



ATCO Pipelines

2010-2012 Revenue Requirement Settlement and
Alberta System Integration

May 27, 2010



ALBERTA UTILITIES COMMISSION

Decision 2010-228: ATCO Pipelines

2010-2012 Revenue Requirement Settlement and Alberta System Integration

Application No. 1605226

Proceeding ID. 223

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1 INTRODUCTION

1. On June 26, 2009 ATCO Pipelines (AP), a division of ATCO Gas and Pipelines Ltd., filed an application (Application or Integration Application) with the Alberta Utilities Commission (AUC or the Commission). AP had received Commission approval in Decision 2009-051¹ to negotiate its 2010-2012 General Rate Application (GRA) Phase I revenue requirements, subject to AP filing certain information with the Commission.² The Application sought a number of approvals from the Commission with respect to a proposal to integrate regulated gas transmission services in Alberta involving the AP and NOVA Gas Transmission Ltd. (NGTL) systems. The Application also included in section 5 thereof a request to approve AP's revenue requirement for each of 2010, 2011 and 2012 as may be negotiated with interested parties. Upon filing this Application, AP commenced revenue requirement settlement discussions with customers.

2. In order to streamline the provision of natural gas transmission services and address competitive pipeline issues in Alberta, AP and NGTL entered into the Alberta System Integration Agreement dated April 7, 2009 (Integration Agreement).³ The Integration Agreement requires AP and NGTL, subject to acceptable regulatory approvals, to swap ownership of certain physical assets within distinct operating territories or "footprints" in Alberta (Asset Swap), and to work together in Alberta under a single rates and services structure, while maintaining separate ownership, management and operation of their assets (Integration). NGTL would be the party that interfaces contractually with customers for regulated gas transmission services using the combined regulated AP and NGTL gas transmission systems within Alberta (collectively, the Alberta System). AP proposed that NGTL would include AP's approved revenue requirement, through a monthly charge by AP to NGTL (AP Charge), in NGTL's revenue requirement which will be collected from customers using the Alberta System. The total

¹ Decision 2009-051: ATCO Pipelines Request to Negotiate 2010-2012 General Rate Application Phase I (Application 1604425; Proceeding ID. 160) (Released: April 29, 2009).

² AP was required to file the following information (Decision 2009-051, paragraph 21):

1. General Rate Application for the 2010-2012 test years, including all supporting schedules (including 2008 actuals) before commencement of settlement discussions.

2. If a settlement is reached, AP is required to file a Settlement Brief that provides a detailed explanation of all issues settled and supporting schedules.

3. AP is directed to file a justification of the prudence of AP's actual 2008 and 2009 capital expenditures to be included in AP's opening balance for property, plant, and equipment (rate base). If a settlement is reached before AP's 2009 actuals are available, the Commission will not approve the opening balance for property, plant, and equipment in 2010 included within any settlement that may be reached, in which case AP must justify the prudence of its 2009 capital expenditures to be included in AP's opening balance for property, plant, and equipment in 2010 at its next GRA Phase I.

³ On September 8, 2008, ATCO Ltd. issued a news release indicating that AP and NGTL had reached a proposed agreement to provide seamless natural gas transmission service to customers. The Alberta System Integration Agreement, dated April 7, 2009, between AP and NGTL was attached as Appendix 1 to the Application.

Alberta System revenue requirement would therefore be composed of the AP revenue requirement approved by the Commission and charged to NGTL plus the NGTL revenue requirement approved by the National Energy Board (NEB). This would form the basis for the determination of Alberta System rates and tariffs for all customers. Regulatory approvals for Integration will also be required from the NEB and the federal Competition Bureau in order for Integration to take place.

3. As part of the implementation of the Integration, all AP contracts will be transitioned to Alberta System contracts with NGTL. A contract transition mechanism (Contract Transition Mechanism) is being developed by AP and NGTL in consultation with customers, to ensure that customer rights and obligations under AP contracts will be carried forward in NGTL Alberta System contracts.

4. AP referred to the following conditions precedent to Integration:

- receipt by AP of an acceptable approval from the Commission of the Application, receipt by NGTL of an acceptable approval from NEB of NGTL's Integration Application and receipt of an acceptable opinion from the Federal Commissioner of Competition; and
- an acceptable approval of AP's 2010, 2011 and 2012 revenue requirements which will be inputs into NGTL's revenue requirement.

5. On receiving their respective AUC and NEB approvals for the Integration, the parties will swap assets of equal value (i.e. AP will swap AP assets within the NGTL Footprint for NGTL assets within the AP Footprint, but excluding major NGTL throughput pipelines) estimated at approximately \$150 million.

6. The Application indicates that Integration is to occur on the "Integration Effective Date." The Integration Effective Date is estimated to occur 12 months from the date of receipt of the later of the AUC and NEB approvals. At this time the contracts would be transitioned, NGTL would start paying the AP Charge and regulated transmission service in Alberta would be coordinated. AP submitted that the swap of assets is estimated to occur within 18 months from the date of the later of each of the AUC and NEB approvals. Unless terminated as a result of the failure to comply with or waive conditions precedent, the Integration Agreement is to remain in effect for the life of the Alberta System facilities.

7. On July 10, 2009, the Commission issued the Notice of Application. Any party who wished to intervene in this Proceeding was to submit a Statement of Intent to Participate (SIP) to the Commission by the participation closing deadline of July 30, 2009.

8. The Commission received SIPs from the following parties:

- | | |
|--|--|
| • Alliance Pipeline Ltd. | • Gas Alberta Inc. (Gas Alberta) |
| • ATCO Gas North | • Industrial Gas Consumers' Association of Alberta (IGCAA) |
| • Aux Sable Canada Ltd. | • Imperial Oil Resources |
| • BP Canada Energy Company (BP) | • NOVA Chemicals Corporation (NCC) |
| • Canadian Association of Petroleum Producers (CAPP) | • Nexen Marketing |
| • The City of Calgary (Calgary) | |
| • Consumers' Coalition of Alberta | |

- | | |
|---------------------------------|---------------------------|
| (CCA) | • NGTL |
| • ConocoPhillips Canada Limited | • TransAlta Corporation |
| • ENMAX Energy Corporation | • Talisman Energy Inc. |
| • ExxonMobil Canada Ltd. | • Office of the Utilities |
| • EnCana Corporation | Consumer Advocate (UCA) |

9. In a letter dated September 25, 2009, the Commission deferred setting a process schedule with regard to the Application. The Commission noted that revenue requirement settlement negotiations were underway and that it would be more efficient to establish a regulatory process that would include both the Integration component and any settlement reached regarding AP's Revenue Requirement.

10. On November 12, 2009, AP applied under section 28.53 of the *Alberta Gas Utilities Act*, R.S.A. 2000, c.G-5, as amended and in accordance with [AUC Rule 018: Rules on Negotiated Settlements](#) (Rule 018) (Settlement Filing), for approval of a 2010-2012 Revenue Requirement Settlement (Settlement or Settlement Agreement), which is attached to this Decision as [Appendix 2](#).⁴ AP submitted that the Settlement assumed approval of Integration, was a product of negotiations between AP and interested parties, represented an acceptable balance of interests amongst the parties, and was in the public interest. AP further submitted that the Settlement reflected compromises by diverse interests. Consequently, the components of the Settlement were linked and should be considered by the Commission for approval as a single package. The following parties were signatories to the Settlement:

- | | |
|-----------|---------------|
| • AP | • IGCAA |
| • Calgary | • UCA |
| • CAPP | • Gas Alberta |
| • CCA | |

11. Under the Settlement, AP's initial revenue requirement forecasts were \$211,782,000 for 2010, \$207,482,000 for 2011 and \$215,182,000 for 2012. The final revenue requirements for each year are subject to various terms agreed to in the Settlement.

12. In a letter dated December 2, 2009, the Commission established a process schedule with regard to the Application and the Settlement. The Commission described AP's requested approvals as follows:

- (i) issue an Order, pursuant to section 22 of the *Gas Utilities Act*, declaring Integration to be in the public interest and convenience and providing approval for AP to proceed with implementing Integration (AUC Step 1);
- (ii) approve, pursuant to section 36 of the *Gas Utilities Act* (AUC Step 2):
 - (a) the AP revenue requirements for 2010, 2011 and 2012, as set out in the Settlement; and
 - (b) the AP Charge payable by NGTL to AP as of the Integration implementation date and equal to the AP revenue requirement as approved under (a);

⁴ Exhibit 61.

- (iii) approve, pursuant to sections 22 and 36 of the *Gas Utilities Act* the transitioning of AP contracts to NGTL Alberta System contracts, effective on the Integration implementation date, in accordance with the Application (Contract Transitioning);
- (iv) approve, pursuant to section 26 of the *Gas Utilities Act*, the sale of AP assets to NGTL to effect a swap of assets between AP and NGTL, as reflected in the Integration Agreement; and
- (v) provide such further and other relief as AP may request or the Commission may deem appropriate.

13. In its letter of December 2, 2009, the Commission determined that the process schedule would address only AUC Steps 1 and 2 of AP's requested approvals. The Commission stated that the remaining requested approvals appeared to be subject to further refinement and the Commission expected that those would be examined in future application processes.

14. In a letter dated December 2, 2009, AP requested that the Commission include item (iii) Contract Transitioning and approval in principle of item (iv) in the current process.

15. In support of its request, AP filed a copy of section 2.7 of NGTL's November 27, 2009 application with the NEB. The NGTL application requested approval of a rate design methodology, terms and conditions of services, and the Integration of the AP System with the NGTL System. The NGTL application also described how Contract Transitioning of all existing AP's service contracts into NGTL Alberta System service agreements would occur.

16. In light of the new evidence filed by AP, the Commission indicated, in a letter dated December 4, 2009 revising the schedule, that it was amenable to expanding the scope of this proceeding to include item (iii) Contract Transitioning. The Commission also confirmed that any explicit approval related to AP's swap of assets with NGTL, item (iv), would be the subject of a future detailed application to be filed with the Commission.

17. The process schedule was revised as follows to include the matter of Contract Transitioning:

Revised Process Schedule

Activity	Due Date
Information Requests to AP on AUC Steps 1 & 2	December 9, 2009
ATCO Pipelines and NGTL Evidence on Contract Transitioning (Item iii)	December 14, 2009
Information Responses from AP on AUC Steps 1 & 2	December 21, 2009
Information Requests to NGTL and AP on Evidence of Contract Transitioning (Item iii)	January 14, 2010
Information Responses from AP and NGTL on Contract Transitioning (Item iii)	January 22, 2010
Argument	February 12, 2010
Reply Argument	February 26, 2010

18. The Commission considers that the record for the proceeding closed on February 26, 2010. The division of the Commission assigned to the proceeding was Carolyn Dahl Rees (Vice-Chair), N. Allen Maydonik Q.C.,⁵ and Thomas McGee.

2 BACKGROUND

19. In Decision 2009-051 the Commission granted the application by AP to negotiate its 2010-2012 Phase I revenue requirement subject to certain matters which were precluded from discussion in the settlement negotiation. Specifically, the Commission did not allow discussion or negotiations regarding:

- i. the Competitive Pipeline Review proceeding (Application 1466609),
- ii. the Utility Asset Disposition Rate Review proceeding (Application 1566373, Proceeding ID. 20),
- iii. issues related to certain salt cavern assets as described in Application 1527976 (Identified Salt Cavern Assets),
- iv. ATCO Utilities 2003-2007 Benchmarking and I-Tek Placeholders True Up (Application 1562012, Proceeding ID. 32), and
- v. ATCO Utilities Evergreen Application (Application 1577426, Proceeding ID. 77).

20. In a letter dated June 17, 2009, AP requested “confirmation from the Commission that the restrictions imposed on its negotiated settlement process regarding the Identified Salt Cavern Assets, as non-utility assets, are lifted, so that AP’s 2010, 2011 and 2012 revenue requirement negotiations can reflect the removal of the Salt Caverns assets from rate base.” AP’s request followed the Alberta Court of Appeal decision in *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246 (Appeal Decision), which addressed the Identified Salt Cavern Assets and the requirement of the Commission of an application by AP under section 26(2)(d) of the *Gas Utilities Act* prior to the withdrawal of the Identified Salt Cavern Assets from rate base. In the Appeal Decision the Court stated that ceasing to use an asset for utility purposes does not involve or require a section 26 application.⁶

21. In light of the Appeal Decision, the Commission in Decision 2009-111⁷ removed the restriction imposed by Decision 2009-051 with respect to the negotiation of issues related to the Identified Salt Cavern Assets in AP’s 2010, 2011 and 2012 revenue requirement negotiations. However, the Commission specified certain filing requirements in the event that the parties negotiated a revenue requirement which did not include the Identified Salt Cavern Assets and stated:

5. ...In the event that the Identified Salt Cavern Assets and associated costs are not included in any resulting 2010-2012 revenue requirement settlement agreement, the settlement agreement

⁵ Deceased May 16, 2010.

⁶ Please refer to paragraph 56 of the Appeal Decision.

⁷ Decision 2009-111: ATCO Pipelines Request to Remove Restriction Related To Identified Salt Cavern Assets Decision 2009-051: Approval to Negotiate 2010-2012 Revenue Requirements (Application 1605226, Proceeding ID. 223) (Released: July 24, 2009).

or the accompanying application for approval of the settlement must provide the following information to enable the Commission to assess the prudence of the removal of the Identified Salt Cavern Assets from rate base and the associated costs from revenue requirement, and the public interest impacts of the settlement agreement:

- a narrative description of how the Identified Salt Cavern Assets have been dealt with in the settlement and in the proposed revenue requirement;
- confirmation that the Identified Salt Cavern Assets are not being sold, leased or otherwise disposed of;
- the rationale for exclusion of the Identified Salt Cavern Assets as well as an assessment of the impacts to present and future utility service as a result of the removal of the assets from utility service;
- a business case analysis with respect to how future transmission capacity requirements that might have been accommodated through the development of additional salt caverns using the land and mineral interests included within the Identified Salt Cavern Assets are anticipated to be addressed in the absence of these assets. The business case will include an assessment of the comparative costs of providing the needed capacity through the development of additional salt caverns using the Identified Salt Cavern Assets versus the construction of new pipelines or compression;
- a detailed listing of all assets, their gross and net values and vintages which are recorded in accounts 451 through 459, Underground Storage Plant, remaining after the removal of the Identified Salt Cavern Assets;
- an explanation of how servicing and maintaining the integrity of the salt caverns which will remain in regulated service will be accomplished without the use of the water pipeline and related facilities included within the Identified Salt Cavern Assets;
- an accounting of the revenue requirement and rate base adjustments as a result of the removal of the Identified Salt Cavern Assets from rate base and utility service: and
- confirmation that no costs associated with any of the Identified Salt cavern Assets, including costs of decommissioning, salvage, reclamation or any similar expense relating to any of these assets will remain in AP's revenue requirement.

6. The Commission will consider the above information and also take into consideration the terms of any settlement agreement in considering prudence and the public interest. The fact that a settlement agreement may exclude the Identified Salt Cavern Assets will not in and of itself be considered as determinative of the prudence and public interest issues.⁸

22. In the November 12, 2009 Settlement Filing AP confirmed that agreement could not be reached on the treatment of the "Salt Cavern Surplus Assets"⁹ and that the costs referred to in Decision 2009-051 were not removed from rate base or revenue requirements in the Settlement.

⁸ Decision 2009-111, paragraphs 5 and 6.

⁹ The Commission assumes for the purpose of this Decision that the terms "Salt Cavern Surplus Assets" and "Surplus Assets" used by AP refer to the same assets as the "Identified Salt Cavern Assets" as referenced in Decisions 2009-111 and 2009-253 and the correspondence referred to in paragraphs 24, 25, and 26 of this Decision.

23. In AUC-AP-4(a) dated December 21, 2009 AP referred to Decision [2009-253](#)¹⁰ and stated:

In summary, consistent with Decision 2009-253, AP requests that the Commission now confirm that the Surplus Assets are not used or required to be used for utility service and are removed from rate base effective January 1, 2010.

While the issue of any required prudence review with respect to the Surplus Assets remains, AP submits that such a review can be conducted in the course of the present proceeding. To that end, AP proposes that:

- (i) the Commission conduct any required prudence review related to the Surplus Assets in the context of the present Settlement approval process, with input from interested parties as appropriate;

24. Following the issuance of additional information requests by the Commission, AP notified the AUC in a letter dated January 18, 2010 that it was withdrawing its proposal to address the Identified Salt Cavern Assets issue in the context of this proceeding. AP stated that “[i]ncorporating the Surplus Assets issue into the present proceeding will thus entail delay to the present Integration proceeding, an outcome that AP cannot support.” AP indicated that it had canvassed all other parties to the Settlement and all except Calgary, which had not responded, were in agreement that the present proceeding should not be delayed and that the Identified Salt Cavern Assets issue should be dealt with in a separate proceeding. AP clarified that dealing with the Identified Salt Cavern Assets issue in a subsequent proceeding was entirely compatible with the Settlement and that no amendment of the Settlement was required given that the Identified Salt Cavern Assets issue was assigned a placeholder in the Settlement.

25. On January 21, 2010 the Commission received Calgary’s letter in which it submitted that if the Commission was inclined to accept and approve AP’s January 18th request and proposal that the Identified Salt Cavern Assets should be dealt with in a separate proceeding, “that approval should be subject to the express condition that the separate proceeding should be a rate-setting or GRA type of proceeding.” Calgary added that it agreed with parties that the present proceeding should continue without delay, insofar as it related to the timely disposition of the negotiated settlement on revenue requirement.

26. In a letter dated January 22, 2010, the Commission agreed with all parties that the present proceeding should not be delayed as a result of any issues regarding the Identified Salt Cavern Assets. The Commission granted AP’s request to deal with the Identified Salt Cavern Assets in a separate, subsequent proceeding. Given that the removal of Identified Salt Cavern Assets would constitute a change to revenue requirement which would ultimately be reflected in a change to rates, the Commission considered that any such Identified Salt Cavern Assets proceeding would be a rate-setting proceeding. The Commission concluded by stating:

7. As per AP’s suggestion that the issues relating to the Surplus Assets be resolved by way of a separate proceeding, AP is directed to file a separate application with the Commission in order to resolve these outstanding matters. To enhance the efficiency of the consideration of such

¹⁰ Decision 2009-253: ATCO Gas South Review and Variance Proceeding Of Decision 2009-004 and Decision 2009-067 (Removal of Carbon Related Assets from Utility Service) (Application No. 1605365, Proceeding ID. 281) (Released: December 16, 2009).

an application, the application should address the information requests filed in this proceeding relating to the Surplus Assets.

27. On December 11, 2009 AP filed an application¹¹ seeking approval of 2010 Interim Revenue Requirements for AP North and AP South and Revised Rate Schedules, effective January 1, 2010 or February 1, 2010. AP included revised 2010 Settlement revenue requirements based on an updated forecast for capital expenditures, capital additions, construction work in progress (CWIP), and depreciation expenses for 2009 and 2010.¹² These revisions had been presented at the November 27, 2009 AP annual meeting with customers.

28. On January 22, 2010, the Commission issued Decision [2010-038](#),¹³ which approved a 2010 interim revenue requirement and 2010 interim rates effective February 1, 2010.

3 ISSUES

29. The Commission notes that no parties objected to the proposed Integration and the Settlement was unopposed.

30. With respect to the Settlement, CAPP initially disagreed with AP on the interpretation of two clauses of the Settlement, Clause 2 (Cost of Capital) and Clause 9 (Audit Provision). AP and CAPP later agreed on the treatment of Cost of Capital¹⁴ but not on the costs of an audit.

31. While all parties expressed support for the fundamental purpose and principles of Integration, some interveners expressed concerns with details respecting Contract Transitioning, gas quality, a future contract between ATCO Gas and NGTL, impact of Integration on straddle plant owners, the proposed purchase of line pack, and the proposed Asset Swap with NGTL. Specifically, the Commission notes the following comments from interveners:

- The UCA expressed concern with respect to a new contract between NGTL and ATCO Gas that would be required given NGTL's proposed new role in providing transmission service to ATCO Gas under Integration. The UCA added that a process be established for parties affected by the new NGTL and ATCO Gas transportation agreement to examine the agreement and request further details and information related to the agreement, including but not limited to the NGTL Quality of Gas provisions and the impact on ATCO Gas and its customers.
- Gas Alberta submitted that Integration was in the public interest and that the Commission should provide approval to ATCO Pipelines to proceed. Gas Alberta argued that the Commission should only grant approval in principle to the Asset Swap and the proposal to purchase line pack from customers, with final approval only upon finalization of the details of Integration upon subsequent scrutiny from customers and the Commission.
- CCA submitted that it could not provide unqualified support for Integration and recommended that the AUC make only a conditional or qualified declaration of "public convenience" because the detailed surrounding the asset swaps was outstanding. CCA

¹¹ Application No. 1605716, Proceeding ID. 424.

¹² CWIP was only applied for the year 2009.

¹³ Decision 2010-038: ATCO Pipelines 2010 Interim Revenue Requirement and 2010 Interim Rates (Application No. 1605719, Proceeding ID. 424) (Released: January 22, 2010).

¹⁴ Exhibit 124.01, CAPP Reply Argument, page 1; and Exhibit 128.01, ATCO Pipelines Reply Argument, page 6.

also submitted that AP should be directed to provide further details with respect to gas quality issues. The CCA considered that the line pack issue should be considered as part of a new and separate application dealing with the one-time purchase referenced by AP.

