

The CCA submitted a table (included in Appendix E to this Decision) that illustrated the changes from the 1998 Canadian Western Natural Gas Company Limited (CWNG)[38] COSS to the 2002 ATCO Gas COSS.

The CCA understood that ATCO Gas did not provide the 1998 COSS because ATCO Gas considered that the 1998 CWNG study was not reflective of current practices and did not reflect recent Board decisions with respect to COS and COP.[39] The CCA considered that the COSS should be adjusted to reflect recent Board decisions concerning COS and COP. The CCA disagreed that adjustments should be made for cost classification and allocation purposes without

37 Tr. pp. 337-338
38 Canadian Western Natural Gas Company Limited was a predecessor to AGPL
39 Information response CCA-AG-4(b)

appropriate justification. The CCA argued that it was unreasonable not to provide the effects of changes as compared to the 1998 COSS. The CCA considered that, although some of the changes were minor, the effects of the change of the classification of Account 713[40] appeared significant.

The CCA noted that in Decision 2003-028[41] that dealt with the need for a 2002 GRA Phase II filling by AGS, the Board did not approve a COSS or changes in methodology but simply examined the reasonableness of existing rates. The CCA argued that the 1998 COSS methodology approved by the Board in Decision 2000-16[42] that dealt with CWNG's 1998 GRA Phase II should be the methodology used by ATCO Gas in the Application.

Customer Billing and Accounting

The CCA submitted that Account 713 was historically classified as 78% customer and 22% demand and that, in the unbundling study, ATCO Gas classified the cost as 100% customer.[43] The CCA noted that Account 713 costs were $11,308,000 in the 2002 unbundling allocation study.[44]

The CCA noted that Rate 1 had approximately 97%[45] of the customers but was only responsibility for 79%[46] of the demand, based on the 1998 GRA compliance filing. The CCA also noted that ATCO Gas used a weighted customer count, which allocated a greater number of customers to Rate 1. The CCA observed that the use of average customers assigned 99%[47] of the customers to Rate 1. The CCA submitted that the movement of costs from demand to a customer classification would negatively impact residential customers.

The CCA argued that ATCO Gas did not follow the Board's direction in Decision 2003-006. In that Decision the Board stated "… the Board expects ATCO, at a minimum, to file information on the new revenue/cost ratios for each customer class based on an appropriate allocation of the 2002 revenue requirement using the parameters in the latest COSS approved by the Board in Decision 2000-16." The CCA argued that, given that the change in the classification of customer billing and accounting was not a parameter in the COSS approved in Decision 2000-16 and that ATCO Gas had not justified the change, ATCO Gas should be directed to re-file the COSS in its compliance filing to meet the Board's expectations in Decision 2003-006. [48]

Demand Cost Allocation

The CCA noted that ATCO Gas chose to change customer billing and accounting classification in the COSS, which its unbundling application approved.

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40 Customers' Billing and Accounting, Uniform Classification of Accounts for Natural Gas Utilities
41 Decision 2003-028 – ATCO Gas South 2001/2002 General Rate Application, Evaluation of the Need for a 2002 Phase II, dated April 30, 2003
42 Decision 2000-16 – ATCO Gas and Pipelines Limited, 1998 GRA Phase II, dated June 13, 2000
43 Information response CCA-AG-4(a), attachment 1, p. 4 of 4
44 Application Tab 2, p. 62
45 76,197/78,427 customers; refer to CCA-AG-26
46 50,784/64,532 demand; refer to CCA-AG-26
47 418,042/420,623 weighted customers; refer to p. 43 of the 2002 COS backup
48 Decision 2003-006, p. 7, AGS 2001/2002 GRA Second Compliance Filing, dated January 21, 2003

The CCA noted that in Decision 2000-16 the Board stated the following:

> However, the Board directs CWNG to provide information, in the next GRA, to indicate the relative proportions of system facilities installed using design criteria of -40°C and -36°C, and to demonstrate the continuing appropriateness of the assumptions used to determine NCP [non-coincident peak].[49]

The CCA argued that ATCO Gas did not address changes in its COSS methodology. The CCA noted the change in demand cost allocation would benefit residential customers; however, given that ATCO Gas did not justify cost of service changes nor provide the data concerning proportions of facilities designed to different temperature criteria, it was inappropriate to change the customer billing and accounting classification.

PICA/STMG

PICA/STMG stated that they were not opposed to implementation of the rates on an interim basis except for the proposed recovery of COP and COS asset related costs and expenses through the COPRR and COSRR on an energy basis, as this could potentially have a negative impact on larger customers.

Views of the Board

The Board notes Calgary's view that the proposed interim rates did not include the impacts of the Retail Sale and as a result the Application was of limited benefit in selecting an appropriate level of interim rates. The Board notes that the Retail Sale, while approved, has not yet closed. If and when the Retail Sale closes, the Board considers that all impacts of the Retail Sale can be reviewed in the final ATCO Gas 2003/2004 GRA compliance filing, which is to be submitted once all placeholders for the GRA are completed.

For the purpose of setting interim rates, which will also be refundable and will require reconciliation with the final revenue requirements for 2004, the Board will focus on those costs that should be removed at this time from the distribution rates. The costs to be removed will be collected through the GCRR process, which will be superceded if and when the rates for the DSP are initiated.

The Board notes that the CCA argued that ATCO Gas had not submitted a COSS that had received Board approval. The CCA submitted that use of the 2002 COSS was inappropriate because it had not been tested.

The Board agrees with the CCA that the methodology used by ATCO Gas in the Application includes elements that have not been approved by the Board. However, the Board does not believe it is necessary to have ATCO Gas redo the COSS for the purpose of setting interim refundable rates. The Board considers that there will be ample opportunity to examine the COSS methodology during Phase II of the ATCO Gas 2003/2004 GRA, and to reconcile any differences that might result.

[49] Decision 2000-16, pp. 20-21

The Board directs ATCO Gas, when filing its 2004 COSS, to provide the study based on the methodology approved in Decision 2000-16. ATCO Gas may then propose changes and show the impact on customers that would result if the changes were approved.

4.2 Level of Interim Rates

Views of the Interveners

AIPA

AIPA was concerned with the proposed net increase in irrigation and farm rates that would result from the Application and the associated DERS DRT. AIPA argued that the fixed cost increases were particularly onerous ranging from 19% for irrigation to 37% for farm service. AIPA argued that these increases were not mitigated by the proposed energy cost decreases. AIPA considered that if the Board did not approve the Retail Sale to DEML then customers would not be subjected to these forecast increases.

AIPA expressed concerns with the proposed level of interim rates and submitted an adjustment to interim rates should be considered. AIPA argued for an additional reduction of $2.7 million for sharing CIS asset related costs 50/50 between the PSP and the DSP.

AIPA noted that the impact by rate class shown in Table D of the Application was not proportionate to rate class revenues due to the classification and functionalization process in the model.[50] However, AIPA noted that the 2002 COSS model was not the same as the 1998 COSS model from which existing rates were derived.[51] AIPA argued that with a changed model that was relatively untested in this proceeding it might be preferable to simply pro-rate the reductions across the board to rate classes. AIPA also suggested that the CIS reduction should be incorporated in a compliance filing for this Application on an across the board basis, or incorporated into the 2002 COSS if the Board accepts the basis of the changed model.

AIPA was concerned that existing Rates 1 and 3 included a credit for late payment penalty revenues but that there was no similar credit for Rate 5 when in fact ATCO Gas had received such payments from Rate 5 customers.[52] AIPA argued that for equity considerations ATCO Gas should be directed to maintain late payment revenues within the rate classes for the upcoming ATCO Gas GRA Phase II filing.

AIPA submitted that removal of COS costs from existing delivery rates should be at 12.5¢/GJ, the amount that was originally added to rates for consistency purposes. AIPA argued that if the new COSS indicated the COS was 10.7¢/GJ, this was the amount that should be included in the storage rider.

AUMA/EDM

AUMA/EDM argued that ATCO Gas had failed to remove sufficient costs related to the Retail Sale.

AUMA/EDM noted that ATCO Gas had identified a number of other adjustments resulting from the Retail Sale that it proposed be dealt with in one final application (also referred to as a "loose-

[50] Tr. p. 251
[51] Tr. p. 164; p. 165
[52] Undertaking Tr. p. 260, lines 5-8; Tr. p. 276

ends" application)[53] that would take place once all outstanding matters related to the ATCO Gas 2003/2004 GRA had been addressed. AUMA/EDM expressed concern with this position in that the scope of the so-called "loose-ends" application had not been determined. AUMA/EDM submitted there was no logical reason why the known, albeit not finalized, adjustments should not be reflected for purposes of the interim rate reductions, particularly as ATCO Gas had provided details of these other adjustments[54]. AUMA/EDM submitted that, although they pertain to ATCO Gas as a whole, these adjustments could be reasonably allocated to AGS for purposes of determining the interim rate reductions applicable to both AGS and AGN.

Marketing and Customer Information Costs

AUMA/EDM noted that ATCO Gas South included $2.259 million for marketing in its 2002 cost of service. AUMA/EDM also noted that, in Decision 2001-75, the Board concluded that marketing costs related to safety and general information and marketing costs related to increasing use of gas should remain in the base delivery charges but that it would not be appropriate to include marketing costs incurred to attract customers specifically to utility gas supply service. AUMA/EDM submitted that ATCO Gas did not exclude any marketing costs due to the Retail Sale nor due to the Board's conclusion in Decision 2001-75 (refer to Appendix C).

AUMA/EDM noted that ATCO Gas suggested that not one single marketing communication was intended to attract new customers to utility gas supply service.[55] AUMA/EDM argued that a reasonable person reading a number of the marketing messages would be left with the conclusion that ATCO Gas was attempting to entice or solicit new customers to using or switching to utility gas supply service.

AUMA/EDM submitted that ATCO Gas had failed to reasonably demonstrate that none of the $2.259 million of Marketing and Customer Information was in any way related to attracting customers to utility gas supply service. AUMA/EDM argued that ATCO Gas had every opportunity to acknowledge at least a portion of the marketing costs related to utility gas supply service.[56] Instead ATCO Gas simply asserted that no portion whatsoever of that amount relates to attracting customers to utility gas supply service, a position that AUMA/EDM submitted was refuted by the documented evidence. AUMA/EDM argued that ATCO Gas's claim is further exacerbated by the fact that the Government of Alberta had announced a $3 million Consumer Protection/Customer Choice Campaign to provide even more information about the restructured market and also by the fact that DERS had forecast to spend $2.75/year million on customer awareness.[57]

AUMA/EDM argued that for purposes of interim and for that matter, final rates, it would reasonable for the Board to reduce the Marketing and Customer Information Costs by 10% to 20% to reflect the Board's findings in Decision 2001-75 respecting expenditures by ATCO Gas on attracting customers to utility gas supply service. AUMA/EDM noted that the full amount of the 2002 Marketing and Customer Information Costs were implicitly reflected in the existing rates and therefore the portion deemed to be related to attracting customers to utility gas supply service should be removed and not recovered through the rates in 2004.

[53] Tr. p. 154
[54] Refer to Exhibit 54
[55] Tr. p. 28
[56] Information response AUMA/EDM-AG-5
[57] Tr. p. 32

Administration and Supervision Costs

AUMA/EDM noted that ATCO Gas agreed to remove $995,000 of ATCO/CU Corporate Costs upon approval of the Retail Sale. AUMA/EDM also noted that this amount reflected the removal of energy costs from the ATCO/CU Corporate Costs allocation formula and that ATCO Gas had not included this amount in the impacts. AUMA/EDM noted that this was "due to the fact that Decision 2003-072[58] required the removal of energy costs from the corporate cost allocation, the adjustment to the ATCO Gas revenue requirement related to this directive will already be incorporated in the ATCO Gas GRA compliance filing."[59] AUMA/EDM argued that, while this reduction should be reflected in the compliance refiling, it should also be reflected in the interim rate reduction since approximately one-half of that amount was built into existing AGS rates, and since the interim rates were based on incremental cost reductions to existing rates.

AUMA/EDM argued that, for the same reasons, the $8.548 million reduction deemed to be RSP costs, as adjusted by the Board, should also be reflected in the corporate cost allocation formula. AUMA/EDM argued that, as shown in AUMA/EDM-AG-8, Attachment 1, the Corporate Costs allocated to AGS would be reduced by a further $19,000 to $1,014,000. AUMA/EDM considered that in principle, although this might be a small amount for interim rate purposes, the corporate costs allocation should be adjusted.

AUMA/EDM noted that ATCO Gas allocated no indirect, administrative or supervisory costs to the Customer Care Functions (refer to Appendix C). AUMA/EDM agreed with Calgary that, "it is incredible that not one dollar of cost reduction will occur related to administrative and general (A&G) or overhead costs."[60]

AUMA/EDM noted that ATCO Gas indicated that an existing three full time equivalent positions (FTE) would be redeployed to handle the ATCO I-Tek contract dealing with (wholesale) billing, plus managing retailer issues and service requests associated with changes in the settlement process,[61] and that all 11 FTEs that dealt with the natural gas functions of load balancing, COP, storage, load settlement and regulatory support[62] would be still required after the retail transition.

AUMA/EDM agreed with PICA/STMG that ATCO Gas's assumption that all of the 11 FTEs would be required for redefined functions was arbitrary and that ATCO Gas should be directed to provide a specific forecast of FTEs required or, alternatively, that 50% of the costs applicable to the 11 FTEs should be included in the final adjustments.[63]

AUMA/EDM noted that Account 722, Special Services, was comprised of legal fees of $313,000, audit fees of $71,000 and consultant fees of $72,000.[64] AUMA/EDM submitted that the portion of this account relating to fees in excess of Board approved guidelines were nonetheless built into the existing 2002 base rates. AUMA/EDM submitted that based on the manner in which interim rates were designed and the fact that such excess fees were not included

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58 Decision 2003-072 – ATCO Gas 2003/2004 General Rate Application, dated October 1, 2003
59 Exhibit 54 note 11
60 Exhibit 36 Calgary Evidence, p. 13
61 Tr. p. 38
62 Tr. p. 109
63 PICA/STMG Argument p. 6
64 Information response AUMA/EDM-AG-20; refer to footnotes

in the forecast for 2003 and 2004, the portion of the costs in this account representing costs in excess of the EUB guidelines should be peeled for purposes of interim, and for that matter, final rates. AUMA/EDM argued that in the absence of specific amounts ATCO Gas should be directed to remove costs in excess of the EUB guidelines in its refiling.

