Decision **2012-191**

Alberta Utilities Commission

ATCO Gas

2011-2012 General Rate Application
Phase I Compliance Filing

July 20, 2012

The Alberta Utilities Commission
Decision 2012-191: ATCO Gas
2011-2012 General Rate Application Phase I Compliance Filing
Application No. 1608144
Proceeding ID No. 1709

July 20, 2012

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

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1 Introduction

1. On December 5, 2011, the Alberta Utilities Commission (AUC or the Commission) issued Decision 2011-450[1] regarding the 2011-2012 General Rate Application (GRA) Phase I for ATCO Gas (AG). In Decision 2011-450, the Commission directed AG to refile its 2011-2012 GRA incorporating the Commission's findings, conclusions and directions (directions) in that decision and provide a detailed reconciliation of the 2011-2012 revenue requirements.

2. On February 9, 2012,[2] AG refiled its 2011-2012 GRA (the compliance filing), reflecting the revisions required to comply with the Commission's directions in Decision 2011-450.

3. On February 13, 2012, the Commission issued notice of application with respect to the compliance filing. Subsequently, statements of intent to participate in the proceeding were received from the Consumers' Coalition of Alberta (CCA), The City of Calgary (Calgary) and the Office of the Utilities Consumer Advocate (UCA).

4. On March 2, 2012, the Commission established a process schedule in order to examine and address any issues with respect to the compliance filing. Information requests to AG were due on March 13, 2012, and information responses from AG were due March 27, 2012. By letter dated March 29, 2012, the Commission set the dates for argument and reply argument as April 12, 2012, and April 26, 2012, respectively.

5. The Commission considers that the record for this proceeding closed on April 26, 2012.

6. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and 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 all relevant portions of the record with respect to that matter.

[1] Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - 2011-2012 General Rate Application Phase 1, Application No. 1606822, Proceeding ID No. 969, December 5, 2011.

[2] AG GRA Proceeding ID No. 969, Exhibit 221, The Commission extended the deadline for AG to re-file its 2011-2012 GRA Compliance application to February 9, 2012.

2 Background

7. On June 8, 2012, the Commission issued Decision 2012-156,[3] the Phase I review and variance (R&V) of Decision 2011-450. AG requested a review and variance of Decision 2011-450, the AG 2011-2012 GRA decision, for the following matters:

- Demand Side Management (DSM) programs
- The Edmonton Blue Flame Kitchen (BFK)
- Customer Information System (CIS) enhancements
- Head Office Advertising Costs
- Oracle HRX (HRX)
- NOVA Gas Transmission Ltd.(NGTL)/ATCO Pipelines (AP) Integration Matters
- Late Payment Penalty
- Calgary Office Lease
- Production Abandonment

8. The Commission determined that AG had not demonstrated a substantial doubt as to the correctness of Decision 2011-450 regarding the issues of DSM, the Edmonton BFK, head office advertising costs, or a deferral account for NGTL/AP Integration. Further review of these matters was denied. However, the Commission granted a second stage review of the CIS enhancements, HRX, the legal costs associated with the NGTL hearing, the Calgary office lease and late payment penalty. For production abandonment costs, the Commission determined that a substantial doubt as to the correctness of the decision was raised, and this matter would be considered in the Utility Asset Disposition Rate Review Proceeding (Proceeding ID No. 20) or in a generic proceeding on asset disposition and stranded assets.

9. On June 19, 2012, the Commission received a letter from AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Utilities, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. (the Utilities) requesting clarification of Decision 2012-154 and Decision 2012-156. The Utilities requested confirmation whether or not stranded cost risk exists for any of the Utilities for the 2011-2012 test period and how the Commission proposed to address the fact that such risk was not reflected in the Commission's determination of fair return. The Utilities also wanted confirmation that any findings made in future proceedings would only apply prospectively. The Commission determined that the issues raised by the Utilities in the clarification letter would be addressed in Proceeding ID No. 20 or another generic proceeding. If the issue of prospectivity has not been addressed in Proceeding ID No. 20 or the generic proceeding, the Commission would establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

3 Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) – Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, Application No. 1608121, Proceeding ID No. 1698, June 8, 2012.

3 Particulars of the application

10. AG updated its revenue requirement in the compliance filing application and provided summary tables comparing the applied-for revenue requirements and the approved revenue requirement from Decision 2011-450 for each of 2011 and 2012:

Table 1. ATCO Gas 2011 base rate revenue requirements ($000's)

Line		2011			
No.		As Filed	GRA Update	AUC 2011-450	Change
1	Rate Base	1,566,115	1,562,650	1,524,391	(38,259)
2	Return on Rate Base	7.200%	7.200%	7.156%	8.942%
3	Utility Income	112,767	112,514	109,093	(3,421)
	Cash Operating Expenses				
4	Other Taxes	335	335	335	0
5	Other Operating Expenses	368,404	365,873	346,586	(19,287)
6	Total Cash Operating Expenses	368,739	366,208	346,921	(19,287)
7	Depreciation	126,386	114,828	100,487	(14,341)
8	Provision for Income Taxes	14,012	9,502	8,003	(1,499)
9	Base Rate Revenue Requirement	621,904	603,052	564,504	(38,548)
10	Less Revenue on Existing Rates	560,436	561,426	585,624	24,198
11	Revenue Shortfall	**61,468**	**41,626**	**(21,120)**	**(62,746)**

Table 2. ATCO Gas 2012 base rate revenue requirement ($000's)

Line No.		2012 As Filed	2012 GRA Update	2012 AUC 2011-450	2012 Change
1	Rate Base	1,760,535	1,758,185	1,673,701	(84,484)
2	Return on Rate Base	7.130%	7.141%	7.071%	8.529%
3	Utility Income	125,530	125,555	118,349	(7,206)
	Cash Operating Expenses				
4	Other Taxes	358	358	358	0
5	Other Operating Expenses	378,844	377,613	360,372	(17,241)
6	Total Cash Operating Expenses	379,202	377,971	360,730	(17,241)
7	Depreciation	137,522	126,165	109,292	(16,873)
8	Provision for Income Taxes	15,807	11,952	9,925	(2,027)
9	Base Rate Revenue Requirement	658,061	641,643	598,296	(43,347)
10	Less Revenue on Existing Rates	571,285	571,952	623,814	51,862
11	Revenue Shortfall	**86,776**	**69,691**	**(25,518)**	**(95,209)**

4 Compliance with directions from Decision 2011-450

11. In Decision 2011-450, the Commission made 59 separate directions to be addressed in its compliance filing.[4] AG further addressed additional directions, number 60 through 65 which were not highlighted in Appendix 3 of the decision. The Commission has regrouped some of the directions by subject matter rather than by numerical order and certain sections of the decision will not follow the numerical order set out in Decision 2011-450 Appendix 3 – Summary of Commission Directions.

12. During the course of this proceeding, interveners argued that there were some Commission directions with which AG had not properly complied in its compliance filing.

[4] Decision 2011-450, Appendix 3.

13. The Commission has reviewed the explanations, detailed calculations and adjustments AG has made for each direction. In the following sections of this decision, the Commission will identify each direction separately, address the items at issue and make a finding on AG's compliance with each direction.

4.1 Commission Direction 1 – opening rate base

14. In Decision 2011-450, the Commission issued the following direction to AG:

> 83. The Commission will review the prudence of some of the 2008 to 2010 capital expenditures in the other sections of this report. The Commission directs AG in its compliance filing to update its 2011 opening rate base in accordance with the findings in other sections of this decision. The 2011 opening property, plant, and equipment accounts are approved subject to the Commission's directions relating to specific assets addressed in subsequent sections of this decision.[5]

15. The Commission also issued the following directions summarized in Appendix 3 of Decision 2011-450, which are relevant to the discussion of the opening rate base adjustments, and the Commission directions on the costs associated with the service initiation and billing system (SIBS), HRX, the BFK and DSM:

> 13. The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission.
>
> 14. The Commission finds the actual cost of $15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent.
>
> 30. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK while the forecast for the test period for the BFK is $2 million per year. The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre. The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening

[5] Decision 2011-450, paragraph 83.

rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied.

33. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base.

16. AG summarized the opening rate base reductions and these reductions are reflected in the following table:

Table 3. Opening Rate Base Reductions (000's)

Description	Reference	Original Cost	Accumulated Depreciation	Net Utility Property, Plant and Equipment
SIBS	CD 13	(2,476)	(206)	(2,270)
HRX	CD 14	(1,439)	(130)	(1,309)
Blue Flame Kitchen	CD 30	(2,044)	(228)	(1,816)
DSM	CD 33	(335)	(58)	(277)
Total Adjustments		**(6,294)**	**(622)**	**(5,672)**

17. AG noted that these assets would not be fully depreciated for 30 years, and that it would have to keep track of the differences between property, plant and equipment (PP&E), undepreciated capital costs for income tax purposes, depreciation expense, and capital cost allowance for accounting purposes and income tax purposes in two sets of books. AG proposed to make a present value payment of $6,376,000 to customers to allow AG to retain its existing opening rate base. AG stated "The present value payment provides the financial impact to customers of adjusting rate base while avoiding the unnecessary administrative burden involved in tracking these adjustments over an extended period of time."[6] AG also noted that keeping two sets of books rather than using the present value payment would increase the administrative burden. Present value payments were approved by the Commission in the ATCO Utilities 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-up Proceeding[7] and the 2008-2009 Evergreen Application Compliance Filing to Decision 2011-228.[8]

18. The UCA stated that it did not favour the use of one-time adjustments and the decisions noted by AG were related to adjustments to ATCO I-Tek costs as a result of a benchmarking report.[9] The asset cost adjustments, reflected as a one-time payment in Decision 2010-102, did not reflect adjustments for disallowed assets, but rather reflected the amounts for ATCO I-Tek costs that were determined to be too high. Further, in that decision, there was no mention of imprudent costs or disallowed assets unlike the asset costs that were disallowed in Decision 2011-450. The approach of removing assets from rate base is not a new process and

6 Application, page 1, Opening Rate Base Adjustments.

7 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010.

8 Decision 2011-485: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2008-2009 Evergreen Application Compliance Filing to Decision 2011-228, Application No. 1607460, Proceeding ID No. 1321, December 12, 2011, paragraphs 24 and 25.

9 Exhibit 40.02, UCA argument, paragraph 3.

AG's methodology was more the exception than the rule.[10] In prior proceedings the removal of costs was shown as a separate line item of disallowed or as non-utility assets.

19. The UCA considered that future changes to income tax rates, depreciation rates, return on equity and capital structures virtually guarantee that the assumptions used in the net present value calculations will become inaccurate over time. The UCA submitted that "Leaving the assets as disallowed or non-utility assets will allow for the most appropriate treatment of these costs and ensure future changes to the above components of revenue requirement are properly reflected in customer rates."[11]

20. The UCA also argued that an appropriate discount rate had not been determined or argued in the 2011-2012 GRA, and as a result, it recommended that the Commission reject AG's proposal to use a present value method to determine the refund to customers. However, should the Commission be persuaded by the AG proposal, the UCA recommended that the Commission adopt a deferral account approach to take into account future income tax, depreciation rates, rates of return, and capital structure changes that can and likely will occur over the next 10 years and into the future. Further, the appropriate discount rate would be the same discount rate used in carrying cost calculations in deferral account applications.[12]

21. Calgary was opposed to AG's net present value (NPV) approach and considered that the benefit customers receive from removing these items from rate base may be different than AG's calculated revenue impact adjustments.[13]

22. Calgary asserted that allowing these items to remain in rate base was contrary to the findings from the Supreme Court of Canada in the Stores Block decision[14] and the Alberta Court of Appeal in the Carbon decision[15] that only assets providing utility service should be included in rate base. AG's treatment allows non-utility items to remain in rate base. Further, under performance based regulation, AG's going-in revenue requirement would be higher than it should be and AG would receive adjustments based upon that higher revenue requirement.[16]

23. Calgary noted AG's position that it could not provide details of the disallowed capital expenditures by asset account. Calgary questioned how proper depreciation rates were determined and a net present value of the revenue requirement for the account was calculated if AG cannot provide details of the fixed asset accounts related to the disallowed assets. If the assets were removed from rate base they would likely be impaired and at some point be removed from the utility assets of AG for financial accounting purposes. The need for two sets of books would be eliminated.[17]

24. Calgary submitted that the Commission should reject AG's NPV approach and require the assets to be removed from rate base.[18]

10 Exhibit 40.02, UCA argument, paragraph 5.
11 Exhibit 40.02, UCA argument, paragraph 6.
12 Exhibit 40.02, UCA argument, paragraph 7.
13 Exhibit 41.01, Calgary argument, page 3.
14 ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utilities Board) 2006 SCC 4.
15 ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utilities Board) [2008] ABCA 200.
16 Exhibit 41.01, Calgary argument, page 3.
17 Exhibit 41.01, Calgary argument pages 3 and 4.
18 Exhibit 41.01, Calgary argument, page 4.

25. CCA noted AG's response to CCA-AG-02[19] that customers are not harmed by holding smaller assets such as the BFK assets in the legal entity. CCA disagreed that customers are not harmed. Interest rates were currently low and would likely increase over the next 30 years. Changes in income rates, capital cost allowance rates and methodologies are likely to occur in the future. These changes cause risk for customers, for which they should not be responsible. Further, there will be increased regulatory activity as the disallowed assets must continue to be reviewed and keeping non-regulated or disallowed assets in rate base was not good regulatory practice.[20]

26. CCA was concerned about the cumulative risk and magnitude as disallowed assets continue to be placed into rate base over time.[21] The appropriate regulatory practice is to remove disallowed assets from rate base, as noted in Decision 2005-128:[22]

> …the Board finds it preferable that, within a corporate group, assets which are not engaged in rate regulated service should be held by a separate legal entity from the one holding rate regulated assets ... With respect to existing material assets already owned by a utility that have never been included in rate base like the MRP, or assets which at some point in time are removed from rate base, the preference of the Board would be that these assets also be moved into a separate legal entity.[23]

27. AG agreed that it is common to see a "Disallowed Asset" or "Non-Utility Asset" category in utility revenue requirement summaries and that the present value approach is more the exception than the rule. These adjustments are unique in that, for the most part, they do not refer to whole assets being removed from utility service. The majority of the disallowed costs relate to SIBS and HRX which are software applications that are clearly still in utility service. This is the exact same situation that arose from actual I-Tek costs being charged to PP&E being determined to be too high in which the Commission ruled that something less than the total dollars in PP&E were to be included in rates.[24]

28. Similar to the I-Tek costs, AG is attempting to avoid a situation where the same asset or assets have a portion of their costs included in utility operations and a portion in non-utility operations. AG argued, "In this situation depreciation expense must be split between utility and non-utility, capital cost allowance must be split between utility and non-utility and the ultimate retirement of the asset must be split between utility and non-utility."[25]

29. While the Blue Flame Kitchen is an entire program and not a disallowance of partial costs there would be a significant amount of administrative burden to isolate what is a small portion of AG's overall leasehold improvement costs. This is similar to SIBS and HRX, where costs for leasehold improvement depreciation and capital cost allowance need to be split and an amount is assigned to non-utility.[26]

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19 Exhibit 37.01 CCA-AG-02(a) page 2 of 3, page 4 PDF.
20 Exhibit 42.01, CCA argument, paragraph 8.
21 Exhibit 42.01, CCA argument, paragraph 8.
22 Exhibit 42.01, CCA argument, paragraph 9.
23 Decision 2005-128: ATCO Pipelines - Muskeg River Pipeline Application, Application No, 1393613, November 29, 2005, page 6 (page 10 in PDF).
24 Exhibit 45.01, ATCO Gas reply argument, paragraph 7.
25 Exhibit 45.01, ATCO Gas reply argument, paragraph 8.
26 Exhibit 45.01, ATCO Gas reply argument, paragraph 9.