32. Other issues raised by parties included:

- NOVA Chemicals Corporation argued that the elimination of stacked tolls should apply to all customers of AP and NGTL, and should therefore include the NPS¹⁵ 16 Joffre Ventures Pipeline.
- BP argued that Integration and the Settlement were not linked and that the Commission was free to approve one and not the other. BP argued that prior to final approval of Integration further clarity and resolution is required with respect to ATCO Straddle Plant Delivery contracts and associated impacts on others

33. In reaching the determinations set out in this Decision, the Commission has considered the record of this proceeding, including the Argument and Reply Argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider other relevant portions of the record with respect to that matter.

4 SETTLEMENT PROVISIONS

34. Under the Settlement, AP's initial forecast revenue requirements were \$211,782,000 for 2010, \$207,482,000 for 2011 and \$215,182,000 for 2012. The revenue requirements were calculated as detailed in the schedules included as Attachments 2.1, 2.2 and 2.3 of the Settlement. Attachments 2.1, 2.2 and 2.3 of AP's Integration Application were the basis for the Settlement schedules, with revisions to reflect the Settlement.

35. In the Settlement Filing, AP indicated that it does not expect to file a GRA Phase II given the contemplated Integration with NGTL. AP stated that following approval of the Settlement, AP would file for 2010 rates on a basis consistent with the methodology used in calculating 2009 rates, as approved by the Commission in Decision [2009-110](#).¹⁶

36. AP requested that the Commission approve the Settlement and the Integration Application in their entirety.

37. The terms of the Settlement are provided below:¹⁷

1. Overview

The Settlement includes all aspects of ATCO Pipelines' ("AP") 2010-2012 revenue requirement, except for issues addressed in the following proceedings:

- The Competitive Pipeline Review proceeding (Application 1466609);

¹⁵ Nominal Pipe Size.

¹⁶ Decision 2009-110: ATCO Pipelines 2008-2009 Rate Compliance Filing to Decision 2009-033 (Application No. 1604966, Proceeding ID. 187) (Released: July 29, 2009).

¹⁷ AP letter of November 12, 2009, Attachment 1, pages 1-6 of 7.

- The Utility Asset Disposition Rate Review proceeding (Application 1566373);
- Issues related to certain salt cavern assets (Application 1527976);
- ATCO Utilities 2003-2007 Benchmarking and I-Tek Placeholders True Up (Application 1562012);
- ATCO Utilities Evergreen I Application (Application 1577426);
- ATCO Utilities Evergreen II Application (Application 1605338); and
- ATCO Utilities Pension Common Matters Application (Application 1605254).

Should a decision by the Alberta Utilities Commission (“AUC”), after any review and variance or appeal process is completed, relating to any of the foregoing proceedings result in approved costs that are different from the costs in this Settlement, then that difference will be captured in a deferral account to be addressed in AP’s revenue requirement for the next year.

Section 5 of AP’s Alberta System Integration Application filed on June 26, 2009 forms the base point with respect to the Settlement, and is modified as per the Settlement provisions outlined herein.

“Flow through” items are items that either: (i) have offsetting revenues and expenses (e.g. franchise fees); or (ii) have the difference between the actual amount and forecast amount placed in a deferral account for collection from or refund to customers at a later time (e.g. hearing costs, Integration costs/savings).

Proper notice of the Settlement proceedings was provided by AP to all interested parties.

2. Cost of Capital

- (a) Return on Equity (“ROE”) will be set at the final rate for ATCO Pipelines (AP) determined by the AUC in its final decision after any reviews or appeals (the “GCOC Decision”) in its Generic Cost of Capital proceeding (Application No. 1561663, Proceeding No. 15) if the GCOC Decision provides an explicit ROE or formula that is applicable to each year of this Settlement. If the GCOC Decision does not provide an ROE or formula that is applicable to each year of this Settlement, the ROE for those years will be set at the last approved ROE set by the GCOC Decision for AP.
- (b) The equity ratio for each year of the Settlement will be deemed to be as follows:
 - (i) For 2010 and 2011, the pre-Integration equity ratio set for AP by the AUC in the GCOC Decision.¹⁸

¹⁸ Exhibit 128.01, ATCO Pipelines Reply Argument, pages 6-7: With respect to Clause 2 (Cost of Capital), AP has had discussions with CAPP to ensure a common interpretation (“Common Interpretation”), as described below. The Common Interpretation was forwarded to the other signatories to the Settlement and all have advised that they do not oppose the Common Interpretation. As such, this should be the interpretation that governs Clause 2 and the one on which any Commission approval of the Settlement is based. In AUC-AP-6(d), AP noted that the Settlement ROE applicable to 2011 and 2012 will be the ROE or formula set in the

- (ii) The equity ratio for 2012 will be:
 - (1) any post Integration equity ratio set for AP by the AUC in the GCOC Decision; or
 - (2) if the equity ratio for AP in the post Integration period is not set by the GCOC Decision, the equity ratio set by an AUC decision for 2012 resulting from an AP application for a post Integration equity ratio filed no later than September 1, 2011.
- (c) The impact on debt costs, both in the quantum and changed debt rate, as a result of any change in equity ratio will be treated as “flow through”.
- (d) No party is constrained by this Settlement from appealing or requesting a review and variance of the GCOC Decision.
- (e) For greater certainty, to the extent that any equity ratio specified for AP in the GCOC Decision conflicts with any equity ratio specified for AP in this Settlement in clause 2(b), the equity ratio specified in this Settlement shall prevail.
- (f) The discussion in clause 2(b) regarding a potential AUC decision on a post Integration equity ratio for AP in the GCOC Decision does not reflect any agreement by AP or any other party to the Settlement as to whether or not the GCOC Decision should address a post Integration equity ratio for AP and all parties acknowledge the entitlement of any party to appeal or review a decision which sets a post Integration equity ratio for AP.

3. **O&M**

- (a) The total 2009 Estimate Operating & Maintenance (“O&M”) amount of \$65,094,000 in Schedule 2.1-6 of the Integration Application (which amount is the base for calculating O&M for 2010 to 2012) will be reduced by \$500,000. The reduction will be allocated 35% to “Base Utility Labour” and 65% to “Base Utility Supplies”. These amounts will be further allocated two thirds North and one third South in Schedules 2.2-13 and 2.3-13 respectively. Labour costs, net of flow-through items, will increase by the forecast percentage change in the Alberta Consumer Price Index (“CPI”) as provided by the Conference Board of Canada released in the fourth quarter each year plus 2.0% for each year of the

Commission’s announced 2011 proceeding. The Common Interpretation is consistent with this position. In AUC-AP-6(e) (Revised), AP confirmed its understanding that the final equity ratio for 2011 would remain at 45 percent, but noted that this was based on AP’s understanding that the 2011 proceeding referred to by the Commission would not be reviewing AP’s equity ratio prior to Integration (this was based on paragraph 392 of Decision 2009-216 where the Commission noted that it would re-evaluate AP’s business risk following Integration). In accordance with the Common Interpretation, AP supported the position that the Settlement Equity Ratio for 2011 and 2012 can be determined in the Commission’s announced 2011 proceeding, provided that any equity ratio for 2011 shall not take into account any impact of Integration—i.e. it will be based on AP’s pre-integration status. Should the Commission’s 2011 proceeding not determine an Equity Ratio for 2012, the Settlement Equity Ratio applicable to 2012 will be set in a future Commission proceeding after application by AP. The Equity Ratio for 2012 will take into account the impact of Integration. This footnote is provided to clarify the interpretation of Clause 2 and is not part of the terms of the Settlement as per footnote 17.

Settlement period to account for steps, promotions, progression and growth. Supplies costs, net of flow-through items, will be inflated by the forecast percentage change in the CPI for each year of the Settlement.

- (b) O&M costs and savings resulting from Integration, as shown as separate line items under Base Utility Labour and Base Utility Supplies in Tables 2.1-6, 2.2-13 and 2.3-13 and more fully described in AP's responses to CAPP-AP-17 (Revised), UCA-AP-3(a) (Revised) and CCA-AP-8(d), attached hereto as Attachment 1, will be treated as "flow-through".
- (c) Pension and Hearing costs will be as determined for each year by the AUC and will be "flow through".
- (d) NGTL Tolls incurred by AP will be "flow through".

4. Depreciation

- (a) In the month of November in each of 2009, 2010 and 2011, depreciation for the following year will be recalculated using the revised forecast rate base and capital additions forecast for the following year. The depreciation rates and accumulated depreciation reserve adjustment, where applicable, by asset account or the lowest asset class level for "non-study" assets (i.e. software, leaseholds and specific facility contracts) separately for North and South will be the same as rates in place in 2009 based on the most recent depreciation study subject to agreed to changes in the last negotiated settlement agreement. The "non-study" asset depreciation is also subject to no "over-depreciation" of non-depreciation study assets (i.e. software, leaseholds and contracts).
- (b) Details of depreciation rates for leaseholds, computer software and other non-depreciation study assets will be provided annually.

5. Income Tax

AP agrees that for calculating income taxes for 2010, 2011 and 2012, it will use the methodology used in preparing its 2009 general rate application in determining the eligibility of the deductibility of 2010, 2011 and 2012 costs. This agreement is for the purposes of the Settlement only and does not constitute agreement by any party to a particular position or methodology. AP and/or parties may bring forward issues related to the eligibility of the deductibility of costs that affect 2010, 2011 and 2012 UCC balances in any negotiation or hearing process as they relate to AP's next GRA.

6. Taxes Other than Income Taxes

- (a) Franchise fees will be treated as "flow through".
- (b) The property tax forecast will be set at \$12.3 million for 2010, \$12.9 million for 2011 and \$13.6 million for 2012 and will be treated as "flowthrough".

7. Significant Legislative Changes

The impact of legislative changes that impact earnings by greater than \$1 million, plus or minus, in a given year will be placed into a deferral account and cleared using the same methodology as other deferral accounts.

8. Revenues

- (a) Consistent with the Integration proposal, AP revenues for any part of the 2010 – 2012 time frame will be treated as “flow through”.
- (b) Upon the transfer of customers, NGTL will be billed by AP for inclusion of AP’s revenue requirement in NGTL’s revenue requirement. Parties acknowledge there may be other costs billed by AP to NGTL that are outside of the approved revenue requirement but are nevertheless approved by the AUC (e.g. Franchise Fees).

9. Audit Provision

Parties to the Settlement have the right to request an external audit of the Settlement, such audit to be performed by June 30, 2014. This audit will verify compliance by AP with the terms of the Settlement. AP will provide reasonable access to all necessary source data. If AP is found to be in material (i.e. in excess of plus or minus \$500,000) breach of a clause of this Settlement, the cost of the audit will be borne by AP. If AP is not found to be in material breach of a clause of the Settlement, the cost of the audit will be paid by AP and placed in a deferral account, with such cost to be added to AP’s revenue requirement in the subsequent year.

10. Capital Expenditures

- (a) In the month of November in each of 2009, 2010 and 2011, an update of the forecast for capital expenditures, capital additions and construction work in progress (“CWIP”) for the current year and the capital expenditures and capital additions planned for the upcoming year will be reviewed with customers and filed with the AUC for approval of the upcoming year amounts. This updated forecast information will be used to determine the opening forecast rate base for the following year and to adjust the return, income tax and depreciation expense components of revenue requirement for the following year.
- (b) Business cases for capital projects for the upcoming year greater than \$500,000 will be provided as part of the November review and filing to the AUC.

11. Rate Base

Opening 2010 rate base will be based upon the 2009 actual closing balance, to be subsequently adjusted (in the opening balances for 2011 or 2012) by any placeholders (see clause 1 above) subsequently approved by the Commission for December 31, 2009.

12. Line Pack

As part of the Integration Application, AP has applied to the AUC to purchase the line pack in its pipelines as per the agreement with NGTL. If regulatory approval of the line pack purchase is received (as part of the Integration Application), AP will pay the AUC approved value to its customers in the year in which the line pack is purchased but in any case prior to the transfer of customers to NGTL and place this value in Necessary Working Capital.

13. No Precedent

Nothing in the Settlement shall set a precedent nor shall it prejudice any position any party may take regarding the matters addressed in the Settlement in other proceedings at any time.

14. Confidentiality

All information exchanged in the Settlement process is confidential and is provided on a without-prejudice basis. AP shall be entitled to file the Settlement with the Commission.

15. Settlement Package

This Settlement represents a balancing of interests by the parties to the Settlement and no single component can be said to be acceptable to any party independent of the entire Settlement. The parties to this Settlement agree that approval of this Settlement, in its entirety as a package, is a requirement for the Settlement to be binding on any party.

16. Definitive Agreement

Notwithstanding any provision within the definition of “ATCO Initial Revenue Requirement” in the Alberta System Integration Agreement between AP and NGTL, AP shall advise NGTL that it will apply for regulatory approval of the ATCO Initial Revenue Requirement on a basis consistent with this Settlement.

17. Annual Interim and Final Revenue Requirement Process

After the annual November meeting with customers, AP will file an application for regulatory approval of items resolved at the November meeting. The application will also include inputs such as inflation rates, CCA [capital cost allowance] rates, and income tax rates for information only. AP will file for interim revenue requirements, and interim rates if required, to be effective January 1 of the following year.

In May of each year, AP will file an application to finalize the revenue requirement for that year. This application will clear the deferral account balances. In 2010, the only deferral account balance to be cleared is the Transition expense deferral account balance as at December 31, 2009. All deferral accounts are to be cleared each year once Integration is implemented. The 2010 final revenue requirement application will also include adjustments to 2010 opening rate base to reflect the 2009 actual closing balances (see clause 11 above).

The revenue requirements will be calculated using the schedules included in Attachments 2.1, 2.2 and 2.3 of AP’s Alberta System Integration Application filed on June 26, 2009, as revised and included as Attachments 2.1, 2.2 and 2.3 to this Settlement.

18. Reporting Package

- (a) AP will provide the AUC annual financial reporting package, which includes a deviation analysis, augmented to provide, with respect to O&M, the three categories on Schedule 3 split between labour and supplies and with respect to labour and supplies to provide the breakdown of the costs by prime account with explanations of deviations/variances greater than 5% between current year and prior year, plus explanation of all variances in the flow-through items between forecast and actual pension, Integration and NGTL charges.
- (b) At the annual November meeting (see clause 10 above), Capital Expenditures, Capital Additions and supporting business cases, as required, will be provided in the 5 categories as identified in the Integration Application.

5 DISCUSSION OF SETTLEMENT ISSUES

5.1 Legislation and Commission Rules

38. AP stated that the Application was being made under section 28.53 of the *Gas Utilities Act*, and in accordance with AUC Rule 018 for approval of the Settlement in its entirety.

39. A number of provisions in applicable legislation and in the AUC's Rule 018 apply to the Commission in relation to negotiated settlements. For ease of reference these are set out in [Appendix 3](#) of this Decision.

40. AP requested that the Commission approve the Settlement and the Integration Application in its entirety. The Settlement was the product of an extensive process and negotiations between AP and interested parties, assumed approval of Integration, and represented an acceptable balance of interests amongst the parties. The results reflect compromises by diverse interests. Consequently, the parties to the Settlement agreed that approval of the Settlement, in its entirety as a package, is a requirement for the Settlement to be binding on any party. AP stated that the components of the Settlement are inextricably linked and should be considered as a single package for approval by the Commission.¹⁹

41. Given that the Settlement was negotiated on the basis that it must either be accepted or rejected contingent upon the Commission accepting it in its entirety, section 28.6 of the *Gas Utilities Act* requires the Commission to either accept or reject the settlement on that basis in this Decision.

42. Section 8 of AUC Rule 018 specifically addresses unanimous or unopposed settlements. Section 8(1) indicates that the Commission must assess whether such a settlement results in rates and terms and conditions that are just and reasonable. Section 8(2) requires the Commission to intervene if it determines that a unanimous settlement is patently against the public interest or contrary to law.

43. The Alberta Court of Appeal in *ATCO Electric Limited v. Alberta (Energy and Utilities Board)*, 2004 ABCA 215 commented on the Alberta Energy and Utilities Board's (EUB or Board) settlement Guidelines, which were the precursor to AUC Rule 018, and provided guidance with respect to the Board's obligations in considering settlement agreements. At paragraphs 138-139 of that Decision the Court stated:

[138] The ultimate responsibility for approving negotiated settlements - and ensuring that the process operates in a fair and reasonable manner - must rest with an independent body. That body is the Board....

[139] Thus, as long as the distribution and transmission functions of electric utilities remain regulated, the negotiated settlement process does not replace an appropriate and informed review by the Board as to what is in the overall public interest. Otherwise, members of the consuming public may rightly ask: "Who's protecting our interest?" The answer, at the end of the day, is the Board. That is why negotiated settlements require Board approval. And it is also why the Board's discretion in controlling rates as mandated by statute cannot be fettered by a negotiated settlement...

¹⁹ Exhibit 61.01, 2010-2012 Revenue Requirement Settlement, page 2.

[...]

[145] First and foremost, when a utility concludes a negotiated settlement and applies, as it is required to do, for Board approval, the Board is entitled to assume that what the utility has negotiated and agreed to is in fact in the utility's best interests. After all, it is difficult to conceive of any party more capable of negotiating the best possible arrangement for a utility than the utility itself. Here, ATCO is a sophisticated corporate investor with ready access to trained personnel and expert assistance in a wide range of highly technical areas. Who better to decide what is in ATCO's interests than ATCO?

[146] That means in determining whether a negotiated settlement submitted for approval by a utility is in the public interest and whether the rates and tariffs therein are "just and reasonable", the Board is not obliged at this point to consider whether the settlement adequately protects the utility's interests. The Board is instead entitled to proceed on the basis that the negotiated settlement fully satisfies the utility's interests. Thus, the Board need only assess the public interest from the perspective of the consuming public.

44. The Court of Appeal also provided the Board with guidance in defining the nature of the public interest to be considered in assessing whether to approve a negotiated settlement and in assessing whether the resulting proposed tariff is just and reasonable. The Court determined that the public interest to consider with respect to both approval of the settlement and approval of the rates and tariffs is the same.

45. The Commission noted a prior Board discussion of unopposed settlements in Decision [2008-133](#)²⁰ as follows:

The Guidelines and subsequent amendments have been considered in several Board and Alberta Court of Appeal decisions. Decision [2000-85](#)¹⁶ considered the 1998 version of the Guidelines at page 6 and outlined the approach to be utilized by the Board when reviewing a unanimous settlement:

In a consensus settlement, the Board considers that two main questions arise. First, the Board must examine the settlement process to ensure it was fair and in accordance with the criteria set out in the Negotiated Settlement Guidelines. In particular, the Board considers that it should be satisfied that proper notice has been provided, no negative response was received to the notice for objections, due process has been provided to participants by allowing for meaningful participation in the process including the funding of interveners' participation, Board staff has participated as an observer in the settlement discussions, and all parties expressing an interest have signed off on the settlement.

Second, the Board must evaluate the settlement to determine whether there are elements which, in the Board's view, could result in rates which are not just and reasonable. In exercising this discretion, the Board believes that it should proceed with caution. The Board is charged with determining whether the settlement will result in rates that are just and reasonable. However, the Board acknowledges that if a settlement is changed in a way that is significant to the parties, it could prove

²⁰ Decision 2008-133: NOVA Gas Transmission Ltd. 2008-2009 Revenue Requirement Settlement Application (Application No. 1566927, Proceeding ID. 23) (Released: December 17, 2008) page 5.

detrimental to that agreement and any future settlements. The Board is mindful that in a package settlement compromises are struck that underpin the acceptability of the agreement among the parties, the importance of which may not be readily apparent to the Board. However, if a review of the settlement, including the possible empanelling of witnesses, reveals provisions that are patently against the public interest, the Board must act to change the agreement. To do otherwise would result in rates that are not just and reasonable. It may do that in a number of ways, including sending the settlement back to enable parties to deal with certain issues before the Board decides, deny the application citing the areas of concern, or direct that the settlement be litigated.

The Board recognizes that when unanimous settlements agreed to by all the interested parties are presented to it, it should restrain any inclination to alter the consensus settlement solely on the basis that it may have done things differently. It is only in circumstances where the settlement is patently against the public interest or contrary to law that the Board should intervene.

¹⁶ Decision 2000-85, Northwestern Utilities Limited Approval of Rates, Tolls, Charges, and Terms and Conditions of Service for Core Customers, and Approval of Amendments to the North Core Agreement (Application 2000297) (Released: December 22, 2000) pp. 3-8

46. Accordingly, in assessing whether or not to approve the Settlement, the Commission must accept or reject the Settlement in its entirety, and in so doing must consider the fairness and public interest factors with the objectives of determining:

- i. If the process resulting in the Settlement was fair; and
- ii. If approval of the Settlement will lead to rates and terms and conditions that are just and reasonable. In making this determination the Commission will consider if the Settlement is patently contrary to the public interest or is contrary to law.

5.2 Fairness of the Negotiated Settlement Process

47. As noted in the previous section, the first question for the Commission to consider is whether the settlement process was fair. This section describes the circumstances related to AP's negotiation of its 2010-2012 GRA Settlement.

48. With regard to the settlement negotiation process, AP submitted that it met the requirements for proper notice as stated in Rule 018.²¹

49. With regard to notice, AP in its Settlement Filing dated November 12, 2009 stated:

On June 15, 2008, AP published notices in the Calgary Herald, the Calgary Sun, the Edmonton Journal, and the Edmonton Sun inviting interested and affected parties to participate in AP's Settlement Negotiations (Attachment 3).

²¹ These provisions are found in section 3 of Rule 018 and are set out in Appendix 3.