Calgary

Calgary noted that ATCO Gas proposed that AGS' interim rates be reduced by $7.035 million based upon the 2002 AGS class COSS, which resulted in a total proposed reduction of approximately $14 million for ATCO Gas. Calgary argued that this amount could be compared to the approximately $62.7 million[65] that DERS proposed to charge for taking over the DSP function. Calgary observed that for 2004 the proposed reduction including the impact of the Retail Sale was $21.912 million of which approximately $3.2 million would have been included in the GCRR in any event[66]. Calgary noted that the amount was $18.2 million[67], which still left approximately $44.5[68] million as the increase if this latter amount was accepted.

Calgary submitted that approximately 25% related to the ATCO CIS, which remained in ATCO Gas[69]. Another significant portion related to ATCO I-Tek charges, including ITBS. Calgary noted that it argued in the DERS Tariff proceeding[70] that the ATCO I-Tek charges decreased by approximately 1/3 but still remain at over $29 million. Calgary noted that ATCO Gas's internal customer care costs remained essentially the same,[71] at $16.9 million versus $16.3 million.

Calgary argued that a significant portion of the approximately $44.5 million of additional costs should be taken out of ATCO Gas's rates for purposes of setting interim rates. Calgary argued that the ATCO I-Tek charges should be reduced by a further 50% to 75%, which would be approximately $15 to 22 million.[72] Calgary also submitted that it had suggested for some time that the cost of the ATCO CIS should not be in the ATCO Gas rate base.

Calgary submitted that it was not clear why the CIS royalty amount could not be treated as a reduction of the undepreciated capital cost pools for income tax purposes rather than as taxable income in the year received.

Calgary considered that with a reduction in the external and internal customer care costs, it would be consistent to expect that the A&G costs should also be reduced. Calgary assumed that the A&G cost would be about 20% of the direct costs. Calgary also submitted that there should be reductions in labour for gas management and that the 10 personnel[73] should not just be redeployed. Calgary argued that if ATCO Gas chose to retain these employees it should be at the shareholder's expense.

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65 DERS Tariff Application, Schedule 6.2 from Schedule AUMA/CE-DERS(DRT)-11-DRT(Supp) for 2004
66 Information response AUMA-EDM-AG-012 Attachment 1, GCRR amounts indicated by * and ** times 2
67 Exhibit 54 Undertaking response p. 321, line 24, to 322, line 9.
68 $62.7 million less $21.9 million.
69 DERS Tariff Application, Calgary's Argument; Tab 2 shows the CIS amortization, interest and taxes of approximately $9.5 million.
70 DERS Tariff Application, Exhibit 005-34, Schedule 1.3 line 57 and 1.1 line 56 the I-Tek charges decrease by approximately 1/3 but still remain at over $29 million
71 DERS Tariff Application, Calgary's Argument; Tab 2 shows the cost increasing slightly from $16.3 million in 2003 to $16.9 million in 2004
72 $29 million times 50% or 75%
73 Retail Sale, Tr. p. 431

Calgary recommended that the 2004 revenue requirement, for purposes of the interim rates, be from $184.2 to $194.1 million,[74] which was a further reduction of $25.5 to $35.4 million above the amounts forecast by ATCO Gas. Calgary considered that adjustments thereafter could be made depending upon the ultimate decision the Board renders in the DERS Tariff proceeding.

Calgary suggested that none of the GRA adjustments per se should be incorporated into the interim rates at this time. However, adjustments that flow out of the separation of the gas costs for purposes of the interim rates should be included.

Calgary submitted that interim rates should be established at a conservative level along the lines as set out in Schedule A of Calgary's argument (see Appendix F of this Decision).

CCA

The CCA considered that the level of interim rates that ATCO Gas was proposing in the Application must be examined both in the context of the Application and the DERS Tariff Application.

The CCA submitted that the effective rate increase for residential AGN customers was 20% and 19% for AGS customers; but that the effective rate for larger Rate 1 customers was 0% for AGN and 1% for AGS customers.[75]

The CCA stated that it had requested ATCO Gas to provide the rate effects of the Application and the DERS Tariff Application, but that ATCO Gas had responded by indicating that this request was not relevant to the Application and the unbundling process must proceed regardless the Retail Sale.[76] The CCA disagreed with ATCO Gas's position. The CCA argued that it was imperative that the Board consider the effects of all three applications on customers and specifically residential customers. The CCA submitted that the rate impact of the applications was devastating to residential customers.

The CCA considered that the fixed rate including both the retail and distribution components for Rate 1 should not increase beyond the currently approved amounts. The CCA noted that other major distribution and retail residential fixed rates were either $10.00 or close to it. The CCA argued that to increase the residential fixed rate beyond the current levels was not appropriate, and that increasing the combined distribution and retail residential fixed rate above other Canadian utilities fixed rates would do little to promote deregulation.

The CCA considered that the Board should examine the rate effects of both the Application and DERS Tariff Application in terms of rate shock. The CCA argued that increasing rates would frustrate customers and lead to political fall out. The CCA did not consider it government policy to increase residential rates. The CCA stated that, in its opinion, Government of Alberta policy was to see to the delivery of services to its citizens at the lowest possible price providing for recovery of only the reasonable and prudent costs.

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74 Refer to Appendix F
75 DERS Tariff Application, Tr. p. 474
76 Information response CCA-AG-28

The CCA noted that a detailed review of the COSS was not undertaken as contemplated by the Board in Decision 2003-028. The CCA stated that the level of the fixed charge was relatively low for a large Rate 1 customer but relatively high for a small Rate 1 customer. The CCA noted that average assets were used for the COSS. The CCA submitted that the rate design of Rate 1 had small customers pick up a higher percentage of asset costs than they caused. The CCA noted, for example, that a meter for a residential customer was significantly less costly than for a larger customer. The CCA argued that to charge the retail costs as proposed by DERS, while residential customers continued to pay large fixed cost in the distribution rates, was not fair. The CCA argued that the process of removing retail costs from the distribution rates had led to an unreasonable situation. The CCA argued that rates from the 1998 COSS, which the Board considered fair, were now going to increase by 20% for residential customers and 0% for large Rate 1 customers. The CCA submitted that the Board must adjust the level of the proposed fixed charges of both DERS and ATCO Gas in order to reduce the level of the rate increase to residential customers.

Indirect Costs

The CCA considered that it was appropriate that indirect and overhead cost reductions be included in the unbundled rates. The CCA noted that customers should not be responsible for previous levels of overheads for ATCO/CU and overheads for DERS. The CCA argued that ATCO/CU overheads and indirect costs must be reduced in the unbundled rates in order for customers to benefit from deregulation. The CCA argued that if ATCO Gas was allowed to continue to apply the same level of overheads customers would not receive the benefits from deregulation but would see long-term costs increase.

Corporate Cost Allocation

The CCA noted that ATCO Gas indicated that the total impact of the administrative and corporate aircraft charges was $1,110,000 ($995,000 + $115,000). The CCA also noted that Rate 1 was allocated $6,735,000 of the total $7,035,000 reduction, or approximately 96%. The CCA calculated that using that factor, the impact for Rate 1 attributed to administrative and corporate aircraft charges would be $1,065,000.

The CCA argued that the change in cost allocation for corporate costs should be reflected in the compliance filing that would result from the Application. The CCA also argued that the unbundled retail costs should be removed from the corporate cost allocations.

Labour Costs

The CCA agreed with PICA/STMG that the labour costs forecast by ATCO Gas were excessive and should be reduced and that ATCO Gas should only be allowed costs associated with efficient operations. The CCA considered that the 11 FTEs to perform load balancing, settlement, COP and storage and regulatory is excessive as all these functions, except load balancing and settlement, were preformed before the retail sale. The CCA argued that given the majority of the load balancing would be preformed by DERS, the CCA did not see ATCO Gas's role as significant. The CCA recommended that the 11 positions be reduced to three. The CCA argued that ATCO Gas's description of the change in duties did not discharge its duty to prove that positions and costs were required. The CCA considered that given the magnitude of the rate increases that residential customers would face, the Board must ensure ATCO Gas maintained efficient operations.

Communication Costs

The CCA argued that independent retailers should fund marketing efforts to move customers from regulated supply to unregulated supply. The CCA considered that under no circumstances should the DSP be allowed recovery of these costs. The CCA noted that no-choice customers, those customers that could not move to unregulated suppliers, could be saddled with marketing costs or public education costs for a deregulated market. The CCA argued that no-choice customers were harmed by these costs and had no possibility of benefit. The CCA submitted that no-choice customers are customers who required the protection of the Board and Government. The CCA argued that, to the extent that any marketing costs should be allowed into the revenue requirements of DERS or ATCO Gas, the costs should appear in the PSP. Placing discretionary costs, such as marketing and customer education, in the PSP would allow all customers to share in these costs and not limit the costs assignment to those customers who chose or must stay in the regulated supply. The CCA also argued that allowing the default supplier, who has unregulated operations, to control marketing and customer education expenditures was inappropriate.

The CCA agreed with the position of the AUMA/EDM that marketing costs of ATCO Gas should be reduced. The CCA recommended that the costs should be reduced by a minimum of 20%.

Return Margin

The CCA agreed with PICA/STMG that the removal of gas purchasing requirements from ATCO Gas reduced the risk and therefore the cost of capital. The CCA suggested that, on an interim basis, ATCO Gas's return should be reduced by the amount of the DERS return on NWC and parental and bank guarantees to reduce the level of customer harm.

FGA

The FGA did not oppose the technical calculation of the proposed interim rates.

PICA/STMG

Labour Costs

PICA/STMG submitted that ATCO Gas did not need the same number of supervisors to manage a wholesale contract as was previously required to manage a combined wholesale and retail function. PICA/STMG argued that a significant reduction in the supervision FTEs was warranted, given the wholesale ITBS contract was unlikely to be as onerous to supervise as the retail ITBS contract requiring decisions related to hundreds of thousands of customers. PICA/STMG submitted that in the absence of details supporting the need for 3 FTEs for supervising the wholesale contract, the FTEs should be reduced to one.

PICA/STMG noted that ATCO Gas indicated that 6.5 FTEs performed front counter service and that ATCO Gas would provide a forecast of the cost recovery for this item and either propose a deferral account for recovery of these costs or treat the costs and revenues related to these services as non-utility.

PICA/STMG submitted that all costs related to provision of transitional services should be treated as non-utility service and therefore, the costs associated with the 6.5 front counter FTEs and any associated supervision and administration FTEs, including related supplies costs, should be removed from PSP costs in the 2004 final adjustments.

PICA/STMG noted that ATCO Gas indicated that about $190,000 of field labour that was involved in collection activity had not been peeled out of the PSP function. PICA/STMG also noted that ATCO Gas had indicated that this component, associated with collections, was only about 1% of 277 field labour FTEs and it would not be possible to shed this cost. PICA/STMG observed that 1% of 277 FTEs was approximately 2.78 FTEs and therefore PICA/STMG submitted that ATCO Gas should be directed to remove the costs associated with 2.78 FTEs from the PSP function in the 2004 final adjustments.

PICA/STMG noted ATCO Gas indicated that 11 FTEs would be performing load balancing, settlement, activities related to COP and COS and some regulatory work. PICA/STMG submitted that ATCO Gas could not provide details, and therefore argued that ATCO Gas's assumption that the 11 FTEs would be required for performing the redefined functions as distributor, was arbitrary. PICA/STMG argued that ATCO Gas should be directed to provide a specific forecast of the number of FTEs required for the above noted functions applicable to distribution only service at the time of the 2004 final adjustments. Alternatively, PICA/STMG recommended that only 50% of the costs applicable to the 11 FTEs should be included in the 2004 final adjustments.

PICA/STMG argued that ATCO Gas should be directed to provide full justification for retaining any of the 11 staff from portfolio management as part of the ATCO Gas Retailer Service and GUA Compliance proceedings.

Communication Costs

PICA/STMG argued that only those communications costs needed for distribution only service should be included in PSP service. PICA/STMG submitted that if the Retail Sale operations to DEML is approved, ATCO Gas and DERS should be directed to coordinate their communications and marketing efforts to avoid unnecessary and costly duplication of messages.

PICA/STMG submitted that all costs related to the budget plan and GCRR should be removed from the revenue requirement since these functions would no longer be performed by ATCO Gas if the sale to DEML was approved. PICA/SMTG noted ATCO Gas stated that it would no longer be able to make use of bill inserts as a means of communication. PICA/STMG argued that this was only a concern if ATCO Gas was unwilling to work cooperatively with DERS. In PICA/STMG's submission, ATCO Gas and DERS should cooperate with respect to communication programs to achieve economies and avoid duplication of message content.

Views of ATCO Gas

ATCO Gas stated that, notwithstanding any approval of the Retail Sale, the approach taken in preparing the analysis was still consistent with customer choice and would therefore be used to prepare unbundled rates.

2002 COSS

ATCO Gas replied that the 2002 COSS was prepared to show that the rates that were in place in 2002 were reasonable rates and that the need for a Phase II for 2002 was not required. ATCO

Gas did not seek approval for any permanent COSS methodology changes in that application nor was it asking for any in the Application.

ATCO Gas argued that detailed discussions related to COSS methodology would be best addressed when ATCO Gas filed its COSS related to the 2003/2004 GRA. ATCO Gas did not believe that it would be valuable to have that discussion now because:

- ATCO Gas had filed a GRA for the 2003/2004 test period;
- interim rates were in place;
- the 2002 COSS in the Application had limited use. It was used to develop the amount of interim rate reduction for each of the rate classes. It was also used to identify the storage and production rider impacts recommended by ATCO Gas; and
- the 2002 COSS was not used to identify the cost reductions.

