Decision 2005-029

AltaGas Utilities Inc.

2003/2004 General Rate Application
Phase II

April 12, 2005

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2005-029: AltaGas Utilities Inc.
2003/2004 General Rate Application – Phase II
Application No. 1359952

April 12, 2005

Published by
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

Contents

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ALTAGAS UTILITIES INC. **Decision 2005-029**
2003/2004 GENERAL RATE APPLICATION – PHASE II **Application No. 1359952**

1 INTRODUCTION

AltaGas Utilities Inc. (AltaGas or AUI) filed the Phase II portion of its 2003/2004 General Rate Application (2003/2004 GRA) with the Alberta Energy and Utilities Board (EUB or Board) on September 8, 2004, with supporting schedules filed October 15, 2004 (the Application).

AUI requested that the EUB determine:

1. the sales, transportation, and buy-sell rates and corresponding service rules, regulations, special charges, and other rate riders.
2. the appropriate treatment of revenue deficiencies for 2003 and 2004.
3. compliance with Board directives provided in:
    - Gas Cost Recovery Rate and Gas Rate Unbundling Decision 2001-75, dated October 30, 2001 (the Unbundling Decision);
    - AltaGas Utilities Inc. GCRR Methodology and Gas Rate Unbundling – Compliance Filing Decision 2002-036, dated March 21, 2002;
    - AltaGas Utilities Inc. Interim Refundable Rates & Harmonization of Bonnyville Service Area's Rates Decision 2003-090, dated November 25, 2003;
    - Generic Cost of Capital Decision 2004-052, dated July 2, 2004;
    - AltaGas Utilities Inc. 2003/2004 GRA-Phase I Request for Approval of Negotiated Settlement and Memorandum of Agreement, Decision 2004-063, dated August 3, 2004.

In a letter dated October 22, 2004, the Board provided Notice of Hearing regarding AltaGas' Phase II portion of its 2003/2004 GRA, distributed by email to interested parties on the AltaGas 2003/2004 GRA Phase I distribution list and published in the major Alberta newspapers on October 27, 2004.

The Board conducted the 2003/2004 GRA hearing during the period January 10-14, 2005, in Edmonton, Alberta. The hearing was presided over by R. G. Lock (Chair), W. K. Taylor, and M. W. Edwards. Oral argument and reply argument were heard on January 13, 2005 and January 14, 2005 respectively. The Board considers that the record with respect to the Application closed on January 14, 2005. Parties that participated in the proceeding are listed in Appendix 1.

2 BACKGROUND

On November 25, 2003, the Board issued Decision 2003-089[1] approving AUI's Memorandum of Agreement (MOA) and Negotiated Settlement Brief (the Agreement) reached with customers for the Phase II portion of its 2000-2002 GRA for AUI and Bonnyville Gas Company Limited (BGCL). The Board agreed with AltaGas that there was no need to change rates for the 2000, 2001, or 2002 test periods. The Board also granted AUI a further delay in complying with directives from Decision 2001-75, pertaining to matters of gas rate unbundling but expected it to comply with these directions in its 2003/2004 GRA Phase II.

On November 25, 2003, the Board issued Decision 2003-090[2] which approved interim refundable rates effective December 1, 2003, until such time as the Board approved other rates for AltaGas. Also, effective December 1, 2003, the Board approved harmonization of rates for the Bonnyville District service area, which resulted in uniform class rates for all of AltaGas' service area. The Board also directed AltaGas to file a 2004 Cost of Service Study with its 2003/2004 GRA Phase II.

On July 2, 2004, the Board issued Decision 2004-052,[3] which instituted a common approach for setting the return on common equity for all electric and natural gas utilities regulated by the EUB. The decision also approved the capital structure for each utility. AltaGas was awarded a rate of return on common equity of 9.6% for 2004 and a debt-to-equity ratio of 59:41.

On August 3, 2004, the Board issued Decision 2004-063[4] which approved the Memorandum of Agreement and Negotiated Settlement reached between AltaGas and customers for the 2003/2004 GRA Phase I. The Board reemphasized that it expected AltaGas to comply with the directions from Decision 2001-75, that were granted an extension in Decision 2003-089, in its 2003/2004 GRA Phase II Application. The Board directed AltaGas to apply the generic return on common equity and capital structure, as determined in Decision 2004-052, to the 2004 test year forecasts, incorporate the results into the placeholder, and advise the Board as to the appropriate amount within two weeks of the date of Decision 2004-063.

In Order U2004-382, dated October 15, 2004, the Board approved AltaGas' compliance filing pursuant to Decision 2004-063, with the expectation that AUI would update its 2004 revenue requirement and revenue deficiency to incorporate the revised Alberta Corporate tax rate, Generic Cost of Capital results from Decision 2004-052, and adjustments related to interim rates. The Board directed AltaGas to reflect these changes in revised schedules in the Application.

In a letter dated October 26, 2004, AUI proposed that the adjustment to the 2003/2004 GRA Phase I Compliance filing, approved by the Board in U2004-382, regarding the revised Alberta Corporate Tax rate would be incorporated into the 2003/2004 GRA Phase II documents after the hearing, along with any other changes that stem from the proceeding. On November 9, 2004, the Board approved AUI's proposal and AUI's revenue requirements for the 2003 and 2004 test years as filed.

---

[1] AltaGas Utilities Inc. 2000/2001/2002 General Rate Application-Phase II Request for Approval of Negotiated Settlement Brief and Memorandum of Agreement

[2] AltaGas Utilities Inc. Interim Refundable Rates & Harmonization of Bonnyville Service Area's Rates

[3] Generic Cost of Capital

[4] AltaGas Utilities Inc. 2003/2004 General Rate Application-Phase I Request for Approval of Negotiated Settlement and Memorandum of Agreement

3 ISSUES

The Board has reviewed the evidence, oral argument and reply from parties to the proceeding, and considers that the main issues in contention are as follows:

1. Unbundling of Customer Care Costs
    a. Retail Credit
    b. Bill Presentation
    c. Deferral Account
    d. Reporting Requirements
    e. EUB Assessment
2. Cost of Service Analysis
    a. Method of Allocating Demand-Related Transmission and Distribution Costs
    b. Weather Normalization
    c. Peak Demands for the Irrigation Rate Class
    d. Allocation of Meter Costs
    e. Use of Distance-Diameter Method
3. Rate Design
    a. Rate Design Criteria
    b. Rate Levels
    c. Rate Structures
    d. Transition Points
    e. Rate Schedules and Rate Riders
4. Specific Sections of AUI's Terms and Conditions
5. Other Issues
    a. Transportation by Others (TBO)
    b. First Nation Issues

Any references to specific parts of the record are to assist the reader in understanding the Board's decision, but should not be taken as an indication that the Board did not consider the entire record as it relates to that issue.

4 REVENUE REQUIREMENT

By letter dated December 16, 2004[5], AUI updated the 2004 revenue requirement to reflect revisions to income tax and the removal of reductions in revenues due to the Memorandum of Agreement. The resulting updated 2004 revenue requirement was $28,439,991.

The Board notes that no party commented on AUI's update to the 2004 revenue requirement. The Board has reviewed the revisions to the 2004 revenue requirement proposed by AUI and considers the revisions to be appropriate.

[5] Exhibit 002-08

Therefore, the Board accepts the updated revenue requirement of $28,439,991 as the basis for the design of AUI's 2004 rates.

5 UNBUNDLING OF CUSTOMER CARE COSTS

In Decision 2001-75[6], the Board evaluated whether or not a particular utility function should be unbundled based on "the function's expected ability to assist in the development of a competitive retail gas market" or "the function's potential for creating large stranded costs or other difficulties."[7] The Board found that the development of the competitive retail gas market would not be hindered if several functions remained bundled within the distribution tariff. Moreover, the Board was not concerned that the following functions, if kept bundled in the distribution tariff, would increase the likelihood of stranded costs or lead to any other undesirable consequences: Transmission, Storage, Meters, Load Balancing, Load Settlement, Customer Enrolment, Marketing and Customer Information.

The Board determined that certain "customer care" functions (billing, customer information system, call centre, and credit and collections) should be unbundled from the distribution tariff. The Board also directed the utilities to consider the impact of unbundling on indirect expenses and overhead costs.

The Board acknowledges that AUI has taken appropriate steps to move costs to the Deferred Gas Account, including uncollectible accounts, gas management fees and carrying costs on cash working capital associated with gas costs. The Board also acknowledges that the retail market is developing slowly among the rural and residential consumers that constitute most of AUI's customers, and that AUI's service area may not be a high priority for retailers.

However, in the Board's view, the movement of appropriate costs to the Deferred Gas Account and the slow development of the retail market in AUI's service area do not alter the Board's direction in Decision 2001-75 to appropriately unbundle customer care costs from the distribution function.

5.1 Retail Credit

With respect to Customer Information System (CIS) costs, the Board notes that most parties either supported, or did not oppose, AUI's proposal to retain all CIS costs under the distribution function. PICA, however, proposed that AUI's entire direct customer care costs, including direct CIS costs, be removed from the distribution function, but that AUI be entitled to recover any amounts not shed through a deferral account.

The Board is persuaded by AUI's evidence that there will not be any material CIS costs avoided when customers migrate to retail supply because AUI will continue to require the CIS for distribution tariff billing, load settlement and pipeline operations. The Board notes that it reached the same conclusion with respect to CIS costs for ATCO Gas in Decision 2003-108.[8] Accordingly, the Board will allow AUI to retain all CIS costs in the distribution function.

[6] Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding – Part A: GCRR Methodology and Gas Rate Unbundling, dated October 30, 2001.

[7] Page 89

[8] ATCO Gas 2003 Gas Rate Unbundling, dated December 18, 2003, page 37

With respect to the other customer care costs, AUI proposed a retail credit of $0.57/customer/month, which reflected the avoided costs of postage and bill stock. In BR-AUI-1, the Board requested that AUI identify what the reduction in the 2004 revenue requirement would be if AUI had no utility-supplied customers in 2004. The cost reductions identified were summarized in an Aid to Questioning prepared by Board staff, and agreed to by AUI, as follows:[9]

Customer Care Function	Cost Reduction
Call Center	$180,000
Credit and Collection	$411,600
Billing – 0.5 FTE Billing – Bills and Postage	$28,000 $393,100
Total	$1,012,700
Total Customer-Months	724,303
Unit Cost Reduction	$1.40/cust./month

MGCI considered AUI's proposed retail credit of $0.57/customer/month to be reasonable at this time because of the difficulty in allocating costs between the distribution and retail functions, the minimal movement of customers to retailer service, and the risk of stranded costs.[10] CCA argued that in light of the relative infancy of the retail business and the unbundling process in the AUI area, there was merit in deferring full consideration of unbundled rates to the 2005 GRA. PICA, however, argued that the level of the retail credit should allow customers who migrate to retail supply to receive the benefits of retail competition immediately.

The Board does not agree with CCA that the relative infancy of retail competition in the AUI service area is a valid reason to delay full consideration of unbundled rates to the 2005 GRA. Rather, the Board agrees with PICA that the level of the retail credit should allow customers who migrate to retail supply to receive the benefits of retail competition immediately. Therefore, the Board considers that the appropriate price signal to facilitate retail market development is a reduction based on the long-term costs avoided by AUI, assuming a material shift of customers to retail supply.

AUMA considered that the reduction should be even greater than $1.40/customer/month, based in part on a comparison to the reductions to ATCO Gas' call centre and administrative and overhead costs following the transfer of the ATCO Gas retail function to Direct Energy Regulated Services (DERS). AUMA also noted that AUI had not included any avoided printing costs (such as toner costs) in its proposed credit of $0.57/customer/month.

The Board agrees with AUMA that the reduction of $1.40/customer/month may be understated as a result of the exclusion of printing costs and avoided administrative and overhead costs. However, the Board does not agree with AUMA that the reductions to ATCO Gas' costs following the transfer of the ATCO Gas retail function to DERS should be given any weight in this proceeding. In this regard, the Board is persuaded by AUI's argument that there is no evidence supporting why the impacts on a large gas distribution system that shed all of its retail customers should be compared to the impacts on a small utility that retains the responsibility for default gas supply.