On June 17, 2009 AP provided notice to participate in AP's Settlement Negotiations to a list of over 270 interested parties provided to AP by the Commission. (Attachment 4). AP also posted notice of the meeting on its Website.

Clause 1 of the Settlement contains a statement confirming that proper notice was provided by AP to all interested parties.

AP submitted that proper notice, according to AUC Rule 018, was provided to interested parties with regard to AP's settlement negotiations. The negotiations were conducted with the Commission's approval.

The following parties responded to the notices provided by AP and indicated their interest in attending the initial negotiation settlement information meeting held on June 29, 2009:

ATCO Gas *
 BECL and Associates *
 BP Canada Energy Company
 Canadian Association of Petroleum Producers
 The City of Calgary
 The City of Edmonton *
 ConocoPhillips Canada Limited
 The Consumers Coalition of Alberta
 EnCana Corporation
 ENMAX Energy Corporation *
 Gas Alberta Inc.
 Graves Engineering Corp. *
 Industrial Gas Consumers Association of Alberta
 Nexen Marketing
 Shell Canada Energy
 Shell Trading *
 Suncor *
 The Office of the Utilities Consumer Advocate

* These parties indicated interest in the initial meeting but did not actively participate in the full negotiation process.²²

50. Negotiation settlement meetings were held on June 29, 2009, September 1, 2009, September 9, 2009, September 10, 2009, and October 15, 2009. A staff representative of the Commission attended all five meetings.

51. The Commission is satisfied that proper notice, according to AUC Rule 018, was provided to interested parties.

52. On October 28, 2009, AP advised the Commission that AP and interested parties had successfully negotiated a settlement of AP's 2010-2012 GRA.

53. As permitted by section 5(2) of Rule 018, the Commission observer advised the Commission as to the fairness of the settlement process. The Commission observer supported AP's assertion that the Settlement process was open and fair and provided a forum for meaningful stakeholder participation.

²² Exhibit 61.02, 2010-2012 Revenue Requirement Settlement Application, pages 6-7.

54. The Commission notes that parties to the settlement negotiations had available to them at the time that negotiations commenced, a substantial amount of information, including section 5 of the Integration Application, and AP's responses to information requests.

55. AP noted that the Settlement document had been approved by all participants. No party opposed the Settlement. No unresolved issues were identified in the Settlement document by any parties, other than the issue related to the Identified Salt Cavern Assets discussed in Section 2 of this Decision and those currently before the Commission in other proceedings, as listed in Attachment 1, section 1 of the Settlement.²³

56. The Commission agrees with AP that the Application meets the requirements of section 6(3) of Rule 018 as follows:

- (a) Evidence of adequate notice was provided.
- (b) The Settlement agreement was provided.
- (c) All issues were resolved, other than the issue related to the Identified Salt Cavern Assets and those issues specifically identified in the Settlement, which are being addressed in other proceedings.
- (d) Acceptance of the Settlement was unanimous.
- (e) This Settlement is a Phase I settlement, not a Phase II settlement, and therefore a new rate design is not provided.
- (f) The terms and conditions of service are not changing as this is a Phase I settlement.
- (g) The basis of the Settlement is provided in the Application.

57. The Commission is satisfied that the materials filed with the Settlement, and the attendance of Commission staff, provide a level of assurance that interested parties were provided with sufficient notice and the opportunity to meaningfully participate, and that the negotiations were conducted in an open and fair manner. Accordingly, the Commission is of the view that the process leading to the Settlement satisfies the requirements relating to fairness of the negotiated settlement process as set out in sections 3, 5, and 6 of Rule 018.

5.3 Just and Reasonable Rates, Public Interest

Basis for Analysis

58. The second question for the Commission to consider is whether the Settlement contains elements that could lead to rates that are not just and reasonable. As indicated in Section 5.1 of this Decision, the Commission must assess whether approval of the Settlement will lead to rates and terms and conditions that are just and reasonable, and whether the Settlement is patently contrary to the public interest or law. The following subsections of this Decision review the Settlement in relation to these requirements.

²³ Exhibit 61.02, page 8.

59. The Commission has considered whether the effect of the Settlement, taken as a whole, will lead to rates and terms and conditions that are just and reasonable and in the public interest, viewed primarily from the ratepayers' perspective. The Commission has reviewed in Section 5.6 "Individual Components of the Settlement" below, each of the material provisions of the Settlement in order to determine if any of these material provisions, individually, appear contrary to accepted regulatory practices, or could result in undue rate and service impacts to customers. This analysis involved a consideration of the application to negotiate a settlement which resulted in Decisions 2009-051 and 2009-111, the Settlement, and the information filed by all parties in connection with the Settlement.

5.3.1 ATCO Pipelines

60. AP requested approval to negotiate a settlement with its customers, negotiated and executed the Settlement, and has applied to the Commission for approval of the Settlement. These factors indicate that the Settlement as a whole is acceptable to AP. The Commission notes that the Settlement includes agreement on traditional Phase I matters but not on Phase II matters. In its November 12, 2009 Settlement filing AP indicated that it does not expect to file a GRA Phase II given the current AP Integration Application.

5.3.2 General Public Interest Factors

61. As noted in Section 1 of this Decision, AP, Calgary, CAPP, CCA, IGCAA, UCA and Gas Alberta participated in the settlement negotiations and are signatories to the Settlement.

62. The Commission notes that AP submitted that the Settlement is reasonable and fair to the parties and is in the public interest. Specifically:

- Interested parties in the negotiations represent a diverse cross-section of AP's shippers, including producer, industrial and distribution customers. These interested parties are knowledgeable concerning AP's system and its operations and their consensus should provide a basis on which the Commission can reasonably conclude the Settlement is in the public interest.
- The Settlement results in greater regulatory efficiency and certainty compared to a litigated process. Determination of revenue requirements in this manner for 2010-2012 will reduce the regulatory time and resources otherwise required.
- The Settlement allows for the determination of revenue requirements that will enable AP to operate its systems safely, reliably, and cost effectively.
- The Settlement is consistent with existing law and Commission policies.²⁴

63. AP also noted the weight that the Board had placed on customer support in determining the public interest. For example, in Decision 2006-010,²⁵ the Board noted (at page 7):

At this time the Board is prepared to approve NGTL's applied for rate design for 2005, in view of the support of the majority of interested parties. In the Board's view significant weight must be given to the overwhelming support for the status quo by almost all

²⁴ Settlement Filing, page 11.

²⁵ Decision 2006-010: NOVA Gas Transmission Ltd. 2005 General Rate Application, Phase II (Application No. 1396409) (Released: February 21, 2006).

parties, particularly end use customers who ultimately may bear the burden of this pricing. The Board relies on this support in determining the public interest in this case.²⁶

64. The Settlement represents a unanimous agreement reached as a result of a successful negotiation reflecting a number of compromises of different interests and positions of the varied stakeholders all of whom are knowledgeable about the AP system and have actively been involved in previous AP rate proceedings. The Commission agrees with AP that approval of the Settlement may result in regulatory costs savings to customers and greater regulatory efficiency than would a litigated process. Accordingly, the Commission considers that approval of the Settlement is consistent with general public interest considerations.

5.4 Revenue Requirement Comparisons

65. In this Section of the Decision, the Commission will compare the revenue requirements in the Settlement to the revenue requirements included in section 5 of the Integration Application. The amounts set out in Attachments 1, 2.1, 2.2 and 2.3 of the Application form the base point for AP's GRA Phase I revenue requirements, which were then modified by the Settlement.²⁷ Under the Settlement, AP's initial revenue requirements were \$211,782,000 for 2010, \$207,482,000 for 2011, and \$215,182,000 for 2012.²⁸ The Commission has prepared the following Table which includes the initial revenue requirements included in the Settlement and the revenue requirements included in the Application.

²⁶ Cover Letter to ATCO Pipelines' Information Responses to the Commission dated December 18, 2009, page 2-3.

²⁷ Exhibit 61, page 8, lines 16-19.

²⁸ Exhibit 61, page 8, lines 22-23.

Table 1: Comparison of Revenue Requirements between the Settlement and the GRA for the Years 2010-2012

	2010 Forecast	2010 Forecast	Variance
	SETTLEMENT	Application	Increase /
	(\$000's)	(\$000's)	(Decrease)
Return on Rate Base	66,589	66,589	-
Operation & Maintenance	72,693	72,121	572
Taxes Other Than Income	13,620	14,207	(587)
Net Depreciation Expense	44,500	44,500	-
Income Taxes	<u>14,380</u>	<u>14,380</u>	-
Total Utility Revenue Requirement	<u>211,782</u>	<u>211,797</u>	(15)
	2011 Forecast	2011 Forecast	Variance
	SETTLEMENT	Application	Increase /
			(Decrease)
Return on Rate Base	69,705	69,705	-
Operation & Maintenance	61,400	61,707	(307)
Taxes Other Than Income	14,237	15,499	(1,262)
Net Depreciation Expense	47,605	47,605	-
Income Taxes	<u>14,535</u>	<u>14,535</u>	-
Total Utility Revenue Requirement	<u>207,482</u>	<u>209,051</u>	(1,569)
	2012 Forecast	2012 Forecast	Variance
	SETTLEMENT	Application	Increase /
			(Decrease)
Return on Rate Base	72,781	72,781	-
Operation & Maintenance	62,290	63,506	(1,216)
Taxes Other Than Income	14,885	16,920	(2,035)
Net Depreciation Expense	50,803	50,803	-
Income Taxes	<u>14,423</u>	<u>14,423</u>	-
Total Utility Revenue Requirement	<u>215,182</u>	<u>218,433</u>	(3,251)

Sources of Information:

Settlement Figures – Exhibit 61.04: Table 2.1-1 of Attachment 2.1

Application Figures – Exhibit 2: Table 2.1-1 of Attachment 2.1

66. Comparing the forecast utility revenue requirements for the three years included in the Settlement to the corresponding amounts included in the Application, the Commission calculated that the Settlement incorporates the following reductions to the forecast utility revenue requirements: 2010 – 0.01 percent; 2011 – 0.75 percent; and 2012 – 1.49 percent. The Commission requested further information from AP, noting that the revenue requirements set out in the Application were substantially similar to the revenue requirement agreed to in the Settlement. In AUC-AP-1²⁹ AP stated that the Integration Application was not reflective of normal circumstances, and that the initial revenue requirements included in the Settlement have a number of placeholders that will further adjust these revenue requirements.

67. AP added that the circumstances in this negotiation are quite different from normal GRA or negotiation processes. In response to comments received from interveners, AP proposed a revenue requirement process that would reduce the need for detailed information, reduce the negotiation time frame, and thereby allow for Integration to take place in a timely manner.

²⁹ Exhibit 81, Response to AUC-AP-1.

68. Regardless of the timeframes involved and the circumstances associated with the negotiations, the Commission has to consider whether the effect of the Settlement, taken as a whole, could lead to rates and terms and conditions that are just and reasonable and in the public interest. Since there is very little change between the negotiated revenue requirements for 2010-2012 and AP's forecast included in the Application, the Commission will focus on comparing the 2010 negotiated revenue requirement to the revenue requirement approved for the year 2009,³⁰ which was also the subject of a negotiated settlement. The negotiated revenue requirement approved for the year 2009 was not itemized on a line by line basis but was aggregated. Consequently, the Commission will focus its comparison between 2009 and 2010 on the total revenue requirements for these years.

69. The Commission has prepared the following Table which contains information regarding the 2009 approved revenue requirement and the negotiated 2010 revenue requirement.

Table 2: Information Regarding the Approved Revenue Requirement for 2009 and the Negotiated Revenue Requirement for 2010

	2010 Forecast SETTLEMENT (\$000's)	2009 Forecast APPROVED (\$000's)	\$ Variance Increase / (Decrease)	% Variance Increase / (Decrease)
Total Utility Revenue Requirement	211,782	191,000	20,782	10.9%
Mid Year Rate Base	767,799	Unknown		
Rate of Return on Equity	12.00%	8.75%		
Common Equity Percentage	43.00%	43.00%		

Sources of Information:

Settlement Figures – Exhibit 61.04: Tables 2.1-1 and 2.1-5 of Attachment 2.1

2009 Forecast Approved Figures – Section 4.1 of Decision 2009-033

70. On initial review, the difference of approximately \$21 million between the 2010 negotiated revenue requirement and the 2009 approved amount is fairly significant and is in excess of 10 percent. However, section 2 of the Settlement contains wording regarding the cost of capital for the three years. Section 2 of the Settlement references the Generic Cost of Capital proceeding which ultimately resulted in Decision 2009-216³¹ and indicates that any return on equity and/or equity percentage for AP for 2010 determined in that proceeding will be reflected in the 2010 revenue requirement.

71. In Decision 2009-216 the Commission set a generic return on equity for the year 2010 of 9.00 percent for all participating utilities and set the equity ratio for AP at 45.00 percent for the year 2010. AP indicated that the impact of using these approved figures will reduce the 2010 revenue requirement by approximately \$13 million.³² In an attachment to its response to AUC-AP-1(a), AP included the 2010 revenue requirement of \$198,572,000 used in its 2010 interim revenue requirement and 2010 interim rates application which resulted in Decision

³⁰ Approved in Decision 2009-033: ATCO Pipelines 2008-2009 General Rate Application Phase I Settlement Agreement (Application No. 1527976, Proceeding ID. 13) (Released: March 18, 2009).

³¹ Decision 2009-216: 2009 Generic Cost of Capital (Application No. 1578571, Proceeding ID. 85) (Released: November 12, 2009).

³² Exhibit 81, Response to AUC-AP-1(a).

2010-038. The return on equity of 9.00 percent and equity ratio of 45.00 percent approved for AP for 2010 in Decision 2009-216 were used in determining the \$198,572,000 used in AP's 2010 interim revenue requirement and interim rates application.³³ The difference between the \$198,572,000 and the \$211,782,000 initially agreed to in the Settlement is \$13.21 million.

72. Once this reduction of \$13.21 million is accounted for, the difference between the 2010 revenue requirement and the 2009 approved revenue requirement is approximately an increase of \$8 million.³⁴ An increase of \$8 million equates to a percentage increase of 4.2 percent, which the Commission considers to be within a reasonable range in the circumstances. While there are no details available on a line by line basis to fully examine this 4.2 percent increase, there is the agreed to placeholder inflation figure of 2.70 percent for labour and supplies costs included in the Settlement.³⁵ In addition, the capital expenditures forecast placeholder for 2010 of approximately \$90 million³⁶ will increase the revenue requirement from the 2009 level due to the associated return and depreciation on these expenditures. These 2010 revenue requirement impacts of inflation and additional capital expenditures could lead to the approximate \$8 million difference between the 2010 revenue requirement and the 2009 approved revenue requirement.³⁷

73. Therefore, taking into account the above analysis, it does not appear that the 2010 negotiated revenue requirement would result in unjust or unreasonable rates or be patently contrary to the public interest or contrary to the law.

74. The forecast negotiated revenue requirement for 2011 of \$207,482,000 is a decrease of \$4.3 million from the 2010 figure. The main reduction is in the operations & maintenance (O&M) area, which is forecast to decrease by approximately \$11 million. This savings is driven primarily by the forecasted elimination of the tolls and fuel previously paid by AP to NGTL. AP forecast the termination of these charges upon implementation of Integration. The forecast reduction attributable to this is approximately \$9 million.

75. Included in the \$11 million reduction in O&M expenses between 2010 and 2011 are forecasted net savings associated with Integration of approximately \$4 million, as shown in the table below:

³³ The Commission reviewed Table 2.1-5 of Exhibit 11.04 of Application No. 1605719, Proceeding ID. 424.

³⁴ Total difference as shown in Table 2 is \$20.782 million. After deducting the \$13.21 million associated with the 2010 return on equity, equity factor and associated income taxes, the remaining difference is \$7.572 million which approximates to \$ 8 million.

³⁵ Exhibit 81, Response to AUC-AP-11(a).

³⁶ Exhibit 2, Application, Table 2.1-4. AP confirmed in response to AUC-AP-1(c) (Exhibit 81) that the capital expenditures placeholders included in the Integration Application and the Settlement Filing were the same.

³⁷ In the AP 2010 Interim Revenue Requirement and 2010 Interim Rates Application (Application No. 1605719, Proceeding ID. 424), AP provided the final figures for these placeholders for 2010 (Exhibit 11.04, Tables 2.1-4 and 2.1-6). The final inflation figure will be 1.90 percent as opposed to the 2.70 percent used in the Settlement. The final capital expenditure forecast will be approximately \$85 million as opposed to \$90 million used in the Settlement. The impact of both of these will be a reduction in the final 2010 revenue requirement.

Table 3: Integration Costs/Savings per Year³⁸

	Per year Costs (Savings) ³⁹		
	(\$000)		
	2010	2011	2012
	Forecast	Forecast	Forecast
Total O&M Costs/(Savings)	1,235	(2,950)	(3,975)
Transition Cost Deferral Account	300		
Legal Costs Not Included in Forecast		(750)	(750)
Total Forecast and Avoided Costs	1,535	(3,700)	(4,725)

76. The total reduction to the 2011 revenue requirement from the elimination of the tolls and fuel previously paid by AP to NGTL (\$9 million) and from Integration savings (\$4 million) is estimated at \$13 million. Inflation increases in O&M for 2011 are forecast at \$2 million. The net result is a forecasted overall O&M reduction of \$11 million. The forecast O&M reduction of \$11 million is partially offset by forecast increases in return on rate base (approximately \$3 million) and depreciation (approximately \$3 million) associated with the forecast increase in mid year rate base. Taxes other than income are also expected to increase approximately \$0.6 million between 2010 and 2011. When these figures are all taken into account the \$4.3 million difference between the 2011 forecast negotiated revenue requirement and the 2010 forecast negotiated revenue requirement is essentially accounted for.⁴⁰ The Commission considers that the 2011 forecast negotiated revenue requirement of \$207,482,000 is reasonable in comparison to the 2010 forecast negotiated revenue requirement of \$211,782,000.

77. The forecast negotiated revenue requirement for 2012 of \$215,182,000 is an increase of \$7.7 million or 3.7 percent from the 2011 figure of \$207,482,000. The main increase is the return on rate base and depreciation associated with the forecast increase in mid year rate base. The Commission considers that the 2012 forecast negotiated revenue requirement is reasonable in comparison to the 2011 forecast negotiated revenue requirement.

78. Although approval of Integration is not an explicit requirement of the Settlement, implicitly the benefits of Integration are key elements of the Settlement. The Commission therefore sees Integration as a contributing factor in its determination that the 2010-2012 revenue requirements are reasonable when compared against AP's 2009 approved forecast.

³⁸ UCA-AP-3(a) (Revised) and CAPP-AP-17 (Revised) included in Attachment 1 of the Settlement.

³⁹ The costs referenced are for land assignments and transfers, mapping, records management, and employee severances. The savings referenced relate to reduced labour costs, office space, IT/phone services, training and furniture costs, and the STAR system. These costs/(savings) are summarized in the table. Costs included in the Transition Cost Deferral Account relate to employee retention bonuses and external costs (legal and consulting) per the AP 2008/2009 Revenue Requirement Settlement. Avoided legal costs not included in the forecast are savings resulting from the elimination of AP Phase II applications and AP challenges of NGTL facility and rate applications, adding to the total forecast and avoided costs savings associated with Integration, as shown in the table.

⁴⁰ Tolls and fuel savings (\$9 million); integration savings (\$4 million); O&M inflation increase \$2 million; return on rate base increase \$3 million; depreciation increase \$3 million; taxes other than income increase \$0.6 million. The sum total of these figures is $(\$9) + (\$4) + \$2 + \$3 + \$3 + \$0.6 = (\$4.4)$.

5.5 Expected Impact on Rates

79. The impact on rates arising from the Settlement was demonstrated in AP's 2010 Interim Revenue Requirement and 2010 Interim Rates application.⁴¹ The updated revenue requirement, as previously mentioned, was \$198,572,000. The impact on AP's primary demand rates arising from this updated revenue requirement, as demonstrated in Tables 1 and 2 of Decision 2010-038, is an increase of 15.4 percent for customers of AP North and an increase of 9.6 percent for customers of AP South. The 2009 final rates approved in Decision 2009-110 were designed based on the approved 2009 revenue requirement of \$191 million. Given that the increase between \$191 million and \$198,572,000 is approximately 4 percent this suggests to the Commission that the remaining impact (15.4 percent - 4 percent = 11.4 percent in the North and 9.6 percent - 4 percent = 5.6 percent in the South) is associated with billing determinants. No party requested a reconsideration of billing determinants in this proceeding or in the 2010 interim revenue requirement proceeding.

80. AP did not file any evidence as part of the Settlement Application that demonstrated the impact on customer rates arising from the Settlement itself. AP indicated that it does not expect to file a Phase II General Rate Application given the Integration Application. AP added that the timing of the expected implementation of the AP/NGTL integration proposal renders an AP Phase II unnecessary at this time.⁴² AP stated that after receipt of the Commission's approval of the Phase I Settlement, AP would file for 2010 rates consistent with the methodology used in calculating 2009 rates, as approved by the Commission in Decision 2009-110.

81. The Commission also notes that should Integration be approved, the relationship between AP's revenue requirement and the rates charged to customers through NGTL's rates would likely be somewhat tempered. Under Integration, the Commission's jurisdiction with respect to rate matters for AP will primarily be comprised of the examination and determination of AP's revenue requirement and related charge to NGTL.