ATCO Gas argued that the Board should reject the CCA's request to redo the 2002 COSS. ATCO Gas stated that the comprehensive discussion on COSS methodology should occur at the next Phase II proceeding when the final rates for 2003/2004 would be set.

Interim Rate Design

ATCO Gas replied that it had considered AIPA's alternative to develop the interim rates by prorating the costs over the rate classes, but had rejected it because the use of the COSS method recognized that most of the costs that are being shed are customer costs.

ATCO Gas argued that it was not appropriate that the Board issue a methodological change with respect to the treatment of late payment revenues for the upcoming Phase II hearing as suggested by AIPA. ATCO Gas submitted that this issue should be discussed at the next Phase II proceeding and the Board could issue its decision once all the facts are before the Board. ATCO Gas noted that this would not be an issue in the future if the Retail Sale were approved, as ATCO Gas would no longer receive late payment revenue.

ATCO Gas argued that the Application was identifying what costs it would no longer incur if the Retail Sale were approved. ATCO Gas submitted that the costs remaining were prudently incurred costs that ATCO Gas should be allowed to recover through its rates, and that costs would eventually be reviewed by the Board for the 2003/2004 test period. ATCO noted that a subsequent Phase II application would set the appropriate rates for all rate classes.

Quantum of Interim Rate Reduction

ATCO Gas submitted that the Board should not adopt AUMA/EDM's suggestion that the adjustments identified in Exhibit 54 should be used for purposes of the interim rate adjustment. ATCO Gas argued that the adjustments identified in Exhibit 54 did not incorporate the impact of Decision 2003-072. For example, the ITBS reduction did not reflect the fact that the Board had directed that ATCO Gas reduce the placeholder forecast by 11.1%. Furthermore, the royalty fee adjustment assumed the royalty fee was received and taxed in the year 2003. The royalty fee adjustment in Exhibit 54 only reflected the estimated 2004 adjustment, without taking into consideration the tax impact in 2003. For these reasons, ATCO Gas argued that the interim rate adjustments as identified in the Application were more appropriate than the estimated impacts provided in Exhibit 54.

ATCO Gas took exception to the adjustments discussed by Calgary in argument under this section as they appeared to relate to the fact that the costs that ATCO Gas was able to shed as a result of the Retail Sale were not as great as the costs that DERS had indicated would be incurred by them as the DSP. Calgary's comparison ignored the fact that ATCO Gas would be operating under a vastly different legislative environment in the future, one where the separation of the regulated retail functions from the distribution function had been mandated. The direct result of this separation was the establishment of a revenue requirement for the DSP on a fully allocated cost basis, while ATCO Gas argued it could only shed the incremental costs associated with the functions it would no longer be responsible for. ATCO Gas submitted that this action would lead to an increase in costs, a consequence of which was clearly contemplated by the legislation.

ATCO Gas argued that Calgary had not provided any support as to why its proposed adjustments were appropriate and suggested that random percentages had been chosen and applied to numbers which were based on calculations that Calgary had provided in other proceedings, and which had not been properly tested as to their validity in this proceeding. ATCO Gas submitted that little if any weight should be afforded these recommendations due to the lack of evidence filed by Calgary in this proceeding to support the adjustments.

Views of the Board

The Board notes that the interveners proposed further reductions to the interim rates in respect of the following costs: marketing and consumer information, CIS, administration, customer care, and labour costs.

The Board considers that all costs related to the functions of the DSP should be removed from the distribution rates and recovered in conjunction with the GCRR.

With respect to marketing and customer information, the Board considers that it would be appropriate to allocate some of the existing marketing and customer information costs to the DSP function. The Board notes that a PSP would not have responsibility with respect to the billing envelope . While the PSP would still be expected to provide some customer information, including safety information, the Board considers that much of the customer information previously provided by ATCO Gas will in future be provided by the DSP or RSPs. Notwithstanding ATCO Gas's submission that its delivery of customer information would be more expensive without control of the billing envelope, the Board considers that there should be a significant portion of marketing and customer information costs reclassified to the DSP function. The Board agrees with the recommendations of AUMA/EDM and CCA that, for the purposes of establishing interim rates, 20% of marketing and customer information costs should be reclassified as DSP costs. The Board will therefore reduce the proposed interim rates by $450,000 in respect of marketing and customer information costs.

With respect to CIS costs, the Board recognizes that ATCO Gas will continue to require the use of the CIS and therefore the Board is not persuaded that any adjustment should be made to interim rates in respect of CIS costs.

With respect to administration costs, the Board notes that ATCO Gas proposed to adjust the interim distribution rates in the event that the Retail Sale transaction closed. However, the Board considers that it would be appropriate to reclassify a portion of the administration costs to the DSP function in the interim rates, regardless of whether the Retail Sale transaction closes. The Board notes that interveners proposed reductions in the amount of administration costs classified to the PSP function in the range of 10 to 20%. The Board considers, for the purposes of establishing interim rates, that it would be appropriate to reclassify 10% of administration costs to the DSP function. The Board will therefore reduce the proposed interim rates by $2,200,000 in respect of administration costs.

With respect to customer care, interveners proposed adjustments in respect of the number of FTEs related to credit and collections, front counter duties, and ATCO I-Tek contract administration. The Board notes ATCO Gas's position that there would be a small reduction in the duties of a large number of people, and that it might not be possible to eliminate any positions. However, the Board also notes that ATCO Gas would receive revenue from DERS in respect of these duties, in the event that the Retail Sale transaction closes. If the Retail Sale transaction does not close, the Board considers that it would still be appropriate to reclassify a portion of these costs to the DSP function. The Board agrees with AUMA that an appropriate adjustment would be in respect of 6.5 FTEs for counter staff plus 1% of 277 FTEs for field staff, for a total adjustment of 9.3 FTEs. The Board will therefore reduce the proposed interim rates by $400,000 in respect of customer care costs.

With respect to labour costs, interveners proposed adjustments in respect gas portfolio planning, production, storage and similar regulated functions. The Board notes that ATCO Gas acknowledged that there were 11 FTEs that would be redeployed to other duties including load balancing and load settlement, which is a subject of the Retail Services and GUA Compliance Application. The Board is not persuaded that it is reasonable, for the purposes of interim rates, to assume that all 11 FTEs are required to be redeployed from performing portfolio management activities to other PSP functions. The Board considers that it would be appropriate to assume that one of the 11 FTEs is required to be deployed to other PSP functions. The remaining FTEs will have to be justified through the ATCO Gas Retailer Service and GUA Compliance proceeding. The Board will therefore reduce the proposed interim rates by $350,000 in respect of labour costs.

In consideration of all the above, the Board will reduce the proposed interim rates for the PSP by a total of $3,400,000 ($450,000 in respect of marketing and customer information costs, $2,200,000 in respect of administration costs, $400,000 in respect of customer care costs and $350,000 in respect of labour costs). The Board considers that, for the purposes of establishing the interim rates, it would be appropriate to consider this further reduction of $3,400,000 to be customer-related costs. Based on the average of 419,699 customers, the Board will reduce the fixed rate component of the proposed interim rates by $0.68/month/customer.

The Board notes that in the event that the Retail Sale transaction does not close, it will be necessary to establish a tariff sheet for each rate class to collect the appropriate non-PSP charges on an interim basis.

The approved interim rates for AGS and AGN are set out in Tables 4 and 5 below.

Table 4. Approved Interim Rates – AGS

Rate	Fixed $/month	Variable $/GJ*	Demand $/GJ
1/11	12.02	1.058	----
3	262.77	0.284	3.35
5/18	18.40	0.876	----
13	283.04	0.154	5.47

*gigajoule

Table 5. Approved Interim Rates – AGN

Rate	Fixed $/month	Variable $/GJ	Demand $/GJ
1/11	11.22	0.990	----
3	256.25	0.267	3.70
13	292.33	0.052	5.68

The Rate Schedules approved in this Decision are attached as Appendices G and H.

4.3 Use of AGS Costs as Proxy for AGN Costs

Views of the Interveners

AUMA/EDM

AUMA/EDM submitted that the use of AGS as a surrogate for AGN was a reasonable approach for purposes of the interim rate reductions. AUMA/EDM noted that in Decision 2003-072 the Board indicated that it expected the outcome of the ATCO Gas Phase I Decision to be separate revenue requirements for the AGS and AGN, and that separate rates could be set for AGS and AGN in the subsequent Phase II.[77] AUMA/EDM submitted that there should be sufficient opportunity to adjust final rates as required.

Calgary

Calgary argued that it was clear from the ATCO Gas 2003/2004 GRA filing that the cost of AGS and AGN were not the same.[78]

Calgary argued that, while the response to AUMA-EDM-AG-012 Attachment 1 might imply a similarity,[79] the other factor that the Board should consider was that many of the cost allocations that related to unbundling and the sale were allocated 50/50, so that the allocation would be expected to be similar.

[77] Decision 2003-072, p. 12
[78] Decision 2003-072, pp. 11 - 13
[79] Information response AUMA-EDM-AG-012 shows that AGN amount of $10.98 million versus $10.93 million for AGS. The undertaking from Tr. p 321 (Exhibit 54) has no split between AGS and AGN.

Calgary took issue with ATCO Gas's proposal that the interim rates be different, while at the same time suggesting that AGS can be a proxy for AGN. Calgary considered the two concepts are inconsistent; if the costs are the same the proposed rates should be the same.

Views of the ATCO Gas

ATCO Gas argued that it was appropriate to use the AGS costs as a proxy for AGN costs because the functions and the associated costs of those functions impacted by the Retail Sale were similar for both the AGS and AGN rate zones. ATCO Gas provided a table[80] that further supported the position that the costs for both AGS and AGN were similar.

ATCO Gas stated that it was using the 2002 AGS data only to develop interim rates for both the south and the north. ATCO Gas stated that the quantum of the adjustments to reflect the Retail Sale would still be open for scrutiny by parties in the final compliance filing, and that filing would be an appropriate forum to address any differences between AGN and AGS.[81] ATCO Gas submitted that, in the event that the Retail Sale was not approved, it would identify the costs to be recovered through the GCRR for each of AGN and AGS in the final GRA compliance filing.

ATCO Gas also indicated that the final rates for the 2003/2004 test period would be determined once the Board had completed the ATCO Gas 2003/2004 GRA Phase II proceeding.

Views of the Board

The Board notes no party opposed the use of AGS rate adjustments as a proxy for AGN rate adjustments. The Board is satisfied that the adjustments are similar enough for both AGS and AGN that it is reasonable to use the AGS rate adjustments as a proxy for the AGN rate adjustments, for the purposes of setting interim refundable rates.

4.4 Production and Storage Riders (COPRR and COSRR)

Views of the Interveners

AIPA

AIPA recommended that the COSRR could include 10.7¢/GJ to account for current COS costs. AIPA noted that, with a storage rider, the irrigation service, Rate 5, did not utilize the COS function, but would nonetheless be charged 10.7¢/GJ for ATCO Gas maintaining this legacy asset. AIPA argued that since there are no COS sales during the irrigation season there must be a continuation of the existing deemed benefit amount for Rate 5 and incorporation of such credit amount in the proposed COSRR.

AIPA expressed concerns that a deferral mechanism for the COSRR had not been clarified in this proceeding. AIPA argued that since storage for Rate 5 was on a deemed basis without withdrawals in the winter season then a reconciliation process, currently undefined, would have to recognize this unique circumstance for seasonal loads, if the ATCO Gas proposal was approved in this proceeding.

[80] Information response AUMA-EDM-AG-012
[81] Tr. p. 293, lines 8-25 and p. 294, lines 1-12

CCA

The CCA argued that large commercial and industrial customers in Rates 1 and 3 benefit from the moving of cost allocations from energy and demand to customer. The CCA considered that residential customers were being excessively harmed by the Application and the Retail Sale and DERS Tariff Applications. The CCA argued that, for the same reasons used by PICA/STMG, that its customers were harmed by the unbundling of storage and production costs.

FGA

The FGA did not contest the technical calculations of the production and storage riders. However, the FGA noted, as argued in a previous section, that COP and COS costs still remaining as part of revenue requirement should not be unbundled to the COPRR and COSRR as proposed by ATCO Gas.

PICA/STMG

PICA/STMG stated that they were not opposed to implementation of the rates on an interim basis with one exception. PICA/STMG noted that ATCO Gas proposed to reduce the distribution tariffs to unbundle the COS and COP cost components included in distribution tariffs and increase the production and storage riders by corresponding amounts. PICA/STMG were concerned that the proposed recovery of these costs through the COPRR and COSRR, on an energy basis, could potentially have a negative impact on larger customers.

PICA/STMG noted that ATCO Gas introduced this tariff change as part of its rebuttal evidence. PICA/STMG argued that rate design alternatives had not been tested nor had here been an assessment of the impact on different customer classes. PICA/STMG recommended that ATCO Gas's proposal should not be dealt with on an interim basis, but instead the matter should be dealt with as part of the ATCO Gas 2003/2004 GRA Phase II proceeding.

Views of ATCO Gas

In its rebuttal evidence ATCO Gas proposed to modify the determination of the Storage Rider and the Production Rider to unbundle all costs related to those two functions. ATCO Gas believed that this was appropriate since the functions of storage and production were not enumerated as gas distribution functions in the *R3 Regulation*.

ATCO Gas noted that the market value adjustment, which was the difference between the deemed market value of any COP gas in a given month and the royalty expenses associated with that COP, was included in the COPRR. ATCO Gas submitted that it would be appropriate to include all costs associated with the COP assets in the determination of the COPRR.

ATCO Gas also noted that the market value adjustment, which was the difference between the deemed market value of any storage gas withdrawals in a given month and the value of the gas injected during the previous summer period, was included in the COSRR. Also included in the COSRR was the NWC costs associated with the stored gas as well as any revenue received by ATCO Gas associated with the operation of the Carbon Storage facility.