9 Exhibit 012-19
10 MGCI Argument, transcript pages 722-729

PICA submitted that the Board should create a credit rider based on AUI's total direct customer care costs of $1.9 million[11], but that AUI be entitled to recover any amounts not shed through a deferral account. The Board is not persuaded by PICA's argument. The Board notes that the direct customer costs of $1.9 million include AUI's direct CIS costs, which the Board has previously determined should be retained in the distribution function, and all call centre costs, a portion of which the Board considers should remain in the distribution function.

The Board does not consider AUI's proposal to establish a retail credit based only on the short-term avoided costs of postage and bill stock to be reasonable because it excludes other costs such as call centre and credit and collection costs that could be avoided.

As a result, the Board considers a reduction of $1.40/customer/month to be more appropriate than AUI's proposed retail credit of $0.57/customer/month, as the $1.40/customer/month reduction is more reflective of potential costs shed due to customers migrating to retail supply. Therefore, the Board approves a reduction for customer care costs for retail customers in the amount of $1.40/customer/month at this time.

However, the Board directs AUI, at the time of its next GRA, to prepare a more comprehensive assessment of the long-term costs that could be avoided by AUI, assuming a material shift of customers to retail supply. The Board expects this assessment to include an assessment of the potential to avoid printing, administrative, and overhead costs.

5.2 Bill Presentation

With respect to bill presentation of the $1.40/customer/month charge for customer care costs for default supply and transportation customers, the Board notes that AUI indicated that a reduction to the fixed charge, rather than a retail credit, for customers on retail supply may be workable. The Board considers that it is appropriate to unbundle the fixed charge for default supply customers into a base charge and a customer care charge of $1.40/customer/month. Therefore, the approved rate schedules attached to this Decision as Appendix 5 have unbundled the fixed charge into a base charge and a customer care charge, where appropriate.

If AUI's billing system is not capable of implementing the unbundled rates in this manner, the Board will allow AUI to combine the base charge and customer care charge into a single fixed charge for the purposes of billing customers on default supply, and, if necessary, to apply a retail credit of $1.40/customer/month to customers on retail supply. However, in this event, the Board directs AUI, at the time of its next GRA, to provide an estimate of the cost of modifying its billing system to display the rates on customer bills as set out in the approved rate schedules.

5.3 Deferral Account

In Decision 2001-75, the Board directed utilities to establish deferral accounts to collect stranded costs arising from the Board's findings in that Decision. The Board notes that AUI did not propose the establishment of such a deferral account in this proceeding. However, most interveners, including AUMA, AIPA, CCA and PICA, supported the establishment of a deferral account to capture any stranded benefits or costs resulting from customer migration to retail supply.

[11] BR-AUI-1

The Board notes AUI's submission that it is not a simple matter to set up a deferral account and that there was no tested evidence in this proceeding on how a deferral account should be structured and managed. AUI also submitted that setting up a new deferral account would be complex and would create monitoring and administration problems. As an alternative, AUI suggested that the $619,000 of call centre, credit and collections and billing costs shown in Exhibit 012-19 that are not reflected in AUI's proposed retail credit could be included in the Deferred Gas Account, in which case there would be little additional administration and no new regulatory procedures.

The Board acknowledges AUI's concern that setting up a new deferral account might be complex and could create monitoring and administration problems. However, the Board does not consider that recovery of fixed customer care costs in the variable Gas Cost Recovery Rate (GCRR) would provide an appropriate price signal to customers. The Board also agrees with AIPA that treating the deferral account as part of the monthly GCRR filings would mask the migration of customers to retail supply.

As noted earlier, the Board acknowledges that the retail market is developing slowly among the rural and residential consumers that constitute most of AUI's customers, and that AUI's service area may not be a high priority for retailers. Consequently, the Board considers that there is a low risk of a material stranded cost or benefit arising from a difference between forecast and actual migration to retail supply.

Therefore, notwithstanding the Board's direction in Decision 2001-75, the Board will not require the establishment of a deferral account to capture any stranded benefits or costs resulting from customer migration to retail supply at this time. The Board considers that the issue of whether or not to establish such a deferral account can be reviewed at the time of the next GRA. If the level of retail activity should increase materially prior to the next GRA, the Board would be prepared to consider an application from AUI for the establishment of such a deferral account prior to the next GRA.

5.4 Reporting Requirements

The Board notes that a number of parties suggested that AUI be required to file periodic reports on the number of customers who left default supply, and the associated cost reductions. AUI indicated that it would be prepared to submit a quarterly report on the development of the retail market in its service area, including the number of customers moving to and from retail supply.

Given that the Board has not required a deferral account to be established at this time, the Board does not consider that there is currently a need for periodic reports on the cost reductions associated with customers who leave default supply. The Board considers that the magnitude of such cost reductions can be adequately addressed at the time of the next GRA, or at the time that AUI applies for the establishment of a deferral account, if AUI so applies before the next GRA.

However, the Board considers that there may be merit in periodic reporting of the number of customers moving to and from retail supply. Given the relatively slow development of the retail market in the AUI service area at this time, the Board considers that an annual report would be sufficient.

Therefore, the Board directs AUI to include, in its Annual Report of Finances and Operations, a report on the number of customers that moved to or from retail supply during the year.

5.5 EUB Assessment

Some parties raised the concern that the annual EUB assessment may change as a result of customer migration to retail supply. The Board agrees with AUI that this concern should be addressed in the 2005/2006 GRA by recovering these costs through the hearing cost reserve account.

6 COST OF SERVICE ANALYSIS

As part of the Application, AUI filed a Cost of Service Analysis (COSA) prepared by EES Consulting (EES). The final version of the AUI COSA, which incorporated various updates and corrections through the course of the proceeding, was filed as Exhibit 012-13.

In summary, the unit costs and existing normalized revenue-to-cost ratios from the AUI COSA were as follows:

Rate Class	Customer Cost ($/month)	Energy Cost ($/GJ*)	Capacity Cost ($/GJ)	Normalized R/C Ratio
1/11	27.31	0.544		99.5%
2/12	197.70	0.521		131.9%
3/13	373.66	0.002	5.874	91.2%
4/14	50.81	0.872		75.2%

*gigajoule

Further detail on the AUI COSA and AUI's proposed rates is included in Appendix 3 to this Decision.

6.1 Method of Allocating Demand-Related Transmission and Distribution Costs

AUI proposed to allocate demand-related transmission costs based on the Coincident Peak (CP) of each rate class, and to allocate demand-related distribution costs based on the Non-Coincident Peak (NCP) of each rate class. In previous Phase II proceedings, AUI had allocated demand-related transmission and distribution costs using a Modified Partial Plant (MPP) method. AUI submitted that the CP/NCP method was used by many gas utilities, including ATCO Gas, and was less complex and less data-intensive than the MPP method.

The change from the MPP method to the CP/NCP method was supported by AUMA, MGCI and PICA. CCA did not oppose the change to the CP/NCP method, but submitted that demand-related transmission costs should not be allocated based on rate class demand at the time of the system coincident peak. AIPA opposed the change to the CP/NCP method and submitted that the MPP method appropriately took into consideration the trade-off between capacity and consumption characteristics.

The Board notes that the CP/NCP method is used by many other gas utilities. The Board agrees with AUI and others who noted that the CP/NCP method is less complex and less data intensive than the MPP method. Although the Board agrees with AIPA that the trade-off between capacity and consumption characteristics is important for seasonal loads, the Board considers that the

CP/NCP method takes this trade-off into consideration. For example, the irrigation rate class would not be allocated any demand-related transmission costs under the CP/NCP method. Contrary to CCA's submission, the Board is satisfied that the allocation of demand-related transmission based on rate class coincident peak appropriately reflects cost-causation on the AUI system.

Accordingly, the Board approves AUI's proposal to use the CP/NCP method to allocate demand-related transmission and distribution costs.

6.2 Weather Normalization

In applying the CP/NCP method, AUI developed weather-normalized daily load forecasts for each rate class. The normalized weather data used by AUI was developed by averaging, for each day of the year, the Heating Degree Days (HDD) over the last 20 years.

At the start of the proceeding, it was discovered that averaging the HDD by individual day resulted in the coldest weather-normalized day being minus 15 degrees Celsius, significantly warmer than the typical coldest day of the year and significantly warmer than AUI's design criterion of minus 40 degrees Celsius.

In response to a request from interveners, AUI filed Exhibit 012-03 on the second day of the hearing, in which AUI adjusted its COSA to reflect both the load factors used by ATCO Gas and the load factors used in AUI's 2002 GRA.

AUI submitted that there was no evidence that using load factors from a previous proceeding would provide a better basis for the COSA. AUI noted that no other COSA expert appeared to offer a differing opinion that could be tested by examination. AUI submitted that the COSA filed by EES was the best basis for deliberations in this proceeding. AUI further submitted that if its weather normalization approach was unacceptable to the Board, then the use of the 2002 load factors would be the next best alternative for this proceeding.

Several parties, including AUMA, AIPA, PICA, and MGCI, submitted that AUI's weather normalization method was deficient and that the weather normalization should reflect AUI's design criterion of minus 40 degrees Celsius. CCA submitted that AUI's use of averaged HDD was a better alternative than the use of a single year that was colder than normal, as was used for AUI's 2002 GRA.

The Board considers that the weather normalization method used by AUI, which resulted in the coldest weather-normalized day being minus 15 degrees Celsius, under-allocates costs to the rate classes that are the most weather-sensitive and therefore does not reflect cost causation. The Board considers that it would be more appropriate to use a weather normalization method that reflects AUI's design criterion of minus 40 degrees Celsius.

The Board directs AUI, at the time of its 2005/2006 Phase II GRA filing, to revise the weather normalization method in its COSA to reflect AUI's design criterion of minus 40 degrees Celsius.

With respect to this proceeding, the Board first notes that no party suggested that any weight be placed on the load factors used by ATCO Gas. The Board agrees with CCA and other parties that it would not be appropriate to import load factors from another utility's cost of service study.

Since the COSA filed in this proceeding resulted in the coldest weather-normalized day being only minus 15 degrees Celsius, for the reasons noted above, the Board does not consider the resulting load factors to be appropriate for the COSA. The Board considers that use of the 2002 load factors is the best available alternative on which to base the COSA in this proceeding. Accordingly, the Board will rely on the COSA adjusted to reflect the 2002 load factors in the rate design section of this Decision, rather than on the COSA as filed by AUI. However, the Board shares CCA's concern that the 2002 load factors were based on a single year that was colder than normal. Consequently, in this Decision the Board will not place as much weight on moving the revenue-to-cost ratios toward 100% as it might otherwise.

The Board notes that some parties, including AIPA and PICA, submitted that AUI should be required to update its COSA, using the 2002 load factors, in a refiling. However, the Board considers that there is sufficient evidence on the record in this proceeding to determine an appropriate allocation of costs between rate classes, without requiring a refiling of the COSA.

In Exhibit 012-21, AUMA estimated the impact of using the 2002 load factors on the COSA by adding the difference between Exhibits 002-10 and 012-03[12] to AUI's final COSA in Exhibit 012-13. The Board notes CCA's argument that Exhibit 012-21 should be given no weight because it was a document produced to support the argument of AUMA and was not evidence.[13] The Board however is satisfied that Exhibit 012-21 summarizes data that was already on the record and represents a reasonable estimate of the impact on AUI's final COSA of using AUI's 2002 load factors.

In Appendix 2 to this Decision, the Board has reproduced the data provided by the AUMA in Exhibit 012-21, using data from Exhibits 002-10, 012-03 and 012-13. This data is then used in Appendices 3 and 4 to determine the unit costs and existing normalized revenue-to-cost ratios for the AUI COSA adjusted for the 2002 load factors.

The resulting unit costs and normalized revenue-to-cost ratios are summarized below:

Rate Class	Customer Cost ($/month)	Energy Cost ($/GJ)	Capacity Cost ($/GJ)	Normalized R/C Ratio
1/11	27.31	0.570		98.3%
2/12	197.70	0.543		128.4%
3/13	373.66	0.002	4.294	116.7%
4/14	50.81	0.658		86.4%

6.3 Peak Demands for the Irrigation Rate Class

AUI assumed that the demand for the irrigation rate class was the same for each day within a month. AUMA submitted that AUI's approach had the effect of muting the peak demands for the irrigation rate class. AIPA replied that, contrary to AUMA's submission, the 2004 forecast irrigation demand appeared to be overstated relative to the last three years.