82. The Commission notes the following finding at paragraph 27 in Decision 2010-038, which remains equally applicable to the present proceeding:

The Commission considers that the customer representatives who were signatories to the Settlement have agreed to the increased 2010 revenue requirements and billing determinants for ATCO Pipelines North and ATCO Pipelines South, at least in principle. The Commission is therefore satisfied that the impact on rates from the Settlement is understood and agreed to by signatories to the Settlement.

5.6 Individual Components of the Settlement

83. In addition to reviewing the overall revenue requirements for 2010-2012, the Commission has reviewed each of the material provisions of the Settlement in order to assess whether any of these material provisions, individually, are contrary to accepted regulatory practices, or could result in undue rate and service impacts to customers. In its assessment of the individual components or provisions of the Settlement, the Commission has not examined whether or not one component favours one party or another. The Commission considers that settlements, by their very nature, are an exchange of compromises and trade-offs among negotiating parties.

⁴¹ Application No. 1605719, Proceeding ID. 424 that resulted in Decision 2010-038.

⁴² Exhibit 61, Settlement Application, page 10, beginning at line 22.

5.6.1 Rate Base – 2008 Closing Balance/2009 Opening Balance

84. In the Integration Application, AP indicated that section 5 included the revenue requirements for the test years 2010-2012 as well as a justification of prudence for AP's actual 2008 capital expenditures. Included as Attachment 4 to the Application were AP's business cases for all expenditures over \$500,000 that occurred in 2008. The signatories of the Settlement have raised no issues with these actual additions to rate base and the 2008 actual closing Plant in Service is incorporated into the Settlement. For the purpose of this Decision the Commission will consider the 2008 actual expenditures that will be utilized in determining the 2009 opening balance for Plant in Service since a settlement was reached before the 2009 actual capital expenditures were known. The prudence test of the expenditures made in 2009 and beyond will be considered in AP's next GRA Phase I. The opening balance for 2010 will be derived using the forecast expenditures, depreciation and contributions for 2009 as filed.

85. The Commission has reviewed the business cases for the capital projects in 2008 that were provided in the 2008-2009 GRA Phase I and supplemented by those in Attachment 4 to the Application. The Commission has also compared the 2008 forecast capital expenditures from the 2008-2009 GRA Phase I with the actual capital expenditures provided in the Application. The Commission observes that not all projects were completed as forecast and some projects that were not forecast materialized and needed attention. In some cases, both anticipated and not, much of the expenditures were to be recovered through contributions in aid of construction from the party requesting the work to be done. The Commission accepts the opening balance for 2009 plant in service being \$860,422, 000, as filed, but subject to any reduction as directed in the following paragraph.

86. As a result of the Commission's review of the business cases, it appears that the "Inland Compression" project has not proceeded to date. The Commission had concerns with respect to this project in past rate filings and hereby advises that the "Inland Compression" project will be the subject of further scrutiny in terms of a prudence review in the future should AP choose to proceed.

5.6.2 Cost of Capital

87. In Argument, CAPP expressed the view that the AUC's Generic Cost of Capital Decision, Decision 2009-216, did not set an explicit return on equity for each of 2011 and 2012 and that, consequently, AP's return on equity for each of those years under the Settlement should be 9.00 percent which was the 2009 generic return on equity determined by the Commission. CAPP subsequently had discussions with AP that led to an agreement between CAPP and AP on a common interpretation of Clause 2 (Cost of Capital).⁴³ CAPP informed other parties to the negotiations of AP's and CAPP's common interpretation of Clause 2 of the Settlement. None of the other parties objected to this interpretation. Under the common interpretation, the Settlement return on equity applicable to 2011 and 2012 will be the return on equity figure or formula set in the 2011 generic cost of capital proceeding.

88. CAPP raised no issue with respect to AP's equity ratio in 2010, which would be unchanged from the Commission determined 2009 equity ratio of 45 percent, as determined in Decision 2009-216. The equity ratio for 2011 and 2012 would be determined in the Commission's announced 2011 proceeding, provided that any equity ratio for 2011 shall not take into account any impact of Integration-i.e. it will be based on AP's pre-integration status and

⁴³ Exhibit 124.01, CAPP Reply Argument, page 1, paragraph 3.

provided that any equity ratio for 2012 shall take into account the impact of Integration – i.e. it will be based on AP’s post-integration status.⁴⁴ Should the Commission’s 2011 proceeding not determine an equity ratio for 2012, the Settlement equity ratio applicable to 2012 will be set in a future Commission proceeding after an application requesting such is filed by AP.

89. Gas Alberta submitted that the cost of capital issue was more a concern with the administration of the Settlement, not the revenue requirement as filed. As such, the Commission should approve the Settlement.⁴⁵

90. The UCA submitted that it did not object to the mutually agreed interpretation of section 2(a)[sic] of the Settlement.⁴⁶

91. The Commission is satisfied that the consensus reached by AP and CAPP on the interpretation of Clause 2 of the Settlement regarding AP’s return on equity is reasonable and consistent with the determinations reached by the Commission in Decision 2009-216. Further, no signatories to the Settlement opposed the agreed upon interpretation of Clause 2. AP’s equity ratio for 2010 and 2011 will exclude the impact of Integration, while 2012 shall take integration into account. The Commission considers that the proposed approach with respect to AP’s equity ratio appears reasonable based on the expected implementation of Integration and its impact on AP’s risk.

5.6.3 Operating and Maintenance Expenses

92. As referenced in Section 4 above, the total 2009 estimated O&M amount of \$65,094,000 in Schedule 2.1-6 of the Integration Application (which amount is the base for calculating O&M for 2010 to 2012) was reduced by \$500,000 in the Settlement.⁴⁷ The reduction will be allocated 35 percent to “Base Utility Labour” and 65 percent to “Base Utility Supplies.” These amounts will be further allocated two-thirds to ATCO Pipelines North and one-third to ATCO Pipelines South. For each year of the Settlement period labour costs net of flow-through items will increase by the forecast percentage change in the Alberta Consumer Price Index (CPI)⁴⁸ plus 2.0 percent to account for employee salary steps, promotions, progression and growth. Supplies costs, net of flow-through items, will be inflated by the forecast percentage change in the Alberta CPI for each year of the Settlement. O&M costs and savings resulting from Integration, NGTL tolls, and pension and hearing costs will be treated as “flow-through.”

93. The Commission considers that the agreed upon annual adjustments to labour and supplies costs are reasonable over the term of the Settlement.

94. The Commission also notes that section 18(a) of the Settlement obliges AP, as part of its AUC annual financial reporting package, to provide a deviation analysis if there is a variance greater than 5 percent for O&M “between current year and prior year, plus explanation of all variances in the flow-through items between forecast and actual pension, Integration and NGTL charges.”

⁴⁴ Exhibit 124.01, CAPP Reply Argument, page 2, paragraph 5.

⁴⁵ Exhibit 126, Gas Alberta Reply Argument, page 1.

⁴⁶ Exhibit 127.02, UCA Reply Argument, page 4.

⁴⁷ Exhibit 61.01 Attachment 1, Clause 3, page 2.

⁴⁸ As released in the fourth quarter of each year by the Conference Board of Canada.

95. The Commission considers the commitment made by AP with respect to the O&M deviation analysis is important given the lack of detail provided for O&M expenses in the negotiated settlement. Through this reporting, interested parties will be able to compare the actual O&M costs between the successive years 2009 to 2012 on a detailed level and will be provided reasons for any differences that exceed 5 percent. This information will be useful in assessing O&M forecasts submitted by AP as part of future revenue requirement applications.

5.6.4 Audit Provision

96. Parties to the Settlement have the right to request an external audit of the Settlement, with any such audit to be performed by June 30, 2014. This audit will verify AP's compliance with the terms of the Settlement. AP will provide reasonable access to all necessary source data. If AP is found to be in material (i.e. in excess of plus or minus \$500,000) breach of a clause of the Settlement, the cost of the audit will be borne by AP. If AP is not found to be in material breach of a clause of the Settlement, the cost of the audit will be paid by AP and placed in a deferral account, with such cost to be added to AP's revenue requirement in the subsequent year.

97. AP interpreted the Audit Provision (Clause 9 of the Settlement) to the effect that the \$500,000 trigger applied to any specific clause and is cumulative over the three years of the settlement based on the language of Clause 9 that states: "If AP is found to be in material (i.e. in excess of plus or minus \$500,000) breach of a clause of this Settlement, the cost of the audit will be borne by AP." (emphasis added by AP).⁴⁹

98. CAPP submitted that its interpretation of the Audit Provision is that the \$500,000 trigger should be cumulative over all clauses for a given year and that this would be closer to cost of service principles which would typically address a yearly approach.⁵⁰

99. The Commission considers that an audit provision is an important element within any Settlement, as it provides customers with an ability to verify compliance by the utility with the terms of the Settlement. The Commission has considered the issue of the \$500,000 trigger, which relates to whether customers or the utility should pay for an audit. CAPP's interpretation, which would accumulate all breaches or defaults in all clauses of the Settlement annually to reach the \$500,000 trigger, could possibly result in a more onerous obligation on the utility to pay for audits than would the trigger relating to a material breach of one clause. However the language of Clause 9 of the Settlement specifically addresses an audit to be performed by June 30, 2014 to verify compliance by AP with the terms of the Settlement. Clause 9 references to a breach of a clause (singular) and not a cumulative breach taking into account all clauses, when dealing with cost responsibility. Therefore the Commission concurs with AP's view that cost responsibility for the audit would rest with AP if AP is found to be in material breach of any clause of the Settlement over the entire three year period.

100. The Commission is satisfied that the audit provision is a fair mechanism to verify AP's compliance with the Settlement.

5.6.5 Capital Expenditures

101. As outlined in Section 4 above, the Settlement requires AP in the month of November in each of 2009, 2010 and 2011 to review an update of the forecast for capital expenditures, capital

⁴⁹ Exhibit 128.01, ATCO Reply Argument, page 7.

⁵⁰ Exhibit 124.01, CAPP Reply Argument, page 2, paragraph 7.

additions and CWIP for the current year and the capital expenditures and capital additions planned for the upcoming year with customers. This will then be filed with the Commission for approval of the upcoming year amounts. This updated forecast information will be used to determine the opening forecast rate base for the following year and to adjust the return, income tax and depreciation expense components of revenue requirement for the following year.⁵¹

102. The Commission is satisfied with the process for reviewing capital additions established by the Settlement. The results of this process will be used to determine the opening forecast rate base for the following year and to adjust the return, income tax and depreciation expense components of revenue requirement for the following year. The Commission expects this focused process will increase regulatory efficiency and will mitigate the risk that changes in capital expenditures might have on customers and the utility.

5.6.6 Line Pack

103. In Clause 12 of the Settlement it is indicated that as part of the Integration Application, AP applied for approval to purchase the line pack in its pipelines as per its Integration Agreement with NGTL. Line pack is the inventory of gas maintained in the AP transmission pipeline at all times to maintain pressure and provide uninterrupted flow of gas between receipt and delivery points.

104. The parties to the Settlement agreed that if regulatory approval of the line pack purchase is received AP will pay the Commission approved value to its customers in the year in which the line pack is purchased, but in any case prior to the transfer of customers to NGTL, and place this value in Necessary Working Capital. AP included a \$2.5 million estimate as the placeholder in 2010.

105. It is of note that without Integration it would be unlikely that the Commission would need to consider a proposal to buy the line pack. However, at this time, and for the purpose of considering the Settlement, the Commission will accept the placeholder.

106. The Commission has included further discussion of the proposed purchase of line pack with the review of the Integration that follows.

5.6.7 Annual Interim and Final Revenue Requirement Process

107. Clause 17 of the Settlement provides that after the annual November meeting with customers, AP will file an application for regulatory approval of items resolved at the November meeting. The application will also include inputs such as inflation rates, capital cost allowance rates, and income tax rates for information only. AP will file for interim revenue requirements, and interim rates if required, to be effective January 1 of the following year.⁵²

108. In May of each year, AP will also be required to file an application to finalize the revenue requirement for that year. This application will clear deferral account balances. In 2010, the only deferral account balance to be cleared is the Transition Expense Deferral Account balance as at December 31, 2009. All deferral accounts are to be cleared each year once Integration is

⁵¹ Exhibit 61.01, Attachment 1, Clause 10, page 4.

⁵² Exhibit 61.01, 2010-2012 Revenue Requirement Settlement Attachment 1, Clause 17, page 6.

implemented. The 2010 final revenue requirement application will also include adjustments to 2010 opening rate base to reflect the 2009 actual closing balances.⁵³

109. The Commission considers that the above process allows customers and AP to plan for and review annual updates to revenue requirement as a result of the inputs included in the Settlement. It also specifies when an application for changes of rates may be expected on an interim or final basis. The Commission considers this approach offers customers, AP and the AUC a more efficient and manageable approach to address concerns regarding AP's Settlement and to finalize revenue requirements for the 2010-2012 period. AP is directed to file its 2010 final revenue requirement within 30 days of the date of this Decision.

5.6.8 Issues addressed in Other Proceedings

110. Clause 1 of the Settlement indicates that the Settlement includes all aspects of AP's 2010-2012 revenue requirement, except for issues addressed in the following proceedings:

- The Competitive Pipeline Review proceeding (Application 1466609);
- The Utility Asset Disposition Rate Review proceeding (Application 1566373);
- Issues related to certain Salt Cavern Assets (Application 1527976);
- ATCO Utilities 2003-2007 Benchmarking and I-Tek Placeholders True Up (Application 1562012);
- ATCO Utilities Evergreen I Application (Application 1577426);
- ATCO Utilities Evergreen II Application (Application 1605338); and
- ATCO Utilities Pension Common Matters Application (Application 1605254).

Should a decision by the Commission relating to any of the foregoing proceedings result in approved costs that are different from the costs in the Settlement, then that difference will be captured in a deferral account to be addressed in AP's revenue requirement for the next year.

111. The Commission considers that the above approach, which deals with approved costs that are different from the costs in the Settlement via a deferral account to be addressed in AP's revenue requirement for the next year, is reasonable.

5.6.9 Conclusion on Individual Components of the Settlement

112. Given the above analysis in respect of the individual material components of the Settlement, the Commission is of the view that no such component appears contrary to accepted regulatory practices, or could result in undue rate and service impacts to customers. The Commission also considers that no component provides the Commission with a sufficient degree of concern to conclude that the Settlement is not in the public interest.

5.7 Conclusion on the Settlement as a Whole

113. Based upon the evidence before the Commission, and considering the unopposed nature of the Settlement and the Commission's analysis of the revenue requirements for 2010, 2011, and 2012, the Commission is of the view that the Settlement when considered as a whole appears to be reasonable. Accordingly the Commission finds that:

- (a) the negotiated settlement process was fair; and

⁵³ Exhibit 61.01, 2010-2012 Revenue Requirement Settlement Attachment 1, Clause 17, page 6.

- (b) the Settlement is fair and reasonable and it forms the basis for developing rates which are fair and reasonable and in the public interest. Nothing in the Settlement is patently contrary to the public interest or contrary to law.

114. Accordingly, the Commission approves the Settlement as filed, in its entirety without expressly approving Integration, which is an implied assumption in the Settlement. Integration is discussed in the next section of this Decision.

6 INTEGRATION

6.1 Introduction

115. As outlined in the Introduction to this Decision, AP's Integration Application and the Integration Agreement, dated April 7, 2009, between AP and NGTL are intended to streamline the provision of natural gas transmission services and address competitive pipeline issues in Alberta. AP and NGTL agreed, subject to acceptable regulatory approvals, to swap ownership of certain physical assets within distinct operating territories and to implement a single rates and services structure for regulated gas transmission service in Alberta. At the same time separate ownership, management and operation of assets will be maintained. NGTL would be the party that interfaces contractually with customers for regulated gas transmission services using the combined regulated AP and NGTL gas transmission systems, the Alberta System. AP's Commission approved revenue requirement would be collected through a monthly charge to NGTL, the AP Charge. NGTL's revenue requirement, including the AP Charge, will be collected from customers using the Alberta System. Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.

116. As outlined in the Introduction of this Decision, AP requested the following approvals in the proceeding:

- (i) an Order pursuant to section 22 of the *Gas Utilities Act*, declaring Integration to be in the public interest and convenience and approval for AP to proceed with implementing Integration;
- (ii) approve pursuant to section 36 of the *Gas Utilities Act*;
 - (a) the AP revenue requirements for 2010, 2011 and 2012, as set out in the Settlement; and
 - (b) the AP Charge payable by NGTL to AP as of the Integration implementation date and equal to the AP revenue requirement as approved under (a);
- (iii) approve pursuant to sections 22 and 36 of the *Gas Utilities Act* Contact Transitioning, being the transitioning of AP contracts to NGTL Alberta System contracts, effective on the Integration implementation date; and
- (iv) approve pursuant to section 26 of the *Gas Utilities Act* the sale of AP assets to NGTL to effect a swap of assets between AP and NGTL, as reflected in the Integration Agreement.

117. This part of the Decision will deal with items (i) and (iii). The previous part of this Decision dealing with the Settlement dealt with item (ii)(a). Item (ii)(b) would be a consequence

of an approval of item (ii)(a). As outlined in the Commission's letter dated December 4, 2009 any explicit approval related to AP's swap of assets with NGTL, item (iv), will be the subject of a future detailed application to be filed with the Commission.

6.2 Discussion of Integration Issues

6.2.1 Integration and the Public Interest

118. As noted above, AP has requested an Order pursuant to section 22 of the *Gas Utilities Act* declaring the Integration to be in the public interest and convenience and approval for AP to proceed with implementing Integration. In the Integration Application AP submitted that Integration addresses many of the difficulties and transmission inefficiencies that exist for customers utilizing both the AP and NGTL systems, including:

- (i) Stacked Tolls: Parties that required service on both systems due to their geographic location within the province were subject to "stacked" tolls, i.e. the payment of tolls on both systems.
- (ii) Duplicative Terms of Service: Parties that required service on both systems were subject to two different tariffs, or terms and conditions of service (e.g. nominations, balancing requirements, payment and credit terms, etc.) in the province. This created added time and cost in the administration of gas transmission service in Alberta.
- (iii) Duplicative Regulatory Proceedings: With two major gas transmission systems operating in the same areas within Alberta, shippers using both systems were subject to an increased regulatory burden (dual GRA's, both Phase I and Phase II, and other regulatory proceedings to deal with pipeline competition before two different regulatory tribunals).
- (iv) Least Cost Regulatory Proceedings: The presence of two major competing transmission pipelines in the province gave rise to least cost issues, with many proceedings requiring regulatory resolution in order to ensure the orderly, efficient and least cost expansion of gas transmission service in Alberta.⁵⁴

119. AP submitted that Integration would provide customers requiring gas transmission service in Alberta utilizing the AP and NGTL systems with the ability to:

- (i) Enter into a single contract for transportation services on both the AP system and the NGTL system;
- (ii) pay a single toll;
- (iii) be subject to one set of terms and conditions of service; and
- (iv) participate in streamlined (fewer) regulatory proceedings.⁵⁵

⁵⁴ Exhibit 1, AP Integration, pages 8-9, paragraph 30.

⁵⁵ Exhibit 1, AP Integration, page 9, paragraph 31.

120. AP submitted that Integration would also provide for the orderly, efficient and cost effective (least cost) expansion of service on the AP and NGTL systems in that system planning and expansion would be conducted on an integrated and coordinated basis.⁵⁶

121. In Reply Argument AP submitted that:

...it is not logical to approve the implementation of Integration absent a finding that Integration is in the public interest. Implementation of Integration is a byproduct of the fundamental conclusion that Integration is in the public interest. An unqualified declaration of Integration being in the public interest is necessary to provide parties with the certainty required to expend the time and effort involved in moving forward with Integration.⁵⁷

122. The CCA submitted that it could not provide unqualified support and the AUC should only make a conditional or qualified declaration of “public convenience” although it did support approval for AP to proceed with implementing Integration. The CCA cited the lack of information and detailed process steps for the Asset Swaps as the basis for its reservation.⁵⁸

123. Gas Alberta as stated in its SIP, supported the Application and recommended that the Commission find that Integration is in the public interest. Gas Alberta agreed with AP that the elimination of duplicative tolls by itself was in the public interest through the equal rate treatment of all customers in Alberta. In addition to the response to NOVA Chem-AP-1(a) which addressed further benefits to producers and industrial customers,⁵⁹ Gas Alberta submitted that Core Customers were equal recipients of these additional benefits, whether directly or indirectly. As Core Customers constituted essentially the entire public of Alberta, the Application was in the public interest.

124. Beyond the elimination of duplicative rates, AP identified customer benefits in the area of Customer Choice, Competition, Service Quality and Regulatory Proceedings.⁶⁰ Gas Alberta added that there were customer benefits to the elimination of duplicative and suboptimal facilities (e.g. the Fort Saskatchewan Extension⁶¹) through the creation of the AP and NGTL Footprints.⁶²

125. Gas Alberta submitted that the public interest goes beyond rates and other benefits provided by the pipeline system. Customers’ internal operations would benefit from system integration due to a simplified interface for gas transmission. These benefits were difficult to quantify⁶³ and are likely outside the Commission’s jurisdiction. That such benefits exist was implied by the fact that no party to this proceeding (whether or not they were parties to the Settlement) have identified in their stated reasons for participation any harm due to the Application. Gas Alberta submitted that the Commission should consider the global benefits that will accrue to both direct and indirect customers.

⁵⁶ Exhibit 1, AP Integration, page 9, paragraph 32.

⁵⁷ Exhibit 128.01, ATCO Pipelines Reply Argument, page 8, paragraph 36.

⁵⁸ Exhibit 122.01, CCA Argument dated February 12, 2010, page 6.