ATCO Gas proposed that these rate riders be treated as deferral mechanisms. ATCO Gas argued that this was consistent with the fact that in Decision 2003-015[82] the Board approved a reconciliation process with respect to the Storage Rider revenues and costs.

ATCO Gas argued that if the Board approved the proposed rate change, the rate embedded in the 2002 revenue requirement of 10.7¢ per GJ was the appropriate reduction to the current distribution rates.

Views of the Board

In the previous sections of this Decision on production and storage, the Board denied the implementation of changes to the COPRR and COSRR at this time, but indicted that the Board is prepared to further consider any such proposal as part of the ATCO Gas 2003/2004 GRA Phase II.

5 PRINCIPLES FOR RETAIL SALE ADJUSTMENTS

In this section the Board will consider the views of parties regarding the principles to be applied when incorporating adjustments due to the impact of the Retail Sale on the ATCO Gas 2003/2004 GRA Phase I compliance filing. The Board will also consider the impact or requirements, if any, which may be appropriate when ATCO Gas files Phase II.

Views of the Interveners

AIPA

AIPA argued that the proposed principles for allocating AGS CIS costs needed to be revisited, pointing out that CIS investment had been substantial with a mid-year 2002 cost of $21 million and a year-end 2003 cost of $17.8 million.[83] AIPA noted that the 2002 asset expense allocated to the CIS was $5.3 million.[84] AIPA also noted that the total 2002 customer billing and accounting O&M expense was $11.3 million of which $6.4 million was allocated to the billing function and $4.9 million was functionalized to the CIS.

Referring to the one-time royalty from ITBS of $1.1 million, AIPA argued that the contribution was low relative to the net book value of $17.8 million for the CIS and did not reflect the usage of the asset, as the CIS must provide all of the load settlement function for retailers.

AIPA argued that the CIS asset expense should be allocated between the PSP and the DSP to account for the load settlement function and other functions provided to the retailer. AIPA recommended an allocation of 50/50 between ATCO Gas and the DSP, which would result in a decrease of $2.7 million in ATCO Gas costs that would be reflected in delivery rates.

AIPA noted Mr. Beckett's view[85] that allocation to retail was not appropriate as it was rejected in the ATCO Electric RROT proceedings and that, as the CIS was integrated software, costs cannot be hived off without stranding costs. AIPA noted that the ATCO Electric RRO proceedings were

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82 Decision 2003-015 – ATCO Gas, Reconciliation Process for Certain Costs and Revenues Charged to the Gas Cost Recovery Rate and Company-Owned Storage Rate Rider, dated February 18, 2003
83 Tr. p. 95
84 Application, Tab 2, p. 4 and Tr. pp. 275-276
85 Tr. p. 270

based on the incremental cost standard whereas the Application addressed costs on a stand-alone basis. AIPA argued that furthermore, costs would not be stranded if ATCO I-Tek paid its appropriate share of an asset that it uses. AIPA recommended a 50/50 cost sharing.

AIPA argued that the information requirements were wholly disproportionate between wholesale and retail when considered on the basis of the number of customers. AIPA further stated that its understanding from the Retail Sale proceeding was that provision of customer information was necessary to discharge the DSP obligation and hence provide value to the transaction. AIPA considered therefore, that the CIS system continued to be used and useful not only for the distributor but also for both the distributor and the DSP. AIPA argued that having the CIS system remain in the distribution rate base with only a nominal royalty contribution did not reflect the importance and necessity of the CIS to the DSP and retail functions.

AUMA/EDM

AUMA/EDM stated that they had some concerns with the following statement by Mr. Beckett:

> Mr. Retnanandan, there's a trend developing to these questions from Mr. McCreary and now from you. And I think it is fair to say that when we looked at the cost estimates necessary for rate unbundling, we did focus on the big ticket items. So there are probably, in the I-Tek costs and our own internal costs, items such as the ones we were discussing with Mr. McCreary this morning that will require additional rigor and scrutiny through the regulatory process; but we didn't feel that it was a good investment of our time and our energy or the regulatory process associated with interim rates to get into excruciating detail on those particular items.[86]

AUMA/EDM addressed the adjustments both in principle and detail, submitting that all of the estimated impacts shown in Exhibit 54, as adjusted by the Board, plus ATCO/CU Administrative Charges and Corporate Aircraft Charges should be reflected in the interim rate reductions, if the Retail Sale was approved. AUMA/EDM argued that the interim rate reductions should reflect the best available estimates of the impacts of the Retail Sale and Decision 2003-072.

EUB Assessment

AUMA/EDM noted that ATCO Gas had included all EUB Assessment Costs in Account 728, Other Administrative General Expenses, with the PSP costs. In AUMA/EDM-AG-8, ATCO Gas indicated that its 2004/05 Assessment would be based on its 2003 revenue requirement but indicated it may request that the 2003 revenue requirement be adjusted to remove the GCRR revenue, although there was no certainty that the Board would approve such a request.

The AUMA/EDM noted that the EUB Assessment is weighted 75% on annual revenue requirement and 25% on number of customers served by the utility.[87] However, AUMA/EDM submitted that the Board should depart from its standard practice whereby a one-year lag is incorporated. This would help avoid the situation where ATCO Gas would pay an assessment for 2004/05 based on a full 2003 distribution plus GCRR revenues while DERS would pay no assessment for that period. AUMA/EDM submitted that this result did not seem reasonable. AUMA/EDM argued that it made better sense to base the 2004/05 Board Assessments on 2004 revenue requirements for each of ATCO Gas and DERS, at least in the first year following the

[86] Tr. p. 99
[87] Tr. p. 334

transfer. AUMA/EDM noted that, as shown in Exhibit 48, the 75% portion of the $1,443,000 assessment based on revenue requirements would be $1,082,000. ATCO Gas's revenue requirements net of the GCRR would be reduced by about 70%, which would in turn reduce the Board's assessment by roughly $750,000. AUMA/EDM submitted that the 2004/05 assessment for DERS should recover that amount.

AUMA/EDM did not agree with ATCO Gas's suggestion that there would be little if any reduction to its 2004/05 Board assessment as the retail sale would close very late in 2003.[88] AUMA/EDM argued that implicit in that position was that the Board should ignore the transfer of over $1 billion of gas and other costs from ATCO Gas to DERS starting about January 2004 and slavishly apply the standard assessment formula that incorporates a one-year lag.

Customer Care Costs

AUMA/EDM noted that ATCO Gas's witness, Mr. Beckett, seemed to imply that the benchmarking consultant would not only determine fair market prices but would also determine the appropriate billing determinants. AUMA/EDM submitted that this was a marked departure from the ATCO I-Tek IT Services module where billing determinants were addressed in the ATCO Gas and Electric GRA's.

AUMA/EDM submitted that the ITBS billing determinants should be subjected to a detailed review by the parties in the ITBS Benchmarking module. AUMA/EDM argued that in order to make any such review meaningful, ATCO Gas should be directed to provide historical billing determinants pre-retail sale over several years and post-retail sale billing determinants, along with a detailed explanation for any changes in the billing determinants.

AUMA/EDM noted that ATCO Gas's witness, Ms. Wilson, indicated that there were about $190,000 of costs related to field labour related to performance of collection activities, which represented about one percent of the cost of 277 positions. AUMA/EDM also noted that ATCO Gas did not consider that any of those costs could be shed.[89] AUMA/EDM argued that it should be possible to eliminate three positions out of 277 positions to reflect the fact that these collection activities would be substantially reduced, and that billing costs could and should be reduced by a further $190,000.

AUMA/EDM noted that during cross-examination ATCO Gas indicated that approximately 6.5 front counter positions would no longer be required following the transition to DERS and that the costs related to those positions would be recovered from DERS during the transition period.[90] AUMA/EDM submitted that the costs attributable to these FTE's were about $400,000.[91] AUMA/EDM argued that billing costs should be reduced by another $400,000 to reflect the elimination of these 6.5 positions.

AUMA/EDM noted that ATCO Gas had functionalized all of Account 710, Supervision of Distribution Customer Accounting-Operation, to Meter Reading[92]. AUMA/EDM also noted that ATCO Gas's witness indicated that some small amount of supervision costs in Account 710 was

88 ATCO Gas Argument pp. 21-22
89 Tr. p. 115
90 Tr. p. 112
91 Tr. p. 114
92 Application, Tab 2, p. 59

associated with the front counter services that ATCO Gas provided in 2002 and estimated about $100,000 for AGS. [93]

Based on the foregoing, AUMA/EDM submitted that a minimum of $790,000 ($190,000 + $400,000 + $100,000 for each of AGS and AGN) of billing costs related to front counter and collection activities could be shed. AUMA/EDM argued that, for purposes of determining the interim rate reduction, it was reasonable to estimate that $395,000 of that $790,000 amount (or one-half) related to AGS.

CIS Royalty Fee

AUMA/EDM noted that ITBS would pay a one-time royalty of $2.00 per customer. Based on an estimated 950,000 customers served by DERS, the total royalty would be $1.9 million, of which ATCO Gas would receive 60% or $1.14 million.

AUMA/EDM believed it was worth remembering that the Board expressed substantial reservations in the Affiliates Transactions Proceeding about the one-time royalty payment, and only approved that royalty fee for GRA purposes.[94] AUMA/EDM noted that ATCO Gas's witness further acknowledged that the Board only approved the royalty fee for 2001 and 2002.[95]

AUMA/EDM submitted that a detailed review of the CIS royalty fee should also be included in the ITBS benchmarking module. AUMA/EDM argued that such a review should take into account the following circumstances that might be different than those considered in the Affiliates Proceeding in establishing the royalty fee for 2001 and 2002:

i) DERS DRT Customer Care Costs are $47.7 million per year;[96]

ii) DERS RRT Customer Care Costs are $9.5 million; [97]

iii) the contract with DEML is for an exclusive 10-year period;[98]

iv) the retail sale value may reflect the significant revenues that ITBS will receive from DERS;[99] [100]

v) the asset-related costs of the CIS ($5.264 million for AGS) are borne by customers;[101] and

vi) customers do not agree with ATCO and DERS that full separation of customer information is required.[102] [103]

93 Tr. p. 88
94 Decision 2002-069 – ATCO Group, Affiliate Transactions and Code of conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues, dated July 26, 2002, p. 69
95 Tr. p. 76
96 DERS Tariff Application, Schedule 6.3
97 DERS Tariff Application, Schedule 6.2
98 Retail Sale, AUMA/CE Argument, p. 22
99 Retail Sale, AUMA/CE Argument, p. 22
100 Retail Sale, Calgary Argument, p. 68
101 Tr. p. 76
102 Retail Sale, Calgary Argument, p. 25
103 DERS Tariff Application, CG Argument, p. 25

AUMA/EDM recommended that the impact of the $1.1 million contribution to the CIS be reflected in the interim rates when and if the retail sale was approved.

Other Adjustments

AUMA/EDM argued that for the reasons noted under 'Administration and Supervision Costs', the reductions in ATCO/CU Corporate Costs Corporate Aircraft Costs, Working Capital, O&M and Penalty Revenues, should also be included in the interim rate reductions. AUMA/EDM submitted that there was no logical reason why these known, albeit not final, adjustments should not be reflected for purposes of the interim rate reductions when and if the retail sale was approved.

Calgary

Calgary noted that ATCO Gas was seeking approval directionally for the treatment of the CIS royalty, NWC, certain O&M expenses including corporate costs, the GCRR revenue treatment, long term financing adjustments, and large corporation taxes. Calgary had no issue in principle with any of the concepts and principles set out in section 5 of the Application. However, Calgary took issue with certain aspects of the approval sought by virtue of what was not contained in section 5 of the Application.

Calgary had no objection to the royalty fee related to the use of the ATCO CIS by ITBS for DERS being credited to rate base, but questioned the continuing applicability of the ATCO Gas CIS being included in rate base and earning a return. Calgary argued that the inclusion made it difficult to compare the cost of ATCO Gas's customer accounting/care costs with other companies.

Calgary noted that there appeared to be a difference of opinion over whether or not the issue of a Royalty Fee was settled in Decision 2002-069. Calgary submitted that if the Board considered that the issue of a Royalty Fee for the use of the ATCO CIS was to be further discussed and incorporated in the ITBS MS Agreement and Benchmarking proceedings, the amount estimated by ATCO Gas should be placed in a deferral account and dealt with, if and when, the ITBS MS Agreement and Benchmarking proceedings were completed.

Calgary argued that the unbundling process should include all the indirect or assigned costs, such as the working capital impacts, including PEP, storage, production and gathering. Calgary also agreed that if the rate base was reduced, working capital items related to income tax, debt, preferred shares, common equity would also be impacted. Calgary also noted that there might be a working capital adjustment required for any changes to depreciation, which should also be reflected.

Calgary submitted that there should also be changes to Franchise Fees assuming the sale was approved. It was Calgary's understanding that DERS' non-gas costs were not subject to Franchise Fees, so that costs other than gas costs that are removed from the ATCO Gas Revenue Requirement and transferred to DERS will reduce the Franchise Fees currently paid.

Calgary expressed concern that while ATCO Gas acknowledged that there would be changes in its long term financing, ATCO Gas did not acknowledge that, if the long term financing changed, so would the equity financing and the associated income taxes. Calgary noted that ATCO Gas appeared to only recognize the potential change in the large corporation tax.

CCA

EUB Assessment

The CCA agreed with AUMA/EDM that the assessment of Board costs should be assigned on a current year basis rather than a prior year basis. However, the CCA did not consider the use of customer weighting to be inappropriate. The CCA argued that the use of customer weighting would over allocate costs to those customers who had both a regulated LDC and retailer. The CCA submitted that Board costs should be allocated on revenue requirements.

Royalty Fees

The CCA was concerned that if the royalty fee was allowed as part of the Retail Sale and was amortized, significant customer value would be lost because of income tax timing issues. The CCA preferred that the fee not be allowed as part of the Retail Sale or if it was allowed, that it not be included as an eligible cost in DERS' rates. The CCA argued that if the fee was allowed and included in customer rates, the CCA preferred that the fee be treated as a one-time fee to minimize losses due to income tax timing effects.