30. AG did not agree with CCA's argument that further regulatory activity will be increased as a result of the NPV proposal. Under AG's proposal, these assets will remain in rate base to be depreciated for both accounting purposes and income tax purposes in their normal course until they reach the end of their useful lives, when they will be retired. This will not create any incremental regulatory activity unlike isolating the costs as non-utility. Isolating these costs as non-utility would create additional administrative burden in splitting the depreciation expense and capital cost allowance every year between utility and non-utility, and maintaining a life to date continuity of the accumulated amounts.[27]

31. In response to the UCA, AG considered that these assets are unique and warrant different treatment as they are not disallowances of whole assets, but rather partial disallowances of assets that, for the most part, remain in utility service. The UCA's suggested use of the standard approach to disallowed assets is not appropriate.[28]

32. Noting the UCA and CCA's concerns with respect to changing interest rates, tax rates, capital cost allowance rates and methodologies, and UCA's recommendation to adopt a deferral account approach regarding potential changes in these rates, AG noted that the 2011 revenue requirement related to these assets is $850,000, which represents less than two tenths of one per cent of the 2011 revenue requirement of $564.5 million and these amounts are not material.[29]

33. AG also considered the materiality on the impact in the one time payment if the weighted average cost of capital (WACC), income tax rates, and depreciation expense were increased by 10 per cent and capital cost allowance claims reduced by 10 per cent. Assuming these changes would occur at the earliest possible time, the magnitude of the one-time payment changed by $218,000 from $6,376,000 to $6,594,000, or $0.22 per customer based on 1,000,000 customers. AG submitted that those amounts are not material and any risk that customers are exposed to is insignificant regardless of the standard applied. The immateriality of the amounts demonstrates that there is no need for a deferral account.[30]

34. AG agrees with the UCA that the appropriate discount rate would be the same discount rate used in carrying cost calculations for deferral accounts. Both the recently established weather deferral account and load balancing deferral account have carrying charges applied to the average monthly balances, and, in both cases, apply the WACC rate approved by the Commission for accrual of carrying costs.[31]

35. While Calgary argued that the NPV methodology was a zero sum game in which ATCO suffers no loss, AG argued that this was incorrect. AG submitted that "When items are removed from rate base there is no recovery of depreciation expense, income taxes or return provided for in customer rates/revenue. Under the AG proposal, the one-time payment along with a financing accretion amount is amortized and offsets the higher revenue AG receives by these assets

27 Exhibit 45.01, ATCO Gas reply argument, paragraph 11.
28 Exhibit 45.01, ATCO Gas reply argument, paragraph 12.
29 Exhibit 45.01, ATCO Gas reply argument, paragraph 15.
30 Exhibit 45.01, ATCO Gas reply argument, paragraph 16.
31 Exhibit 45.01, ATCO Gas reply argument, paragraph 19.

remaining in rate base."[32] The financial result for AG is identical whether the NPV methodology is used or the amounts are removed from rate base.[33]

36. In response to Calgary's argument that allowing items to remain in rate base was inconsistent with the Stores Block and Carbon decisions, AG indicated that these assets have not been removed from utility service but rather a portion of their costs have been disallowed. The remaining minority of these assets, for the BFK and DSM, are immaterial amounts.[34]

37. AG also acknowledged Calgary's position that under a performance-based regulation (PBR) regime, its going in revenue would be higher than it otherwise would be, but AG could remove the revenue requirement impact for the insignificant amounts from the indexing mechanism in its PBR formula and treat these amounts as a Y Factor flow through adjustments.[35]

38. With respect to asset accounts, AG is aware of what asset accounts the disallowed assets are in, which allows AG to properly determine the depreciation expense and calculate a net present value. Under International Financial Reporting Standards (IFRS), these assets are not impaired and will not be removed from the financial assets of AG for accounting purposes, which gives rise to the issue of keeping two sets of books.[36]

39. AG submitted that its proposal for a present value payment was reasonable. The present value payment provides the financial impact to customers of adjusting rate base while avoiding the significant and unnecessary administrative burden involved in tracking these adjustments over an extended period of time.[37]

40. Both the UCA and CCA argued that future changes in income tax rates, depreciation rates, rates of return on equity, and capital structures would impact the current NPV calculation and place customers at risk for bearing costs that should have been removed from ratebase.

41. When determining the merits of using a net present value approach to address rate base adjustments, an assessment of the benefits and concerns of using a net present value approach, including the reasonableness of the approach to the utility, present ratepayers, and future ratepayers, must be made based on the circumstances of the particular situation. The Commission agrees with both the UCA and CCA that future changes may occur. However, the calculations done by AG indicated that dramatic changes to WACC, income tax rates, depreciation and capital cost allowance claims, should they occur, should not have a material impact on the NPV amount to be refunded to customers.

42. While it would be preferable to remove costs from rate base for assets that are not required for utility service, the Commission realizes that this may not be practical in every situation. As indicated by AG, the majority of disallowed costs are related to SIBS and HRX programs, which are currently in utility service. Given the current use of these programs, the Commission considers that it would not be efficient to require AG to track differences for income tax and accounting purposes until these assets are retired as the costs for these projects have been reduced, but the programs have not been disallowed.

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[32] Exhibit 45.01, ATCO Gas reply argument, paragraph 21.
[33] Exhibit 45.01, ATCO Gas reply argument, paragraph 21.
[34] Exhibit 45.01, ATCO Gas reply argument, paragraph 22.
[35] Exhibit 45.01, ATCO Gas reply argument, paragraph 23.
[36] Exhibit 45.01, ATCO Gas reply argument, paragraph 25.
[37] Exhibit 45.01, ATCO Gas reply argument, paragraph 28.

43. Given the small reduction in the NPV amount that would be refunded to customers should WACC, income tax rates, depreciation and capital cost allowance assumptions change, and the fact that a portion of the assets in question are still in utility service, the Commission considers the proposal advanced by AG is an effective way to balance the amounts owing to customers with regulatory efficiency. On this basis, the Commission approves the NPV methodology recommended by AG for the SIBS and HRX amounts.

44. With respect to the BFK and DSM, the Commission finds that these costs are related to entire programs which have been disallowed by the Commission, and costs associated with these programs are not required for utility service, unlike SIBS and HRX costs which were split between utility and non-utility service. On this basis the Commission directs AG to remove the BFK and DSM reductions accounted in for its opening rate base in its second compliance filing to Decision 2011-450.

45. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in this compliance filing. This issue of the 10 per cent cost reduction for HRX is currently before the Commission in Proceeding ID No. 1698, the ATCO Gas 2011-2012 Phase II Review and Variance (Phase II R&V). In Decision 2012-156, the Phase I R&V decision, the review panel stated that AG did not have a reasonable opportunity to place its HRX business case in context as the business case was filed after the cross examination of the AG panel was completed.[38] Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount for 90 per cent of the actual costs of HRX in its second compliance filing to Decision 2011-450.

4.2 Commission Direction 2 - Tier 2 and Tier 3 meters

46. The Commission issued the following direction to AG:

> 163. The Commission directs AG in the compliance filing to this decision to provide the Commission with the actual number of Tier 2 meters replaced in 2010 and the actual capital costs incurred. AG is directed to indicate the number of Tier 2 meters and Tier 3 meters with a medium risk factor left to be replaced in 2011 and 2012 and to provide the forecast capital costs in each year using the forecast capital costs calculated from Tables 2.1.1.2(c) and (d) in the application.[39]

47. In the application AG identified the actual number of Tier 2 and Tier 3 meters which were replaced in 2012 and the capital costs, not including removal costs.[40] A summary table was provided showing the breakdown between Tier 2 and Tier 3 medium risk and Tier 3 low risk. In 2010, AG performed a total of 3,356 above ground moves for the total capital cost of $8,819,000. The Commission is satisfied that AG has complied with this request.