⁵⁹ Exhibit 85, NOVA Chem-AP-1 (a).

⁶⁰ Exhibit 1, AP Integration, pages 8-9 of 19 and Exhibit 81, AUC-AP-28(a).

⁶¹ Decision [2002-058](#): NOVA Gas Transmission Ltd. Application To Construct Fort Saskatchewan Extension And Scotford, Josephburg And Astotin Sales Meter Stations (Application No. 1245440) (Released: July 2, 2002).

⁶² Exhibit 1, AP Integration, page 6 of 19, paragraph 21.

⁶³ Exhibit 85, NOVA Chem-AP-1(g).

126. NGTL indicated that it had filed an application⁶⁴ with the NEB requesting approval of Integration. NGTL submitted that Integration will result in seamless service to customers on the integrated Alberta System with accompanying cost efficiencies through the elimination of duplicative functions. Therefore, NGTL submitted that Integration is in the public interest.

6.2.2 Views of the Commission

127. AP applied for an order pursuant to section 22 of the *Gas Utilities Act* declaring that Integration is in the public interest and convenience and approval for AP to proceed with implementing Integration. Section 22 provides:

22(1) The Board shall exercise a general supervision over all gas utilities, and the owners of them, and may make any orders regarding equipment, appliances, extensions of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

(2) The Board shall conduct all inquiries necessary for the obtaining of complete information as to the manner in which owners of gas utilities comply with the law, or as to any other matter or thing within the jurisdiction of the Board under this Act.

128. Section 22 of the Gas Utilities Act authorizes the Commission to exercise a general supervision over AP and to make orders with respect to its pipeline transmission system that are necessary for the convenience of the public. Integration as proposed by AP is a significant step that will impact the tolls, contractual provisions and costs for regulated service for all AP customers. The Commission considers that an application for the requested order is consistent with the supervisory obligations of the Commission under section 22 of the *Gas Utilities Act*. No party made any submission to the contrary.

129. In considering the issue of whether or not Integration is in the public interest, the Commission is cognizant that competitive issues between AP and NGTL have been the subject of much deliberation before the Commission's predecessor, the EUB. Specifically, the Commission notes that AP submitted that AP and NGTL were encouraged by the EUB to explore collaborative concepts to streamline the provision of natural gas transmission service across Alberta and to address certain competitive pipeline issues and reduce inefficiencies. To that end, AP provided the following overview of the history behind AP's Integration proposal:⁶⁵

By letter dated June 13, 2003, the Board noted that it had previously indicated to parties to the AP 2003-2004 General Rate Application ("GRA")⁶⁶ that the Board wished to examine issues of competition between AP and NGTL. The Board noted that while it may not be possible to effect significant changes in 2003, or perhaps even 2004, to the fundamental competitive framework within which both AP and NGTL operate, the Board should nevertheless continue to explore issues relating to the competitive framework with parties to the AP GRA. The Board also expected these same issues to be further explored in NGTL's 2004 GRA. The Board then proceeded to set aside a day (July 9, 2003) during

⁶⁴ File OF-Toll-Group1-N081-2009-06 01, NOVA Gas Transmission Limited. (NGTL) Application for Approval of a Rate Design Methodology and Terms and Conditions of Services and the Integration of the ATCO Pipelines System with NGTL's Alberta System.

⁶⁵ Exhibit 9.01, ATCO Pipelines Alberta System Integration Application, pages 2-5.

⁶⁶ Decision 2003-100: ATCO Pipelines 2003/2004 General Rate Application Phase I (Application No. 1292783) (Released: December 2, 2003). Footnote added by the Commission.

the course of the AP 2003-2004 GRA to canvass parties' views on inter-pipeline competition.

In its June 13, 2003 correspondence, the Board identified several general competitive issues that could give rise to customer harm. Among these issues are:

- Potential loss of a least-cost perspective - in a competitive environment the focus of pipeline companies may be on acquiring new customers rather than optimizing costs to all customers. In that event, the least-cost solution may be replaced by a higher-cost solution, offered at a more-reduced rate.
- Increased requests for risk-adjusted return and decreased revenue forecast
- Potential for inter-class cost subsidization.
- Increased regulatory cost.

The Board encouraged parties to provide their views on the Board's "straw man" list of potential solutions:

- Keep the status quo - i.e., any potential harms to customers are manageable within the existing regulatory framework.
- Institute franchise areas or conditions (e.g.: distance from mainline) for pipeline service, or otherwise allocate customers.
- Institute Transportation By Others ("TBO") arrangements, or other types of inter-pipeline flow-through tariffs. Institute a structure similar to that of the electric transmission system, with system coordination done by a Transmission Administrator.
- Deregulate the competitive pipeline segments together with related services to industrial and producer customers and retain regulated service to distribution companies.
- Refine and harmonize the AP and NGTL tariffs to fully and accurately reflect costs.

In a letter of July 24, 2003, the Board intended to proceed with a joint NGTL-AP process regarding competitive tariff issues for 2005 and beyond would be held once the respective GRA hearings had been held.

In Decision 2004-069 (NGTL 2004 GRA Phase I), issued on August 24, 2004, the Board reaffirmed its intention to conduct a hearing process on competitive pipeline matters.

In Decision 2004-079 (AP 2004 GRA Phase II), issued on September 24, 2004, the Board again confirmed its intent to conduct a competitive proceeding involving the years 2005 and beyond.

In Decision 2004-097 (NGTL 2004 GRA Phase II), issued on October 26, 2004, the Board directed NGTL to file a GRA Phase II Application for 2005. In doing so, the Board noted that a competitive proceeding would most reasonably be held after NGTL's rate design for 2005 had been considered in the NGTL 2005 Phase II proceeding.

In Decision 2006-010 (NGTL 2005 GRA Phase II), issued on February 21, 2006, the Board was of the view that all interested parties had recognized that appropriate competition between the regulated pipelines under the Board's jurisdiction could be addressed from a tolls perspective or a facilities perspective, or both. Having fully considered the evidence in that proceeding, the Board determined that the NGTL toll design should remain as it was for the time being. That resulted in shifting the

consideration of competitive issues to the facilities perspective, wherein the Board expected parties would emphasize a least-cost approach, based upon prior views of parties. Utilizing the background gained through the NGTL 2005 Phase II proceeding together with the AP and NGTL 2004 rate hearings, the Board believed that all parties would have a good record and solid understanding in order to proceed in consideration of the competitive issues. Consequently, in Decision 2006-010, the Board reaffirmed its intent to conduct a review process on issues that were considered to constitute competitive issues. The Board advised of its intention to canvass interested parties by June of 2006 to assist in developing the scope for that process.

On June 29, 2006, the Board did by letter canvass interested parties to assist in developing the scope of a competitive pipeline proceeding - Application No. 1466609 - *EUB Initiated Review of Competitive Gas Pipeline Issues*—and at the same time, continued to encourage a collaborative process by industry toward competitive pipeline issues that balanced the needs of all stakeholders. The Board requested AP and NGTL to provide updates on the status of industry discussions aimed at resolving competitive pipeline issues by October 31, 2006.

On November 6, 2006, the Board advised that it had received status letters from AP and NGTL on October 31, 2006, stating that although discussions were ongoing between the parties, the issues relevant to the competitive review process were not resolved. As a result, the Board indicated that it would continue the competitive review process as per its June 29, 2006 letter.

On September 8, 2008, AP and NGTL reached a proposed agreement on the integration of their respective systems to respond to the Board's and customers' concerns, which agreement forms the basis for the present application.

On October 3, 2008, the Commission (successor to the Board) issued a letter making reference to a TransCanada Corporation news release announcing the proposed integration between the AP and NGTL systems. Board staff noted that the proposed agreement may address some or all of the competitive pipeline issues included within the scope of the Competitive Pipeline Review Proceeding. As a result, that proceeding was suspended in order to grant NGTL and AP sufficient time to meet with customer representatives to discuss the matter further and to submit the required applications.

On February 26, 2009, the National Energy Board ("NEB") released Decision GH-5-2008 wherein the NEB issued an order recognizing that the NGTL system was under federal (NEB) jurisdiction. Pursuant to that decision, effective as of April 29, 2009, the NEB exercises jurisdiction over the NGTL system. As such, NGTL will be applying to the NEB for the authorizations it requires to proceed with the proposed integration.

130. As noted above, competitive issues between AP and NGTL have been the subject of immense debate and discussion since 2003. The Commission and its predecessor have been supportive of efforts by AP and NGTL to address inefficiencies accompanying two regulated entities providing gas transmission service within the same service area. Competition for customer load and dual tolling issues have often led to protracted regulatory processes and potential increased costs for customers. Under Integration, the AUC's regulatory oversight of AP with respect to rate matters will address AP's revenue requirement, and AP Charge. NGTL's Alberta System rates, facility approvals and tariffs, including terms and conditions of service, will be subject to the jurisdiction of the NEB.

131. Although not all facets of AP's Integration proposal have been finalized, the Commission concurs with AP that Integration eliminates stacked tolls for customers who transport gas in Alberta on both the AP and NGTL pipeline systems, eliminates the need for duplicative terms of service, and reduces the regulatory burden and costs which result when NGTL and AP compete for customers in Alberta, often leading to protracted and contentious regulatory proceedings. The Commission also recognizes that Integration should enhance the orderly, efficient, and cost effective expansion of the Alberta System in that system planning for an expansion is anticipated to be performed on a coordinated basis.⁶⁷ Further, the exclusive footprint areas should lead to efficiencies for facility applications. The Commission also notes that the revised response to UCA-AP-2 included in Attachment 1 of the Settlement forecasted cost savings to AP's customers due to Integration, and reduced business risk for AP.

132. With respect to rates, the Commission anticipates that most customers requiring the use of both the AP and NGTL pipeline systems should benefit by the removal of dual or stacked tolls that inhibited cost effective transportation of gas in the province. However, the rate impact to individual customers will unfold in NGTL's rate application to the NEB. The Commission notes that no parties objected to AP's request that the Commission declare Integration to be in the public interest and convenience, but some interveners expressed reservations as to whether or not such a declaration should be conditional until matters related to line pack, Contract Transitioning, the swap of assets between NGTL and AP, gas quality, and other matters are addressed and/or finalized.

133. Given the above noted benefits associated with Integration, the Commission has concluded that Integration is in the public interest and furthers the convenience of the public. The Commission therefore approves Integration.

134. With regard to Contract Transitioning (including gas quality issues), the purchase of line pack and the contemplated Asset Swap with NGTL, more detail is necessary and further Commission approvals will be required. The Commission is prepared to approve Contract Transitioning and the Asset Swap in principle at this time, subject to further review and final approvals of these matters. The Commission will review the line pack purchase in conjunction with the Asset Swap. Each of these matters is further discussed below.

135. With respect to the Asset Swap, the Commission notes that section 26(2)(d) of the *Gas Utilities Act* requires the approval of the Commission before a designated owner of a gas utility (which includes ATCO Gas and Pipelines Ltd.) may (i) dispose of property, franchises, privileges or rights, or (ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them, outside of the ordinary course of business. No submissions were made to the Commission with respect to the applicability of section 26(2) of the *Gas Utilities Act* in the present Application but presumably this will be addressed in the application relating to the Asset Swap.

6.3 Contract Transitioning

136. In conjunction with the Integration, AP sought Commission approval pursuant to sections 22 and 36 of the *Gas Utilities Act* to proceed with transitioning its customers' contracts with AP to NGTL Alberta System contracts, effective as of the date Integration is fully

⁶⁷ Exhibit 1, AP Integration, page 9, paragraph 32.

implemented (Integration Effective Date). The following information provides an overview of the Contract Transitioning component of Integration.⁶⁸

AP indicated that a customer transition mechanism (Customer Transition Mechanism) was being developed by AP and NGTL in consultation with customers, to ensure that customer rights and obligations under AP contracts will be carried forward in NGTL Alberta System contracts.

As of June 1, 2009 AP had a total of approximately 4,500 terrajoules/day under contract, pursuant to a total of about 180 separate contracts with approximately 150 customers. AP contracts are grouped in the following major categories:

1. FSR (Firm Service Receipt);
2. FSD (Firm Service Delivery);
3. FSU (Firm Service Delivery Distributing Companies); and
4. Non-Standard.

Under the Contract Transition Mechanism, AP contracts, including producer receipt (FSR), industrial delivery (FSD) and distribution (FSU) contracts (AP Contracts), will be converted to NGTL Alberta System contracts (NGTL Contracts) subject to the Alberta System tariff and will be administered by NGTL for the appropriate service which may result from the from the ongoing NGTL rate redesign process.

The Contract Transition Mechanism anticipates the transition occurring as described in the following paragraphs.

Timing: Each applicable AP Contract will be replaced with an NGTL Contract on the Integration Effective Date.

Contract Quantity: Each NGTL receipt service contract will be for a contract quantity (volumetric basis $10^3\text{m}^3/\text{day}$) equivalent (within +/- 1%) to that contract quantity (energy basis GJ/day) contained in the AP receipt service contract. Each NGTL delivery service contract will be for a contract quantity (energy basis GJ/day) equivalent to that contract quantity (energy basis GJ/day) contained in the AP delivery service contract.

Receipt / Delivery Points: Each NGTL Contract will maintain the same receipt point(s) and delivery point(s) as contained in the AP Contract.

Term:

(i) ***Evergreening Contracts***

Each AP Contract that is currently evergreening (rolling, year-to-year contracts subject to termination on 12 months notice) will have a termination date in the NGTL Contract set to October 31 in the year of the Integration Effective Date. The NGTL Contract will contain standard service renewal provisions.

⁶⁸ Exhibit 1, AP Integration, pages 10-12.

- (ii) ***Contracts with Primary Terms Greater Than 1 Year***
NGTL receipt service contracts will have a primary term (no secondary term obligation) equivalent to the AP receipt service minimum term. NGTL delivery service contracts will have a primary term up to five years equivalent to the AP delivery service minimum term. NGTL delivery service contracts will have an additional three year secondary term if the AP delivery service has a minimum term longer than five years.

FSR, FSD and FSU Contracts:

- (i) ***FSR***
AP FSR contracts will have the NGTL receipt toll applicable at the respective receipt points. For receipt points new to the Alberta System, rates will be set in accordance with NGTL's receipt point rate design.
- (ii) ***FSD***
AP FSD contracts will have the NGTL delivery toll applicable at the respective delivery points.
- (iii) ***FSU***
AP FSU contracts will have a new NGTL rate developed for the Alberta local distribution market.

Other Contracts:

- (i) ***Non-Standard & Straddle Plant***
AP Non-Standard contracts and AP Straddle Plant delivery contracts will be converted to the extent possible (with consideration for existing AP commitments) to an appropriate NGTL Contract.
- (ii) ***Interruptible***
Each AP interruptible receipt service contract will be replaced with an NGTL interruptible receipt service contract where necessary.
- (iii) ***Market Account Service & Service to Other Pipelines-Must Flow***
AP's Market Account Service and Service to Other Pipelines – Must Flow contracts will terminate on the Integration Effective Date as they will no longer be required in order to provide service to customers under the operation of an integrated Alberta gas transmission system.
- (iv) ***Franchise Fees***
Each AP delivery service contract that is replaced by an NGTL delivery service contract and is currently subject to payment of franchise fees/taxes will continue to be subject to the payment of franchise fees/taxes.

6.3.1 Views of the Parties

137. BP expressed concern regarding the transitioning of AP's Straddle Plant Delivery contracts (SPD) and associated impacts on others. BP submitted that third party rights may be impacted by Integration and these contracts may extend beyond the contemplated implementation date and that Integration should not impair these contracts. BP submitted that

the Commission should not approve the Integration until all affected parties can advise the Commission that transitioning on comparable terms, preserving rights, related to both contractual rights under AP contracts and to commercial arrangements, has been agreed to. BP also stated it was “uncertain whether this response amounts to an acknowledgement of extraction rights. Nonetheless, they exist.”⁶⁹ If parties could not agree, for example on the transitioning from AP’s SPD contracts to NGTL’s Other Service (OS) contracts, parties could bring the matter back to the Commission. If the Commission was not persuaded by BP’s submission, a conditional approval was an option that would preserve the existing rights.

138. NGTL submitted that BP had not demonstrated that it was an “affected interested party” as referred to in its argument. BP had not identified itself as an SPD contract holder, nor had BP even confirmed that it was a third party that had contractual arrangements with an SPD contract holder.⁷⁰ Instead, NGTL argued, BP made hypothetical statements regarding the potential impact upon third parties that were not based on filed evidence. NGTL stated that it continued to work with SPD contract holders regarding the transition of their SPD contracts to OS agreements and NGTL was not aware of any concerns that require resolution by the Commission at this time. NGTL argued that the Commission should therefore give no weight to BP’s contentions and should not delay or condition its approval of Integration as proposed by BP. NGTL stated that it continued to meet with Straddle Plant Delivery customers to discuss the transition of ATCO Pipelines SPD contracts to NGTL OS agreements with similar terms and conditions of service. Further, NGTL was also working with Non-Standard Transportation Agreement customers to finalize the details of how their current contracts would be transitioned.

139. AP noted that BP was not an SPD contract holder and that none of the parties actually holding such contracts had raised issues similar to those raised by BP.⁷¹ AP also noted that its SPD contracts were terminable by AP on notice.⁷² There were no “vested rights” or rights in perpetuity associated with these contracts and the suggestion that there should be summarily rejected by the Commission. AP added that BP’s concerns seem to lie with possible changes to SPD contracts that may result from EUB Decision 2009-009.⁷³ AP stated that such changes would be the normal outcome of Decision 2009-009 and in no way can BP, or any actual SPD contract holder, be said to be prejudiced by Integration in this regard. AP considered that a party cannot obtain through Integration a guarantee that the world will not change in accordance with Decision 2009-009 or other wise. AP indicated that effectively BP appears to be attempting to review Decision 2009-009 in the context of Integration, an attempt the Commission should reject.⁷⁴ AP submitted that the public interest was more appropriately reflected in the broad and considerable support Integration received from customers. To hold up Integration in respect of any transition with regard to the Alberta extraction convention would be contrary to the public interest.

140. The UCA’s concerns regarding Contract Transitioning were with respect to the existing elimination of the transmission contract between ATCO Gas and AP and its replacement with an NGTL contract on the Integration Effective Date. The UCA submitted that:

⁶⁹ Exhibit 120.01, Argument of BP Canada, page 3.

⁷⁰ Exhibit 125.01, NGTL Reply Argument, page 2.

⁷¹ Exhibit 128.01, ATCO Pipelines Reply Argument, page 5, paragraph 19.

⁷² Exhibit 128.01, ATCO Pipelines Reply Argument, page 5, paragraph 20.

⁷³ Decision 2009-009: Inquiry into Natural Gas Liquids (NGL) Extraction Matters (Application No. 1513726) (Released: February 4, 2009).

⁷⁴ Exhibit 128.01, ATCO Pipelines Reply Argument, paragraphs 21 and 22.

...the UCA is not recommending that approval of the current application be contingent on the signing of or approval by the AUC of the NGTL and ATCO Gas transportation agreement. However, without knowing whether the new transportation agreement between NGTL and ATCO Gas will be same, similar or different than other delivery agreements, the UCA wants to ensure that the “seamless” service that is intended to result from the approval of the Settlement Agreement and Integration Application will not be affected by a new, “untested”, transportation agreement that includes NGTL Quality of Gas provisions that are different than those between ATCO Gas and AP in the current transportation agreement. While ATCO Gas may not have outstanding concerns regarding Gas Quality or other components of an unsigned agreement, there has been no detail provided regarding this and other issues.⁷⁵

141. The UCA submitted that following approval of this Application and the signing of the transportation agreement between NGTL and ATCO Gas, a process be established for parties affected by the new transportation agreement to examine the agreement and request further details and information related to the agreement, including but not limited to the NGTL gas quality provisions and the impact on ATCO Gas and its customers. The process could take the form of a further application by AP and ATCO Gas for approval of or examination of the ATCO Gas – NGTL Transportation Agreement. The issue of Contract Transitioning itself did not change the UCA’s view that the Application, as filed, should be approved by the AUC.

142. The UCA disagreed with BP that approval of the Integration component of the Application, or the AP Application in its entirety, should be delayed while the affected parties negotiate NGTL contracts.

143. NGTL submitted that a further process to examine the transportation agreement between NGTL and ATCO Gas was not required. The transportation agreement between ATCO Gas and NGTL will be a standard tariff service which will be subject to oversight by the NEB. Specifically, NGTL proposed FT-D3 Service at specified locations to meet ATCO Gas’ requirements. This service is a part of NGTL’s application for approval of its Rate Design Methodology and Terms and Conditions of Services and Integration that is currently before the NEB for consideration. NGTL noted that ATCO Gas had not raised any objections or concerns about the transition of its service contract from AP to NGTL in this proceeding.

144. AP submitted that NGTL’s new FT-D3 Service had been designed to make it similar to the service presently provided by AP under Rate FSU.⁷⁶ AP argued that the UCA’s request for a further process to review any transportation agreement between ATCO Gas and NGTL was unnecessary. The replacement agreement with ATCO Gas will be an NGTL agreement, as would all transitioned contracts. As such, this agreement would be under the jurisdiction of the NEB, which regulates NGTL and its terms and conditions of service.

145. Gas Alberta submitted that the Commission should approve Integration in principle, but suggested that issues such as gas quality, a gas transportation agreement between ATCO Gas and NGTL, and other contract transition matters be addressed when AP requests final approval of Integration.