The CCA disagreed with PICA/STMG that the royalty fee should be increased. The CCA considered that the CIS system was sized and designed to perform all the billing and customer services of all ATCO Gas customers, and all customers should be charged a standby fee to have this capability in place. The CCA argued that it was inappropriate to have smaller customers support the excess capacity of the CIS system since an increase in the royalty fee would allocate smaller customers a larger portion of the CIS system. Given the large rate increase smaller customers are facing, the CCA argued that the PICA/STMG proposal was inappropriate.

PICA/STMG

With respect to the royalty fee of about $1.1 million, PICA/STMG noted that in Decision 2002-069 the Board expressed substantial reservations about a one-time royalty payment and indicated that it would monitor the situation carefully at future GRAs. PICA/STMG argued that the proposed sale of the retail function had brought to light the probable inadequacy of the royalty amount specified in the 1998 MS Agreement. PICA/STMG based its submission on the following facts:

- CIS was maintained on the books of AGS at a net book value of about $17 million as of year-end 2003, or approximately $34 million for ATCO Gas.
- Prior to the proposed sale, ITBS used the CIS system to record customer information and to provide billing services to ATCO Gas.
- Following the proposed sale, in addition to maintaining customer information and providing billing services to ATCO Gas, ITBS would provide similar services to DERS under a 10-year exclusive contract using the same CIS system.
- The billing services provided by ITBS to DERS on the gas side were forecast at an annual cost of $22.3 million at a base fee of $2.20 per month per bill.[104]

[104] DERS Tariff Application; information response BR-DERS-15(c)

- ITBS would use the ATCO CIS for billing purposes and incur a one-time royalty fee of approximately $1.1 million. DERS will pass the $22.3 million cost of billing to its default supply customers.

PICA/STMG submitted that the adequacy of the royalty provisions should be reviewed as part of the ITBS benchmarking module currently under way with any adjustments reflected in the final determination of the 2004 revenue requirement.

Cost of Capital

PICA/STMG did not agree that the Board gave zero weight to credit risk. PICA/STMG believed that the Board's concern in Decision 2000-88[105] was not that retail service did not justify risk compensation, but whether or not retail service was significantly more onerous than other services provided by the utility to justify compensation over and above the allowed return on rate base. PICA/STMG submitted that the Board did not arrive at any definitive conclusions as to the risk of providing retail service relative to other services.

PICA/STMG considered that, irrespective of Decision 2000-88 respecting ATCO Electric, ATCO Gas's business risk in the 2003/04 GRA was assessed assuming ATCO Gas provided both distribution and retail services. PICA/STMG noted that all the evidence submitted by the expert witnesses was predicated on this assumption. PICA/STMG also noted that the evidence in those proceedings made reference to the flow through aspect of gas costs contributing to lower risk. PICA/STMG noted further that in spite of the gas cost flow through mechanism that has been in place for some time, Standard & Poors referred to retail as a higher risk operation.

PICA/STMG submitted that depending on the Board's treatment of this request, it was fair to say that any corresponding risk compensation included in ATCO Gas's return should be unbundled and treated as related to RSP service. PICA/STMG argued that a process should be established for assessment and final determination of the risk compensation impact of the separation of ATCO Gas's retail operations.

ATCO/CU Corporate Charges

PICA/STMG considered that there was no distinction between allocated costs and incurred costs, and that any costs previously caused by the retail function must not be borne by the distribution customers. All of the costs to be borne by the distribution customers must be reasonable, prudent and necessary. PICA/STMG argued that the onus was on ATCO Gas to demonstrate that the allocated costs, particularly those related to ATCO/CU corporate costs, were reasonable.

PICA/STMG argued that updating the corporate cost allocation factors to reflect the reality of ATCO Gas's status as a pure distributor, following separation of retail, was appropriate. Therefore, PICA/STMG submitted that ATCO Gas should be directed to update corporate cost allocations as part of its 2004 refiling, using current corporate information for allocation purposes.

[105] Decision 2000-88 – ATCO Electric Ltd., Regulated Rate Option Tariff Part B: Non-Energy Cost Components, dated December 22, 2000

Views of ATCO Gas

ATCO Gas requested that the Board approve that the components of the 2003/2004 GRA revenue requirement forecasts that would be impacted, in the event that the Retail Sale to DERS was approved, had been properly identified. ATCO Gas noted that the final determination of the amount of the adjustments related to the Retail Sale would depend on the following:

- the closing date of the sale;
- finalization of placeholder amounts, most specifically related to ITBS; and
- changes to the Weighted Average Cost of Capital and income tax rates as a result of other regulatory decisions such as Decision 2003-072.

ATCO Gas stated that the impact of the adjustments related to the Retail Sale would be incorporated in a final proceeding once the above matters had been finalized.

Capital Changes

ATCO Gas was not opposed to reflecting the Royalty Fee as a one-time adjustment in order to avoid the income tax timing issue, if the Board preferred that treatment.

ATCO Gas argued that the CIS system was designed to meet the needs of the ATCO utilities for both distribution and retail services and that, in the future, the only function not required by the utilities would be the production of a paper bill. ATCO Gas noted that this function would be replaced by the need to send information with respect to the billing of the ATCO Gas distribution charges to retailers and the DSP electronically, and to send information required by retailers and the DSP for billing of their charges to customers. ATCO Gas argued that the capital investment of the ATCO utilities in the CIS system continued to be fully used and useful and was appropriately included in rate base.[106]

NWC Changes

ATCO Gas submitted that since the gas supply working capital was charged to the GCRR, and assuming the implementation of the proposed changes to the production and storage riders, the removal of the budget plan (PEP) would not impact the ATCO Gas revenue shortfall. ATCO Gas noted that changing the revenue lag would impact all of the other lags resulting in a change to the NWC.

ATCO Gas identified that the Retail Sale would likely result in a reduction to the long term financing requirement and that this change would be due to the recovery of outstanding budget plan receivables, net of the payment of consumer deposits, from DERS. ATCO Gas submitted that the estimated impact of the receipt of the budget plan receivables had already been factored into the working capital change.[107]

Income Tax Changes

ATCO Gas stated that it would adjust the Large Corporation Tax for changes to its balance sheet as a result of the sale.

[106] Information responses CAL-AG-24 and CAL-AG-25
[107] Rebuttal Evidence, p. 16

O&M

ATCO Gas noted that as a result of the benchmarking process, there would be no requirement to use the ITBS cost reduction guidelines/estimates that had been identified in the Application for the setting of interim rates to determine the final GRA revenue requirement forecast.

ATCO Gas submitted that it would no longer be able to make use of bill inserts as a communication vehicle, but would have to find new ways to provide information to customers, which would in all likelihood be more costly. ATCO Gas argued therefore, that an adjustment to the ATCO Gas revenue requirement forecast for communication costs would be inappropriate.

Revenues

ATCO Gas stated that it would address any anticipated revenue from DERS related to the provision of transition services in its final compliance filing.[108] The alternatives under consideration were:

- incorporate a revenue forecast;
- propose to defer the revenue to a future GRA; and
- treat the revenues and the costs associated with the provision of transition services as non-utility.

ATCO Gas noted that its 2003/2004 GRA included a revenue forecast with respect to disconnect and reconnect activities for which ATCO Gas would continue to be responsible. ATCO Gas submitted that the only change with respect to this function was that ATCO Gas would charge the cost of these services to retailers in the future, rather than to customers directly. ATCO Gas stated that currently the revenue did not fully offset the costs associated with these activities. Therefore it was ATCO Gas's intention to request an adjustment to the charge for these services in Phase II of the 2003/2004 GRA.

ATCO Gas argued that it had considered all aspects of the potential impacts of the Retail Sale on its 2003/2004 GRA revenue requirement forecast and that the adjustments that ATCO Gas was proposing were reasonable and appropriate. ATCO Gas argued that further adjustments would impair the ability of ATCO Gas to properly meet its continuing requirement to provide the high quality distribution service that customers expected.

Indirect and Overhead Costs

ATCO Gas argued that there was no support for Calgary's recommendation to reduce the A&G costs of ATCO Gas by applying a 20% reduction to the reductions identified in their Schedule A.[109] ATCO Gas argued that it did not incur fringe benefits, rent, HR costs or any other type of administrative cost for services provided by ITBS, with the exception of the FTEs required to administer the contract for ATCO Gas. ATCO Gas had identified the reductions in administrative charges that it would be able to shed as a result of the Retail Sale. Further

[108] Tr. p. 320
[109] Refer to Appendix F for Calgary's Schedule A

reductions would impair the ability of ATCO Gas to properly function as a distribution service company.

Marketing and Customer Information Costs

ATCO Gas argued that the Board clearly considered it appropriate for ATCO Gas to promote the use of natural gas. It was also clear that the referenced advertisement by the AUMA/EDM on page 7 of its Argument was intended to promote the use of natural gas, rather than promote the GCRR over other retailers, as suggested by the AUMA/EDM. ATCO Gas submitted that the materials filed in information response EEC-AG-2(b)(ii) were of a nature considered appropriate by the Board in Decision 2001-75 and that any suggestion by the AUMA/EDM to the contrary was not supported by the facts.

ATCO/CU Corporate Costs

ATCO Gas argued that it would submit the compliance filing for Decision 2003-072 on December 1, 2003, as a result of which rate adjustments would occur shortly before or after the Retail Sale or implementation of the One-Bill Model. ATCO Gas argued that adjusting for corporate costs in the unbundling interim rate adjustment and in the compliance filing would result in the costs being removed from customers rates twice, which would not be appropriate. Contrary to the comments of AUMA/EDM, ATCO Gas had indicated that the adjustment to Corporate Costs and Corporate Aircraft charges should be removed from the adjustments related to the Retail Sale, as Decision 2003-072 had already addressed this.

ATCO Gas argued that if there was a requirement to remove the energy component from the revenues used in the allocation of corporate costs in determining the impact of the Retail Sale (which would be difficult to quantify), the revenues should also be adjusted to reflect the impact of the rate increase in the 2003/2004 GRA. In effect, ATCO Gas would no longer be using the allocation methodology approved in the Affiliate proceeding. ATCO Gas argued that if a change in the corporate cost allocation methodology was under consideration, it should not be as a result of the Retail Sale.

Customer Care Costs

ATCO Gas argued that staff providing front counter services were also involved in supervision of other staff, and management of customer service applications. As such, ATCO Gas was not able to shed all of the costs currently charged to the front counter activities.

ATCO Gas argued that collection activities performed by customer service staff represented approximately 1% of the their responsibilities and accordingly ATCO Gas was unable to shed any of that staff.

ATCO Gas noted that ATCO Pipelines would continue to be responsible for the billing of Rate 13 customers until at least October 2004, and that any reduction in this revenue should be discussed as part of the Retailer Service and GUA Compliance filing.

ATCO Gas argued that the general postage charges did not relate to postage charges for the billing of customers and that ATCO Gas intended to continue to make use of all of its agency offices in the test period.

ATCO Gas argued that the recommendation of Calgary that the Board should just arbitrarily reduce the ATCO Gas revenue requirement by $3 to $4 million dollars did not properly consider what those costs related to, or the requirement of ATCO Gas to continue to incur those costs in the provision of delivery service.

ATCO Gas argued that the CIS system would continue to be required for management of customer and site data, site enrollment and de-enrollment, management of meter reading routes, meter reading information and meter inventories, management of service orders, management of rate information and calculations including riders, franchise fees, one-time adjustments, and GST. Consequently, the full cost of the CIS system continued to be prudent and used and useful, and appropriately recovered in the ATCO Gas revenue requirement. ATCO Gas argued that the response to BR-AG-14(g) explained why the contribution could not be treated as a reduction to the UCC pools.

With respect to AIPA's argument that some of the CIS asset expense should be allocated between the PSP and the DSP to account for the load settlement function and other functions provided to the retailer, ATCO Gas argued that the *R3 Regulation* section 4(l)(i) stipulated that gas distributors would be responsible for performing distribution system Load Balancing. As a result, ATCO Gas submitted that it does not incur these costs on behalf of retailers, but instead incurs these costs in performance of its responsibilities under legislation.

ATCO Gas argued that the License Agreement provided a proper balance between the interests of ratepayers and the costs and risks assumed by ITBS in pursuing third party opportunities. ATCO Gas submitted that the level of the royalty payment was based on the higher of two expert opinions filed by the ATCO Utilities in the Affiliate proceeding, and was not intended to compensate the ATCO Utilities for the costs of developing the CIS system. ATCO Gas pointed out that the CIS system was and continued to be required for the provision of utility service, and had been approved by the Board. The CIS system was designed to provide the full functionality required by ATCO Gas in the provision of distribution service to customers, and was not developed with distinct distribution and retail modules. ATCO Gas submitted that in order for ITBS to use the system to provide service to DERS, a separate retail module needed to be developed and that ATCO Gas would not be responsible for any costs related to the development of that module. Therefore, ATCO Gas considered that the License Agreement continued to be appropriate, and that another review of the agreement was not warranted so soon after the previous review.

EUB Assessment Costs

ATCO Gas argued that the fact that no increases had been built into the ATCO Gas 2004 Assessment forecast, despite having experienced significant increases in the assessment, and that its revenue requirement would increase as a result of the GRA, in effect resulted in incorporation of the potential effect (if any) of the Retail Sale.

Labor Costs

ATCO Gas noted that the costs associated with portfolio planning were currently charged to the GCRR and would therefore not impact distribution rates. ATCO Gas had identified this as a reduction related to the Retail Sale in Exhibit 54.

In its Retailer Service and the GUA Compliance Application, ATCO Gas had identified costs associated with load balancing and load settlement. ATCO Gas submitted that the review of these costs would occur through that proceeding.

ATCO Gas argued that it was entering a transition phase with respect to these matters and needed to ensure that the right level of staff was in place to properly implement these changes to ensure success. The staff that currently performed the portfolio planning functions was experienced and would provide great assistance in this transition. Accordingly, ATCO Gas argued that it would be imprudent to attempt to manage this significant transition with less staff.