4.3 Commission Direction 3 – Tier 2 and Tier 3 meters

48. The Commission issued the following direction to AG:

> 164. The Commission further directs AG to plan the replacement of the Tier 2 and the portion of the Tier 3 meters with a medium risk factor in a manner that achieves efficiencies and distributes the costs evenly over the period 2011 to 2014.[41]

38 Decision 2012-156, page 17, paragraph 65.
39 Decision 2011-450, paragraph 163.
40 Application, Commission Direction 2.
41 Decision 2011-450, paragraph 164.

49. AG adjusted the 2011 to 2014 forecast expenditures for meter relocation and replacement program (MRRP), and provided a summary of the changes in Commission Direction 3 attachment.[42]

50. In reviewing the MRRP forecast expenditure changes, the UCA raised concerns regarding the addition of 1,240 meters into the project, the apparent shifting of 1,200 meter replacements from 2014 to 2011 and 2012, and the addition of 16.5 per cent cost premium. UCA noted that 1,240 meters that were previously scheduled to be replaced as part of the urban mains replacement (UMR) program were added into the total number of meters to be moved or replaced in 2014 as part of MRRP. Further a 16.5 per cent cost premium was added to the average unit cost for above ground meters.

51. With respect to the additional 1,240 meters added to MRRP, UCA pointed out that it appeared 1,200 meters were removed from 2014 and redistributed primarily to 2011 and 2012. UCA considered that the need for these moves was not previously identified, discussed or tested in the GRA. UCA argued that assuming that the 1,240 additional meters need to be replaced at some point as part of the program, it would be reasonable to schedule those meter replacements in 2014 without "redistributing" them into the test years.

52. UCA noted the 16.5 per cent cost premium was approved in AUC Decision 2008-113[43] because work was to be performed on sites spread out across the province. Having reviewed the reference to the cost premium in Decision 2008-113, UCA considered that there was no reason to believe that the circumstances that led to the approval of a cost premium in 2008 currently existed and should be applied in this case. There is no reasonable evidentiary basis for adding the 16.5 per cent premium and the premium should be removed.

53. AG stated that with the proposed acceleration of the UMR program 1,240 meters were removed from the MRRP. However, with the Commission's reductions to UMR, the 1,240 meters were returned to MRRP, as the meters in these locations would now not be moved as part of the reduced UMR program.

54. With the addition of these meters to the MRRP, the costs were distributed evenly over the period 2011 to 2014, as ordered in Commission Direction 3. The 1,200 "redistributed" units noted by the UCA as shown in 2011 and 2012 were only coincidentally close to the same number of units that were removed from 2014. AG stated that scheduling these meter replacements in 2014, as argued by UCA, was contrary to the Commission direction to distribute the costs evenly over the period 2011 to 2014.

55. While AG did not dispute UCA's argument that the circumstances surrounding the 16.5 per cent cost premium approved in Decision 2008-113 may be different than the circumstances in the 2011-2012 GRA, the resulting inefficiencies are similar. The loss of efficiencies due to the work being more spread out as a result of the exclusion of the Tier 3 low risk meter replacements from the approved program relates to approximately 28 per cent of the requested work being excluded from the revenue requirement forecasts.

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42 Application, Exhibit 1, pages 122 of 238 PDF.

43 Decision 2008-113: ATCO Gas – 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID No. 11, November 13, 2008.

56. Rather than completing the work as planned, AG is now required to skip over both the Tier 3 low risk meters as well as the Tier 4 meters, resulting in increased inefficiencies. The costs to set up in a neighbourhood, pack up for a relocation and travel costs will now be spread over 28 per cent less units which will have a significant impact on unit cost rates. AG submitted that while the circumstances may be different, the resulting impact of lost efficiencies on unit cost rates is very much the same.

57. The Commission notes that due to the overlap of the UMR program with the MRRP, AG removed the installation of 1,240 meters from the MRRP, as these meters would be replaced under the UMR program. Given the Commission directions and resulting reductions to the UMR program, the Commission agrees with AG that the previously removed 1,240 meters should be restored to the MRRP is consistent with the findings in the GRA decision.

58. The Commission also agrees with the shifting of 1,200 meters from the 2014 forecast to the 2011 and 2012 forecasts. The Commission finds that this shifting of meters was done in response to the Commission's direction to distribute the costs evenly over the 2011 to 2014 period and the forecasts in 2011 and 2012 are reflective of the Commission's direction.

59. With respect to the 16.5 per cent premium added to the MRRP costs for work being spread out over 2011 to 2014, while the average installation cost per meter may change as noted by AG, there was no evidence presented by AG to suggest that there will be additional set-up, pack-up and travel costs as a result of the reduction in meters being replaced. Decision 2008-113 allowed for the 16.5 per cent premium based on the midrange of three per cent and 30 per cent of subsequent contractor premiums quoted to AG. The Commission in that decision recognized labour constraints in allowing the premium but also indicated that it expected AG to make its best efforts to utilize in house labour in carrying out the MRRP.

60. The Commission finds that there was limited evidence provided by AG in the compliance filing with regard to increased labour requirements or travel costs to support a premium in the 2011 and 2012 test years. However, the Commission recognizes that potential inefficiencies may have resulted due to AG's required exclusion of Tier 3 low risk meter replacements as per Commission Direction 2. As a result, the Commission directs AG in its second compliance filing to provide a detailed justification of any premium that should be applied to AG's forecast due to the above noted inefficiencies.

4.4 Commission Direction 4, 5 and 6 – plastic pipe

61. The Commission issued the following directions to AG:

> 4. With respect to the second UCA recommendation the Commission acknowledges that pre-1973 plastic pipe and 1973 to1975 plastic pipe were subject to different certification practices and approved for different operating pressures. However, the Commission notes that neither vintage group was required to meet the CSA standard which became mandatory in 1975. Accordingly, the Commission considers it in the public interest to remove all pipe manufactured prior to 1973. With respect to pipe manufactured from 1973 to 1975, the Commission notes AG's comment that it is acting with an "abundance of caution." With regard to the UCA's first recommendation, the issue for the Commission to address is the extent to which inventory practices may have resulted in the installation in 1976 or 1977 of interim certified pipe from the 1973 to1975 period. AG's records are inadequate. AG is neither able to identify whether pipe purchased during the interim 1973 to1975 period was certified nor has it the ability to determine how long pipe remained in inventory and therefore, what portion, if any of the pipe was

installed in 1976 and 1977. These facts have made the consideration of this program difficult. Nonetheless, the Commission considers the risk of brittle failure associated with plastic pipe and PVC pipe when subjected to stress to be a serious safety and reliability issue, and therefore, the Commission approves the entire program. However, the Commission directs that the program be implemented over a 20-year period considered in alternative three in the business case rather than the 17-year proposed in alternative two. Given the fact that the pipe manufactured during the 1973 to1975 period was of a higher quality than the pre-1973 pipe and some of the 1973 to 1975 pipe may have met the then voluntary CSA standard and noting that this vintage of pipe was proposed to be removed last, the Commission considers the extended installation period to be warranted. Lengthening the time period over which replacement occurs will reduce the magnitude of the impact on rates to customers but does put in place a comprehensive plan to replace PVC and early generation PE.[44]

5. As additional leak history data on pipe installed from the 1973 to1977 period becomes available it may be appropriate to reconsider the program scope and timelines. The Commission directs AG to continue to provide plastic pipe leak history in future capital program applications.[45]

6. The Commission directs AG in the compliance filing required by this decision to indicate what the 2011 and 2012 plastic pipe replacement program revenue requirement would be based on a 20-year program, without considering the actual 2011 expenditures.[46]

62. In its application, AG reduced its forecast for the PE/PVC Pipe replacement by 15 per cent in the test years to reflect the extension of the program from 17 years to 20 years.[47] The 15 per cent reductions result in an impact of $2.9 million and $3.5 million in 2011 and 2012 respectively. AG will continue to identify leak information for pipe installed in the 1973 to 1977 period as a subgroup in order to comply with Direction 5. In its response to Direction 6, AG provided the 2011 and 2012 revenue requirements of the plastic pipe replacement program based on the compliance filing capital expenditures included in the response to Commission Direction 4. The forecast revenue requirements are $1 million for 2011 and $3.1 million for 2012.