146. The CCA’s concern in this area was to identify any concerns that ATCO Gas (and for that matter any other local gas distribution entity) might have with the quality of gas and to

⁷⁵ Exhibit 118.02, UCA Argument, pages 2-3, paragraph 10.

⁷⁶ AUC-NGTL-1.

document the outcome of the discussion of how NGTL and ATCO Gas would manage the issue in the future.

147. As noted earlier the CCA was unable to provide unqualified support for Integration, but supported approval that AP proceed with the next steps to Integration. In response to UCA-AP-14, AP stated:

The Quality of Gas Provisions in Article 4 of the existing Transportation Service Agreement will cease to exist upon the Integration Effective Date along with the existing Transportation Service Agreement. Subsequent to the Integration Effective Date the gas quality provisions of the Alberta System Tariff will be in effect for all Alberta System customers, including ATCO Gas. AP understands that NGTL and ATCO Gas have discussed how to manage this issue and ATCO Gas has no outstanding concerns.

148. The CCA submitted that AP should be directed to provide further details about the ATCO Gas concerns regarding gas quality and how any natural gas quality issues would be addressed.⁷⁷

149. NGTL suggested that the concerns regarding gas quality raised by the UCA and the CCA were unfounded.

150. AP explained in response to information request UCA-AP 14(e) that NGTL and ATCO Gas had discussed the issue of gas quality and NGTL understood that ATCO Gas did not have any outstanding concerns. Although the terms and conditions of NGTL's service will be approved by the NEB, the terms and conditions of ATCO Gas' service, including the quality of the gas it delivers to end use consumers, will continue to be regulated by the Commission.

151. CAPP noted that NGTL had filed an application⁷⁸ with the NEB for approval of a new rate design that incorporated changes related to AP/NGTL integration. This application was a result of a Rate Design and Services Review Settlement which was entered into by NGTL and many of its major stakeholders including CAPP. The rate design described in the Settlement and in the NGTL application addressed the rate design and tariff issues raised by Integration. Given the broad support extended to the Rate Design and Services Review Settlement, CAPP submitted that it expected that the NGTL application would be approved by the NEB.

152. CAPP also noted that with respect to issues that had been identified or may arise in the Integration process, NGTL had committed to address them collaboratively through a subcommittee of its Tolls, Tariff, Facilities and Procedures (TTFP) Committee. CAPP submitted that it was confident that this process would be able to resolve any remaining integration issues. In CAPP's view, the business case for Integration had been established.

153. NCC raised concerns with respect to customer rights and obligations relating to the NPS⁷⁹ 10 Joffre Sales Lateral and the NPS 16 Joffre Ventures Pipeline and whether NGTL and AP would continue to honour all of their obligations with respect to the NPS 10 Joffre Sales Lateral and the NPS 16 Joffre Venture Pipeline.

⁷⁷ Exhibit 122.01, CCA Argument, pages 6-7, paragraph 7.

⁷⁸ File OF-Toll-Group1-N081-2009-06 01, NOVA Gas Transmission Limited. (NGTL) Application for Approval of a Rate Design Methodology and Terms and Conditions of Services and the Integration of the ATCO Pipelines System with NGTL's Alberta System.

⁷⁹ Nominal Pipe Size.

154. AP noted that by virtue of the definition of “Alberta System” in section 1.1 of the Integration Agreement, the NPS 16 Joffre Ventures Pipeline was not part of the Integration.

6.3.2 Views of the Commission

155. Although not opposed to the proposed Contract Transitioning Mechanism as explained in AP’s Application and evidence, interveners expressed some concerns with respect to the transition of contracts from AP to NGTL as it related to straddle plants, gas quality, and the future transportation agreement between NGTL and ATCO Gas.

156. With respect to BP’s concerns regarding straddle plants, the Commission concurs with AP and NGTL that BP has not shown that it is a SPD contract holder. The Commission acknowledges however, that BP is a participant in the straddle plant industry in Alberta. The Commission further notes AP’s submission that BP should not be allowed to effectively seek a review of the recommendations in Decision 2009-009 regarding transition to a receipt point convention by requesting that AP either provide confirmation and preservation of contract service rights and attributes of SPD customers, or alternatively, that the Commission approve the Application conditional upon such confirmation.

157. The Commission cannot accept the BP position that Integration should not proceed until parties to SPD contracts have fully agreed to the terms of a new service agreement with NGTL. However, the Commission notes that NGTL indicated that it continues to meet with SPD customers to discuss the transition of AP contracts to NGTL Other Service agreements with similar terms and conditions of service.

158. With respect to issue of the NPS 16 Joffre Ventures Pipeline and NPS 10 Sales Lateral the Commission notes that AP, in response to NOVA Chem-AP-2(a), explained that the NPS 16 Joffre Ventures Pipeline which is owned by Trans Canada Ventures Ltd was not included in the blue area (ATCO Footprint) of Attachment 1 of the AP Integration Application. Further, ATCO explained that the NPS 10 Sales Lateral is owned and operated by NGTL while NPS 16 Ventures Pipeline is owned by TransCanada Pipeline Ventures Ltd. but operated by NGTL via an Operations Service Agreement. The Commission therefore concludes that the NPS 16 Joffre Ventures Pipeline is not part of the Integration Agreement between AP and NGTL.⁸⁰ Further the Commission expects that customers that receive service from NGTL on the NPS 10 Joffre Sales Lateral would continue to receive service from NGTL.⁸¹

159. The UCA and the CCA indicated concerns with respect to the form of contract to be put into place between ATCO Gas and NGTL and in particular questions with respect to gas quality. While AP and NGTL noted that ATCO Gas appears to be satisfied with the Contract Transitioning proposal, the final form of such agreement between ATCO Gas and NGTL is not certain at this point.

160. The Commission considers that the Contract Transition Mechanism, which provides for the transition from AP approved rates and approved tariff terms and conditions of service to NGTL Alberta System approved rates and approved tariff terms and conditions of service, appears reasonable at a high level and will likely result in just and reasonable rates for

⁸⁰ Exhibit 85.01, NOVA Chem-AP-2(b) Attachment.

⁸¹ Exhibit 85.01, NOVA Chem-AP-2(d).

customers. Therefore, as indicated above, the Commission is prepared to approve Contract Transitioning in principle at this time.

161. However, the Commission considers final approval to be premature. The Contract Transitioning Mechanism requires greater detail and greater clarity on how customers holding each type of AP contract may be impacted. The Commission concurs with the UCA and the CCA that the evidence on the record with respect to gas quality and a future transportation agreement between ATCO Gas and NGTL lacks sufficient detail. Further, the details of how non-standard agreements and SPD contracts will be transitioned are vague and apparently subject to discussions with individual customers. As a result, further process is required to examine these issues before the Commission can provide final approval to the Contract Transitioning proposals.

162. The Commission directs AP to file an application as soon as may be practicable with the Commission that clearly addresses the Contract Transitioning matters of concern in this Decision. Specifically AP must address terms and conditions of service as it relates to gas quality issues, a comprehensive draft or final agreement between NGTL and ATCO Gas, and how AP's non-standard agreements and SPD contract holders will be transitioned to NGTL contracts. For purposes of efficiency the Commission is amenable to considering these issues through a combined process with an application related to the Asset Swap, if that is suitable to AP and NGTL in terms of timing.

6.4 Asset Swap

163. AP and NGTL provided general information in this proceeding in respect of the assets to be swapped between them as part of the Integration proposal. The book value of the assets to be swapped is expected to total approximately \$150 million for each company.⁸² AP estimated that approximately six months following the Implementation Effective Date AP assets in the NGTL footprint would be swapped for NGTL assets in the AP footprint to rationalize operations post Integration⁸³ (refer to [Appendix 4](#) for map of AP footprint). AP submitted that Commission approval of the Asset Swap, on a conceptual basis, was consistent with approval to implement Integration and will provide the necessary certainty to proceed with Integration.

164. NGTL had similarly requested the NEB to approve the Asset Swap in principle. Representatives of NGTL and AP continue to meet to finalize footprint boundaries and identify the specific facilities to be swapped. Operational and other considerations, such as municipal franchise areas, continue to be considered. In subsequent applications, NGTL and AP will seek approvals from the NEB and the Commission, respectively, for the transfer of specific facilities.

165. Gas Alberta stated that consideration of the Asset Swap should be limited to consideration of whether or not it is in the public interest, as the exact assets to be transferred and their values have not been settled at this point in time.

166. The CCA was concerned with the transfers of accumulated depreciation as well as other issues related to asset transfers. The CCA noted, however, that these issues could be addressed in later asset specific proceedings.

⁸² Exhibit 9, page 12.

⁸³ Exhibit 1, AP Integration, page 8 of 19, paragraph 27.

6.4.1 Views of the Commission

167. In a letter dated December 4, 2009 the Commission indicated that any explicit approval related to the Asset Swap will be the subject of a future detailed application to be filed with the Commission. Accordingly, the Commission will not make any findings here, which would be premature. However, the Commission does agree in principle that an asset exchange supported by an appropriate business case demonstrating operational efficiencies, reduced costs and enhanced flexibility for coordinated system expansion and development is in the public interest. The Commission also notes that there has been no objection to the concept of the Asset Swap, and in fact, Gas Alberta stated that it was in the public interest. Therefore, as stated above, the Commission approves the Asset Swap in principle.

6.5 Line Pack

168. AP proposed to purchase from its customers the line pack in its system in 2010 upon final approval of the Integration. The value of the line pack would be included in Necessary Working Capital and would be refunded to customers through a one time rate refund adjustment.

169. AP submitted that it would be required to acquire the line pack in its system in order to facilitate Integration. It would simplify and accommodate the Asset Swap since NGTL owns its line pack and as such both parties would be on equal footing.⁸⁴ AP considered that customers owned the line pack on the AP system as line pack had been accounted for through the unaccounted-for gas (UFG) collected from customers each year that additional facilities have been added to the system. The Settlement noted that as part of the Integration Application, AP applied for approval to purchase the line pack in its pipelines as per its Integration Agreement with NGTL. The parties to the Settlement agreed that if regulatory approval of the line pack purchase was received AP would pay the Commission approved value to its customers in the year in which the line pack was purchased, prior to the transfer of customers to NGTL, and place the value in Necessary Working Capital. A portion of the line pack for both AP and NGTL will be included in the assets to be swapped.

170. AP provided an estimated cost for line pack (including volumes and price) at \$2.5 million,⁸⁵ and stated that the actual amounts will be reviewed in a future proceeding along with other actual rate base expenditures.

171. The CCA argued that the line pack issue should be considered as part of a new and separate application dealing with the one-time purchase referenced by AP.

172. Gas Alberta supported the line pack purchase in principle. The administration of line pack by one party should reduce operating costs and complexities, which it considered consistent with the principle that System Integration was in the public interest. Since line pack would be part of the Asset Swap, the Commission should approve the line pack proposal on the same basis as the Asset Swap for which AP sought approval in principle. Gas Alberta submitted that the Asset Swap and line pack purchase should receive full and final approval only upon finalization of the details of Integration following subsequent scrutiny from customers and the Commission. In support of its position, Gas Alberta suggested there might be some question as to whether AP's proposed 12-month index versus NGTL's method of using a 13-month average was appropriate. Gas Alberta also noted the final details concerning the calculation of line pack

⁸⁴ Settlement Application, paragraph 62.

⁸⁵ AUC-AP-26 (a) and CCA-AP-2(b).

volumes had not been confirmed and that further scrutiny of the volume as well as pricing of line pack gas was required.

173. AP submitted that the record was sufficient to support approval of the proposed line pack purchase, with no need to expend additional time and resources on another application.

174. Regarding Gas Alberta's request for a further approval process for the line pack purchase, AP did not believe any such further process was needed. As with other rate base expenditures, AP had provided its estimated cost for line pack (including volumes and price), and indicated that the actual amounts can be reviewed in a future proceeding along with other actual rate base expenditures.

6.5.1 Views of the Commission

175. The Commission agrees in principle that the ownership of the line pack should be with AP if the Integration is approved, at least for the assets to be swapped. This would make AP and NGTL's line pack ownership the same, as NGTL owns its line pack and therefore the assets to be swapped would be equivalent, i.e. the facilities to be swapped would include line pack. However, the Commission agrees with Gas Alberta that there are significant outstanding issues that need to be dealt with before the Commission can approve the purchase as proposed in the Application.

176. The timing, price and volume are of particular concern, and since line pack is considered an asset, the Commission will defer its decision regarding line pack until further review in conjunction with the future submission by AP of a detailed application regarding the Asset Swap.

177. The Commission has considered AP's intention that Integration, including the Asset Swap, is estimated to occur 18 months following the later of the approvals from the AUC and the NEB. AP is directed to file an application respecting the Asset Swap, to include line pack considerations, within a reasonable period of time following this Decision and with a view to allowing sufficient process time for consideration by all parties. If AP wishes to include the application regarding the Contract Transitioning matters with the Asset Swap application, as referenced in paragraph 162 above, the combined application should be made at an earlier date than an application to consider the Asset Swap alone.

178. AP's application addressing the Asset Swap should include a business case complete with alternatives for purchasing and selling line pack on the swapped assets alone versus line pack on the total AP system. This business case should also substantiate the response provided by AP to AUC-AP-24(a), which indicates that customers have not always been the owner of line pack and therefore brings into question to what extent does AP remain the owner of some line pack. In responding to the question: "Has line pack always been owned by the customers of AP?", AP stated:

No. AP Customers have been responsible for providing line pack through Rider D (Unaccounted For Gas/Fuel) for APN/APS since the implementation of the ATCO Gas Deferred Gas Accounts (DGA) in 1988. Prior to the implementation of the DGA, pipeline line pack, including first fills, may have been provided through various means including company owned production, connecting pipeline operators or customers.

7 OTHER ITEMS

7.1 Outstanding Directions

179. The Commission has compiled a summary of outstanding directions from 2003 to the end of 2009 (refer to [Appendix 5](#)), many of which are ongoing and some applicable to a GRA Phase II. AP should review and identify those that will become redundant in the event Integration receives universal approval and a GRA Phase II or other routine filings become unnecessary. AP is directed to clarify the matter of outstanding directions in its future detailed application for the Asset Swap.

7.2 Deferral Accounts

180. In response to AUC-AP-23(a), AP explained that at the end of 2009 it expects to have the following regulatory deferral accounts:

- Salt Cavern Working Gas
- Deferred Hearing Costs
- Load Balancing
- Reserve for Injuries and Damages
- Other Pipeline Deliveries
- Facility Connection Service
- Other Pipeline Receipts
- Transition Expense

181. As a result of the Settlement, AP may have deferral accounts at the end of 2010 for:

- Benchmarking and I-Tek True-Up
- Evergreen I
- Evergreen II
- Pension Funding
- Integration Costs
- NGTL Tolls
- Property Taxes
- Revenues

182. AP went on to add in response to AUC-AP-23(b) that:

If Integration is approved, AP will clear the Load Balancing Deferral accounts, Other Pipeline Deliveries deferral accounts, Other Pipeline Receipts deferral accounts and Facility Connection Service accounts as these accounts will no longer be required post Integration. The deferral accounts to be cleared each year once Integration is implemented would likely consist of those remaining deferral accounts identified in AUC-AP-23(c)-[sic].

183. Given the above deferral accounts, the Commission directs AP to clarify, in its future detailed application for the Asset Swap, whether it expects that some of the aforementioned deferral accounts and mechanisms required to clear these deferral accounts might require their own separate application process. The Commission also directs AP to list all routine applications, other than a GRA Phase II, that have historically been subject to AUC review that,

if Integration is approved, would no longer be subject to AUC jurisdiction or required to be submitted (for example: Unaccounted For Gas).

8 ORDER

184. IT IS HEREBY ORDERED THAT:

- (1) The Settlement Agreement, attached as Appendix 2 of this Decision, is approved as filed, in its entirety.
- (2) The proposed Integration of the regulated gas transmission service in Alberta of ATCO Pipelines and NOVA Gas Transmission Ltd. under a single rates and services structure while maintaining separate ownership, management and operation of their respective assets is approved.
- (3) The Integration matters relating to Contract Transitioning and the Asset Swap are approved in principle, subject to the requirements for further approval and all other directions and terms set forth in this Decision.

Dated on May 27, 2010.

ALBERTA UTILITIES COMMISSION

(original signed by)

Carolyn Dahl Rees
Vice-Chair

(original signed by)

Thomas McGee
Commissioner

APPENDIX 1 – PROCEEDING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative
ATCO Pipelines (AP) E. L. Jansen R. Mair D. Dunlop N. Maclean
Alliance Pipeline Ltd B. Troicuk
ATCO Gas North D. Wilson L. Taylor J. Teasdale D. Zavaduk
Aux Sable Canada Ltd. D. Golonsinski
BP Canada Energy Company (BP) C. G. Worthy J.D. Brett J. Hagel
Canadian Association of Petroleum Producers (CAPP) R. Fairbairn R. Graham
ConocoPhillips Canada Ltd. J. Gilholme
Consumers' Coalition of Alberta (CCA) J. Wachowich J. A. Jodoin
The City of Calgary (Calgary) M. Rowe H. Johnson D. Evanchuk
EnCana Corporation R. Powell
ENMAX Energy Corporation A. Morgans
ExxonMobil Canada Ltd. R. R. Moore

Name of Organization (Abbreviation) Counsel or Representative
Gas Alberta Inc. (Gas Alberta) D. Symon T. Marriot K. Dannacker G. Garbutt R. Daw
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Nexen Marketing D. White
NOVA Chemicals Corporation (NCC) P. Bourdon J. Smellie J. Cusano
NOVA Gas Transmission Ltd. (NGTL) L. Angus R. Stevens P. Keys
Talisman Energy G. Giesbrecht
TransAlta Corporation R. Marx P. Serafini K. Perley
Office of the Utilities Consumer Advocate (UCA) J. A. Bryan, Q.C. B. Shymanski C. Flieger

Alberta Utilities Commission
Commission Panel C. Dahl Rees, Vice-Chair N. A. Maydonik, Q.C., Commissioner ⁸⁶ T. McGee, Commissioner
Commission Staff B. McNulty (Commission Counsel) M. McJannet R. Armstrong, P.Eng. U. Pillai D. Mitchell

⁸⁶ Deceased May 16, 2010.

APPENDIX 2 – SETTLEMENT AGREEMENT

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Appendix 2 -
Settlement Agreement

(consists of 13 pages)

APPENDIX 3 – LEGISLATION AND COMMISSION RULES

[\(return to text\)](#)



Appendix 3 -
Legislation and Comr

(consists of 5 pages)

APPENDIX 5 – ATCO PIPELINES OUTSTANDING DIRECTIONS

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Appendix 5 - ATCO
Pipelines Outstanding

(consists of 13 pages)

APPENDIX 6 – SUMMARY OF COMMISSION DIRECTIONS

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

1. The Commission considers that the above process allows customers and AP to plan for and review annual updates to revenue requirement as a result of the inputs included in the Settlement. It also specifies when an application for changes of rates may be expected on an interim or final basis. The Commission considers this approach offers customers, AP and the AUC a more efficient and manageable approach to address concerns regarding AP's Settlement and to finalize revenue requirements for the 2010-2012 period. AP is directed to file its 2010 final revenue requirement within 30 days of the date of this Decision. Paragraph 109
2. The Commission directs AP to file an application as soon as may be practicable with the Commission that clearly addresses the Contract Transitioning matters of concern in this Decision. Specifically AP must address terms and conditions of service as it relates to gas quality issues, a comprehensive draft or final agreement between NGTL and ATCO Gas, and how AP's non-standard agreements and SPD contract holders will be transitioned to NGTL contracts. For purposes of efficiency the Commission is amenable to considering these issues through a combined process with an application related to the Asset Swap, if that is suitable to AP and NGTL in terms of timing. Paragraph 162
3. The Commission has considered AP's intention that Integration, including the Asset Swap, is estimated to occur 18 months following the later of the approvals from the AUC and the NEB. AP is directed to file an application respecting the Asset Swap, to include line pack considerations, within a reasonable period of time following this Decision and with a view to allowing sufficient process time for consideration by all parties. If AP wishes to include the application regarding the Contract Transitioning matters with the Asset Swap application, as referenced in paragraph 162 above, the combined application should be made at an earlier date than an application to consider the Asset Swap alone. Paragraph 177
4. The Commission has compiled a summary of outstanding directions from 2003 to the end of 2009 (refer to Appendix 5), many of which are ongoing and some applicable to a GRA Phase II. AP should review and identify those that will become redundant in the event Integration receives universal approval and a GRA Phase II or other routine filings become unnecessary. AP is directed to clarify the matter of outstanding directions in its future detailed application for the Asset Swap. Paragraph 179
5. Given the above deferral accounts, the Commission directs AP to clarify, in its future detailed application for the Asset Swap, whether it expects that some of the aforementioned deferral accounts and mechanisms required to clear these deferral accounts might require their own separate application process. The Commission also directs AP to list all routine applications, other than a GRA Phase II, that have historically been subject to AUC review that, if Integration is approved, would no longer be subject to AUC jurisdiction or required to be submitted (for example: Unaccounted For Gas). Paragraph 183

ATCO Pipelines

2010-2012 Revenue Requirement Settlement (the “Settlement”)

1. Overview

The Settlement includes all aspects of ATCO Pipelines’ (“AP”) 2010-2012 revenue requirement, except for issues addressed in the following proceedings:

The Competitive Pipeline Review proceeding (Application 1466609);

The Utility Asset Disposition Rate Review proceeding (Application 1566373);

Issues related to certain salt cavern assets (Application 1527976);

ATCO Utilities 2003-2007 Benchmarking and I-Tek Placeholders True Up (Application 1562012);

ATCO Utilities Evergreen I Application (Application 1577426);

ATCO Utilities Evergreen II Application (Application 1605338); and

ATCO Utilities Pension Common Matters Application (Application 1605254).