ATCO Gas argued that, with time, it might be possible to adjust the level of staff required to administer the ITBS contract. However, ATCO Gas submitted that until ATCO Gas had some experience of operating in the new world and under the new contract, it would be imprudent to reduce the level of staff required to administer the contract.

ATCO Gas submitted that collection activities were not scheduled functions for customer service employees, but arose through the performance of other services that would continue to be required by ATCO Gas. ATCO Gas argued that to assume that three positions could be lost simply because a small function might no longer be required was not realistic, and would impede the ability of ATCO Gas to properly provide service to customers.

ATCO Gas argued that if the Board removed these costs from revenue requirement, ATCO Gas would not reflect any revenues from Direct for these services.

ATCO Gas submitted that it took supervisory staff into consideration in the calculation of the 6.5 front counter positions that would no longer be required after the Retail Sale (with the exception of transition activities).

Cost of Capital

ATCO Gas argued that in numerous regulatory decisions, most recently Decision 2003-072, the Board had clearly made its views known with respect to the minimal risk associated with use of deferral accounts such as the DGA and the RRO. ATCO Gas submitted that no adjustment to the cost of capital component of revenue requirement was warranted as a result of the Retail Sale.

Long term Financing Impacts

ATCO Gas argued that the response to BR-AG-16 showed a reduction to both long term financing and common equity. ATCO Gas indicated that the only change was that the impact of capital structure changes had already been incorporated in the estimated working capital change impacts. ATCO Gas had removed the financing adjustment because including it separately would have resulted in double-counting the impact.

Views of the Board

ATCO Gas requested confirmation that it had identified all of the components of the 2003/2004 GRA revenue requirement that would be impacted in the event that the Retail Sale to DERS were approved.

The Board notes the significant level of comment on the topic of Retail Sale adjustments. At this time the Board is not prepared to confirm that only those components identified by ATCO Gas cover all of the cost areas that could be considered for potential adjustments. The Board will not limit the topics that may be discussed when reviewing the compliance filings for completion of the ATCO Gas 2003/2004 GRA Phase I process.

With respect to the EUB Assessment, the Board does not consider it necessary to alter the practice of using the prior year data to establish the assessment level. However, the Board notes the CCA's concern with respect to using the customer count as a basis for assessing the amount to be collected. The introduction of the DSP raises an issue for consideration with respect to the application of the formula and the Board will take this matter under advisement.

The Board also notes that it is the practice of some other regulated utilities to include the EUB Assessment in the deferred hearing account. The Board directs ATCO Gas to address this concept in the final compliance filing for the ATCO Gas 2003/2004 GRA Phase I.

With respect to the appropriateness of further unbundling of the distribution tariff, the Board notes that ATCO Gas and certain interveners were concerned that further unbundling would be an unnecessary exercise that might be fraught with additional issues, such as stranded costs. Other interveners, and Calgary in particular, took the position that unbundling is a worthwhile exercise as it will lead to a transparent view of the utility's costs and provide outsiders with the information they could use to propose a competitive alternative. Calgary noted that a competitive alternative might involve outsourcing an activity rather than doing it in-house or continuing to use an existing service provider. Calgary also proposed that the unbundled costs should not appear on the customer's bill, but that the costs should be unbundled on the tariff sheet.

The Board is not persuaded that there is merit in including a level of unbundling on the tariff sheets that is not reflected on customer bills. The Board considers that the transparency sought by Calgary should be available from an approved COSS.

However, the Board considers that this issue can be further addressed as part of the ATCO Gas GRA Phase II. To assist the Board and interested parties in this regard, the Board considers that a change to the COSS presentation would be helpful.

The Board therefore directs ATCO Gas to add to its COSS a summary of the costs of each of the functions in a rate format.

The Board expects that this modification to the COSS can be accomplished without undue expense or significant effort.

6 FRANCHISE FEES

In this section the Board will consider the views of parties as to the appropriateness of the proposed change in the method of collecting franchise fees for those municipalities using Method B.

Views of the Interveners

AUMA/EDM

AUMA/EDM did not oppose ATCO Gas's proposals with respect to franchise fees as long as municipalities would be left whole. AUMA/EDM submitted that for those municipalities on Method A, the unbundling of costs and sale to DERS would result in a franchise fee reduction of about 5%.[110] AUMA/EDM expressed concern that ATCO Gas had not had specific discussions with any municipality regarding this reduction.[111] AUMA/EDM pointed out that ATCO Gas decided unilaterally to sell the retail function to DERS without any municipality's input.

AUMA/EDM argued that ATCO Gas should be directed to ensure that the franchise fee level of each municipality within the ATCO Gas service territory would not be negatively impacted by the unbundling process and retail sale.

Calgary

Calgary did not believe that ATCO Gas should be able to unilaterally change the terms of franchise agreements. Calgary argued that if changes were required to franchise agreements as result of the Retail Sale and the Application, the agreements should be amended, and not changed unilaterally by ATCO Gas in this Application.

Calgary submitted that it would be appropriate for the Board to provide a mechanism for amendment to a large number of franchise agreements in order to provide for revenue neutrality for all municipalities.

Calgary submitted that the franchise agreements, if they are to be amended, be done so with the knowledge and approbation of the parties involved.

CCA

The CCA considered the requested change to franchise agreements to be unduly discriminatory, and that both sales and transportation customers should pay the same franchise fees. The CCA argued that the increased revenue arising from the charging of fees to transportation customers should be used to lower the rate charged to all customers within that municipality.

The CCA noted that municipalities were not guaranteed revenues under franchise agreements. The fees were based on a percentage, and customers were not protected from fee increases when the utility rates increased. The CCA submitted that similarly municipalities should not be protected from fee decreases when ATCO Gas reduces its rates. The CCA argued that any municipality desiring stable revenue could opt for a direct recovery under a property tax system. The CCA considered it inappropriate to protect municipalities from revenue losses given the large increase faced by residential customers arising from the proposed DERS tariff and the Application.

PICA/STMG

PICA/STMG were not opposed to ATCO Gas's intention to replace franchise fee dollars with a different mechanism and collection through Rider A. However, PICA/STMG noted that

[110] Tr. p. 78
[111] Tr. p. 80

transportation customers on Rates 11 and 13, presently in Method B communities were currently paying no franchise fees. PICA/STMG noted that if ATCO Gas began collecting franchise fees from Rate 11/13 customers under Method C, the amount of franchise fees collected by the communities would increase. PICA/STMG expressed concern that the introduction of franchise fees under Method C for Rates 11/13 customers would result in significant increases to those customers.

PICA/STMG submitted that if the Board approved the ATCO Gas proposal for conversion to Method C, consideration should be given to exempting Rates 11/13 customers from franchise fees in those communities where they were not presently paying franchise fees. PICA/STMG considered that, alternatively, measures should be taken to mitigate the rate impact on these customers.

Views of ATCO Gas

In response to an undertaking[112] ATCO Gas updated the number of communities on Method B to 34. ATCO Gas submitted that in total, those 34 communities received approximately $6,600,000 in franchise fees in 2002. ATCO Gas noted that the franchise fee revenue would be reduced to zero if the Retail Sale was approved but the change from Method B to Method C for these communities was not approved.

ATCO Gas argued that Board precedent supported the proposed change. ATCO Gas also noted that discussions currently underway with the Method B communities to amend or renew their franchise agreements would require some time to complete.

ATCO Gas submitted that a change requested related to the definition of deemed value of gas would not alter the dollar value of the franchise fee collected from a customer within a Method C community.

ATCO Gas argued that if the Board were to follow the suggestion that franchise fee rates should be increased to ensure that the same level of fee revenues were collected, the precedent would be established that franchise fee rates would be reduced if ATCO Gas rates were increased in the future. ATCO Gas also pointed out that for communities like the City of Calgary that had franchises fees applied to the cost of gas, the level of fee rates would be adjusted to maintain the same level of revenue as the price of gas went up and down on a monthly basis. ATCO Gas submitted that the Board should allow ATCO Gas and the municipalities to review the level of franchise fees and other issues related to their franchise agreements through the normal course of business.

Views of the Board

The Board notes that interveners raised two concerns regarding franchise fees. The first concern raised by interveners was whether or not the Board should alter an agreement that had been reached between ATCO Gas and a municipality. The second concern related to the impact on franchise fees from a reduction in distribution rates.

Regarding the first issue, the Board agrees with ATCO Gas that unless there is a change to Method C, a municipality currently using Method B would receive no revenues until a new

[112] Tr. p. 327, line 24 to p. 328, line 4

agreement was established with ATCO Gas. The Board accepts the position of ATCO Gas that the change from Method B to Method C is in the best interests of the community, and is consistent with the spirit of the existing franchise agreements. The Board therefore approves the change from Method B to Method C.

The Board also approves the change to the definition of the deemed gas price, which the Board considers necessary to ensure that the Method C formula remains in step with the legislative changes regarding the DSP.

However, the Board directs ATCO Gas, prior to implementing the change from Method B to Method C, to notify all municipalities currently using Method B. The Board expects ATCO Gas to clearly explain the Board's Decision, and to indicate that Method A is an alternative that the municipality can choose.

The Board also notes that, in those communities using Method B, there are some customers who are currently purchasing directly from a retailer and who therefore are not paying a franchise fee. The Board notes that the requested change from Method B to Method C will result in those direct purchase customers receiving a bill that will now include a franchise fee. The Board is concerned that these customers may not have been advised that they could be affected by the change in method.

Therefore, the Board directs ATCO Gas to formally notify each affected customer prior to implementation of Method C.

Regarding the second issue, the Board acknowledges that, all things being equal, a reduction in distribution rates would result in a lower franchise fee, and that an increase in distribution rates would result an increase in the franchise fee. When evaluating proposed changes to utility rates, the Board does not consider the impact on franchise fees. The Board notes that, while the Application proposes a lower distribution rate on an interim basis, Decision 2002-115[113] relating to Phase I of the ATCO Gas 2003/2004 GRA has resulted in an interim increase in rates.

The Board notes that the municipality determines the level of the franchise fee. The Board does not consider it appropriate for the Board to increase the level of the franchise fee when distribution rates are decreased, nor for the Board to decrease the level of the franchise fee when distribution rates are increased.

7 IMPLEMENTATION AND TIMING ISSUES

In this section the Board will consider the views of parties regarding the timing and implementation of the proposed interim rates.

[113] Decision 2003-115 – ATCO Gas 2003/2004 General Rate Application – Interim Rate Application, dated December 24, 2002

Views of the Interveners

AUMA/EDM

AUMA/EDM did not disagree with the proposal to provide the transition on a cyclical basis on the understanding that, to ensure no duplication in cost recovery, it might be necessary to deem a date when ATCO Gas would cease to provide service and DERS would commence service.

Calgary

Calgary explained that it was most important to be able to test certain of the modules, particularly the compliance filing with respect to this interim application.

Calgary argued that, given ATCO Gas's emphasis on principles versus numbers, it was virtually impossible to test the reasonableness of costs and rates without an information request process and hearing.

Calgary considered it optimistic to rely on the timing shown in Exhibit 55 and stated that there appeared to be sufficient time, possibly seven or eight months, for filing of a true unbundling application either before the ATCO Gas 2003/2004 GRA Phase II proceeding or following the date of the decision on the Application.

Calgary considered that the rates should become effective with the approval of the AGN and AGS Application for Retailer Service and GUA Compliance

Calgary submitted that the decision on whether or not interim rates commence on a date certain at the end of a billing cycle needed input not only from the DSP provider, but also from the retailers.

Calgary recommended that the implementation and timing of the various proceedings set out in Exhibit 55, including the provision for an ATCO Gas 2003/2004 GRA Phase II hearing, be extended to allow a period of time for a collaborative process to be undertaken by all stakeholders, and that due process for these proceedings provide for sufficient participation of all stakeholders in the form of information requests and written and/or oral hearings, where appropriate.

CCA

The CCA considered it imperative that there should be a compliance filing process.

The CCA considered it appropriate that, if the Board approved the Retail Sale, the DERS rates and unbundling rate changes should occur concurrently. The CCA considered that failure to implement the rate changes concurrently would result in further rate shock and customer confusion.

FGA

The FGA expressed concern that some parties might propose collaborative processes just for the sake of reducing hearing time. The FGA submitted that, in its experience, negotiations could often be as costly or more costly than hearings simply because there was no guarantee of any resolution. The FGA noted that if a resolution was not reached, the matter must be brought before the Board, which could have been done in the first place.

The FGA expressed general satisfaction with the amount of information ATCO Gas had provided in this hearing, and had proposed to provide as part of the proposed "loose ends" hearing.

The FGA questioned the usefulness and cost-effectiveness of the undefined collaborative processes proposed by Calgary. The FGA submitted that collaborative processes should only be adopted for specific applications or issues if there was a reasonable chance of resolution. The FGA submitted that the Board should carefully consider whether any proposed collaborative process was necessary and should solicit comments from individual interveners regarding the strength and source of their belief that a resolution would be reached on a particular matter, and what steps they would take to assist in achieving that resolution.

PICA/STMG

PICA/STMG submitted that it would be appropriate to include a detailed unbundling module along the lines suggested by Calgary, followed by the ATCO Gas 2003/2004 GRA Phase II proceedings.

PICA/STMG had two concerns with ATCO Gas's proposal for implementation on a cycle-by-cycle basis. First, a cycle-by-cycle implementation of interim rates could result in overlap or duplication of cost recoveries between ATCO Gas and DERS. PICA/STMG considered that if DERS' commencement date for DSP service did not coincide with cycle billings there could be potential for overlap of cost recoveries.

Second, assuming a December 1, 2003 commencement date for DERS' DSP service, all customers with consumption in December should be billed the same tariffs. PICA/STMG considered that this might not be possible with ATCO Gas's cycle-by-cycle billing proposal. PICA/STMG argued that, in the event that the sale to DERS is approved, ATCO Gas should address these issues in any refiling of interim rates.

Views of ATCO Gas

ATCO Gas argued that if DERS did not begin to provide regulated natural gas services, costs would not disappear from the ATCO Gas revenue requirement as the result of the move to the One-Bill Model. ATCO Gas submitted that costs were simply allocated between the distribution/transmission component of the bill and the regulated retail (GCRR) component of the bill.