12 Exhibit 002-10, Rate Design Schedule 3.1 (Revised January 7, 2005); Exhibit 012-03, page 4, Allocated Cost of Service Using 2002 GRA Heat Load Allocators (January 11, 2005)

13 CCA argument, Transcript, pages 853-854.

Notwithstanding AIPA's observation that the 2004 forecast irrigation peak demand may be higher than the actual peak demand in the last three years, the Board shares the concern raised by AUMA that assuming the irrigation rate class has the same peak demand for each day within a month may understate the peak demand of the irrigation rate class.

Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review the method of forecasting peak demand for the irrigation rate class.

6.4 Allocation of Meter Costs

AIPA submitted that the allocation of capital-related meter costs based on Reproduction Cost New (RCN) without a depreciation component impacts a rate class such as irrigation that has had no growth for the past number of years. No other party commented on the use of RCN to allocate meter costs.

The Board is not persuaded that the rate of growth of a rate class should have any bearing on the allocation of meter costs to that rate class. The Board will therefore accept the use of RCN data to allocate capital-related meter costs.

However, some parties including CCA, submitted that AUI be directed to conduct a minimum system cost study for meters, to ensure that small Rate 1 customers are not being over-allocated meter costs. Recognizing the wide range of meter costs within Rate 1, the Board shares the concern raised by CCA.

Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review whether a minimum system cost study for meters would be a more appropriate method of classifying meter and service costs within Rate 1.

6.5 Allocation of Customer Care Costs

AUI allocated customer care costs based on the number of customers in each rate class.

AIPA and MGCI submitted that AUI be directed to study the demands on the customer care functions by each class for the next GRA. The Board considers that there would be merit in ensuring that the use of unweighted customers is the most appropriate allocator for customer care costs.

Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review whether the use of unweighted customers is the most appropriate allocator for customer care costs.

6.6 Use of Distance-Diameter Method

AUI used the distance-diameter method to classify the costs of distribution mains between customer-related costs and demand-related costs.

CCA submitted that unless there is clear evidence that most residential customers are served through a pipe size larger than 26.7 millimeters, these customers end up paying twice - once through the customer-related charge which represents the minimum system approach and again through the demand-related costs for the larger pipe sizes. CCA requested that AUI be directed, in the next GRA, to assess the distribution pipe size that is installed to meet the requirements of residential customers, and to assess whether the distance-diameter method adequately captures the costs allocated to the residential class. No other party commented on the use of the diameter-distance method.

The Board considers that the use of distance-diameter method to classify the costs of distribution mains between customer-related costs and demand-related costs is reasonable, and consistent with the approved practice of other distribution utilities. The Board is not persuaded by CCA's submission that a further review of this issue is warranted.

7 RATE DESIGN

7.1 Rate Design Criteria

AUI submitted that its guiding rate design considerations had been to meet the overall revenue requirement, to recover costs by customer class at a level between 95 and 105 percent of the cost determined by the COSA, and to address the issues of customer acceptance and rate stability and continuity. No party opposed the rate design criteria proposed by AUI.

The Board notes that the rate design criteria proposed by AUI are similar to the rate design criteria that have been accepted by the Board in previous rate design proceedings. Subject to the clarifications below regarding appropriate revenue-to-cost ratios, the Board accepts the rate design criteria proposed by AUI for the purposes of this proceeding.

With respect to rate shock, PICA submitted that the Board should institute a cap of 10% on the increase for any individual rate class, consistent the Board's recent decisions regarding ENMAX Power Corporation (ENMAX) and EPCOR Distribution Inc. (EPCOR)[14], while AUMA supported an 8% cap consistent with the Board's findings in the Aquila Networks 2002/2003 GRA.[15] In this proceeding, the Board considers that a cap of 10% on the increase for any individual rate class is appropriate, given that distribution rates only encompass a small portion of a customer's bill, and consistent with the recent ENMAX and EPCOR decisions.

With respect to revenue-to-cost ratios, the Board is of the view that cost of service analysis is not an exact science, and that blind adherence to 100% revenue-to-cost ratios in the design of rates would not be appropriate. Nevertheless, the Board considers that one objective of rate design is to design rates that recover 100% of allocated costs. The Board recognizes, however, that consideration of other rate design criteria such as rate stability, mitigation of rate shock and customer acceptance, may conflict with the desire to achieve a 100% revenue-to-cost ratio. Recognizing that cost of service analysis is not an exact science, and recognizing that other rate design criteria may conflict with the desire to achieve a 100% revenue-to-cost ratio, the Board remains of the view that a revenue-to-cost ratio range of 95% to 105% generally remains an appropriate target for all rate classes. However, the Board agrees with MGCI that due to the size of the Rate 1 class, small changes in the revenue-to-cost ratio for Rate 1 would have very large impacts on the revenue-to-cost ratios for the other rate classes. Therefore, the Board considers that the revenue-to-cost ratio for Rate Class 1 should be maintained as close as practicable to 100%.

14 Decisions 2004-066 and 2004-067
15 Decision 2003-019

With respect to the revenue-to-costs ratios for individual components of a rate, the Board holds the same view as with respect to the revenue-to-cost ratios for each rate class. Specifically, the Board considers that one objective of rate design is to design rate components that recover 100% of allocated unit costs. However, the Board again recognizes that other rate design criteria may conflict with this objective, and the Board further recognizes that it may be even more difficult to achieve revenue-to-cost ratios of 100% for individual rate components.

7.2 Rate Levels

The rate changes proposed by those parties who made specific proposals are summarized in the following table:

Rate Class	AUI	MGCI	AIPA	AUMA
1/11	2.9%	3.2%	2.6%	3.8%
2/12	-13.6%	-19.5%	2.6%	-13.6%
3/13	12.8%	12.5%	2.6%	-5.0%
4/14	15.2%	15.2%	2.6%	8.0%
Total	2.6%	2.6%	2.6%	2.6%

The Board notes that the average rate increase is 2.6%.

MGCI accepted the rate increase proposed by AUI for Rate 4, and proposed that Rates 1 and 3 be moved to 100% revenue-to-cost ratios, based on the COSA filed by AUI. By difference, the resulting increase proposed for Rate 1 was 3.2%.

AUMA proposed an 8% cap on the increase for Rate 4. AUMA accepted the decrease proposed by AUI for Rate 2, and proposed a decrease for Rate 3 to achieve the same revenue-to-cost ratios for Rates 2 and 3, based on the COSA amended to reflect the 2002 load factors. By difference, the resulting increase proposed for Rate 1 was 3.8%.

CCA supported the rate changes proposed by AUI.

PICA did not propose specific rate increases, but proposed that, following a refiling of the COSA, rates be moved toward the 100% revenue-to-cost ratio, subject to a 10% cap.

AIPA proposed an across-the-board rate increase of 2.6% since the existing rate structure incorporates the previously approved MPP method, the differences between the revenues at existing rates and the approved revenue requirement was relatively small, and no acceptable daily load forecast exists.

With respect to AIPA’s proposal of an across-the-board increase of 2.6%, the Board notes that it approved the change from the MPP method to the CP/NCP method, and that the Board also determined that the AUI COSA adjusted to reflect the 2002 load factors is a reasonable basis for the allocation of costs to rate classes for the purposes of this decision. The Board does not consider the fact that the differences between the revenues at existing rates and the approved revenue requirement is relatively small should have any impact on the objective of designing rates to reflect, among other rate design criteria, cost causation. The Board will therefore not accept AIPA’s proposal of an across-the-board rate increase.

With respect to Rate 4, AUI proposed an increase of 15.2%, whereas AUMA proposed an increase of 8.0%. As set out above, the Board considers that a maximum rate increase for any class of 10% would be appropriate to mitigate rate shock. Therefore, the Board approves an increase for Rate 4 of 10%.

With respect to Rates 2 and 3, the Board considers that there is merit in AUMA's proposal that these two rates have similar revenue-to-cost ratios, based on the COSA adjusted for the 2002 load factors. As discussed in the cost of service section of this Decision, the Board recognizes that the 2002 load factors were based on a single year which was colder than normal, and consequently the Board will not place as much weight on the cost of service study as it otherwise would. Therefore, the Board considers it appropriate to reduce the revenue-to-cost ratios to approximately 110% for Rates 2 and 3 at this time.

The resulting increase for Rate 1 is 3.6%. The Board notes that this increase is well below the cap of 10% established above to mitigate rate shock and within the range suggested by the parties.

The details on the Board approved rates are set out in Appendix 4. In summary, the Board approved rate changes are as follows:

Rate Class	Board Approved	R/C Ratio
1/11	3.6%	99.2%
2/12	-11.8%	110.4%
3/13	-3.2%	110.1%
4/14	10.0%	92.8%
Total	2.6%	100.0%

7.3 Rate Structures

The fixed charge in the existing rates, and the fixed costs allocated under the COSA[16], are as follows:

Rate Class	Existing Fixed Charge	COSA Fixed Cost	AUI Proposed Fixed Charge
1/11	$14.00	$27.31	$14.00
2/12	$250.00	$197.70	$250.00
3/13	$375.00	$373.66	$450.00
4/14	$23.00	$50.81	$27.00

AUMA and CCA supported AUI's proposal to maintain the fixed charge for Rate 1 at $14.00. MGCI recommended increasing the fixed charge for Rate 1 to $16.45, and PICA recommended increasing the fixed charge for Rate 1 to $17.75. AIPA recommended that the fixed charge for Rate 4 be maintained at $23.00.

The Board notes AUI's submission that increases to the fixed charge on Rate 1 would result in significant negative reaction from customers and may result in hardship on low-consumption customers with low or fixed incomes. The Board also notes the submissions from AUMA and CCA that AUI's existing fixed charge is comparable to the fixed charge for other utilities including ATCO Gas.

[16] The allocated fixed cost is the same for both the AUI COSA and the COSA adjusted for the 2002 load factors.

The Board acknowledges that it is not unusual for the fixed charge to residential customers to be less than the fixed costs incurred to serve residential customers. The Board agrees with CCA that increasing the fixed charge would result in a bigger percentage rate increase for low volume customers than for high volume customers.

The Board is not persuaded that a modest increase in the fixed charge for Rate 1 customers would have a material impact on customers, particularly recognizing that the distribution charge is small compared to the commodity cost. The Board also considers that the appropriate comparison to the fixed charge of default supply customers in the ATCO Gas service area should include the fixed charge in the DERS tariff. The Board noted[17] the combined fixed charge for a default supply customer in the ATCO Gas service area is approximately $18/month, significantly higher than the current fixed charge on AUI's Rate 1. The Board also accepts the arguments of MGCI and PICA that a fixed charge that is below cost transfers costs from small Rate 1 customers to large Rate 1 customers. The Board further agrees with MGCI that a small change in the cost of energy resulting from changes to the design of the distribution tariff is unlikely to affect energy conservation, which is driven primarily by the cost of the commodity.

Therefore, for all of these reasons, the Board considers that all of the approved increase for Rate 1 should be reflected in the fixed charge. The resulting fixed charge for Rate 1 is $15.25/month.

For the same reasons, the Board considers that all of the approved increase for Rate 4 should be reflected in the fixed charge. The resulting fixed charge for Rate 4 is $31.00/month.

For Rates 2 and 3, the Board notes that the fixed charge is already higher than the allocated fixed costs. The Board is not persuaded by AUI's argument that it is appropriate to further increase the fixed charge for Rate 3, even though the fixed charge for Rate 3 had been higher in the past. The Board considers that the entire decreases approved for Rates 2 and 3 should be reflected in the energy charge. The Board notes from Appendix 4 that the resulting energy charges for Rates 2 and 3 are still higher than the allocated energy costs.

Therefore, the final rates approved by the Board, including the customer care charge of $1.40/customer/month, are as follows:

Rate Class	Fixed Charge ($/month)	Energy Charge ($/GJ)	Demand Charge ($/GJ)
1	15.25	1.308	
2	250.00	0.552	
3	375.00	0.015	4.650
4	31.00	0.857	

The Board notes that customers on Rates 11, 12, 13, and 14 who are supplied by retailers will not be subject to the customer care charge of $1.40/customer/month.