63. The Commission has reviewed the calculation of the plastic pipe program extension revenue requirement and the Summary of Capital Expenditures spreadsheet[48] and is satisfied that AG has complied with these directions.

4.5 Commission Direction 7 – line heaters

64. The Commission issued the following direction to AG:

200. The Commission relies on AG's statement that OH&S regulations require AG to update its line heaters. A three-year program has been proposed to complete the work to bring the non-compliant line heaters into compliance and to do reliability work at the same time. The plan by AG to complete the compliance work in three years seems reasonable and the Commission approves this portion of the program for inclusion in

44 Decision 2011-450, paragraph 191.
45 Decision 2011-450, paragraph 192.
46 Decision 2011-450, paragraph 193.
47 Application, Commission Direction 4.
48 Application, Exhibit 7.

> revenue requirement. The Commission finds that when reliability improvements are to be made on heaters for which compliance work is to be done, it is practical to do both at the same time over the three year period. However, the Commission does not consider that justification has been made for a three-year period to complete work on line heaters that do not have a compliance component. Therefore the Commission directs AG to exclude from its program, line heaters that are in compliance with OH&S regulations. The Commission directs AG in the compliance filing to this decision to reflect two years of the three-year replacement and upgrading of the non-compliant line-heaters.[49]

65. AG revised the line heater program to exclude work on line heaters that do not have a compliance component and to only reflect sites which require improvements to bring non-compliant line heaters into compliance with Occupational Health and Safety (OH&S) regulations. The revised program results in expenditures of $6 million in each of 2011 and 2012, resulting in a reduction of $1 million for each test year. The Commission has reviewed the Summary of Capital Expenditures spreadsheet[50] and is satisfied that AG has reflected the change to the Line Heater program in its revenue requirement for the test years.

4.6 Commission Direction 8 – AMR contingency

66. The Commission issued the following direction to AG:

> 216. The UCA's primary concern with the AMR program was the magnitude of the contingency included in the forecast estimates. The Commission agrees that the contingency may be too high, but notes that AG was expected to complete a "proof of concept" by the end of June 2011. The Commission directs AG to report in the compliance application to this decision on the results and effects of the "proof of concept" stage for installations made in the initial phase of the project and the results and the effect on the contingency, if any. AG is directed to submit an update to its business case economic analysis. The Commission will finalize the test year forecast amounts along with the contingency following the compliance application.[51]

67. AG completed a proof of installation concept review in October 2011. The forecast automated meter reading (AMR) capital expenditure and removal costs are $18.5 million for 2011 and $39.5 million for 2012, respectively. AG explained that the 20 per cent contingency forecast of 3.1 million for 2011 and $6.6 million for 2012 included in the AMR project continues to be reasonable based on the requirements identified in the proof of installation concept. AG confirmed that no change to the contingency was required.[52] Additional costs were identified in the proof of concept as follows:[53]

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49 Decision 2011-450, paragraph 200.
50 Application, Exhibit 7.
51 Decision 2011-450, paragraph 216.
52 Exhibit 36, AG information response to UCA-AG-06(a).
53 Application, Exhibit 1, page 129 of 238 PDF.

Table 4. Contingency requirements

Contingency requirements ($ millions)	2011	2012
Finalization of Contract with Intron	0.8	1.7
Additional Project Management Requirements	0.5	0.7
Additional costs related to Installation Quality Assurance & Materials	0.8	1.2
Additional costs to retrofit ERT's	0.4	0.4
Additional Costs to address return to utility work	0.8	2
Increase in remote mount installation & cabling costs	0.2	0.5
Total Additional Costs identified	3.5	6.5

68. The Commission is satisfied that the additional costs identified by AG in the proof of concept for 2011 and 2012 of $3.5 million and $6.5 million are consistent with the 20 per cent contingency applied to the AMR project capital expenditures and the removal cost forecast of $18.5 million in 2011 and $39.5 million in 2012. Further, the Commission has reviewed the explanations provided by AG for the additional costs and is satisfied that AG's 20 per cent contingency amount of $3.1 million in 2011 and $6.6 million in 2012 as forecast in its general rate application continues to be reasonable. The Commission approves these forecast amounts for inclusion in AG's revenue requirement.

4.7 Commission Direction 9, 10 and 11 – Irma and Okotoks agency offices

69. The Commission issued the following direction to AG:

> 9. Accordingly, retired assets that are not anticipated to be disposed of at approximately the same time that they are retired should be moved to a non-utility account where any ongoing costs associated with the assets would be for the account of the utility shareholder. Given that the Irma agency office has been retired and not disposed of, the Commission directs AG to move the Irma agency office to the applicable non-utility accounts effective January 1, 2011. Operating costs and other costs associated with the facility, to the extent there are any, will be for the account of the AG shareholder from and after January 1, 2011.[54]
>
> 10. The Commission directs AG in the compliance filing to this decision to reflect the movement of the Irma agency office to a non-utility account as of January 1, 2011 and to reflect the removal of any operating or related costs associated with the facility as of that date.[55]
>
> 11. Should the Okotoks agency office not be disposed of at approximately the same time as it is retired, AG is directed to move the asset to a non-utility account where further operating and capital costs would be for the account of the utility shareholder.[56]

70. In its compliance filing, AG confirmed that no Irma agency costs were included in the 2011/2012 revenue requirement forecast and that the assets associated with the Irma agency office were retired in accordance with the Uniform Classification of Accounts for Gas Utilities.[57] As a result, AG stated that no associated changes were required to the 2011-2012 forecast revenue requirements for the Irma agency office. AG has also removed $8,000 in operating costs

54 Decision 2011-450, paragraph 320.
55 Decision 2011-450, paragraph 323.
56 Decision 2011-450, paragraph 330.
57 AR 546/63.

related to the Okotoks facility from its 2012 revenue requirement. The Commission is satisfied with these adjustments and considers that AG has complied with these directions.

4.8 Commission Direction 12 - moveable equipment

71. The Commission issued the following direction to AG:

> 355. Rather than an across the board reduction, the Commission prefers to use an escalation of past costs based on a three-year average of the actual expenditures in 2008, 2009 and 2010. AG has noted it has used a three-year average of past costs in other categories. In this case the three year average applied across-the-board to all the accounts noted above in the table equals $13.6 million. Allowing for inflation of three per cent, the amount approved for all the above accounts in 2011 is $14.0 million and in 2012 is $14.4 million. AG is directed to indicate in its compliance filing how it proposes to allocate the approved total amounts between the different accounts.[58]

72. AG provided a table in its response to Direction 12 showing the weightings of each category making up the other moveable equipment category.[59] The original forecast for the moveable equipment category was $17.4 million and $19.4 million. The total impact on revenue requirement using the approved amounts in Direction 12 is a reduction of $3.4 million and $5 million, which has been reflected in the table and the Summary of Capital Expenditures spreadsheet[60] attached to AG's application. The Commission has reviewed the reductions in the other moveable equipment category and is satisfied that AG has complied with this direction.

4.9 Commission Direction 13 - SIBS

73. The Commission issued the following direction to AG:

> The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission.[61]

74. For SIBS, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the SIBS replacement program in opening rate base was addressed in paragraph 43 of Direction 1 above. The Commission finds that AG has complied with this direction. The Commission also notes that the ongoing Evergreen 2 proceeding[62] will determine the final pricing amount for inclusion in 2011 and 2012 revenue requirements.

58 Decision 2011-450, paragraph 355.
59 Application, Exhibit 1, page 136 of 238 PDF.
60 Application, Exhibit 7.
61 Decision 2011-450, paragraph 359.
62 Proceeding ID No. 240, Application No. 1605538.