ATCO Gas submitted that the interim rate approach described in the Application would not provide the final unbundled/avoided costs required by the Board for its final decision on the ATCO Gas 2003/2004 Revenue Requirement, or required to make final adjustments to the ATCO Gas distribution tariff (and the GCRR). ATCO Gas argued that those adjustments must await the replacement of placeholders in the ATCO Gas 2003/2004 Revenue Requirement, and submitted that Exhibit 52 and Exhibit 55[114] described the inter-relationship of the adjustments.

[114] In its reply argument ATCO Gas noted that the filing date of the 2003-2004 GRA Decision Compliance Filing was incorrectly noted on Exhibit 55 as October 31 rather than December 1. Also the footnote 1 attached to the Unbundling proceeding on line 1 should be deleted, and attached to line 26, Retailer Services and GUA/EUA Compliance.

ATCO Gas submitted that the desired end result of these proceedings was the finalization of the ATCO Gas 2003/2004 Distribution Revenue Requirement, and the portion of the ATCO Gas 2003/2004 Revenue Requirement, which, through the unbundling process, would be allocated to the GCRR.

Timing of Interim Rates

ATCO Gas noted that for the effective date of interim rates to coincide with the Retail Sale was a matter of convenience and that if the Retail Sale was not approved, interim rates would still be required. ATCO Gas indicated that in the event that the Retail Sale was not approved, the interim rates should become effective with the implementation of the One-Bill Model.[115]

Application of Interim Rates

ATCO Gas noted that the transition of the DSP function to DERS would occur on a cycle-by-cycle basis i.e., ATCO Gas would final bill each of its customers in each cycle and then service by DERS would begin thereafter. ATCO Gas noted that, as the interim rate reduction represented services that ATCO Gas would no longer provide after DERS began to provide the DSP function, the effective date for the interim rates was to be implemented on a cycle-by-cycle basis. By way of example, ATCO Gas indicated that, if it was determined that DERS could begin the DSP function in December, ATCO Gas would final bill each of its customers by cycle in the month of December. A cycle 1 customer in December with a billing period of Nov 1-30 would be charged based on existing rates, and the distribution charges for that customer in the next cycle would be based on the new interim rates.

Views of the Board

The Board considers ATCO Gas's proposal to implement the interim rates on a cycle-by-cycle basis to be reasonable, and hereby approves this method of implementation.

The Board notes PICA/STMG's concern that there should be no duplication or overlap between ATCO Gas and DERS during the implementation, in the event the Retail Sale is approved. The Board expects ATCO Gas to ensure that there is no such duplication or overlap.

The Board agrees with CCA that it would be appropriate to implement the interim rates concurrently with the implementation of DERS rates. If the appointment of DERS as DSP does not close, the Board considers that the implementation of the interim rates should coincide with the implementation of the One-Bill Model.

The Board also approves ATCO Gas's proposal to implement the change in the franchise fee calculation method in conjunction with the implementation of the interim rates.

[115] Tr. p. 280, lines 22-25; p. 281, lines 1-25; p. 282, lines 1-8

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

9 ORDER

IT IS HEREBY ORDERED THAT:

(1) The distribution rates, as adjusted by the Board in this Decision, are approved for ATCO Gas South and ATCO Gas North as interim and refundable pending final determination of distribution rates in the ATCO Gas 2003/2004 General Rate Application Phase II. The interim rates, attached as Appendices G and H, will replace the interim rates approved in Decision 2002-115, dated December 24, 2002.

(2) ATCO Gas North and ATCO Gas South shall file rate schedules setting out the interim rates as approved in this Decision for acknowledgement by the Board indicating the date the rates are implemented.

(3) ATCO Gas shall amend its Franchise Agreements that use Method B to Method C in accordance with the directions contained within this Decision, until such time as the municipality and ATCO Gas agree to amend or replace the existing agreement and submit it to the Board for approval.

(4) The interim distribution rates approved in this Decision shall be effective on the earlier of the implementation of Direct Energy Regulated Services's Default Rate Tariff or the implementation of the One-Bill Model.

Dated in Calgary, Alberta on December 18, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

B. T. McManus, Q.C.
Presiding Member

(original signed by)

J. I. Douglas, FCA
Member

(original signed by)

W. K. Taylor
Acting Member

APPENDIX A – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations Used in Report)	Witnesses
ATCO Gas L. Smith K. Illsey	D. Wilson R. Trovato J. Beckett
Direct Energy Regulated Services (DERS) G. Newcombe	
Alberta Urban Municipalities Association and the City of Edmonton (AUMA/EDM) R. McCreary	
City of Edmonton (Edmonton) W. Follett	
Public Institutional Consumers of Alberta (PICA) R. Retnanandan	
Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc., Town of Redwater and Samson Band (FGA) T. Marriott D. Jenkins	
City of Calgary (Calgary) B. Meronk	K. Sharp H. Johnson H. Vander Veen
Consumers Coalition of Alberta (CCA) J. Wachowich	
EnCana Corporation (EnCana) D. Davies	
AltaGas Utilities Inc. (AltaGas) R. Jeerakathil	
Aboriginal Communities (AC) and St. Michael's Extended Care Society (STMG) A. Ackroyd R. Bellows	

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Irrigation Projects Association (AIPA) H. Unryn	
Board Panel B. T. McManus, Q.C., Presiding Member J. I. Douglas, FCA, Member W. K. Taylor, Acting Member	
Board Staff B. McNulty, Board Counsel R. Armstrong, P. Eng D. R. Weir, C.A.	

APPENDIX B – ABBREVIATIONS

A&G	Administrative and General
AGN	ATCO Gas North
AGPL	ATCO Gas and Pipelines Ltd.
AGS	ATCO Gas South
ATCO Electric	ATCO Electric Ltd.
ATCO/CU	ATCO Ltd./Canadian Utilities Limited
Board or EUB	Alberta Energy an Utilities Board
CIS	Customer Information System
COP	Company-Owned Production
COPRR	COP Rate Riders
COS	Company-Owned Storage
COSRR	COS Rate Riders
COSS	Cost of Service Study
CWNG	Canadian Western Natural Gas Company Limited
DEML	Direct Energy Marketing Limited
DEP	Direct Energy Preferred
DERS	Direct Energy Regulated Services
DGA	Deferred Gas Account
DGS Regulation	*Default Gas Supply Regulation*, AR 184/2003
DRT	Default Rate Tariff
DSP	Default Supply Provider
FTE	Full-Time Equivalent Positions
R3 Regulation	*Roles, Relationships and Responsibilities Regulation*, AR 186/2003
GCRR	Gas Cost Recovery Rate
GRA	General Rate Application
GUA	*Gas Utilities Act*, R.S.A. 2000, c. G-5
IT	Information technology
ITBS	I-Tek Business Services
LDC	Local Distribution Company
MS Agreement	Master Service Agreement
NWC	Necessary Working Capital
O&M	Operating and Maintenance
PSP	Pipe Service Provider
RRT	Regulated Rate Tariff
RSP	Retail Service Provider

APPENDIX C – SUMMARY OF DIRECT AND INDIRECT COSTS BY FUNCTION

ATCO Gas South
2002 Base Rate Revenue Requirement
Summary of Direct and Indirect Costs by Function
Cost Impact to Pipe Service Provider (PSP) and Retail Service Provider (RSP)

SECTION 2.5
SCHEDULE 1

		DIRECT COSTS ($000's)	INDIRECT COSTS ($000's)	TOTAL COSTS ($000's)	Reference: Allocation Study Tab 4	PSP COSTS ($000's)	RSP COSTS ($000's)
DISTRIBUTION SERVICE	Distribution Mains and Service	58,572	8,762	67,334	page 1,2	67,334	-
	Meters	21,349	5,579	26,928	pages 3-5	26,928	-
	Customer Enrollment	-	-	-	page 6	-	-
	Load Settlement/Load Balancing	-	-	-	page 7	-	-
	Marketing and Consumer Information	1,907	352	2,259	page 8	2,259	-
	Customer Information System	10,126	31	10,157	page 9	10,157	-
	Administration	18,310	3,613	21,923	page 10	21,923	-
		110,264	18,337	128,601		128,601	-
NON DISTRIBUTION SERVICE	Transmission	20,552	178	20,730	page 11	20,730	-
	Storage	10,945	420	11,365	page 12	11,365	-
	Production and Gathering	2,361	347	2,708	page 13	2,708	-
		33,858	945	34,803		34,803	-
CUSTOMER CARE	Billing	6,845	63	6,908	page 14	4,121	2,787
	Call Centre	2,830	27	2,857	page 15	1,005	1,852
	Credit and Collections	4,288	18	4,306	page 16	448	3,858
		13,963	108	14,071		5,574	8,497
GAS SUPPLY	Gas supply	(18)	23	5	page 17	(46)	51
		(18)	23	5		(46)	51
	TOTAL	158,067	19,413	177,480		168,932	8,548

APPENDIX D – EXISTING INTERIM RATES

ATCO GAS SOUTH
EXISTING INTERIM RATES
RATES EFFECTIVE JANUARY 1, 2003

Rate	Fixed $/mo	Variable $/GJ	Demand $/GJ/mo
1	13.79	1.074	0.00
3	265.25	0.284	3.45
5	21.22	0.895	0.00
13	291.78	0.156	5.62

ATCO GAS NORTH
EXISTING INTERIM RATES
RATES EFFECTIVE JANUARY 1, 2003

Rate	Fixed $/mo	Variable $/GJ	Demand $/GJ/mo
1	12.99	1.006	0.00
3	258.73	0.267	3.80
5	301.07	0.054	5.83

APPENDIX E – CCA'S TABLE COMPARING CWNG 1998 COSS TO ATCO GAS SOUTH 2002 COSS

Changes from 1998 CWNG – Cost of Service Study to February 18, 2002 AGS – Cost of Service Study
Accounts and Functionalization Methodology

	1998	2002
Page 3		
487 NGV – Equipment on Customers Premises	Usage	Marketing
496 Computer Equipment – CUL	Usage	Included with Account 494
Page 4		
WC Deferred Hearing Costs	COS Costs No Gas	n/a
WC Hearing Costs Reserve	n/a	COS Costs No Gas
WC GST – DGA Carrying Costs of Nat Gas	n/a	Gas Supply
WC Crown Royalty Deposit	n/a	P & G
WC Computer Reserve Def Account	n/a	Admin
		Admin
Page 5		
703 Revenue from Jobbing & Contract Work	Marketing	Included in Income Credits
Page 6		
719 Debit/Credit Charges	Cust Acct	Included with Account 728
Classification into Customer, Commodity and Demand Costs		
Page 8 713 Customer Billing & Accounting	Classified Customer 78%; Demand 22%	713 Customer Billing classified as 100% customer
Page 13		
All Acct Underground Storage	Expenses classified as 100% Demand	Classified 100% Commodity
Income Credits		
Page 21 Underground Storage – Condensate	Classified 100% Demand	Classified 100% Demand
Distribution of Costs by Function Page 29 Underground Storage	Classified as Demand and distributed to Rates 1, 3	Classified as Commodity and distributed to Rates 1, 3, 13
Page 33 Overhead Recoveries	Distributed to Rates 1, 3, 5, 6, 13	Distributed to Rates 1, 3, 5, 13
Backup Studies and Methodologies Page 9	Functionalization of Account 487, 490	Functionalization of Account 490
Page 18, 19, 20	WCB/EI included in Account 723	WCB/EI included in Account 725

APPENDIX F – CALGARY'S EXAMPLE FOR DETERMINING INTERIM RATES

Schedule A

($,000)

	North	South	50% I-Tek	75% I-Tek
Total Revenue Requirement	124,789	113,068	237,857	237,857
Deduct:				
Ex 54 Undertaking at p321			18,195	18,195
			219,662	219,662
I-Tek Charges			14,550	21,800
Internal Customer Care			3,000	4,000
Gas Supply Personnel			700	700
Administrative and General @20% of direct costs			7,289	8,939
Amount for 2004 before 2003-072 for interim rates			194,123	184,223
Suggested further reduction			25,539	35,439

APPENDIX G – ATCO GAS SOUTH RATE SCHEDULES

"App G - South Rate Schedule.doc"

(Consists of 12 pages)

APPENDIX H – ATCO GAS NORTH RATE SCHEDULES

"App H - North Rate Schedule.doc"

(Consists of 7 pages)

APPENDIX G

ATCO GAS AND PIPELINES LTD.

ATCO GAS SOUTH

RATE SCHEDULES

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 1
Previously Effective January 1, 2003
Rate 1 Page 1 of 1

ATCO GAS AND PIPELINES LTD. – SOUTH
RATE NO. 1 – GENERAL SALES SERVICE RATE

Available to all customers using less than 8,000 GJ per year except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

CHARGES:

Fixed Charge:	$12.02 per Month
Energy Charges:	
Base	$1.058 per GJ
Gas Cost Recovery	Rider "F"
Company Owned Production	Rider "G"
Company Owned Storage	Rider "H"
Minimum Monthly Charge:	Fixed Charge

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 3
Previously Effective January 1, 2003
Rate 3 Page 1 of 2

ATCO GAS AND PIPELINES LTD. - SOUTH
RATE NO. 3 LARGE USE SALES SERVICE

Available to all customers using 8,000 GJ or more per year on an annual contract except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

CHARGES:

Fixed Charge: $262.77 per Month plus $3.35 per Month per GJ of 24 Hr. Billing Demand

Energy Charges:

Base	$0.284 per GJ
Gas Cost Recovery	Rider "F"
Company Owned Production	Rider "G"
Company Owned Storage	Rider "H"

Minimum Monthly Charge: Fixed Charge

DETERMINATION OF BILLING DEMAND:

The Billing Demand shall be the greater of:

1. The greatest amount of gas in GJ delivered in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any consecutive 24 hours in the summer period shall be divided by 2, **or**
2. The Nominated Demand

PROVIDED that for a customer who elects to take service only during the summer period, the Billing Demand for each billing period shall be the greatest amount of gas in GJ in any consecutive 24 hours in that billing period.