Details on the approved rates are set out in Appendix 4 to this Decision. The Board has incorporated these approved rates in the rate schedules included in Appendix 5 of this Decision.

[17] Transcript pages 633-634

The Board also revised the approved rate schedules to more appropriately reflect services provided by AUI by replacing the term energy charge with variable charge.

7.4 Transition Points

The Board does not consider that transition points should be a direct rate design criterion, but that the transition points resulting from any proposed rate design should be reviewed to ensure that there is no rate shock or other concern caused by material shifts in the transition points.

CCA expressed concern that the migration of customers from Rate 1 to Rate 2 might not be revenue and cost neutral for customers remaining on Rate 1. However, the Board notes that AUI did not reflect the impact of any such migration in its rate design. Furthermore, the Board agrees with AUMA that there would be no impact on remaining Rate 1 customers if the large Rate 1 customers who migrated to Rate 2 were not subsidizing small Rate 1 customers. Therefore, the Board is not persuaded that it is necessary or appropriate to assess the impact on remaining Rate 1 customers of the migration of Rate 1 customers to Rate 2.

From Appendix 4 to this Decision, the Board notes that under the approved rates, the transition point between Rates 1 and 2 is 3,726, and the transition point between Rates 2 and 3 is 13,184. In both cases, these transition points are closer to the transition points under the current rates, than the transition points arising from the rates proposed by AUI. The Board is therefore satisfied that the transition points arising from the approved rates do not result in any rate shock or other concern.

7.5 Rate Schedules and Rate Riders

In BR-AUI-14, AltaGas proposed that the 2003 and 2004 revenue deficiencies, now finalized and incorporating all changes relevant to both the Generic Cost of Capital proceeding and compliance filings from Phase I, be combined to create a deficiency rider (Deficiency Rate Rider F). AUI submitted that the collection of deficiencies would take a format similar to that used in 2003 for the distribution of revenue and excesses of other gains stemming from the 2000/2001/2002 GRA. In general:

- The combined deficiencies would be first allocated to sales, end-use transportation, and buy-sell rate classes based on the 2004 COSA revenue requirement allocations.
- For each class of sales, end-use transportation, and buy-sell rate classes, a rider would be calculated and one-time collection performed based on each individual customer's proportionate share of actual billed revenue (excluding gas costs) in 2004.

With the exception of a final Board-approved allocation of the 2004 revenue requirement by rate class, all other data requirements to compute a proposed rider schedule would be available by approximately the beginning of February 2005. AUI suggested that it would file an application in February 2005 with sufficient detail for the Board and interested parties to review. If approved, only a compliance filing updating the rider schedule using the results of the Phase II decision would be required.

AltaGas suggested that the undistributed surplus of roughly $80,000 from the 2000/2001/2002 application and the deficiency of about $630,000 arising from the 2003/2004 application be recovered through a one bill deficiency rider (Rider F), given the level of that impact.

Both MGCI and AUMA expected that Rider F would be addressed in AUI's 2005 GRA. AUMA suggested that the deficiency rider should be spread over several months to avoid any unnecessary rate impact.

The Board expects AUI to file the aforementioned deficiency rider application expeditiously. Given that no intervener expressed opposition to this approach, the Board defers a determination on the deficiency Rider F to the deficiency rider application or to AUI's 2005/2006 GRA.

The Board notes that the Unaccounted-For Gas Rider E was approved in Order U2004-404 effective November 1, 2004. The Gas Cost Recovery Rate Rider D is approved by the Board monthly.

With regards to the AUI's proposed rate Riders A, B, and C, the Board notes that no intervener opposed AUI's proposed riders, nor the elimination of Rider G. The Board is satisfied that the rate riders are reasonable, and therefore are approved as filed.

The Board has attached, in Appendix 5, AUI's approved rate schedules and rate riders. The rates and rate riders A, B, and C are effective May 1, 2005.

8 TERMS AND CONDITIONS OF SERVICE

8.1 Natural Gas Service Rules

AUI submitted its proposed Natural Gas Service Rules with the Application. AUI specified which sections of the Natural Gas Service Rules it was proposing to change.

The Board is addressing the following sections of the Natural Gas Service Rules that were contentious in the proceeding. Any other changes proposed by AUI that have not been specifically addressed are considered to be approved as proposed.

Part 1: What these rules are about

PICA took issue with the use of the word "set" in the paragraph and the heading *"These Rules are set by the Alberta Energy and Utilities Board"* in Part 1 of the Natural Gas Service Rules rather than using the word "approved". AUI agreed to change it to "approved". The Board agrees and so directs AUI to make the change in its refiling.

Part 3: Installing or changing your service

PICA submitted that at AUI's next GRA it should be directed to develop benchmarks for providing service to customers. In some cases there will be exceptions, but PICA believed AUI could provide general time frames in its service rules that give customers some feel for how long it will take to get service. AUI explained[18] that it was completely unrealistic to develop benchmarks as they could not take into account the many different factors that have to be weighed in determining when something can be connected.

[18] Transcript 309

The Board understands that there may be complexities and exceptions, but considers that it may be possible to provide some general time frames. AUI is directed to provide, in its 2005/2006 GRA Phase II filing, general time frames for providing service to customers and discuss further any reasons why AUI would oppose the inclusion of these general time frames in its service rules.

Section 3.3 (1) Our installation charges are set by the Board

Section 3.3 (1) of the Natural Gas Service Rules notes that the Board approves the determination of the charge for installing a service line and that the basic approach is set out in the Special Charges Schedule attached to the Natural Gas Service Rules. AUI did not propose any changes to this section. However, the Board considers that it would be advantageous for customers to have greater clarity in the Natural Gas Service Rules regarding how charges for installing a service are set.

In response to an inquiry from the Board, AUI provided[19] the details outlining the process used and the timelines involved in setting charges for installing a service. AUI stated that:

> If this is a single service, after the project is reviewed the customer is advised verbally if the standard contribution is applicable, or in writing if an additional contribution is required. In either case, the customer is advised that the costs are applicable for the current construction season and under frost-free conditions.
>
> If costs change (for example frost charges come into effect) because a project is delayed, the customer is advised in writing and given the option of canceling or proceeding.

The Board therefore directs AUI to include in its refiling a revision to section 3.3 of the Natural Gas Service Rules that reflects the intent of its response to BR-AUI-23 as outlined above.

Section 4 (4) We can enter when necessary, and use force in an emergency

Section 4 (4) of the Natural Gas Service Rules provides the conditions in which AUI can enter a service site. It is the practice of AUI to enter the service site at any reasonable time to do anything necessary to maintain, repair, and operate its system safely and efficiently. AUI did not propose any changes to this section. However, the Board was concerned that this section did not allow for reasonable notice to customers prior to entering the service site.

Specifically, there is no mention of any required notice to be provided to the customer for any work necessary on the service site. AUI stated that notice is provided to customers either globally or specifically depending on the circumstance. AUI expressed concern regarding the feasibility of providing notice to customers for routine work, although AUI did acknowledge that it is standard practice to notify customers of all non-routine work either by global notification or specific customer notification.

The Board considers it appropriate to include language stating that AUI will provide notice to customers prior to entering a service site when practicable, and therefore directs AUI to incorporate this into section 4 (4) of the Natural Gas Service Rules. The Board considers that similar wording as provided in the response to BR-AUI-25 would be appropriate.

[19] BR-AUI-23

Section 5 (2) You pay for special meter readings

Section 5 (2) of the Natural Gas Service Rules deals with the fees that may be administered by AUI in the event of an off cycle meter read. AUI did not propose any changes to this section. However, the Board considers that it would add clarity to the Natural Gas Service Rules if AUI clearly identified when charges for a special meter read would be applicable.

In BR-AUI-27, the Board requested that AUI determine the parameters for assessing the charges of a special meter read, and at the same time review the criteria that would validate charges for an inaccessible meter. AUI identified that its billing system will allow only three consecutive monthly billings to be estimated and every fourth month, as a minimum, the meter should be read. AUI noted that customers have the option of providing their own meter read or accepting a special meter read appointment during regular business hours at no charge. If the appointment is not secured during regular business hours a special charge would then be levied against the customer account.

The Board considers that these further details regarding the charge for off cycle meter readings should be incorporated into the Natural Gas Service Rules. Therefore the Board directs that the wording in section 5 (2) of the Natural Gas Service Rules be revised to include the specifics detailed above or as set out in the response to BR-AUI-27.

Section 6 (1) The Board decides all of our rates and charges

Section 6 (1) of the Natural Gas Service Rules states that the Board approves all of AUI's rates and charges. AUI has not proposed any changes to section 6 (1). Section 6 (1) includes the statement that "If you think any charge is unfair, you can complain to the Board, and they can change it." The Board considers that this sentence may be misleading to customers. The Board therefore directs AUI to replace the wording "If you think any charge is unfair, you can complain to the Board and they can change it" with "If you think any charge is unfair, you should advise us and we will attempt to resolve your concern on a timely basis. If you are still not satisfied, you can complain to the Board."

Section 6 (3) If you want, we can turn your gas off temporarily, but you will be charged for reactivation and the minimum charge

Section 6 (3) of the Natural Gas Service Rules deals with temporary disconnections of service. AUI proposed some minor wording changes to the section. Specifically, AUI proposed to change the term 'reconnection' to 'reactivation'. The Board notes that section 6 (3), does not clearly identify the maximum period of time that the minimum monthly charge would be applied to a customer's site when the service has been temporarily disconnected.

AUI has indicated[20] that, in order to discourage the misuse of disconnection requests made to avoid monthly services charges, a 24 month minimum monthly charge has been implemented. A typical period of time for other utilities would range from 10 to 14 months as this would discourage the most common type of temporary disconnection such as recreational properties. In argument, AUI agreed to reduce the 24 month period to a shorter timeframe consisting of 12 months.

[20] BR-AUI-29 and BR-AUI-31

The Board approves the wording changes proposed by AUI, and directs AUI to amend section 6 (3) of the Natural Gas Service Rules to state that the minimum monthly charge would be applicable for a period of 12 months.

Section 7 (2) Our Budget Payment Plan allows fixed monthly payments

Section 7 (2) of the rules describes an optional service available to most AUI customers. The budget payment plan allows customers to pay 11 fixed monthly installments of AUI's estimate of the customer's annual usage. To enroll in this plan, a customer must apply directly to AUI.

AUI originally proposed to remove this section from the rules, however, indicated that the service would still be available to customers. Both CCA and MGCI expressed concern with respect to the removal of the wording for the budget billing plan from the rules.

As a result of the concerns expressed by the interveners, AUI agreed to retain the budget billing section in the Natural Gas Service Rules. Accordingly, the Board directs AUI to retain the budget billing plan section and all applicable sections pertaining to the budget plan in the rules.

Section 7 (3) We will apply a late payment charge to overdue accounts

CCA submitted that the Board and companies should be monitoring any changes to late payment penalties to ensure AUI remains in compliance with the Criminal Code. CCA noted the decision of the Supreme Court of Canada in *Garland v. Consumers' Gas Co.*, [2004] 1 S.C.R. 629, which considered whether a late payment penalty charged by Consumers' Gas Co. was in excess of the interest limit prescribed by s.347 of the Criminal Code. Although the CCA suggested that the Board and company should monitor whether the utilities remain in compliance with the Criminal Code, the AUMA indicated it was not aware that the 1.5 percent late penalty was in violation of the Criminal Code. The AUMA supported the 1.5 percent late penalty as a means of ensuring that delinquent customers do not place any burden on those customers who pay on time.

The Board is of the view that AUI's late payment penalty provision is reasonable, and sees no evidence to suggest that it is in violation of the Criminal Code. Therefore, the Board approves AUI's late payment provision. The Board notes that any future changes to AUI's late payment penalties would have to be approved by the Board. In the event that AUI proposes such a change, interested parties would have the opportunity to assess the compliance with the Criminal Code at that time.

Section 8 (1) You have to tell us if you want to stop taking service

Section 8 (1) of the Natural Gas Service Rules indicates that a customer is required to notify AUI when the customer wants to stop the supply of service. AUI did not propose any changes to this section. The Board notes that in section 8 (1) the onus is placed on the customer to relay information to both the distribution and retail companies if service is no longer required.