4.10 Commission Directions 14 and 15- HRX and TMS

75. The Commission issued the following direction regarding HRX:

> 14. The Commission finds the actual cost of $15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent.[63]

76. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the remaining costs of HRX in opening rate base was addressed in paragraph 43 of Direction 1 above. As stated in Direction 1, the issue of Oracle HRX is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V and pending the outcome of the Phase II R&V and any appeals on this issue, AG is directed to include a placeholder amount for Oracle HRX of 90 per cent of the actual cost in its second compliance filing to Decision 2011-450.

77. The Commission issued the following direction regarding AG's talent management system (TMS):

> 15. The Commission considers the HRchitect report which assumes a different platform, is helpful in providing directional guidance. Similarly, the Commission considered the 15 to 25 per cent application cost to total cost ratio as put forward by AG in the HRX business case. This analysis also provided directional guidance for a reduction in forecast costs for TMS. AG had agreed to address in testimony and rebuttal to remove the costs of the three TMS modules that will not be implemented in the test years. The Commission directs AG in its compliance filing to only include the forecast costs of the two modules to be implemented in the test years; performance management and succession planning. For all other costs in the business case, the Commission finds that in consideration of all the evidence before it, the TMS project is approved but that the forecast capital costs should be reduced by 10 per cent.[64]

78. AG noted in its application that the three modules of TMS which are not in use results in a reduction of $0.234 million.[65] AG is proposing to assign this amount to Plant Held for Future Use.[66] The 10 per cent reduction for all other costs in the business case results in an additional removal of $0.162 million. The Commission has reviewed AG's calculations for the TMS reductions and confirms they have been accurately reflected in the GRA schedules and the Capital Adjustments sheet.[67]

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[63] Decision 2011-450, paragraph 386.
[64] Decision 2011-450, paragraph 410.
[65] Application, Exhibit 1, page 139 of 238 PDF.
[66] Application, Exhibit 2, Schedule 2.5-A.
[67] Application, Exhibit 7.

4.11 Commission Direction 16 – Oracle E

79. The Commission issued the following direction to AG:

> The Commission finds that the proposed update to Oracle E in Business Case 16 is premature. A major argument in support of this business case is that support of the current version of Oracle E will end in 2013. The Commission agrees with Calgary that the need for this project has not been demonstrated as the current software support does not expire until 2013 and the benefits were not quantified. For these reasons the Commission denies the application for this business case and directs that the forecast costs related to this business case should be removed from its revenue requirement in the compliance filing for this application.[68]

80. In its application, AG has removed the Oracle E forecast capital expenditure amount of $2.748 million for 2011 in determining its revised revenue requirement and no capital expenditures were included for Oracle E in 2012. The Commission has confirmed that the forecast costs have been removed and the reduction has been reflected in the Capital Adjustments sheet.[69] The Commission concludes that AG has complied with this direction.

4.12 Commission Direction 17 – Oracle mid-size

81. The Commission issued the following direction to AG:

> Business Case 17 for oracle mid-size is proposed based on the fact that support of the current version will end in July 2013. The application states that Oracle will terminate the existing level of support on January 1, 2012. The Commission notes that there is a discrepancy in the dates of termination. According to AG's business case support will not be withdrawn but the level of support may change. The Commission does not consider it has sufficient information to determine if support will be withdrawn, and whether any change in the existing level of support will impact AG's operations. The Commission directs AG in the compliance filing to this application to provide information from the vendor regarding the proposed withdrawal of support, including the level of support which will continue to be available. If the vendor provides the option of continuing support at a lower level, AG is directed to provide an analysis of any impact on its operations.[70]

82. AG provided further information on Oracle product technical support levels. Premier product support is available from the product version availability date and extended support adds an additional three years. Sustained support is available as long as the technical support is maintained. The three different levels of support involve different service levels. Extended support for the current version, Oracle database 10g, will end in July 2013. AG stated there is risk associated with sustained support as problems with the database management system would most likely impact multiple applications.[71]

83. The Commission has reviewed the additional information provided by AG in support of the upgrade to Oracle database management system version 11g. AG stated it has 13 mid-size applications which currently use the Oracle 10g databases[72] and that that operation of the Daily

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68 Decision 2011-450, paragraph 437.
69 Application, Exhibit 7.
70 Decision 2011-450, paragraph 438.
71 Application, Exhibit 1, page 114 of 238 PDF.
72 Application, Commission Direction 17, page 5 of 9, paragraph 15.

Forecasting and Settlement System (DFSS) and Imbalance Reporting Information System (IRIS) are dependent on the Oracle databases. Given the additional information provided regarding the limitations of support, the integration with other programs, and risks of continuing with the current version of Oracle, the Commission approves the costs to upgrade to Oracle 11g for inclusion in the 2011-2012 revenue requirement.

4.13 Commission Direction 18 - Maximo

84. The Commission issued the following direction to AG:

> Business Case 19, work enhancements, also proposes a Maximo software upgrade in 2012. The Commission notes that functional benefits are forecast and that withdrawal of support anticipated for the fourth quarter of 2012. The Maximo software appears to have been installed as part of work management Phase II in October 2009 at a cost of $3.9 million. As Calgary noted the entire work management Phase II project was installed at a cost of $17 million compared to a forecast cost of $13.5 million. Calgary also noted a discrepancy in the cost breakdown between the business case and the schedule provided at page 16 of Tab 4.2 Attachment 1. The argument in support of the business case is premised on the withdrawal of support by the vendor. The Commission notes, as acknowledged by AG, that the vendor has not announced the withdrawal of support for the software. For the preceding reasons, the Commission denies approval of the forecasts costs for the Maximo software proposed in Business Case 19. The Commission directs AG to remove the forecast costs associated with this software package from its revenue requirement in the compliance filing for this application.[73]

85. AG removed the Maximo software upgrade forecast amount of $0.4 million, from its 2012 revenue requirement.[74] The Commission has confirmed that removal of this amount has been reflected in the capital adjustment sheet[75] and considers that AG has complied with this direction.

4.14 Commission Direction 19 - CIS

86. The Commission issued the following direction to AG:

> AG has forecast costs for the general CIS enhancement program of $1 million in 2011 and $0.6 million in 2012. This program and the related benefits are not clearly described. The Commission finds the explanation in paragraph 129 of the application does not justify the requested capital expenditure for this project. Therefore, the Commission denies this proposed enhancement and directs that related costs be removed from the revenue requirement in the compliance filing to this decision.[76]

87. AG has removed the CIS enhancement program, forecast amounts of $1 million and $0.6 million, in 2011 and 2012, respectively, determining its revised revenue requirement [MH1]. The Commission has confirmed that this amount has been reflected in the capital adjustment sheet.[77] The issue of the CIS enhancement program forecast costs is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V of Decision 2011-450. In the Phase I R&V, the review panel found that it was unclear whether the hearing panel considered

[73] Decision 2011-450, paragraph 441.
[74] Application, Exhibit 1, page 150 of 238 PDF.
[75] Application, Exhibit 7.
[76] Decision 2011-450, paragraph 443.
[77] Application, Exhibit 7.

AG's response to the business case in AUC-AG-43(b).[78] Pending the outcome of the Phase II R&V, AG is directed to include a placeholder amount for CIS of zero in its second compliance filing to Decision 2011-450.

4.15 Commission Direction 20 – IT capital projects

88. The Commission issued the following direction to AG:

> For approved IT capital projects the Commission directs AG in its compliance filing to provide a description of volume metrics and a detailed breakdown of the labour units related to the different classifications with the current rates in support of the forecast labour costs. For any items without units, an explanation should be provided of the reason for inclusion in labour costs. Similarly, AG shall provide an explanation for all projects that have been allocated a volume of processing costs.[79]

89. The Commission has reviewed the tables provided in Attachment 1-4[80] and finds that AG has provided the volume metrics and breakdown of the labour units and costs related to the different classifications as requested. AG has complied with Direction 20.