Should a decision by the Alberta Utilities Commission (“AUC”), after any review and variance or appeal process is completed, relating to any of the foregoing proceedings result in approved costs that are different from the costs in this Settlement, then that difference will be captured in a deferral account to be addressed in AP’s revenue requirement for the next year.

Section 5 of AP’s Alberta System Integration Application filed on June 26, 2009 forms the base point with respect to the Settlement, and is modified as per the Settlement provisions outlined herein.

“Flow through” items are items that either: (i) have offsetting revenues and expenses (e.g. franchise fees); or (ii) have the difference between the actual amount and forecast amount placed in a deferral account for collection from or refund to customers at a later time (e.g. hearing costs, Integration costs/savings).

Proper notice of the Settlement proceedings was provided by AP to all interested parties.

2. Cost of Capital

- (a) Return on Equity (“ROE”) will be set at the final rate for ATCO Pipelines (AP) determined by the AUC in its final decision after any reviews or appeals (the “GCOC Decision”) in its Generic Cost of Capital proceeding

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

(Application No. 1561663, Proceeding No. 15) if the GCOC Decision provides an explicit ROE or formula that is applicable to each year of this Settlement. If the GCOC Decision does not provide an ROE or formula that is applicable to each year of this Settlement, the ROE for those years will be set at the last approved ROE set by the GCOC Decision for AP.

- (b) The equity ratio for each year of the Settlement will be deemed to be as follows:
 - (i) For 2010 and 2011, the pre-Integration equity ratio set for AP by the AUC in the GCOC Decision.
 - (ii) The equity ratio for 2012 will be:
 - (1) any post Integration equity ratio set for AP by the AUC in the GCOC Decision; or
 - (2) if the equity ratio for AP in the post Integration period is not set by the GCOC Decision, the equity ratio set by an AUC decision for 2012 resulting from an AP application for a post Integration equity ratio filed no later than September 1, 2011.
- (c) The impact on debt costs, both in the quantum and changed debt rate, as a result of any change in equity ratio will be treated as “flow through”.
- (d) No party is constrained by this Settlement from appealing or requesting a review and variance of the GCOC Decision.
- (e) For greater certainty, to the extent that any equity ratio specified for AP in the GCOC Decision conflicts with any equity ratio specified for AP in this Settlement in clause 2(b), the equity ratio specified in this Settlement shall prevail.
- (f) The discussion in clause 2(b) regarding a potential AUC decision on a post Integration equity ratio for AP in the GCOC Decision does not reflect any agreement by AP or any other party to the Settlement as to whether or not the GCOC Decision should address a post Integration equity ratio for AP and all parties acknowledge the entitlement of any party to appeal or review a decision which sets a post Integration equity ratio for AP.

3. O&M

- (a) The total 2009 Estimate Operating & Maintenance (“O&M”) amount of \$65,094,000 in Schedule 2.1-6 of the Integration Application (which amount is the base for calculating O&M for 2010 to 2012) will be reduced by \$500,000. The reduction will be allocated 35% to “Base Utility Labour” and 65% to “Base Utility Supplies”. These amounts will be further allocated two thirds North and one third South in Schedules 2.2-13 and

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

2.3-13 respectively. Labour costs, net of flow-through items, will increase by the forecast percentage change in the Alberta Consumer Price Index ("CPI") as provided by the Conference Board of Canada released in the fourth quarter each year plus 2.0% for each year of the Settlement period to account for steps, promotions, progression and growth. Supplies costs, net of flow-through items, will be inflated by the forecast percentage change in the CPI for each year of the Settlement.

- (b) O&M costs and savings resulting from Integration, as shown as separate line items under Base Utility Labour and Base Utility Supplies in Tables 2.1-6, 2.2-13 and 2.3-13 and more fully described in AP's responses to CAPP-AP-17 (Revised), UCA-AP-3(a) (Revised) and CCA-AP-8(d), attached hereto as Attachment 1, will be treated as "flow-through".
- (c) Pension and Hearing costs will be as determined for each year by the AUC and will be "flow through".
- (d) NGTL Tolls incurred by AP will be "flow through".

4. Depreciation

- (a) In the month of November in each of 2009, 2010 and 2011, depreciation for the following year will be recalculated using the revised forecast rate base and capital additions forecast for the following year. The depreciation rates and accumulated depreciation reserve adjustment, where applicable, by asset account or the lowest asset class level for "non-study" assets (i.e. software, leaseholds and specific facility contracts) separately for North and South will be the same as rates in place in 2009 based on the most recent depreciation study subject to agreed to changes in the last negotiated settlement agreement. The "non-study" asset depreciation is also subject to no "over-depreciation" of non-depreciation study assets (i.e. software, leaseholds and contracts).
- (b) Details of depreciation rates for leaseholds, computer software and other non-depreciation study assets will be provided annually.

5. Income Tax

AP agrees that for calculating income taxes for 2010, 2011 and 2012, it will use the methodology used in preparing its 2009 general rate application in determining the eligibility of the deductibility of 2010, 2011 and 2012 costs. This agreement is for the purposes of the Settlement only and does not constitute agreement by any party to a particular position or methodology. AP and/or parties may bring forward issues related to the eligibility of the deductibility of costs that affect 2010, 2011 and 2012 UCC balances in any negotiation or hearing process as they relate to AP's next GRA.

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

6. Taxes Other than Income Taxes

- (a) Franchise fees will be treated as “flow through”.
- (b) The property tax forecast will be set at \$12.3 million for 2010, \$12.9 million for 2011 and \$13.6 million for 2012 and will be treated as “flowthrough”.

7. Significant Legislative Changes

The impact of legislative changes that impact earnings by greater than \$1 million, plus or minus, in a given year will be placed into a deferral account and cleared using the same methodology as other deferral accounts.

8. Revenues

- (a) Consistent with the Integration proposal, AP revenues for any part of the 2010 – 2012 time frame will be treated as “flow through”.
- (b) Upon the transfer of customers, NGTL will be billed by AP for inclusion of AP’s revenue requirement in NGTL’s revenue requirement. Parties acknowledge there may be other costs billed by AP to NGTL that are outside of the approved revenue requirement but are nevertheless approved by the AUC (e.g. Franchise Fees).

9. Audit Provision

Parties to the Settlement have the right to request an external audit of the Settlement, such audit to be performed by June 30, 2014. This audit will verify compliance by AP with the terms of the Settlement. AP will provide reasonable access to all necessary source data. If AP is found to be in material (i.e. in excess of plus or minus \$500,000) breach of a clause of this Settlement, the cost of the audit will be borne by AP. If AP is not found to be in material breach of a clause of the Settlement, the cost of the audit will be paid by AP and placed in a deferral account, with such cost to be added to AP’s revenue requirement in the subsequent year.

10. Capital Expenditures

- (a) In the month of November in each of 2009, 2010 and 2011, an update of the forecast for capital expenditures, capital additions and construction work in progress (“CWIP”) for the current year and the capital expenditures and capital additions planned for the upcoming year will be reviewed with customers and filed with the AUC for approval of the upcoming year amounts. This updated forecast information will be used to determine the opening forecast rate base for the following year and to adjust the return, income tax and depreciation expense components of revenue requirement for the following year.

- (b) Business cases for capital projects for the upcoming year greater than \$500,000 will be provided as part of the November review and filing to the AUC.

11. Rate Base

Opening 2010 rate base will be based upon the 2009 actual closing balance, to be subsequently adjusted (in the opening balances for 2011 or 2012) by any placeholders (see clause 1 above) subsequently approved by the Commission for December 31, 2009.

12. Line Pack

As part of this Integration Application, AP has applied to the AUC to purchase the line pack in its pipelines as per the agreement with NGTL. If regulatory approval of the line pack purchase is received (as part of the Integration Application), AP will pay the AUC approved value to its customers in the year in which the line pack is purchased but in any case prior to the transfer of customers to NGTL and place this value in Necessary Working Capital.

13. No Precedent

Nothing in the Settlement shall set a precedent nor shall it prejudice any position any party may take regarding the matters addressed in the Settlement in other proceedings at any time.

14. Confidentiality

All information exchanged in the Settlement process is confidential and is provided on a without-prejudice basis. AP shall be entitled to file the Settlement with the Commission.

15. Settlement Package

This Settlement represents a balancing of interests by the parties to the Settlement and no single component can be said to be acceptable to any party independent of the entire Settlement. The parties to this Settlement agree that approval of this Settlement, in its entirety as a package, is a requirement for the Settlement to be binding on any party.

16. Definitive Agreement

Notwithstanding any provision within the definition of "ATCO Initial Revenue Requirement" in the Alberta System Integration Agreement between AP and NGTL, AP shall advise NGTL that it will apply for regulatory approval of the ATCO Initial Revenue Requirement on a basis consistent with this Settlement.

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

17. Annual Interim and Final Revenue Requirement Process

After the annual November meeting with customers, AP will file an application for regulatory approval of items resolved at the November meeting. The application will also include inputs such as inflation rates, CCA rates, and income tax rates for information only. AP will file for interim revenue requirements, and interim rates if required, to be effective January 1 of the following year.

In May of each year, AP will file an application to finalize the revenue requirement for that year. This application will clear the deferral account balances. In 2010, the only deferral account balance to be cleared is the Transition expense deferral account balance as at December 31, 2009. All deferral accounts are to be cleared each year once Integration is implemented. The 2010 final revenue requirement application will also include adjustments to 2010 opening rate base to reflect the 2009 actual closing balances (see clause 11 above).

The revenue requirements will be calculated using the schedules included in Attachments 2.1, 2.2 and 2.3 of AP's Alberta System Integration Application filed on June 26, 2009, as revised and included as Attachments 2.1, 2.2 and 2.3 to this Settlement.

18. Reporting Package

- (a) AP will provide the AUC annual financial reporting package, which includes a deviation analysis, augmented to provide, with respect to O&M, the three categories on Schedule 3 split between labour and supplies and with respect to labour and supplies to provide the breakdown of the costs by prime account with explanations of deviations/variances greater than 5% between current year and prior year, plus explanation of all variances in the flow-through items between forecast and actual pension, Integration and NGTL charges.
- (b) At the annual November meeting (see clause 10 above), Capital Expenditures, Capital Additions and supporting business cases, as required, will be provided in the 5 categories as identified in the Integration Application.

19. AUC Approval

The Settlement is subject to approval by the AUC.

20. Execution

A fax or scan signature shall be deemed to be an original. The Settlement may be executed in counterparts and all executed counterparts shall constitute one Settlement.

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
12th day of November, 2009.

Company or Association Name

ATCO Pipelines

Per: [Signature]

Title: Sr Vice-President and G.M.

Per: [Signature]

Title: VP Regulatory + Controller

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
12 day of November, 2009.

Company or Association Name

Consumers' Coalition of Alberta

Per: [Signature]

Title: Legal Counsel

Per: _____

Title: _____

AP 2010-2012 NSP - Final version

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ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
10th day of November, 2009.

Company or Association Name

Per: KC Gas

Title: Advocate

Per: _____

Title: _____

ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
5th day of November, 2009.

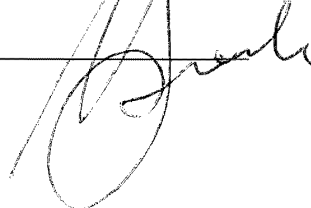
Company or Association Name

Industrial Gas Consumers Association of Alberta (IGCAA)

Per: Greg Sproule

Title: Executive Director

Per: _____

Title: _____


ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
5th day of November, 2009.

Company or Association Name

Gas Alberta Inc.

Per: [Signature]

Title: V.P. Operations

Per: _____

Title: _____

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ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
10th day of November, 2009.

Company or Association Name

Canadian Association of Petroleum Producers

Per: [Signature]

Title: VICE PRESIDENT

Per: [Signature]

Title: Manager, Natural Gas

4032684777

City of Calgary Finance

03:55:12 p.m. 11-10-2009

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ATCO Pipelines
2010-2012 Revenue Requirement Settlement

The executing parties agree to all the terms and conditions of the Settlement the
10 day of Nov., 2009.

Company or Association Name

CITY OF CALGARY

Per: [Signature] D. MOUNT

Title: MANAGER - CALL TAX & REG. AFFAIRS

Per: _____

Title: _____

APPENDIX 3 – LEGISLATION AND COMMISSION RULES

Legislation

1. The Alberta Utilities Commission (AUC or the Commission) has the power to set just and reasonable rates and tolls under section 36 of the *Gas Utilities Act*. The *Gas Utilities Act* also provides the Commission with various powers to consider and approve negotiated settlements. The salient provisions in relation to the Application are set out below.¹

2. Sections 28.51, 28.52 and 28.53 of the *Gas Utilities Act* require the Commission to establish rules, practices and procedures that facilitate settlements. These sections also address the powers of the Commission in relation to such rules, practices and procedures, and the consideration and approval of settlements.

Facilitated negotiation

28.51(1) The Commission shall recognize or establish rules, practices and procedures that facilitate

- (a) the negotiated settlement of matters arising under this Part, and
- (b) the resolution of complaints or disputes regarding matters arising under this Part.

(2) The rules, practices and procedures recognized or established under this section apply whether or not an application relating to an issue has been made to the Commission.

Powers of the Commission

28.52 As part of the rules, practices and procedures for the negotiated settlement of matters or the resolution of complaints or disputes, the Commission may

- (a) provide for the appointment of mediators to assist parties in negotiating the settlement of an issue;
- (b) provide for the appointment of employees of the Commission as mediators;
- (c) provide for employees of the Commission to attend the settlement process;
- (d) recognize or establish rules to ensure that the parties to an issue receive
 - (i) adequate notice of the settlement process and the matters in issue,
 - (ii) adequate disclosure of the positions of the parties and the basis for those positions, and

¹ The provisions of sections 28.7 and 28.8 of the *Gas Utilities Act* have not been set out here. These sections address, respectively, the participation in Commission proceedings of mediators or facilitators of negotiated settlements, and the treatment by the Commission of confidential information when considering a negotiated settlement.

- (iii) an appropriate opportunity to participate in the settlement process;
- (e) recognize or establish rules governing the extent to which persons who are not parties, or classes of persons who are not parties, may participate in the settlement of an issue;
- (f) provide that, before an issue may become the subject of a hearing before the Commission, the parties must attempt to negotiate a settlement of the issue in accordance with the Commission's rules, practices and procedures;
- (g) determine whether any costs of negotiating the settlement of an issue are payable and, if so, by whom and to whom the costs are to be paid.

Commission approval of a settlement

28.53(1) If a settlement of an issue that is within the jurisdiction of the Commission has been negotiated, the Commission may approve the settlement.

(2) Any issue dealt with in a settlement approved by the Commission is not subject to further consideration in the hearing of the matter to which the settlement relates.

(3) Subject to subsection (4), the Commission may require a party to provide to it any records relating to the settlement that it considers appropriate.

(4) The Commission shall not receive or consider any submission, position, evidence or information provided by a party on a without prejudice or confidential basis in the course of negotiating a settlement under this Part without the express consent of that party.

3. Section 28.6 of the *Gas Utilities Act* provides that if parties negotiate a settlement on the basis that the settlement is contingent on the Commission's accepting the entire settlement, the Commission must either approve the entire settlement or refuse it.

Limit on Commission discretion

28.6 If the parties negotiate a settlement on the basis that the settlement is contingent on the Commission's accepting the entire settlement, the Commission must either approve the entire settlement or refuse it.

Commission Rules – Negotiated Settlements

4. Rules for settlements were established by the Alberta Energy and Utilities Board (Board) in *Informational Letter IL 98-04: Negotiated Settlement Guidelines* (Guidelines) issued on May 15, 1998. The Board revised its Guidelines through various amendments with the latest amendment being released on December 19, 2006.

5. On January 2, 2008, the Commission issued Rule 018: *Rules on Negotiated Settlements*, which is set out below.

Definitions

1 In these rules

- (a) “Act” means the *Alberta Utilities Commission Act* and any other enactment under which the Commission is charged with the conduct of a negotiated settlement or other proceedings,
- (b) “AUC staff” means employees of the Commission,
- (c) “applicant” means a person who files an application with the Commission,
- (d) “Commission” means the Alberta Utilities Commission,
- (e) “intervener” means a person, other than an applicant who files a submission with the Commission in respect of a proceeding,
- (f) “non-participant” means an intervener to an application who does not participate in a negotiated settlement proceeding,
- (g) “proceeding” means a matter brought before the Commission by application or by the Commission on its own initiative,
- (h) “Rules of Practice” means the Commission *Rules of Practice*.

Application of Rules

2 These rules apply to negotiated settlement proceedings of the Commission respecting rates and tariffs.

Notice

3(1) The Commission requires a statement in the settlement agreement confirming that proper notice was provided by the applicant to all interested parties.

(2) The notice provisions in the *Rules of Practice* apply the giving of notice under these rules.

Initiation of Process

4(1) An applicant may only commence negotiations with the approval of the Commission.

(2) An applicant must notify the Commission of its intention to initiate a negotiated settlement process and provide the Commission with an outline of the pertinent issues to be resolved.

(3) In issuing its approval to negotiate, the Commission may provide directions to the parties regarding information to be filed with the Commission

Role of AUC Staff

5(1) Subject to subsection (2), AUC staff involved in the negotiated settlement process must not participate in proceedings by the Commission arising from or relating to any issue in the negotiated settlement proceeding, without the express written consent of all parties to the negotiations.

(2) AUC staff may advise the Commission as to the fairness of the process without obtaining the consent of the parties.

Filing of the Application and Settlement Agreement

6(1) Subject to section 3, when an agreement is reached on all or some of the issues, the text of the agreement, including a representation that no party has withheld relevant information, must be circulated to all parties to the agreement.

(2) Upon the concurrence of the parties on the text of the agreement, an application for approval, must be filed with the Commission.

(3) At a minimum, the application must include the following:

- (a) evidence of adequate notice,
- (b) the settlement agreement,
- (c) details of issues not resolved,
- (d) outline of issues where acceptance is not unanimous, including the names of those who disagree,
- (d) the rates that result or will result from the settlement, supported by schedules, to assist the Commission in understanding how the rates were derived,
- (e) the text of any changes to the terms and conditions of service with supporting information,
- (f) a description of any outstanding issues, and
- (g) unless the Commission directs otherwise, a settlement brief explaining the basis of the settlement and how it meets the interests of the parties and the public interest.

(4) The Commission may seek additional information it considers necessary.

(5) The onus is on the applicant to ensure that there is sufficient evidence to support the application, and that the quality and detail of the evidence and the rationale for the

settlement of issues are sufficient to enable the Commission to understand and assess the agreement.

Evaluation and Acceptance of a Settlement Agreement

- 7(1)** The Commission must give notice of the application.
- (2)** The Commission, in its consideration of a settlement agreement, must consider dissenting views which may relate to one issue, portions of the settlement agreement, or its entirety.
- (3)** The Commission must determine the process for dealing with the issues identified by non-participants to the settlement negotiations or parties with dissenting views.
- (4)** If it determines that a hearing is not required, the Commission shall consider such views in its deliberations.
- (5)** If it determines that a hearing is required, either oral or written, the parties will have the opportunity to offer evidence and to question all or any portion of the settlement.

Unanimous or Unopposed Settlement

- 8(1)** Upon presentation of a unanimous settlement or a settlement that is unopposed, the Commission must assess whether the settlement results in rates and terms and conditions that are just and reasonable.
- (2)** If a unanimous settlement is determined by the Commission to be patently against the public interest or contrary to law, the Commission must intervene.

Costs

- 9(1)** Costs incurred in the negotiated settlement process are generally the responsibility of the applicant utility, to be recovered through customer rates.
- (2)** All costs must be approved by the Commission, pursuant to the Commission *Rules on Intervener Costs*, whether the parties reach agreement on costs or not.
- (3)** Parties to the negotiated settlement must provide sufficient detail for the Commission to assess the reasonableness of costs.
- (4)** The Commission will not recognize costs as a substantive term or condition of the negotiated settlement.