AUI clarified that its intent is to help ensure that the AUI is aware of when a customer plans to move in order that proper service and billing functions are performed, regardless of gas supplier. AUI stated that in general, notification to a customer's retailer is sufficient:

> The Natural Gas Service Rules have been developed to apply to both default (utility) supplied and retailer supplied customers. This wording has been used to help ensure that the Company is aware of when a customer plans to move in order that proper service and

> billing functions are performed, regardless of gas supplier. However, the Company agrees that in general, notification to a customer's retailer is sufficient so long as the retailer has the necessary processes in place to inform AltaGas Utilities in a timely manner.[21]

The Board considers that inclusion of AUI's response to BR-AUI-31(a) in section 8 (1) of the Natural Gas Service Rules is appropriate, excluding the following wording "so long as the retailer has the necessary processes in place to inform AltaGas Utilities in a timely manner". The Board notes that customers do not have control over whether the retailer has the appropriate processes in place. The Board is of the view that inclusion of the aforementioned wording is unfair to customers as the responsibility to ensure appropriate processes are in place should more appropriately fall on AUI and the retailer. The Board considers notification to a customer's retailer should therefore be sufficient. The Board directs AUI to include in its refiling a revision to section 8 (1) of the Natural Gas Service Rules that reflects the intent of its response to BR.AUI-31 (a) and the Board's findings in this regard.

Special Charges Schedule

Non-Refundable Contributions

PICA submitted that customers need to be aware of AUI's contribution policy and AUI should not be allowed to separate out part of the Natural Gas Service Rules that can be changed without Board approval. AUI indicated that it was following a prior procedure approved by the Board in its 1995/1996 GRA.

The Board agrees that the customer should have a clear understanding of and a reference for the contribution policy and it would be an improvement if it were provided in the Natural Gas Service Rules. The Board notes that the approval indicated by AUI is several years old and believes it will be appropriate to revisit the contribution matter in the upcoming 2005/2006 GRA. The Board directs AUI to include its contribution policy and formula in its Natural Gas Service Rules in its 2005/2006 Phase II GRA.

8.2 General Conditions of Service

PICA noted that AUI's General Conditions of Service dealt with AUI's transportation customers' requirement to balance on a monthly and daily basis, but that AUI acknowledged that there were no customers balancing on a daily basis. AUI indicated[22] that as more customers moved to transportation service and the retail market expanded into AUI's service territory there would be a need for daily balancing. PICA considered AUI's proposal unnecessarily proactive and that the reference should be removed.

The Board does not see the harm of including the reference to daily balancing, since that is the direction in which the industry is moving. AUI would of course be expected to implement daily balancing on a uniform basis when it determined it is necessary. Accordingly, the Board approves AUI's reference to daily balancing.

Other than for the preceding comments, the Board approves the balance of the General Conditions of Service.

[21] BR-AUI-31(a)
[22] Transcript 306

8.3 Retailer Transportation Service Contract and Regulations

AUI indicated in a response to PICA-AUI-16(d) that it would be appropriate to remove references to Common Stream Arrangements as they were not relevant to end-use transportation customers. The Board agrees and directs AUI to remove the references.

Other than for the preceding comments, the Board approves the balance of the Retailer Transportation Service Contract and Regulations.

8.4 Buy/Sell Contract and Regulations

PICA raised issues regarding terminology with respect to words *"Act"*, "TCPL", and "ATCO" as used in the Buy/Sell Contract and Regulations. AUI indicated it was prepared to amend the document to improve the readability and use the legally correct names as they needed to be referenced. The Board agrees that the change will improve the readability and precision of the reference and so directs AUI to amend the wording.

Other than for the preceding comments, the Board approves the balance of the Buy/Sell Contract and Regulations.

8.5 Transportation Service Regulations

As noted in the Buy/Sell Contract and Regulations section previously discussed, AUI is directed to revise the references to "ATCO" and amend all the appropriate sections of the Transportation Service Regulations accordingly.

Also, as noted in the Retailer Transportation Service Contract and Regulations section above, AUI is directed to remove the references to Common Stream Arrangements.

PICA submitted the Board should direct AUI to provide a Transportation Service Contract, on a best-efforts basis, as soon as possible following the conclusion of this hearing. AUI indicated that it was prepared to provide a standard agreement to correspond with the Transportation Service Regulations. The Board agrees that a standard agreement would be useful and would provide a reference point for the regulations. AUI is directed to prepare a standard agreement on a best-efforts basis and submit it as soon as possible, but no later than at the time of its 2005/2006 Phase II GRA filing.

Article 7 Force Majeure

AUI's force majeure clause includes orders of any court or government authority (e.g. the EUB) as an event of force majeure. AUI stated that it would only view a decision of the EUB as its regulator as constituting force majeure in the rarest circumstances. CCA noted that the regulator is a form of corporate governance. CCA submitted that there are avenues to appeal if orders are not proper, but the Board must be clear that orders do not constitute and should not be allowed to constitute force majeure events for companies such as AUI.

Consistent with Decision 2005-019[23], the Board considers that the determination of just and reasonable rates is not a force majeure event. A distribution utility cannot circumvent the

[23] AltaLink Management Ltd. & TransAlta Utilities Corporation, 2004-2007 General Tariff Applications, dated March 12, 2005

Board's role in determining revenue requirements or rates determinations to provide safe and reliable service by invoking the force majeure terms and conditions of its contract.

Accordingly, the Board directs AltaGas, in its Refiling to amend its Terms and Conditions to reflect the Board's findings on force majeure in this regard. While the Board does not wish to dictate the form of amendment, the Board considers that one option would be to include an exclusion clause and insert it in Article 7.3 Exceptions. For example:

> **7.3 Exceptions**
> Notwithstanding Section 7.2(h), a decision, direction, or order made by the Board in the normal course of it exercising its authority to establish the appropriate revenue requirement or rates of the parties to this agreement shall not be considered an event of force majeure.

Other than for the preceding comments, the Board approves the balance of the Transportation Service Regulations.

9 OTHER ISSUES

9.1 Transportation by Others

Mr. Duncan requested that the Board direct AUI to apply to NOVA Gas Transmission Ltd. (NGTL) for TBO Service for AUI's customers. Mr. Duncan submitted that the Board had not approved NGTL's Guidelines for TBO Service, and that NGTL selects the TBO services that it submits to the Board. Mr. Duncan noted that the Board had approved the TransCanada Pipeline Ventures TBO and that ATCO had accepted a NGTL TBO to serve customers in the Edmonton area. Mr. Duncan submitted that approval of an AUI TBO would increase NGTL's requested 2005 revenue requirement by 2.3%.

AUI submitted that Mr. Duncan appeared to be suggesting a complete restructuring of the gas system in Alberta, and that there was no capacity to address Mr. Duncan's proposal in this proceeding. AUI submitted that it did not have the resources to spend time pursuing speculative proposals involving the fundamental nature of the entire industry.

The Board agrees with AUI that a TBO arrangement between NGTL and AUI would constitute a fundamental restructuring of the gas system in Alberta, and that consideration of such an arrangement is beyond the scope of this proceeding. The Board therefore denies Mr. Duncan's request.

9.2 First Nations Issues

The Aboriginal Communities (ABCOM) intervened in this proceeding to explore whether the AUI tariff should contain any amount allocated to recovery of income tax owing as a result of earning on First Nation reserve lands, among other reasons.[24] ABCOM did not present evidence on this issue but did present argument.

In argument, ABCOM submitted that First Nations should receive an income tax rebate for all utility customers situated on reserves. ABCOM noted that s.87 of the *Indian Act (*the *IA)*, RSC

[24] ABCOM Intervention letter dated November 1, 2004.

1985, c.I-5 affords a tax exemption to First Nations for personal property situated on reserves. ABCOM argued that gas and the delivery of gas is personal property and that when AUI collects taxes payable in its gas rates charged to First Nations, First Nations are being taxed.

MGCI submitted that in *Saugeen Indian Band v. Canada*, [1990] 1 F.C. 403, the Federal Court of Appeal dealt with a similar issue and determined that the issue was who pays the tax, not who bears the burden of the tax. In that case, the Court determined that it was the supplier, not the band that paid the tax, and the Court therefore concluded that the *IA* had not been contravened. MGCI submitted that in *Petro-Canada Inc. v. Fort Nelson Indian Band* (1992), 95 D.L.R. (4th) 69, the B.C. Supreme Court reached the same result on a similar issue. AUI supported MGCI's position.

In both its intervention and its argument, ABCOM noted that this issue is before the Board in the ATCO Electric Ltd. 2004 Phase II Distribution Tariff Application. The Board has reviewed the decision in relation to the ATCO Electric Ltd. 2004 Phase II Distribution Tariff Application.[25] It appears that the argument raised by ABCOM in that proceeding is similar to the argument here. For the convenience of parties, the Board has reproduced a portion of Decision 2005-025:

> The Board is being asked to make a determination regarding the interpretation and applicability of section 87 of the *IA* and to exempt First Nations from paying AE's income taxes payable for where services are provided to First Nations situated on reserves.
>
> The Board must first determine whether this matter is within its jurisdiction. In doing so, the Board must consider which parties are subject to its jurisdiction. In this case, AE is the entity subject to the Board's regulation and as such, is before the Board with this Application. In determining AE's revenue requirement in the Phase I DTA, one of the items the Board reviews is AE's income tax payable. In doing so, the Board looks at the income tax status of the AE corporate structure. In certain cases, the Board may assess the income tax status of other entities within the utility's corporate structure to ensure that the regulated utility is not being charged with a disproportionate share of the income taxes payable by the corporate structure on a consolidated basis. For example, in the case of AltaLink,[26] the income tax status of the limited partners of the AltaLink limited partnership was examined in determining the revenue requirement. The Board does not, however, look at the income tax status of AE's customers as this is not relevant to the determination of AE's revenue requirement.
>
> As indicated, the focus is on whether the regulated utility (taking into account the corporate structure of the utility) pays income tax, not on whether any particular customer is subject to income tax. This applies equally to setting just and reasonable rates for a utility, and the establishment of the utility's revenue requirement. In this case, AE is required to pay income tax under federal law. The Board does not have jurisdiction to exempt AE from paying income tax. Further, any exemption from paying income tax which First Nations may receive does not flow through to AE. That is, AE does not receive the benefit from any such exemption. As a result, the Board finds that the income tax status of First Nations is not a matter that the Board must address to determine AE's revenue requirement or its rates. Given the facts of this case, the Board does not consider

[25] Decision 2005-025, dated April 6, 2005

[26] Decision 2003-061: AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariff for May 1, 2002 – April 30, 2004; TransAlta Utilities Corporation Transmission Tariffs for January 1, 2002 - April 30, 2002, dated August 3, 2003.

> it necessary to embark upon an analysis of the case law cited by the parties, as it is the income tax status of AE that the Board must consider.

The Board notes that ABCOM did not present any evidence in this proceeding. Accordingly, the Board does not consider that there is any information on the record in this proceeding that would support a different decision than the Board reached in the AE proceeding cited above. Consequently, the Board denies ABCOM's request that First Nations receive an income tax rebate for all utility customers situated on reserves.

ABCOM also requested changes to data reporting by AUI. Specifically, ABCOM requested the asset values of utility assets provided for each reserve, the customer count and energy-use data be summarized by rate class for each reserve, the number of status Indians which make up utility manpower complement as recorded, the dollar amount for contract labour of capital and maintenance awarded to native-owned companies be recorded, the status of Indian Affairs permits, and any agreements for property taxation or use or, at the very least, a summary of a calculation methodology for each reserve.

ABCOM submitted that this information is required by First Nations to develop business plans and other documents to assist in First Nations employment and investment planning activities.

The Board considers that the reporting requested by ABCOM could be onerous, and the Board is therefore not persuaded that AUI should be required to provide the requested information. Rather, the Board considers that First Nations should communicate directly with AUI as necessary in the development of their business plans and other documents.