4.16 Commission Direction 21 and 22 – preferred shares

90. The Commission issued the following directions to AG:

> 21. Accordingly, the Commission finds the preferred share issuance to have been prudent. However, given that preferred shares are subordinate to debt and in certain market conditions, the issuance of preferred shares may demand higher dividend rates than anticipated, alternative debt options should be examined in such circumstances. The Commission directs AG in its next preferred share application to provide a comparative analysis of the alternative of issuing debt.[81]
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> 22. The Commission notes that AG offered to prepare a similar analysis to the one directed from ATCO Electric, concurrent with or prior to AG's next preferred share application. The Commission considers such an analysis is required and directs AG to prepare an updated analysis concurrent with or prior to AG's next preferred share application to assess whether the optimal range of five to 10 per cent for preferred shares as discussed in Decision 2006-100 should be continued thereafter. This analysis should also include a number that represents the most cost effective level of preferred shares for AG and should be submitted to the Commission concurrently with or before AG's next preferred share application to the Commission. Accordingly, approval of the actual preferred share issue is subject to the Commission's approval of the directed analysis.[82]

91. AG stated in its application that it will provide a comparative analysis of the alternative of issuing debt in its next preferred share application and prepare an updated analysis of whether the optimal range of AG's capital structure should include five to ten per cent of preferred shares concurrent with or prior to AG's next preferred share application.[83] For the purposes of this application, the Commission finds that Directions 21 and 22 have been complied with. AG is

[78] Decision 2012-156, paragraph 48, pages 12 and 13.
[79] Decision 2011-450, paragraph 450.
[80] Application, Commission Direction 20, Attachment 1-4.
[81] Decision 2011-450, paragraph 469.
[82] Decision 2011-450, paragraph 489.
[83] Application, Exhibit 1, pages 157 and 158 of 238 PDF.

directed to include the alternatives and analysis as directed in Decision 2011-450 in its next preferred share application.

4.17 Commission Direction 23 – preferred shares

92. The Commission issued the following direction to AG:

> Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual preferred share rates for preferred shares issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 preferred shares in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 preferred share rate and the rate of any preferred shares issued in 2011.[84]

93. AG stated in its application that it did not issue any preferred shares in 2011. AG also provided a revised forecast preferred share rate for 2012 of 4.25 per cent.[85] AG requested that the forecast rate be used as a placeholder pending the outcome of its leaves to appeal and review and variance of Decision 2011-450 and Decision 2011-474[86] as the forecast may be directly and materially affected by these decisions. The Commission has reviewed the information provided in the response to this direction, including the market forecast information from three Canadian Banks.[87] The Commission accepts the revised forecast preferred share rate of 4.25 per cent for 2012. In relation to the leaves to appeal and R&V applications of Decisions 2011-450 and Decision 2011-474, the Commission recently issued a June 28, 2012, clarification letter addressing stranded cost risk and any adjustments to the fair return:

> The Commission has reviewed the Utilities' letter and considers that the issues raised by the Utilities will be determined as part of either Proceeding ID No. 20 or another generic proceeding. In that proceeding, the Commission will consider whether its findings should apply to 2011 and 2012 or prospectively. Following the completion of either Proceeding ID No. 20 or another generic proceeding, and if the matter has not already been addressed, the Commission will establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

94. The Commission accepts that it is possible that the proceeding mentioned above, whether under Proceeding ID No. 20 or another generic proceeding, may have a potential effect on the 2012 preferred share forecast depending the outcome of the issue of stranded cost risk and any adjustments to the fair return. AG's request that the forecast 2012 preferred share rate be used as a placeholder is granted.

4.18 Commission Direction 24 - debt

95. The Commission issued the following direction to AG:

> Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual long-term debt rates for long-term debentures issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast

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84 Decision 2011-450, paragraph 494.

85 Application, Exhibit 1, page 159.

86 Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011.

87 Application, Commission Direction 23 Attachment 1-3.

> utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 long-term debt in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 long-term debt rate and the rate of any long-term debt issued in 2011.[88]

96. On October 24, 2011, AG issued two tranches of debt: a 30 year debenture at 4.543 per cent and a 50 year debenture at 4.593 per cent.[89]

97. AG also provided a forecast long-term debt rate for 2012 of 4.75 per cent. AG requested that the forecast rate be used as a placeholder pending the outcome of its leaves to appeal and R&V of Decision 2011-450 and Decision 2011-474, as the forecast may be directly and materially affected by these decisions. The Commission has reviewed the information provided in the response to this direction, including the market forecast information from three Canadian Banks.[90] The Commission accepts the revised forecast long-term debt rate of 4.75 per cent for 2012. In relation to the leaves to appeal and R&V applications of Decision 2011-450 and Decision 2011-474, the Commission recently issued a June 28, 2012, clarification letter addressing stranded cost risk and any adjustments to the fair return:

> The Commission has reviewed the Utilities' letter and considers that the issues raised by the Utilities will be determined as part of either Proceeding ID No. 20 or another generic proceeding. In that proceeding, the Commission will consider whether its findings should apply to 2011 and 2012 or prospectively. Following the completion of either Proceeding ID No. 20 or another generic proceeding, and if the matter has not already been addressed, the Commission will establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

98. The Commission accepts that it is possible that the proceeding, mentioned above, whether under Proceeding ID No. 20 or another generic proceeding, may have a potential effect on AG's long-term debt forecast depending the outcome of the issue of stranded cost risk and any adjustments to the fair return. AG's request that the forecast 2012 long-term debt rate be used as a placeholder is granted.

4.19 Commission Direction 25 – vacancy rate

99. The Commission issued the following direction to AG:

> The Commission has not been persuaded that the proposed decrease to a six per cent vacancy rate due to an increasing proportion of vacancies caused by retirements is warranted. A six per cent vacancy rate is inconsistent with historical results and unsupported by the evidence filed in this proceeding. AG is therefore directed to increase its forecast vacancy rate for 2011 and 2012 to 8.3 per cent based on a three-year historical average and to revise its forecast FTE levels and revenue requirement in the compliance filing to this decision.[91]

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88 Decision 2011-450, paragraph 507.

89 Application, Commission Direction 24, page 1 of 2.

90 Application, Commission Direction 23, Attachment 1-3.

91 Decision 2011-450, paragraph 538.

100. As part of its application, AG calculated the 8.3 per cent adjustment to the vacancy rate, subject to exclusions,[92] and reduced its operation and maintenance (O&M) forecasts by $123,000 for 2011 and $131,000 for 2012.[93] This amount was included in the summary of O&M adjustments.[94]

101. The UCA submitted that Direction 25 requires AG to revise its forecast capital component, rather than only its O&M forecasts, to reflect a higher vacancy rate. The UCA argued that this would seem to imply that the Commission expects the company to adjust both O&M and capital components of its revenue requirement.[95] The UCA submitted that the Commission should adjust AG's capital program to reflect a reduction in the vacancy rate, based on AG's estimates of full time equivalents (FTE) labour allocated to capital.[96]

102. With respect to O&M expenses, the UCA stated that AG did not adjust forecast O&M labour costs to account for a higher vacancy rate in any account for which the original forecast was either specifically approved by the Commission or for which the forecast was adjusted on some other basis. The net result is that the 2011 vacancy rate adjustment is applied to only $5.3 million of labour expense out of a total O&M labour expense of $101.4 million and the resulting adjustment is only $123,000.[97]

103. The UCA submitted that Direction 2011-450, as a whole "is most reasonably understood as requiring AG to implement both a general or over-arching reduction in O&M labour expense pursuant to Direction 25 and various other account-specific reductions as discussed in subsequent sections of the Decision."[98] Direction 25 is not qualified in any way nor is there any discussion of the issue of vacancy rates in subsequent sections of the decision.