In the first contract year, the Company shall estimate the Billing Demand from information provided by the customer.

NOMINATED DEMAND:

A customer whose maximum consumption exceeds 4 500 GJ for any 24-hour period in the winter period must nominate in writing twelve months in advance of each contract year the maximum consumption for any 24-hour period in the winter period in that contract year (the “Nominated Demand”). The Company reserves the right to restrict the amount of gas in GJ delivered in the winter period to the Nominated Demand and to restrict the amount of gas in GJ delivered in any one hour to **5%** of the Nominated Demand.

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 5
Previously Effective January 1, 2003
Rate 5 Page 1 of 1

ATCO GAS AND PIPELINES LTD. - SOUTH
RATE NO. 5 - OPTIONAL IRRIGATION PUMPING SERVICE RATE

Available on special contract to all customers who use natural gas as a fuel for engines pumping irrigation water between April 1 and October 31.

CHARGES:

Fixed Charge:	$18.40 per Month
Energy Charges:	
Base	$0.876 per GJ
Gas Cost Recovery	Rider “F”
Company Owned Production	Rider “G”
Company Owned Storage	Rider “I”
Minimum Monthly Charge:	Fixed Charge

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 11
Previously Effective January 1, 2003
Rate 11 Page 1 of 2

ATCO GAS AND PIPELINES LTD. - SOUTH
RATE NO. 11 TRANSPORTATION SERVICE RATE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO CORE MARKET END-USERS

Available under an Annual Contract for the transportation of Gas owned by others provided that:

(i) The Customer uses less than 8,000 GJ per year.

(ii) The Customer does not utilize the Company's facilities only for standby, peaking, or emergency service.

(iii) The Gas is delivered from the Company's Gas Pipeline System to a Core End-user.

(iv) The Customer has the exclusive contractual control of Gas flows at the Point of Delivery and contractual control of Gas flows at the Point(s) of Receipt.

(v) The Customer has executed a Core Market Transportation Service Agreement with the Company which is subject to the provisions of this Rate Schedule, General Conditions and/or Special Contract Conditions and incorporates the Company's Core Market Transportation Service Regulations (Regulations) as amended from time to time and approved by the Alberta Energy and Utilities Board.

CHARGES:

Fixed Charge per Month:	$12.02 per Month
Energy Charge:	
Variable	$1.058 per GJ
Company Owned Production	Rider “G”
Company Owned Storage	Rider “H”

Rate 11 Page 2 of 2

PLUS

A provision for Unaccounted For Gas as per Rider “D” of the Rate Schedules

Minimum Monthly Charge: The minimum monthly charge is the Fixed Charge plus any Specific Facility Charges

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 13
Previously Effective January 1, 2003
Rate 13 Page 1 of 3

ATCO GAS AND PIPELINES LTD. - SOUTH
RATE NO. 13 – GENERAL TRANSPORTATION SERVICE RATE

Available under an Annual Contract for the transportation of Gas owned by others provided that:

(i) The customer uses in excess of 8,000 GJ per year.

(ii) The Customer has the exclusive contractual control of Gas flows at the Point of Delivery.

(iii) The Customer has executed a Transportation Agreement with the Company which is subject to the provisions of this Rate Schedule and incorporates the Company's Natural Gas Transmission Transportation Service Regulations (Regulations) as amended from time to time and approved by the Alberta Energy and Utilities Board.

A. FIRM SERVICE CHARGES AT EACH POINT OF DELIVERY

Fixed Charge: $283.04 per Month

Energy Charge:

Variable $0.154 per GJ

Company Owned Production Rider “G”

Company Owned Storage Rider “H”

PLUS

Demand Charge: $5.47 per Month per GJ of 24-Hour Billing Demand

PLUS Rider “D” of the Rate Schedules

B. OVERRUN SERVICE

CHARGES AT POINT OF DELIVERY:

Provided Company accepts a Customer's Nomination at the Point of Delivery in excess of 110% of the Customer's Nominated Demand, the charge for the amount of gas in excess of 110% of the Nominated Demand shall be:

Variable Charge:	$0.277 per GJ
PLUS	Rider "D" of the Rate Schedules

C. UNAUTHORIZED SERVICES

CHARGES AT POINT OF DELIVERY:

For all gas taken in excess of 110% of the Customer's Nominated Demand where Company has refused to accept a Nomination or where Company has advised the Customer to curtail service to 110% of the Nominated Demand, the charge shall be:

Charges as per:	Rate 7 b (ii)

D. APPLICABLE to "A", "B" or "C"

NOMINATED DEMAND:

The Nominated Demand will be as specified in the Regulations and the Firm Service Agreement (FSA).

BILLING DEMAND:

The Billing Demand for any month equals the maximum gas flow in any 24-hour period during the month subject to a minimum amount of 90% of the Nominated Demand and a maximum amount of 110% of the Nominated Demand.

GAS IMBALANCES:

Settlement of Monthly Imbalance Quantity when Based on Daily Information:

Magnitude of Imbalance Quantity	Reasons for Imbalance Quantity	Settlement by Company	Price
<5%	Overdeliveries	N/A	N/A
	Underdeliveries	N/A	N/A
>5%	Overdeliveries	Purchase	75% of the Average Daily AECO "C" prices for that Month
	Underdeliveries	Sale	130% of the Average Daily AECO "C" prices for that Month

Settlement of Imbalance Quantity Arising from Adjustments:

When the Customer's Account is put out of balance by actual adjustments, the Customer is required to bring the account into balance by providing 1/25 of the imbalance amount on a daily basis over a 25-day period.

Effective By Decision 2003-108
On Consumption _________, 2004
This replaces Rate 18
Previously Effective January 1, 2003
Rate 18 Page 1 of 2

ATCO GAS AND PIPELINES LTD. - SOUTH
RATE NO. 18 TRANSPORTATION SERVICE RATE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO CUSTOMER'S WHO USE NATURAL GAS AS A FUEL FOR ENGINES PUMPING IRRIGATION WATER

Available under a Summer Period contract for the transportation of Gas owned by others provided that:

(i) The Customer is using natural gas as a fuel for engines pumping irrigation water between April 1 and October 31.

(ii) The Customer does not utilize the Company's facilities only for standby, peaking, or emergency service.

(iii) The Gas is delivered from the Company's Gas Pipeline System to a customer who uses natural gas as a fuel for engines pumping irrigation water.

(iv) The Customer has the exclusive contractual control of Gas flows at the Point of Delivery and contractual control of Gas flows at the Point(s) of Receipt.

(v) The Customer has executed a Core Market Transportation Service Agreement with the Company which is subject to the provisions of this Rate Schedule, General Conditions and/or Special Contract Conditions and incorporates the Company's Core Market Transportation Service Regulations ("Regulations") as amended from time to time and approved by the Alberta Energy and Utilities Board.

CHARGES:

Fixed Charge per Month:	$18.40 per Month
Energy Charge:	
Variable	$0.876 per GJ
Company Owned Production	Rider "G"
Company Owned Storage	Rider "I"

PLUS

A provision for Unaccounted For Gas as per Rider "D" of the Rate Schedules

Minimum Monthly Charge: The minimum monthly charge is the Fixed Charge plus any Specific Facility Charges

APPENDIX H

ATCO GAS AND PIPELINES LTD.

ATCO GAS NORTH

RATE SCHEDULES

Effective By Decision 2003-108
On Consumption _________, 2004
This Replaces Rate 1
Previously Effective January 1, 2003
Rate 1 Page 1 of 1

ATCO GAS AND PIPELINES LTD. - NORTH
RATE NO. 1 GENERAL SALES SERVICE

Available to all Customers using less than 8000 GJ per year, except those Customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

CHARGES:

Fixed Charge:	$11.22 per Month
Energy Charges:	
Base	$0.990 per GJ
Gas Cost Recovery	Rider "F"
Company Owned Production	Rider "G"
Minimum Monthly Charge:	Fixed Charge

Effective By Decision 2003-108
On Consumption _________, 2004
This Replaces Rate 3
Previously Effective January 1, 2003
Rate 3 Page 1 of 2

ATCO GAS AND PIPELINES LTD. - NORTH
RATE NO. 3 GENERAL SALES SERVICE - LARGE USE

Available to all Customers using 8000 GJ or more per year on an annual contract except those Customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

CHARGES:

Fixed Charge:	\$256.25 per Month ***plus*** \$3.70 per Month per GJ of 24 Hr. Billing Demand
Energy Charges:	
Base	\$0.267 per GJ
Gas Cost Recovery	Rider "F"
Company Owned Production	Rider "G"
Minimum Monthly Charge:	Fixed Charge

BILLING DEMAND PERIOD:

The Billing Demand Period shall mean the twelve month period commencing November 1 and ending October 31.

DETERMINATION OF BILLING DEMAND:

The Billing Demand shall be the greater of:

1. The greatest amount of gas in GJ delivered in any consecutive 24 hour billing period during the current Billing Demand Period provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period shall be divided by 2, ***or***

2. The Nominated Demand.

PROVIDED that for a Customer who elects to take service only during the summer period, the Billing Demand for each billing period shall be the greatest amount of gas in GJ in any consecutive 24 hours in that billing period.

In the first contract year, the Company shall estimate the Billing Demand from information provided by the Customer.

NOMINATED DEMAND:

A Customer whose maximum consumption exceeds 4,500 GJ for any 24 hour period in the winter period must nominate in writing twelve months in advance of each contract year the maximum consumption for any 24 hour period in the winter period in that contract year (the "Nominated Demand"). The Company reserves the right to restrict the amount of gas in GJ delivered in the winter period to the Nominated Demand and to restrict the amount of gas in GJ delivered in any one hour to 5% of the Nominated Demand.

Effective By Decision 2003-108
On Consumption _________, 2004
This Replaces Rate 11
Previously Effective January 1, 2003
Rate 11 Page 1 of 1

ATCO GAS AND PIPELINES LTD. - NORTH
RATE NO. 11 TRANSPORTATION SERVICE RATE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO CORE MARKET END-USERS

Available under an annual contract for the transportation of Gas owned by others provided that:

(i) The Customer uses less than 8,000 GJ per year.

(ii) The Customer does not utilize the Company's facilities only for standby, peaking, or emergency service.

(iii) The Gas is delivered from the Company's Gas Pipeline System to a Core End-user.

(iv) The Customer has the exclusive contractual control of Gas flows at the Point of Delivery and contractual control of Gas flows at the Point(s) of Receipt.

(v) The Customer has executed a Core Market Transportation Service Agreement with the Company which is subject to the provisions of this Rate Schedule, General Conditions and/or Special Contract Conditions and incorporates the Company's Core Market Transportation Service Regulations (Regulations) as amended from time to time and approved by the Alberta Energy and Utilities Board.

CHARGES:

Fixed Charge: $11.22 per Month

Energy Charge:

Variable: $0.990 per GJ

Company Owned Production: Rider "G"

PLUS Rider "D" of the Rate Schedules

Minimum Monthly Charge: The Minimum Monthly Charge is the Fixed Charge ***plus*** any Specific Facility Charges

Effective By Decision 2003-108
On Consumption _________, 2004
This Replaces Rate 13
Previously Effective January 1, 2003
Rate 13 Page 1 of 2

ATCO GAS AND PIPELINES LTD. - NORTH
RATE NO. 13 GENERAL TRANSPORTATION SERVICE RATE

Available under an annual contract for the transportation of Gas owned by others provided that:

(i) The Customer uses in excess of 8,000 GJ per year.

(ii) The Customer has the exclusive contractual control of Gas flows at the Point of Delivery.

(iii) The Customer has executed an Annual Contract with the Company which is subject to the provisions of this Rate Schedule and incorporates the Company's Natural Gas Transmission Transportation Service Regulations (Regulations) as amended from time to time and approved by the Alberta Energy and Utilities Board.

A. FIRM SERVICE CHARGES AT EACH POINT OF DELIVERY

Fixed Charge: $292.33 per Month

Energy Charge:
Variable $0.052 per GJ

Company Owned Production Rider "G"

PLUS

Demand Charge: $5.68 per Month per GJ of 24-Hour Billing Demand

PLUS Rider "D" of the Rate Schedules

B. OVERRUN SERVICE

CHARGES AT POINT OF DELIVERY:

Provided the Company accepts a Customer's Nomination at the Point of Delivery in excess of 110% of the Customer's Nominated Demand, the charge for the amount of gas in excess of 110% of the Nominated Demand shall be:

Variable Charge: $0.288 per GJ

PLUS Rider "D" of the Rate Schedules

C. *UNAUTHORIZED SERVICES*

CHARGES AT POINT OF DELIVERY:

For all gas taken in excess of 110% of the Customer's Nominated Demand where the Company has refused to accept a Nomination or where the Company has advised the Customer to curtail service to 110% of the Nominated Demand, the charge shall be:

Charges as per: Rate 8 b (ii)

D. *APPLICABLE TO "A", "B" or "C"*

NOMINATED DEMAND:

The Nominated Demand will be as specified in the Regulations and the Firm Service Agreement (FSR).

BILLING DEMAND:

The Billing Demand for any month equals the maximum gas flow in any 24-hour period during the month subject to a minimum amount of 90% of the Nominated Demand and a maximum amount of 110% of the Nominated Demand.

GAS IMBALANCES:

Settlement of Monthly Imbalance Quantity when Based on Daily Information:

Magnitude of Imbalance Quantity	Reasons for Imbalance Quantity	Settlement by Company	Price
<5%	Overdeliveries	N/A	N/A
	Underdeliveries	N/A	N/A
>5%	Overdeliveries	Purchase	75% of the Average Daily AECO "C" Prices for that Month
	Underdeliveries	Sale	130% of the Average Daily AECO "C" Prices for that Month

Settlement of Imbalance Quantity Arising from Adjustments:

When the Customer's Account is put out of balance by actual adjustments, the Customer is required to bring the account into balance by providing 1/25 of the imbalance amount on a daily basis over a 25-day period.