10 COMPLIANCE FILING

All Board directions included within this Decision are summarized in Appendix 6. The Board expects AUI to submit its compliance filing to the Board by May 9, 2005. In its compliance filing, the Board directs AUI refile a complete package of its Terms and Conditions of Service, including blacklined and clean copy versions of its:

- Natural Gas Service Rules
- General Conditions of Service
- Buy/Sell Contract and Regulations
- Transportation Regulations
- Retailer Transportation Service Contract and Regulation

11 ORDER

IT IS HEREBY ORDERED THAT:

(1) AltaGas Utilities Inc. shall comply with all Board directions in this Decision.

(2) AltaGas Utilities Inc. shall refile its 2003/2004 GRA Phase II (the Compliance Filing) as required by this Decision, on or before May 9, 2005 incorporating the findings and directions in this Decision.

(3) The Rate Schedules and Rates, Tolls and Charges included in the Rate Schedules attached as Appendix 5 of this Decision Report are hereby approved as final for AltaGas Utilities Inc. effective on and after May 1, 2005 in accordance with and subject to the provisions of this Decision Report.

Dated in Calgary, Alberta on April 12, 2005.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

R. G. Lock, P.Eng.
Presiding Member

(original signed by)

M. W. Edwards
Acting Member

(original signed by)

W. K. Taylor
Acting Member

APPENDIX 1 – PROCEEDING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
AltaGas Utilities Inc. (AltaGas or AUI) F. V. Martin	L. Heikkinen A. Mantei N. Chymko G. Saleba
Aboriginal Communities and Natural Resource Initiative (ABCOM) J. L. Graves	
Alberta Irrigation Projects Association (AIPA) J. H. Unryn	
Alberta Urban Municipalities Association (AUMA) J. A. Bryan	
Consumers Coalition of Alberta (CCA) J. A. Wachowich	
Direct Energy Partnership K. F. Miller	
Municipal and Gas Co-op Intervenors (MGCI) T. D. Marriott	
Public Institutional Consumers of Alberta (PICA) N. J. McKenzie B. Shymanski	
Russ Duncan (on his own behalf) R. Duncan	
Utilities Consumer Advocate (UCA) D. Gray	

Alberta Energy and Utilities Board
Board Panel
R. G. Lock, Presiding Member
W. K. Taylor, Acting Member
M. W. Edwards, Acting Member

Board Staff
R. Marx, Board Counsel
M. McJannet
R. Armstrong, P. Eng

APPENDIX 2 – COSA ADJUSTMENT FOR 2002 LOAD FACTORS

COSA
Adjustment.xls

(consists of 1 page)

APPENDIX 3 – AUI PROPOSED RATES

AUI Proposed
Rates.xls

(consists of 1 page)

APPENDIX 4 – BOARD APPROVED RATES

Appendix 4 Board
Approved Rates.xls

(consists of 1 page)

APPENDIX 5 – APPROVED RATE SCHEDULES AND RATE RIDERS

RATE SCHEDULES

AUI Rate 1.doc

AUI Rate 1 – Small General Service
(consists of 1 page)

AUI Rate 2.doc

AUI Rate 2 – Optional General Service
(consists of 1 page)

AUI Rate 3.doc

AUI Rate 3 – Optional General Service Demand/Commodity
(consists of 1 page)

AUI Rate 4.doc

AUI Rate 4 – Optional Irrigation Pumping Service
(consists of 1 page)

AUI Rate 6.doc

AUI Rate 6 – Standby, Peaking, and Emergency Service
(consists of 1 page)

AUI Rate 10a.doc

AUI Rate 10a – Transportation Service Producer “Closed Rate”
(consists of 1 page)

AUI Rate 10b.doc

AUI Rate 10b - Transportation Service Producer “Closed Rate”
(consists of 1 page)

AUI Rate 10c.doc

AUI Rate 10c - Transportation Service Producer “Closed Rate”
(consists of 1 page)

AUI Rate 11.doc

AUI Rate 11 – Transportation Service for Natural Gas Delivered from the Company’s System to Retail-Supplied Small End Users
(consists of 1 page)

AUI Rate 12.doc

AUI Rate 12 - Transportation Service for Natural Gas Delivered from the Company’s System to Retail-Supplied Large End Users
(consists of 1 page)

AUI Rate 13.doc

AUI Rate 13 – Transportation Service End User
(consists of 2 pages)

AUI Rate 14.doc

AUI Rate 14 - Transportation Service for Natural Gas Delivered from the Company’s System to Irrigation Pumping Retail/Core Market End Users
(consists of 2 pages)

AUI Rate 23.doc

AUI Rate 23 – Buy/Sell Service for Natural Gas Supplied by a Demand/Commodity End User (Rate No. 3) for Sale to Company
(consists of 2 pages)

AUI Rate 30.doc

AUI Rate 30 – Transportation Service “Closed Rate”
(consists of 1 page)

RATE RIDERS

AUI Rider A.doc

AUI Rider A - Franchise Tax Riders
(consists of 3 pages)

AUI Rider B.doc

AUI Rider B – Municipal Property Tax Riders
(consist of 1 page)

AUI Rider C.doc

AUI Rider C – Deemed Cost of Gas Rider
(consists of 1 page)

AUI Rider D.doc

AUI Rider D – Gas Cost Recovery Rate Rider
(consists of 1 page)

AUI Rider E.doc

AUI Rider E – Unaccounted-For Gas Rider
(consists of 1 page)

APPENDIX 6 – 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.

1. However, the Board directs AUI, at the time of its next GRA, to prepare a more comprehensive assessment of the long-term costs that could be avoided by AUI, assuming a material shift of customers to retail supply. The Board expects this assessment to include an assessment of the potential to avoid printing, administrative, and overhead costs.................. 6
2. If AUI's billing system is not capable of implementing the unbundled rates in this manner, the Board will allow AUI to combine the base charge and customer care charge into a single fixed charge for the purposes of billing customers on default supply, and, if necessary, to apply a retail credit of $1.40/customer/month to customers on retail supply. However, in this event, the Board directs AUI, at the time of its next GRA, to provide an estimate of the cost of modifying its billing system to display the rates on customer bills as set out in the approved rate schedules. 6
3. Therefore, the Board directs AUI to include, in its Annual Report of Finances and Operations, a report on the number of customers that moved to or from retail supply during the year. 8
4. The Board directs AUI, at the time of its 2005/2006 Phase II GRA filing, to revise the weather normalization method in its COSA to reflect AUI's design criterion of minus 40 degrees Celsius.. 9
5. Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review the method of forecasting peak demand for the irrigation rate class. 11
6. Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review whether a minimum system cost study for meters would be a more appropriate method of classifying meter and service costs within Rate 1. 11
7. Therefore, the Board directs AUI, at the time of its 2005/2006 GRA Phase II filing, to review whether the use of unweighted customers is the most appropriate allocator for customer care costs.. 11
8. PICA took issue with the use of the word "set" in the paragraph and the heading *"These Rules are set by the Alberta Energy and Utilities Board"* in Part 1 of the Natural Gas Service Rules rather than using the word "approved". AUI agreed to change it to "approved". The Board agrees and so directs AUI to make the change in its refiling. 17
9. The Board understands that there may be complexities and exceptions, but considers that it may be possible to provide some general time frames. AUI is directed to provide, in its 2005/2006 GRA Phase II filing, general time frames for providing service to customers and discuss further any reasons why AUI would oppose the inclusion of these general time frames in its service rules.. 18
10. The Board therefore directs AUI to include in its refiling a revision to section 3.3 of the Natural Gas Service Rules that reflects the intent of its response to BR-AUI-23 as outlined above. 18

AltaGas Utilities Inc.
2003/2004 General Rate Application - Phase II

COSA Adjustment for 2002 Load Factors

	Draft AUI COSA (Exhibit 002-10)				Draft AUI COSA Adjusted (Exhibit 012-03)				Difference Due to 2002 Load Factors			
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Total
Rate 1/11	19,736,051	20,686	6,228,298	25,985,035	19,736,051	20,686	6,523,122	26,279,859	-	-	294,824	294,824
Rate 2/12	335,666	2,161	622,866	960,693	335,666	2,161	649,262	987,089	-	-	26,396	26,396
Rate 3/13	184,733	5,283	1,090,039	1,280,055	184,733	5,283	796,936	986,952	-	-	(293,103)	(293,103)
Rate 4/14	99,549	237	114,422	214,208	99,549	237	86,305	186,091	-	-	(28,117)	(28,117)
	20,355,999	28,367	8,055,625	28,439,991	20,355,999	28,367	8,055,625	28,439,991	-	-	-	-

	Final AUI COSA (Exhibit 012-13)				Final AUI COSA Adjusted for 2002 Load Factors				Exhibit 012-21	
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Total	Total	Difference
Rate 1/11	19,658,499	20,686	6,228,297	25,907,482	19,658,499	20,686	6,523,121	26,202,306	26,202,306	-
Rate 2/12	348,748	2,161	622,867	973,776	348,748	2,161	649,263	1,000,172	1,000,172	-
Rate 3/13	246,615	5,283	1,090,039	1,341,937	246,615	5,283	796,936	1,048,834	1,048,834	-
Rate 4/14	102,137	237	114,422	216,796	102,137	237	86,305	188,679	188,679	-
	20,355,999	28,367	8,055,625	28,439,991	20,355,999	28,367	8,055,625	28,439,991	28,439,991	-

	Final AUI COSA Adjusted for 2002 Load Factors				Billing Determinants			Unit Costs		
	Customer	Energy	Capacity	Total	Billings Units	Energy Units (GJ)	Demand Units (GJ)	Customer	Energy	Capacity
Rate 1/11	19,658,499	20,686	6,523,121	26,202,306	719,866	11,489,958		$ 27.31	$ 0.570	
Rate 2/12	348,748	2,161	649,263	1,000,172	1,764	1,200,435		$ 197.70	$ 0.543	
Rate 3/13	246,615	5,283	796,936	1,048,834	660	2,934,413	185,580	$ 373.66	$ 0.002	$ 4.294
Rate 4/14	102,137	237	86,305	188,679	2,010	131,500		$ 50.81	$ 0.658	
	20,355,999	28,367	8,055,625	28,439,991	724,300	15,756,306	185,580			

AltaGas Utilities Inc.
2003/2004 General Rate Application - Phase II

AUI Proposed Rate Design

	Billing Determinants			Existing Rates			Revenues at Existing Rates ($)			
	Billings Units	Energy Units (GJ)	Demand Units (GJ)	Fixed Charge ($/mo.)	Base Energy ($/GJ)	Demand Charge ($/GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	719,866	11,489,958		$ 14.00	$ 1.308		10,078,124	15,028,865	-	25,106,989
Rate 2/12	1,764	1,200,435		$ 250.00	$ 0.675		441,000	810,294	-	1,251,294
Rate 3/13	660	2,934,413	185,580	$ 375.00	$ 0.028	$ 4.650	247,500	82,164	862,947	1,192,611
Rate 4/14	2,010	131,500		$ 23.00	$ 0.857		46,230	112,696	-	158,926
	724,300	15,756,306	185,580				$ 10,812,854	$ 16,034,019	$ 862,947	$ 27,709,820

	AUI Proposed Rates			Revenues at Proposed Rates ($)			
	Fixed Charge ($/mo.)	Base Energy ($/GJ)	Demand Charge ($/GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	$ 14.00	$ 1.371		10,078,124	15,752,732	-	25,830,856
Rate 2/12	$ 250.00	$ 0.533		441,000	639,832	-	1,080,832
Rate 3/13	$ 450.00	$ 0.041	$ 5.000	297,000	120,311	927,900	1,345,211
Rate 4/14	$ 27.00	$ 0.980		54,270	128,870	-	183,140
				$ 10,870,394	$ 16,641,745	$ 927,900	$ 28,440,039

	AUI COSA (Exhibit 012-13)				Unit Costs			Proposed Rates		Existing
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Revenue to Cost Ratios	Percentage Change	Revenue to Cost Ratios Normalized
Rate 1/11	19,658,499	20,686	6,228,297	25,907,482	$ 27.31	$ 0.544		99.70%	2.88%	99.46%
Rate 2/12	348,748	2,161	622,866	973,776	$ 197.70	$ 0.521		110.99%	-13.62%	131.89%
Rate 3/13	246,615	5,283	1,090,039	1,341,937	$ 373.66	$ 0.002	$ 5.874	100.24%	12.80%	91.21%
Rate 4/14	102,137	237	114,422	216,796	$ 50.81	$ 0.872		84.48%	15.24%	75.24%
	20,355,999	28,367	8,055,625	28,439,991					2.64%	