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2003-100 2003/2004 GRA - Phase I	6	Therefore, while the Board accepts that the Airdrie Heartland Lateral is needed, the Board considers that a reduction of 15% should be applied to this capital expenditure to reflect the lack of adequate justification provided in relation to this item. In future GRA proceedings where ATCO Gas forecasts are used as a rationale for additional transmission facilities, the Board expects, and directs, ATCO Pipelines to produce and file a study validating the findings of ATCO Gas via a business case, to provide a witness of ATCO Gas or ATCO Pipelines to defend the ATCO Gas forecasts and to provide pertinent information showing that the proposed expenditures represent the optimum facilities to meet the demand. P. 21	Ongoing
	11	The Board supports the AUMA/EDM/CG submission that it would be beneficial to have information concerning the number of personal computers and servers being upgraded and the cost per unit. Information concerning software implementation and training costs would also be of assistance in reviewing projects of this nature. Therefore, the Board directs ATCO Pipelines, in future GRA's, to include this level of this detail in its business cases for IT projects of this nature. P. 37	Ongoing
	13	The Board also considers, and directs, that for all future IT application or technology projects over \$500,000, ATCO Pipelines should provide, within the IT project business cases, the impact on I-Tek volumes in the same manner as contracted from its I-Tek affiliate (e.g. mainframe services, distributed services, network services, workstation services, and application services). P. 38	Ongoing
	14	The Board considers that the forecast amounts for Transmission Replacement-General for APN are reasonable. In the future, the Board expects ATCO Pipelines to alleviate the concerns of interveners regarding double counting by providing greater clarity in expenditure descriptions and breakdowns of costs in the original application. The Board accepts the forecasts as filed. P. 39	Ongoing

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2003-100 2003/2004 GRA - Phase I	29	The Board also directs ATCO Pipelines to file, in future GRA applications, more detailed information supporting its inflation factors. P. 87	Ongoing
	33	Accordingly, the Board directs ATCO Pipelines in future GRAs, to provide details of all retirements from regulated operations since the preceding GRA, specifying years worked in regulated and non regulated divisions, the related chronology and the total number of years of employment used for pension purposes. Furthermore, for the purposes of completion of the record, ATCO Pipelines is directed, in its Refiling, to complete the Deferred Pension Continuity schedule, shown above, to include amounts for the years 2000 to 2004 inclusive. P. 94	Ongoing
	41	The Board also agrees with the recommendation of Calgary as to the appropriate detail required for ATCO I-Tek capital and operations expenses. The Board directs ATCO Pipelines, in all future GRAs, to provide a table of ATCO I Tek volumes contracted from its I Tek affiliate, showing volumes for operating the existing systems for the 3 preceding years and forecast test years and volumes for new project development for the forecast test years. P. 102	Ongoing
	49	Therefore, the Board directs that ATCO Pipelines to file any future non-standard contracts with the Board prior to implementation, allowing sufficient time for interveners and the Board to conduct an appropriate review. The Board considers that this requirement applies to all utilities that it regulates. P. 135	Ongoing
2004-038 2003/2004 General Rate Application – Phase I Compliance Filing	8	The Board directs that, within 30 days of issue of a Board decision affecting the revenue requirements for any placeholder amount not already adjusted in the Second Refiling, AP shall file its calculation of the difference between the final amount approved in any future decision and the placeholder amount in this Decision, and to place the difference in a deferral account for subsequent disposition at an appropriate time in the future. P. 23	Submission required following Benchmarking process

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2005-052 Generic Cost of Capital	1	The Board directs ATCO Pipelines, at the time of its first GRA following the Board’s decision in the Competitive Pipeline Module, to apply either: a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module. P. 47	Submission required after Competitive Proceeding
2004-058 Code of Conduct Exemption	1	In addition to the above approved exemptions, the Board directs AP to maintain on its website the current version of the Board approved Code along with copies of its Policies 10.08 and 10.09. Further, as the Board has granted the exemptions relying, in part, on the presence of Policies 10.08 and 10.09, the Board would expect that any material change to either of these policies that would directly impact the exemptions granted in this decision would be submitted to the Board for approval. P. 8	Ongoing, as required
	2	Further, the Board directs AP to attach a Schedule to the ATCO Code, in the form provided for in Appendix 1 of this Decision, which will be updated from time to time, which will identify all exemptions granted by the Board by reference to the Board’s Decision number, the date of issuance of the decision granting the exemption and the sections of the code to which the exemption applies. P. 8	Ongoing, as required
2004-078 SCADA Project	5	The Board directs ATCO Pipelines to review the merits of alternative allocations of SCADA costs in its next GRA. P. 26	Next GRA Phase II
2004-079 2004 GRA – Phase II Note: all direction numbers revised in 2004-096 (App H & I) as shown here	2	No evidence was presented to indicate a specific amount of peak demand that would be attributable to the isolated systems; however, the Board considers that the peak demand for isolated systems would be insignificant due to the small number of customers being served from the isolated segments. However, for greater clarity in the future, the Board directs AP in its next GRA to remove the peak demand amount for all customer/service classes on “isolated systems” from the peak demand allocator used to allocate general system costs. P. 11	Next GRA Phase II

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
	5	In addition, in its next GRA, the Board directs AP to address the reasonableness of revising the peak demand numbers of the delivery service classes for the purposes of allocating Salt Cavern expenses. The Board considers that the peak demands associated with Distributing Companies and Industrial customers on isolated pipeline systems may not directly cause the requirements of the Salt Cavern peaking facility. P. 19	Next GRA Phase II
	8	As noted in Section 7.1, Peak Demand for Cost Allocation and Rate Design, the Board has directed AP to remove the straddle plant demand from the Industrial class demand. Therefore, the Board considers it appropriate to treat the revenue associated with the SPD service in a similar fashion to non-standard revenue and allocate the revenue as an income credit to all service classes (before reallocation of OPR and OPD revenues and expenses) based on four-hour peak demand. The Board directs AP to allocate the revenue resulting from SPD service to all service classes based on a four-hour peak demand. P. 34	Next GRA Phase II
	9	The Board directs AP to file in its next Phase II application a North and South schedule similar in concept to the response to IGCAA-AP02-1 (a). P. 35	Next GRA Phase II
	10	Given the timing of this Decision and the follow-up Compliance Filing, the Board does not believe that AP would have enough time to discuss potential OPR and OPD services with its customers in order to establish stand alone OPR and OPD services for 2004. The Board is prepared to accept AP's position that OPR and OPD services should not be stand alone services at this time. The Board directs AP to confer with its customers to determine whether stand alone OPR and OPD services are practical and cost effective and to address this matter in its next GRA. P. 47	Next GRA Phase II
	27	With respect to AP's request to directly charge line heater fuel to customers who desire their delivered gas to be heated, the Board notes that no interveners provided comment on this issue. The current practice is to recover this fuel for customer specific facilities through Rider D. The Board notes that, in addition to customers that incur Rider D charges, DSP customers	Subject to future compliance. Information provided but not approved by Commission due to settlement.

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
		would also pay for such line heater fuel. While the Board supports the concept that customers should pay for costs they cause, in this situation, the Board does not consider that AP has provided sufficient information with regard to the scope of this proposal and the cost to measure the line heater fuel. Therefore, the Board is not prepared to grant approval at this time and directs AP to file evidence including a detailed cost/benefit analysis with respect to this matter in its next GRA. P. 93	
	31	However, the Board is not satisfied that a comprehensive study and adequate data was provided to fully support the peak demand relationships provided in this Application. Therefore, the Board directs AP, in its next GRA, to file a comprehensive study with adequate data to support the peak demand relationships for all customer classes. P.106	Next GRA Phase II
	33	The Board considers that the benefits of non-standard contracts can alter over time, and agrees with Calgary and the CG that a COSS which includes the non-standard contracts as a stand alone class of service is the only way to observe the specific impacts of these contracts on the system and on all customer groups. Therefore, the Board directs AP in its next GRA, to provide a COSS which isolates the impact of non-standard contracts by including them as a separate class of service. Further the Board directs that AP address the impact and differences in results in the COSS if the non-standard contracts were specifically included within the Industrial and Producer classes. P. 112	Next GRA Phase II
	35	The Board considers that it may be more appropriate to establish a stand alone process for dealing with the OPR deferral components and to establish an OPR commodity rate that recovers all cost components in the deferral account. Therefore, the Board directs AP to file, as part of its next GRA, such a stand alone proposal so that parties can express their views. The Board is also interested in receiving parties' submissions with respect to alternative mechanisms to adjust the OPR rate that would balance rate stability with larger deferral account balances. The Board notes that this concern may not be an issue if AP files evidence	Next GRA Phase II

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
		in its next GRA indicating that stand alone OPR services are practical and cost effective as discussed in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues. P. 116	
	36	With respect to AP’s proposal to bring the year-end balance in the OPD deferral accounts forward to a future test year and to allocate the balance to customer classes based on four hour peak demand, the Board directs AP to allocate the balance based on delivery nominations to other pipelines consistent with the Board’s findings in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues. P. 117	OPD Application filed on reaching threshold, as required
	37	Although the administration process related to the OPD deferral account was not discussed to any great extent in this proceeding, for the time being, the Board directs AP to follow a process similar to the process approved for the OPR deferral account. In particular, the Board expects that AP will discuss the approach for recovering or crediting the end-of-year balance with its customers on an annual basis. Given that the OPD deferral account is only expected to be in place for two months in 2004 (November and December), the Board directs AP to include the 2004 balance in the 2005 OPD deferral account and to begin formal reporting to its customers by April 30, 2006 with subsequent reporting to the Board by June 30, 2006. P. 118	Posted monthly on AP’s website
	40	In order to maintain transparency with respect to the OPD deferral accounts, the Board directs AP to include the most current actual monthly balances and end-of-year forecast balances for the North and South on its website and to update the information on a monthly basis. P. 118	Posted monthly on AP’s website
	41	As with the OPR deferral account, the Board considers that it may be more appropriate to establish a stand alone process for dealing with the OPD deferral components and to establish a stand alone OPDC rate that is adjusted as such, in order to target a zero forecast balance in the account. Therefore, the Board directs AP to file, as part of its next GRA, such a stand alone proposal so that parties can express their views. The Board is also interested in receiving parties’ submissions with respect to alternative mechanisms to adjust the OPDC rate that would balance rate stability with larger deferral account balances. The Board notes that the	Next GRA Phase II

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
		above matter may not be an issue if AP files evidence in its next GRA indicating that stand alone OPD services are practical and cost effective as discussed in Section 3.7, Reallocation of OPR and OPD Expenses and Revenues. P. 118	
	43	Following consultation with stakeholders, the Board directs AP to file with the Board, for information, the mechanism and application guidelines it proposes to utilize to implement the firm receipt threshold in determining available FSR service, including support for the forecasted threshold levels and proposed implementation dates. The mechanism and forecasting methodology may be further reviewed by the Board at the next GRA or upon application by an interested party. P. 129	Next GRA Phase II
2004-096 GRA Phase II Compliance Filing	1	The Board directs that, within 30 days of issue of a Board decision that finalizes any of the remaining placeholder amounts as shown in Appendix G, AP shall file an application with the Board outlining the difference between the final amount approved in the decision and the placeholder amount. The application should also outline AP’s proposal for dealing with the over or under-recovery. P. 2	File with Benchmark Compliance
2005-115 2005-2006 Unaccounted for Gas and Fuel Gas Rates – Rider “D”	3	In addition, the Board directs ATCO to submit, in future UFG/fuel applications, a detailed analysis of its investigation of the data that gives rise to any gains that are to be used to determine the Rider “D”. P. 4	Ongoing
	4	The Board also directs that both APN and AGN, and both APS and AGS, can change methods when done in concert with each other such that the common measurement is utilized by both parties. The timing of the change in methodology can be separate for each of the North and South zones. P. 4	Ongoing
	5	Accordingly, the Board denies the proposal to move line heater lines downstream and directs AP to suspend any requirement for owners to change piping until the issue of whether fuel costs are a system cost or a customer cost has been examined more fully. Therefore, approval of the requested capital costs is denied. P. 6	Next GRA Business Case included in App #1527976 No approval given by Commission.

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2005-119 Salt Cavern Peaking Working Gas Deferral Account	3	Should the \$2 million threshold be exceeded in either a debit or credit balance at the end of an annual injection/withdrawal cycle on March 31 of a particular year and prior to a GRA in respect of that year, that event would require AP to submit a Cavern Deferred Account Disposition Application or to address the disposition of the account in any GRA application for that year P. 4-5	Submission required if threshold exceeded
2006-020 North and South Other Pipeline Receipt (OPR) Rate Changes	1	In addition, as similarly directed in Decision 2004-079, the Board directs AP to include the most current actual monthly balances and end-of-year forecast balances for the Revised OPR DAs on its website and to update the information on a monthly basis. With respect to the FCS DAs, the Board directs AP to include the most current actual annual balance and end-of-year forecast balance on its website and to update the information on an annual basis. P. 13	Ongoing, update monthly on AP's web site
	2	The Board would prefer that future OPR rate changes would coincide with the beginning of a new gas year. The Board also considers that future OPR rates should be set to recover forecast FT-A expenses, and not to adjust for any OPR/FT-A shortfall or surplus. In this regard, the Board directs AP to file an application by April 30, 2006 (the 2006 Application) which will request an OPR rate change to be effective November 1, 2006. The requested rate should be determined with the objective of recovering forecast FT-A expenses for the period November 2006 to October 2007. The 2006 Application should include supporting rationale and should detail monthly forecast and rate assumptions. The Board also directs AP to file subsequent applications for OPR rate changes by April 30 of each year for implementation as of November 1st in the same year. P.13	First direction completed, see 2006-095 Second OPR direction is ongoing
	4	Based on the foregoing guidelines, the Board directs AP to make proposals in future applications with respect to one-time refunds or charges associated with actual cumulative OPR/FT-A Deviations. The Board also expects AP, as part of its proposals, to validate the assumptions that the Board has used in providing the guidelines above or to identify the assumptions that it considers to be invalid and provide the supporting rationale. P. 15	Ongoing

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
	5	The Board directs AP to make proposals in future applications with respect to one-time refunds or charges associated with the actual FCS Deviation taking into consideration the foregoing guidelines. The Board also expects AP, within its proposals, to validate the assumptions that the Board has used in establishing the guidelines above or to identify the assumptions that it considers to be invalid and to provide the supporting rationale. P. 17	Ongoing
	6	Given the current and potential magnitude of the FCS Deviation and the preference that the OPR rate only recover FT-A expenses, the Board does not see the continuing utility for the FCS related components to reside in the North and South OPR deferral accounts. The Board also does not consider it appropriate to use the OPR rate as a mechanism to reduce the surplus FCS Deviation. Therefore, the Board directs AP to divide the North and South OPR deferral accounts into separate deferral accounts, by separating out the FCS related components from the North and South OPR deferral accounts and establishing two deferral accounts: a revised OPR deferral account to account for OPR/ FT-A variances, and an FCS Deferral Account to account for FCS variances, for both the North and South. (The Board will refer to these amended deferral accounts hereinafter as the North Revised OPR DA, the South Revised OPR DA and collectively the Revised OPR DAs, and the North FCS DA, the South FCS DA and collectively the FCS DAs). P. 12	To be confirmed
	7	After the 2006 Application, subsequent refund/charge proposals required by AP to manage the balances in the Revised OPR DAs or FCS DAs, according to the threshold guidelines, should be filed with the Board one month after the threshold amount has been reached in any of the respective deferral accounts which may be at the end of any month in the case of OPR DAs or at the end of a calendar year in the case of FCS DAs. P. 14	Ongoing, file as required
2006-089 Non-Standard Transportation Service Agreement ATCO Pipelines – NGTL Grande	1	To provide information regarding the management of UFG on the Grande Cache pipeline to the minimum on an ongoing basis, the Board directs AP to submit a report in a compliance filing to this Decision, not later than three months after the date of this Decision,	See clarification letter September 28, 2007 Ongoing

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
Cache		identifying the typical operating percentage of UFG on the new Grande Cache system, which information would then be reviewed by the Board in determining a Board approved “baseline” percentage of UFG compared to the total receipts into the Grande Cache pipeline including the volumes under this NS TSA. P. 10	
	2	...In addition, the Board directs AP to monitor and record the deviations from the baseline percentage UFG in accordance with this Decision and the Board’s compliance decision. Should the UFG percent on the Grande Cache pipeline deviate in a loss direction from the baseline percent UFG in any three month period to such an extent that the amount of net benefit to customers would be eroded for that period, or in a gain direction from the baseline, the Board expects AP to investigate the causes of the deviation from the baseline percent and to correct the causes. P. 10	Submit as required
	3	...The Board directs that at AP’s next GRA or UFG application for the North, (which ever occurs first) and in all subsequent UFG applications until expiry of the NS TSA, AP shall file, for examination by the Board and interested parties, the UFG recorded for the Grande Cache pipeline, including all deviations from the baseline, along with the details of all investigations of deviations and all actions taken to correct the cause of any deviations. P. 11	Ongoing
2006-106 2006-2007 Unaccounted for Gas and Fuel Gas Rates – Rider “D”	1	The Board received clarification on the line “Distributing Company Deliveries” in BR-ATCO-4 and BR-ATCO-9. To avoid such clarifications, the Board directs that in future applications, AP interconnection deliveries to AG be clearly separated and disclosed in any schedules provided. P. 3	Ongoing
2006-136 Muskeg River Pipeline Affiliate Code of Conduct Exemptions	4	ATCO Pipelines is directed to include all approved exemptions when filing their annual compliance report as per Section 7.6(1) of the ATCO Code. P. 20	Ongoing
2007-006 2005-2007 Common Matters Compliance Filing	4	The Board directs ATCO Pipelines to reflect the amounts approved in this Decision in the next GRA Application. P. 6	AP has not complied.

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2007-081 2007-2008 Unaccounted for Gas and Fuel Gas Rates – Rider “D”	1	The Board agrees that the schedule of adjustments similar to that provided in BR-ATCO-1 would be useful and therefore directs ATCO to include such a schedule in its future UFG applications. P. 9	Ongoing
2007-107 Replace Summit Lime Pipeline	1	The Board directs AP to review its Investment Policy in its next Phase II General Rate Application (GRA) to specifically address replacements. This review should include a forecast of all pipeline facilities that may require replacement in the next ten years by type, location, and whether they are customer(s) specific or general system replacements (together with the criteria used in making that determination). P. 7	Next GRA Phase II
2008-120 2008-2009 Revised Interim Rates	1	Given the uncertainty surrounding AP’s GRA Phase II proceeding, AP is directed to address the issues raised by Gas Alberta in this Application with regards to peak demand, cost of service study and rate design (including OPR and OPD) within either a 2008-2009 GRA Phase II proceeding or its application for approval of final rates for 2008 and 2009. P. 12	Next GRA Phase II
2009-017 2008-2009 Load Balancing Deferral Account	2	The Commission notes that under AP’s proposal the LBDA will not be immediately reduced by the actions taken as a result of this Decision. As AP noted in an information response, the LBDA balances would reduce over the period the proposed Rider “D” (volume variance adjustment) and the “general” rate rider (price variance) were in place [AUC-AP-4(b)-(c)]. Accordingly the balances in the North LBDA will exceed the thresholds until such time as the riders effect a reduction in the LBDA balances. Therefore, the Commission directs AP to reflect the estimated impact of the riders on the LBDA balances in AP’s quarterly filing with the Commission; in other words, AP will show the gross amount of the LBDA less the outstanding estimated amount to be collected/refunded as a result of this Decision, to determine a net amount. The net amounts will be subject to the variance threshold limits. P. 9	Ongoing
	3	The Commission rejects APs proposal to meet with stakeholders to address balances which exceed the approved thresholds and instead directs AP to file an application for the proposed disposition of such balances. P. 9	Ongoing

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
2009-027 Application for Approval of Non-Standard Transportation Service Agreements with Shell Canada Energy and North West Upgrading Inc.	1	AP is therefore directed to file an annual reconciliation of the difference between the revenue received under the NSTSAs and the revenue that would have been received had standard rates applied to the volumes covered by the NSTSAs for the preceding year, and to reflect a credit of 10% of this difference in the OPD deferral account. AP will not be entitled to recover this 10% differential from ratepayers. P. 18	Ongoing
2009-110 2008-2009 Rate Compliance Filing to Decision 2009-033	1	Although the Commission agrees with Gas Alberta and the UCA that section 3(a) of the Settlement’s “Other Provisions” (a signed service agreement with respect to a metering operations and maintenance service agreement) has not been completed, finalization of rates related to AP’s 2008-2009 GRA Phase I Settlement (Decision 2009-033) should not be delayed solely based on a lack of agreement between Gas Alberta and AP given that the majority of customers are not impacted by this issue. The Commission considers that the issue should not be an impediment to finalizing AP’s 2008-2009 rates and the recovery of associated revenue shortfall. AP is directed to file a signed metering operations and maintenance service agreement between AP and Gas Alberta with the Commission as required under AP’s 2008-2009 Settlement Agreement. P. 7	Outstanding
	2	Further, the Commission notes that Gas Alberta appears satisfied that concerns regarding the continuation of FSU Rate Clause B (vi) and any demands and forecasts may be resolved within a process for the AP/NGTL Service Integration Proposal. As a result, the Commission expects that Gas Alberta’s FSU issue will be addressed within either the integration process with NGTL or in AP’s next GRA Phase II. If the issue is not resolved within the integration process, AP is directed to bring the matter forward at the time of its next GRA Phase II. P. 8	Next GRA Phase II
	3	The Commission agrees with the CCA that there are numerous outstanding directions related to Phase II matters that again will be deferred if not addressed within a 2008-2009 Phase II proceeding. However, the Commission considers that the AP/NGTL Service Integration	Next GRA Phase II

<u>Decision</u>	<u>Direction No.</u>	<u>Direction</u>	<u>Status</u>
		Proposal could eliminate a need for an AP GRA Phase II process. The Commission sees a protracted Phase II process, at this time, would add little value to customers when considering the potential impact of the AP/NGTL integration and the costs of a Phase II proceeding. However, AP is directed to address all outstanding Phase II directions at its next GRA Phase II. P. 9	
2009-171 2009-2010 Unaccounted for Gas and Fuel Gas Rates – Rider “D”	1	AP also indicated that line gains have moderated in the past year, coincident with changes in the NOVA Gas Transmission Ltd. system. The Commission accepts this explanation and directs AP to report on the UFG status and any inspections or remedial action taken in respect of the Grande Cache system its next UFG application. P. 5	Next UFG Application
2009-261 2009 Load Balancing Deferral Account South System	1	The Commission also expects AP will include a settlement of the LBDA for both North and South in its UFG/Fuel Rider “D” application for 2010-2011, consistent with the Commission’s directions in Decision 2009-117. P. 5	Next UFG Application