	AUI COSA Adjusted for 2002 Load Factors				Unit Costs			Proposed Rates			Existing
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Revenue to Cost Ratios	Percentage Change	Transition Points	Revenue to Cost Ratios Normalized
Rate 1/11	19,658,499	20,686	6,523,122	26,202,306	$ 27.31	$ 0.570		98.58%	2.88%		98.34%
Rate 2/12	348,748	2,161	649,262	1,000,172	$ 197.70	$ 0.543		108.06%	-13.62%	3,379	128.41%
Rate 3/13	246,615	5,283	796,936	1,048,834	$ 373.66	$ 0.002	$ 4.294	128.26%	12.80%	17,073	116.71%
Rate 4/14	102,137	237	86,305	188,679	$ 50.81	$ 0.658		97.06%	15.24%		86.45%
	20,355,999	28,367	8,055,626	28,439,991					2.64%		

AltaGas Utilities Inc.
2003/2004 General Rate Application - Phase II

Board Approved Rate Design

	Billing Determinants			Existing Rates			Revenues at Existing Rates ($)			
	Billings Units	Energy Units (GJ)	Demand Units (GJ)	Fixed Charge ($/mo.)	Base Energy ($/GJ)	Demand Charge ($/GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	719,866	11,489,958		$ 14.00	$ 1.308		10,078,124	15,028,865	-	25,106,989
Rate 2/12	1,764	1,200,435		$ 250.00	$ 0.675		441,000	810,294	-	1,251,294
Rate 3/13	660	2,934,413	185,580	$ 375.00	$ 0.028	$ 4.650	247,500	82,164	862,947	1,192,611
Rate 4/14	2,010	131,500		$ 23.00	$ 0.857		46,230	112,696	-	158,926
	724,300	15,756,306	185,580				$ 10,812,854	$ 16,034,019	$ 862,947	$ 27,709,820

	Board Approved Rates			Revenues at Proposed Rates ($)			
	Fixed Charge ($/mo.)	Base Energy ($/GJ)	Demand Charge ($/GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	$ 15.25	$ 1.308		10,977,957	15,028,865	-	26,006,822
Rate 2/12	$ 250.00	$ 0.552		441,000	662,640	-	1,103,640
Rate 3/13	$ 375.00	$ 0.015	$ 4.650	247,500	44,016	862,947	1,154,463
Rate 4/14	$ 31.00	$ 0.857		62,310	112,696	-	175,006
				$ 11,728,767	$ 15,848,217	$ 862,947	$ 28,439,931

	AUI COSA (Exhibit 012-13)				Unit Costs			Proposed Rates		Existing
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Revenue to Cost Ratios	Percentage Change	Revenue to Cost Ratios Normalized
Rate 1/11	19,658,499	20,686	6,228,297	25,907,482	$ 27.31	$ 0.544		100.38%	3.58%	99.46%
Rate 2/12	348,748	2,161	622,866	973,776	$ 197.70	$ 0.521		113.34%	-11.80%	131.89%
Rate 3/13	246,615	5,283	1,090,039	1,341,937	$ 373.66	$ 0.002	$ 5.874	86.03%	-3.20%	91.21%
Rate 4/14	102,137	237	114,422	216,796	$ 50.81	$ 0.872		80.72%	10.12%	75.24%
	20,355,999	28,367	8,055,625	28,439,991					2.63%	

	AUI COSA Adjusted for 2002 Load Factors				Unit Costs			Proposed Rates			Existing
	Customer	Energy	Capacity	Total	Customer	Energy	Capacity	Revenue to Cost Ratios	Percentage Change	Transition Points	Revenue to Cost Ratios Normalized
Rate 1/11	19,658,499	20,686	6,523,122	26,202,306	$ 27.31	$ 0.570		99.25%	3.58%		98.34%
Rate 2/12	348,748	2,161	649,262	1,000,172	$ 197.70	$ 0.543		110.35%	-11.80%	3,726	128.41%
Rate 3/13	246,615	5,283	796,936	1,048,834	$ 373.66	$ 0.002	$ 4.294	110.07%	-3.20%	13,184	116.71%
Rate 4/14	102,137	237	86,305	188,679	$ 50.81	$ 0.658		92.75%	10.12%		86.45%
	20,355,999	28,367	8,055,626	28,439,991					2.63%		

RATE NO. 1	SMALL GENERAL SERVICE

Description:

Available to all customers 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 services.

Charges:

Fixed Charge:

Base	$ 13.85/Month
Customer Care...	$ 1.40/Month

Variable Charge:

Base	$ 1.308/GJ
Gas Cost Recovery..	Rate Rider "D"

Minimum Monthly Charge:	Fixed Charge

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE: December 1, 2003	Page 1 of 1 SGS

RATE NO. 2	OPTIONAL LARGE GENERAL SERVICE

Description:

Available to all customers on an annual term 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 services.

Charges:

Fixed Charge:

Base	$ 248.60/Month
Customer Care	$ 1.40/Month

Variable Charge:

Base	$ 0.552/GJ
Gas Cost Recovery	Rate Rider "D"

Minimum Monthly Charge:	Fixed Charge

EFFECTIVE DATE:	REPLACING RATE EFFECTIVE:	Page 1 of 1
May 1, 2005	December 1, 2003	LGS

RATE NO. 3	OPTIONAL GENERAL SERVICE DEMAND/COMMODITY

Description:

Available on an annual term, except to 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 services.

Charges:

Fixed Charge:

Base	$ 373.60/Month
Customer Care	$ 1.40/Month
Demand Charge:	$ 4.650/Month/GJ of Billing Demand

Variable Charge:

Base	$ 0.015/GJ
Gas Cost Recovery	Rate Rider "D"
Minimum Monthly Charge:	Fixed Charge plus Demand Charge

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or
2. The Contract Demand, or
3. The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2.

EFFECTIVE DATE:	REPLACING RATE EFFECTIVE:	Page 1 of 1
May 1, 2005	December 1, 2003	OGS-DC

RATE NO. 4	OPTIONAL IRRIGATION PUMPING SERVICE

Description:

Available only to customers for the use of natural gas as a fuel for engines pumping irrigation water between **April 1** and **October 31**.

Charges:

	April 1 to October 31
Fixed Charge:	
Base	$ 29.60/Month
Customer Care	$ 1.40/Month
Variable Charge:	
Base	$ 0.857/GJ
Gas Cost Recovery	Rate Rider "D"
Minimum Monthly Charge:	Fixed Charge

RATE NO. 6	STANDBY, PEAKING, AND EMERGENCY SERVICE

Description:

Available only at the option of the Company.

Charges:

Fixed Charge:

Base	$ 373.60/Month
Customer Care	$ 1.40/Month

Demand Charge: .... $ 4.650/Month/GJ of Billing Demand

Variable Charge:................................. 1.3 times the Variable Base Charge of Rate No. 3 plus the greater of:
(a) 1.3 times the GCRR; or
(b) 1.3 times the actual cost of gas purchased

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or

2. The Contract Demand, or

3. The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2.

RATE NO. 10a	TRANSPORTATION SERVICE PRODUCER ‘CLOSED RATE’

Description:

Transportation service is available to the Rate No. 10a customer on contract for the terms specified for the transportation of natural gas owned by others through the Company's transmission facilities.

Charges:

	Term		
	1 Year	**2 Years**	**3 Years**
Fixed Charge per Month:	$ 250.00	$ 250.00	$ 250.00
Demand Charge per GJ of Billing Demand per Month:...........................	$1.418	$1.333	$1.248
Variable Charge per GJ:..................................	$0.019	$0.019	$0.019

a) The minimum monthly charge will be the fixed plus demand charge.

b) The Company and customer shall determine receipt and delivery locations for transportation service by consultation and agreement.

c) Service under Transportation Rates is subject to available system capacity.

d) The Company reserves the right to restrict the amount of gas received and delivered to the Contract Demand.

e) Billing demand will be the higher of: contracted demand, the greatest amount of gas in any consecutive 24-hour period or the highest demand billed in the previous 11 months.

f) The rates do not include costs payable by the Customer for specific facilities at the point(s) of receipt or delivery provided by the Company for the Customer.

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 1 TS-P10a

RATE NO. 10b	TRANSPORTATION SERVICE PRODUCER 'CLOSED RATE'

Description:

Transportation service is available to the Rate No. 10b customer on contract for the terms specified for the transportation of natural gas owned by others through the Company's transmission facilities.

Charges:

Variable Charge:.. $ 0.850/GJ

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 1 TS-P10b

2003-2004 GRA

AltaGas Utilities Inc.

RATE NO. 10c	TRANSPORTATION SERVICE PRODUCER 'CLOSED RATE'

Description:

Transportation service is available to the Rate No. 10c customer on contract for the terms specified for the transportation of natural gas owned by others through the Company's transmission facilities.

Charges:

Demand Charge: ....$ 0.020/Day/GJ of Billing Demand

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 1 TS-P10c

RATE NO. 11	TRANSPORTATION SERVICE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO RETAILER-SUPPLIED SMALL END USERS

Description:

Transportation service is available to retailer-supplied customers under an Annual Contract for the transportation of natural gas owned by others through the Company's facilities, provided that the Requirements below are met.

Charges:

Fixed Charge: $13.85/Month

Variable Charge:.. $1.308/GJ

Minimum Monthly Charge: .... Fixed Charge

PLUS
A provision for Unaccounted-For Gas as per Rider "E" of the Rate Schedules.

This service is not available for standby, peaking or emergency services.

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE: December 1, 2003	Page 1 of 1 TS-SCM

RATE NO. 12	TRANSPORTATION SERVICE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO LARGE RETAIL END USERS

Description:

Transportation service is available to large retail customers under an Annual Contract for the transportation of natural gas owned by others through the Company's facilities, provided that the Requirements below are met.

Charges:

Fixed Charge: $248.60/Month

Variable Charge:.. $0.552/GJ

Minimum Monthly Charge: .... Fixed Charge

PLUS
A provision for Unaccounted-For Gas as per Rider "E" of the Rate Schedules.

This service is not available for standby, peaking or emergency services.

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE: December 1, 2003	Page 1 of 1 TS-LCM

RATE NO. 13	TRANSPORTATION SERVICE END USER

Description:

Transportation service is available to customers on contract for the terms specified for the transportation of natural gas owned by others through the Company's facilities.

Charges:

Fixed Charge per Month:	$ 373.60/Month
Demand Charge per GJ of Billing Demand per Month:	$4.650/Month/GJ of Billing Demand
Variable Charge per GJ:	$0.015/GJ

PLUS
A provision for Unaccounted-For Gas as per Rider "E" of the Rate Schedules

a) The minimum monthly charge will be the fixed charge plus demand charge.

b) The Company and customer shall determine receipt and delivery locations for transportation service by consultation and agreement.

c) Service under Transportation Rates is subject to available system capacity.

d) The Company reserves the right to restrict the amount of gas received and delivered to the Contract Demand.

Charges: (continued)

e) Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or

2. The Contract Demand, or

3. The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2.

f) The rates do not include costs payable by the Customer for specific facilities at the point(s) of receipt or delivery provided by the Company for the Customer.

EFFECTIVE DATE:	REPLACING RATE EFFECTIVE:	Page 2 of 2
May 1, 2005	December 1, 2003	TS-EU

AltaGas Utilities Inc.

RATE NO. 14	TRANSPORTATION SERVICE FOR NATURAL GAS DELIVERED FROM THE COMPANY'S SYSTEM TO IRRIGATION PUMPING RETAIL END USERS

Description:

Transportation service is available to users of natural gas as a fuel for engines pumping irrigation water under an Annual Contract for the transportation of natural gas owned by others through the Company's facilities, provided that the Requirements below are met.

Charges:

	April 1 to October 31
Fixed Charge:	$29.60/Month
Variable Charge:	$0.857/GJ
Minimum Monthly Charge:	Fixed Charge

PLUS
A provision for Unaccounted-For Gas as per Rider "E" of the Rate Schedules.

This service is not available for standby, peaking or emergency services.

Requirements:

1. The gas is delivered by Customer to Company at one of either a NOVA/Company or an ATCO interconnection or any other interconnection acceptable to the Company specific to the district where the gas is being consumed.

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

Requirements: (continued)

(b) The Company shall determine receipt and delivery locations for transportation service by consultation;

(c) Service under Transportation Rates is subject to available system capacity;

(d) The gas is delivered from the Company's Gas Pipeline System to an End-User; and,

(e) 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.

EFFECTIVE DATE:	REPLACING RATE EFFECTIVE:	Page 2 of 2
May 1, 2005	November 1, 1997	TS-IP

RATE NO. 23	BUY/SELL SERVICE FOR NATURAL GAS SUPPLIED BY A DEMAND/COMMODITY END USER (Rate No. 3) FOR SALE TO COMPANY

Description:

Available under an Annual Contract for Gas supplied and sold by Customer to Company provided that:

1. The Customer is an Industrial End-User who is provided with Gas Sales Service by Company under Rate No. 3.

2. The Gas is delivered by Customer to Company at a mutually acceptable Point of Delivery.

3. The measurement of the Customer's consumption is available daily.

Annual Quantity:

The annual Quantity of Gas to be delivered by Customer and purchased by Company during the Contract Year shall be the amount equal to the total of all daily Customer consumption as measured by the Company. The Company will be obliged to take on an annual basis only the actual amount of gas consumed by the customer.

Maximum Daily Quantity:

The Maximum Daily Quantity that customer shall be obligated to deliver to the Company and the Company to accept on any day shall equal the amount measured two days previous.

If the reporting of measurement fails for any reason, the Maximum Daily Quantity shall be as determined by mutual agreement.

Price Payable by Company:

The Price Payable for gas purchased by Company from Customer shall be the monthly approved Gas Cost Recovery Rate.

Failure of Supply:

In the event of a Failure of Customer's Supply, in whole or in part, the Customer will be charged and amount equal to 130% of the value of the highest priced gas purchased by the Company that day, multiplied by the quantity of gas required, less the Gas Cost Recovery Rate (GCRR) multiplied by the quantity of gas required.

Formula:

(Replacement Gas Cost x 1.3 x Replacement Amount GJ)
- (GCRR x Replacement Amount GJ)
= Failure of Supply Charge

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE: January 1, 1997	BS-EU3

SPECIAL CONTRACT RATE NO. 30	TRANSPORTATION SERVICE ‘CLOSED RATE’

Description:

Transportation service is available to the Rate No. 30 customer for the term and conditions specified in the contract.

Charges:

Fixed Charge: .... $ 250.00/Month

Variable Charge:………………………………………………… $ 0.230/GJ

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 1 TS NUL SC1

RATE RIDER "A"	FRANCHISE TAX RIDERS

Municipalities

Additions to be made to the rates of customers resident in municipalities that have agreed to accept a percentage of gross revenue of the special franchise tax in lieu of a property tax pursuant to Section 360 of the Municipal Government Act, 1994, c. M-26.1 (previously Section 14(7) and 14(8) of the Municipal Taxation Act).

The percentage shown to be applied as an addition to the total billings calculated.

				Board Orders	
Municipality	**District**	**Type**	**Rate (%)**	**Franchise Tax**	**Transportation**
* Athabasca	Athabasca	Town	6.0	U97149	
Barrhead	Barrhead/Westlock/ Morinville	Town	3.1	U98152	
* Beaumont	Leduc/Calmar	Village	6.0	E95093	
Delia	Hanna	Village	4.0	E92122	
Donalda	Stettler	Village	4.0	E92122	
Drumheller	Drumheller	City	7.0	U97134	
Elk Point	St. Paul	Town	7.0	U99062	
Grande Cache	Grande Cache	Town	6.952	U99084	
* Hairy Hill	St. Paul	Village	5.0	E95078	
Hanna	Hanna	Town	3.1	E76087	
* Leduc(1)	Leduc/Calmar	City	6.0	E94060	E94063
Mewatha Beach	Athabasca	SV(2)	3.1	E85124	
Morinville(1)	Morinville	Town	5.1	E95081	
Munson	Drumheller	Village	5.0	E92106	
New Sarepta	Leduc/Calmar	Village	5.5	U98138	
Radway	Westlock	Village	3.0	E90046	
St. Paul	St. Paul	Town	6.0	E91081	
Sunset Beach(1)	Athabasca	Summer Village	6.1	U97151	
Three Hills	Three Hills	Town	4.75	U98033	
Two Hills	Two Hills/Willingdon	Town	5.1	E94038	
Willingdon	Two Hills/Willingdon	Village	5.0	U98106	

(1) The Municipality has elected to have the percentage of gross revenue from the special franchise collected on sales revenue, transportation service revenue, and a deemed value for gas applied to volumes transported.

(2) SV denotes "Summer Village"

* Periodic changes to franchise tax rates have been pre-approved by the Board.

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 3 RIDER "A"

Metis Settlements

Additions to be made to the rates of customers resident in Metis Settlements that have by bylaw approved Utility Services Agreements providing for the payment of annual utility service fees calculated as a percentage of gross revenues.(3) The percentage shown is to be applied as an addition to the total billings calculated.

Metis Settlement	District	Rate (%)	Board Order
Buffalo Lake	St. Paul	7.0	U2000-236
Fishing Lake	St. Paul	5.0	U97153
Kikino	St. Paul	7.0	U2000-107

(3) The *Metis Settlements Act* (S.A. 1998 Chapter M-14.3) enables the Metis Settlements General Council to legislate by Policy and Settlement Councils to legislate by bylaw on matters related to the operations of utilities within the settlement areas, including the granting of interests in land, the assessment and taxation of these interests, and the licencing of related activities. [s.222(1); Sch.1, ss.14, 19]. Under Metis Settlements General *Council Public Utilities Policy* (GC-P9804; Alberta Gazette, Nov.30, 1998, p.2221) a Settlement may enter into Utility Service Agreement allowing a utility to use land and provide utility services in the Settlement Area and providing for the utility to pay an all inclusive annual service fee. The fee may be determined as a percentage of gross revenue received from services provided in the Settlement Area. Each of the listed Settlements has entered into a Utility Service Agreement with AltaGas Utilities. Under the *Public Utility Policy* [s.2.3(3)] the Service Agreement takes effect on being approved by bylaw and by the Alberta Energy and Utilities Board.

Municipalities Governed by Standardized Franchise Agreement

For each calendar year the franchise fee will be calculated as a percentage of the Company's actual total revenue derived from the Delivery Tariff, including without limitation the fixed charge, base energy charge, demand charge but excluding the cost of gas (being the calculated revenues from the gas cost recovery rate rider or the deemed cost of gas) in that year for Gas Distribution Service within the Municipal Area.

Municipality	District	Type	Rate (%)	Board Orders Franchise Fee
Bonnyville	Bonnyville	Town	20.0	2003-068
Botha	Stettler	Village	10.0	2004-260
Calmar	Leduc	Town	20.0	2004-244
Glendon	St. Paul	Village	4.62	2004-264
High Level	High Level	Town	27.5	2004-274
High Level	Rate 23 Customers only		35.0	2004-274
Pincher Creek	Pincher Creek	Town	20.0	2004-293
Stettler	Stettler	Town	18.0	2004-247
Westlock	B/W/M	Town	0.0	2004-232

RATE RIDER "B"	MUNICIPAL PROPERTY TAX RIDERS

Additions to be made to the rates of customers resident in municipalities that receive a property tax assessed pursuant to Section 353 of the *Municipal Government Act*, R.S.A. 2000 c.M-26. The addition is an estimated percentage of gross revenue required to provide for the tax payable each year. To the extent that this percentage may be more or less than that required to pay the tax, the percentage of gross revenue in the rider will be adjusted on an annual basis. The percentages are filed with the Alberta Energy and Utilities Board.

Rate Rider "B" is to be applied as an addition to the gross amount of charges for gas service otherwise payable (including applicable Riders) in the following area(s):

Districts	**Municipalities***
Athabasca	Village of Morrin
Barrhead, Westlock, Morinville	Zama City
Bonnyville	Town of Bonnyville
Drumheller	Town of Calmar
Grande Cache	Town of Stettler
Hanna	Village of Botha
High Level	Town of Westlock
Leduc	Town of Pincher Creek
Pincher Creek	Town of High Level
St. Paul	Village of Glendon
Southeast	
Stettler	
Three Hills	
Two Hills	

*Municipalities will be added as approved

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE:	Page 1 of 1 RIDER "B"

AltaGas Utilities Inc.

RATE RIDER "C"	DEEMED COST OF GAS RIDER

TO ALL TRANSPORTATION END-USER RATES AND TRANSPORTATION RETAIL END-USER RATES FOR THE DETERMINATION OF THE "DEEMED VALUE OF NATURAL GAS" FOR CALCULATION OF RATE RIDER "A" AND RATE RIDER "B" PAYABLE

To be applied to the volume of natural gas delivered to Transportation End-Use and Transportation Retail End-Use customers in the determination of municipal franchise tax payable (Rider "A") where applicable by Transportation End-Use and Retail Transportation End-Use customers in municipalities that have agreed to accept payment of a percentage of gross revenues of the special franchise pursuant to section360 of the *Municipal Government Act* R.S.A. 2000, c. M-26.

To be applied to the volume of natural gas delivered to the Transportation End-Use and Transportation Retail End-Use customers in the determination of Rider "B".

The "Deemed Value" is an amount equal to the arithmetic difference between:

Rate No. 11:

(a) The total variable charge of Rate No. 1 (calculated as the total of the Rate No. 1 Variable Base Charge plus Rider "D"); less
(b) The Variable Charge of Rate No. 11.

Rate No. 12:

(a) The total variable charge of Rate No. 2 (calculated as the total of the Rate No. 2 Variable Base Charge plus Rider "D"); less
(b) The Variable Charge of Rate No. 12.

Rate No. 13:

(a) The total variable charge of Rate No. 3 (calculated as the total of the Rate No. 3 Variable Base Charge plus Rider "D"); less
(b) The Variable Charge of Rate No. 13.

Rate No. 14:

(a) The total variable charge of Rate No. 4 (calculated as the total of the Rate No. 4 Variable Base Charge plus Rider "D"); less
(b) The Variable Charge of Rate No. 14.

EFFECTIVE DATE: May 1, 2005	REPLACING RATE EFFECTIVE: January 1, 1997	Page 1 of 2 RIDER "C"

AltaGas Utilities Inc.

RATE RIDER “D”	GAS COST RECOVERY RATE RIDER

TO ALL SALES SERVICE RATES FOR THE RECOVERY OF GAS COSTS

To be applied to the energy sold to all sales service rates unless otherwise specified by specific contracts.

The recovery of Gas Costs is subject to reconciliation based on actual experienced Gas Costs as approved by the Alberta Energy and Utilities Board.

Gas Cost Recovery Rate:

October 1, 2004 to October 31, 2004: $ 5.498 per GJ

EFFECTIVE DATE: Approved Monthly	REPLACING RATE EFFECTIVE: September 1, 2004	Page 1 of 1 RIDER “D”

AltaGas Utilities Inc.

RATE RIDER "E"	UNACCOUNTED-FOR GAS RIDER

Effective by Order U2004-404
On Transportation November 1, 2004
This Replaces Rider "E"
Previously Effective November 1, 2003

ALTAGAS UTILITIES INC.

RIDER "E"

TO ALL TRANSPORTATION END-USER RATES AND TRANSPORTATION CORE MARKET END-USER RATES FOR THE RECOVERY OF UNACCOUNTED-FOR GAS

All Transportation End-Use and Transportation Core Market End-Use customers must supply at the Point(s) of Receipt 101.03% of the Gas Taken at the Point(s) of Delivery, or in the alternative, must pay the Company a sum equal to 1.03% of the number of GJ taken at the Point(s) of Delivery multiplied by the applicable Gas Cost Recovery Rate.

EFFECTIVE DATE: November 1, 2004	REPLACING RATE EFFECTIVE: November 1, 2003	Page 1 of 1 RIDER "E"