104. The UCA therefore, argued that a 2.3 per cent reduction should be applied to all, or at least most, of AG's O&M labour expenses to reflect a higher vacancy rate[99] and UCA disputed exclusions from the vacancy rate adjustment.[100] However, it is necessary to properly align the O&M reduction under Direction 25 with the Commission's other directions to ensure that AG is not subjected to a double reduction (i.e. for costs that were disallowed by the Commission but were used to reduce O&M adjustments for those cost categories).[101] The UCA recommended that this concern could be addressed by applying the 2.3 per cent vacancy adjustment to overall O&M labour expenses calculated after application of the various other account-specific O&M adjustments that were directed by the Commission.[102]

105. AG disagreed with the UCA's assertion that Commission Direction 25 was a general and over-arching reduction to both capital expenditures and O&M as a result of applying an increase in the vacancy rate to 8.3 per cent.[103] If the Commission wanted a general and overarching

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[92] Exclusions are listed in the Application, Exhibit 1, page 184 and 185 of 238, and include BFK and DSM full program costs, general overall labour reductions, line heater inspections, overall meter reading labour.
[93] Application, Exhibit 1, page 183 of 238 PDF.
[94] Application, Exhibit 8.
[95] Exhibit 40.02, UCA argument, paragraph 12.
[96] Exhibit 40.02, UCA argument, paragraph 14.
[97] Exhibit 1, Response to Commission Direction 25, table at page 183.
[98] Exhibit 40.02, UCA argument, paragraph 17.
[99] Exhibit 40.02, UCA argument, paragraph 33.
[100] Exhibit 40.02, UCA argument, paragraphs 20 to 32.
[101] Exhibit 40.02, UCA argument, paragraph 34.
[102] Exhibit 40.02, UCA argument, paragraph 35.
[103] Exhibit 45.01, AG argument, paragraph 33.

reduction in addition to specific adjustments for capital expenditures and O&M functions, it would have made a specific directive.[104] By applying a general and overarching reduction under Direction 25, the result would be in effect a doubling up of reductions.[105]

106. Regarding capital expenditures, AG stated that they are forecast and approved for each of the various types of capital expenditure projects applied for including all necessary resources to complete capital projects, including internal labour, contractors and the required supply costs. Capital forecasts are calculated using a three year average of historical costs which would already incorporate the actual vacancies in those years.[106] AG submitted that no further reduction to capital forecasts related to vacancy rates is required.

107. The Commission has reviewed AG's adjustment to O&M as per Direction 25 and is satisfied that AG's revised forecast labour costs and associated FTEs complies with Decision 2011-450. AG's adjustment to the vacancy rate, subject to exclusions, and reduced O&M forecasts is consistent with Direction 25 since the intent of this direction was that any reduction to labour with respect to fractional vacancies was specific to O&M related labour expenses, with matters pertaining to capital expenditures or projects being addressed on a project by project basis in the capital section of Decision 2011-450.

4.20 Commission Direction 26 - inspection

108. The Commission issued the following direction to AG:

> Interveners did not oppose this expenditure but the CCA submitted that it should be a one time charge. The Commission agrees with the CCA that this expenditure should be treated as a one-time cost in 2012 revenue requirement. The Commission approves the forecast costs of $0.5 million for an assessment of inspection practices as a one time expense. AG is directed to incorporate these costs as a one time expense in its compliance filing to this decision.[107]

109. AG has included the cost of the $0.5 million for the assessment of inspection practices as a one-time adjustment in 2012 in its compliance filing. The Commission has reviewed the corresponding Summary of Revenue Shortfalls[108] spreadsheet and is satisfied that AG has complied with this direction.

4.21 Commission Direction 27 – capitalization of meter exchange costs

110. The Commission issued the following direction to AG:

> The Commission recognizes the necessity to comply with changing standards and accepts AG's proposed cost increases for the test years for the proposed commercial inspection program. However, the Commission does not approve AG's request for an accounting change to capitalize costs related to meter exchanges when a meter is being permanently retired. The cost of the "original installation of house regulators and meters" is capitalized in Account 474. "Expenses incurred in connection with removing, resetting, changing, testing and servicing customer meters and house regulators" are recorded in Account 673. AG's change in policy to use only new meters does not change the

[104] Exhibit 45.01, AG argument, paragraph 35.
[105] Exhibit 45.01, AG argument, paragraph 35.
[106] Exhibit 45, AG reply argument, paragraph 36.
[107] Decision 2011-450, paragraph 554.
[108] Application, Exhibit 3.

> accounting requirement. AG has stated that without the approval requested the expenses in 2011 and 2012 would need to be increased by $4.2 million. However, this amount does not agree with the $3.1 million in 2011 and $2.8 million in 2012 that AG planned to capitalize for the same activity. The Commission directs AG in its compliance filing to deal with this apparent discrepancy. AG is directed to revise its revenue requirement accordingly in the compliance filing to this decision.[109]

111. The Commission has reviewed AG's response to Direction 27 that the difference between the additional $3.1 million in 2011 and $2.8 million in 2012 is due to capitalization of removal costs. AG clarified in its application that the $4.2 million adjustment to O&M also does not include meter exchange costs associated with the AMR program.[110] AG argued that AMR meter exchange costs should continue to be capitalized as they relate to meters that may be damaged or otherwise cannot be retrofitted with the AMR device. The Commission agrees with this approach and directs AG to continue to capitalize meter exchange costs associated with the AMR program. The Commission considers that AG has explained the discrepancy in metering costs and that the additional $4.2 million in O&M for 2011 and 2012 is consistent with Commission direction. AG has complied with this direction.

4.22 Other O&M Commission Directions – Directions 28, 29, 34 to 41, and 61

112. The Commission issued a number of other directions to AG to adjust their O&M forecasts for the test years and AG provided an O&M summary spreadsheet for each year in its application.[111] The O&M adjustments made in compliance with the directions for the test years can be found in appendices 3 and 4 of this decision. The O&M adjustments in these directions are of a simple nature and were not objected to by interveners. Accordingly the Commission will group the relevant directions together and the attached appendices show specific dollar amounts which have been adjusted.

4.22.1 Commission Direction 28 –aging workforce – Account 674

113. The Commission issued the following direction to AG:

> AG stated that most of the forecast cost increase over 2010 actual costs was driven by inflation and customer growth. However, AG indicated in AUC-AG-65(c) that 1.2 per cent of the total increase in 2011 and an additional 0.5 per cent of the total increase in 2012 related to training in anticipation of higher employee turnover due to aging workforce and a tightening of the market. The Commission previously rejected the justification of forecast cost increases due to an aging workforce and a tightening of the labour market. Accordingly, the Commission directs AG to reduce the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 in the compliance filing to this decision.[112]

114. In its application, AG has changed the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 as reflected in its labor and supplies forecast in appendices 3 and 4, respectively. The Commission has reviewed the adjustments and is satisfied that AG has complied with Direction 28.

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[109] Decision 2011-450, paragraph 558.
[110] Application, Exhibit 1, Commission Direction 27, page 2 of 2.
[111] Application, Exhibit 8.
[112] Decision 2011-450, paragraph 561.

4.22.2 Commission Direction 29 – five per cent inflation factor – Accounts 678 and 679

115. The Commission issued the following direction to AG:

> AG provided limited support for the forecast increase to the costs for accounts 678 and 679. Accordingly, in the absence of any other substantive information, the Commission considers that an adjustment of five per cent for inflation and growth is justified for each of the test years. The Commission directs AG in its compliance filing to forecast costs for accounts 678 and 679 by escalating 2010 actual costs by a factor of five per cent per year.[113]

116. AG has removed the five per cent for inflation and growth for 2011 and 2012 required amounts from its labor and supplies forecast for Accounts 678 and 679, as reflected in appendices 3 and 4. The Commission has reviewed the adjustments in the application and is satisfied that AG has complied with Direction 29.

4.22.3 Commission Direction 34 – governance costs – Account 710

117. The Commission issued the following direction to AG:

> The Commission considers that AG has not provided an adequate explanation for the forecast increases in the account. The discussion of governance provides no explanation of which accounts are impacted by the governance amounts. In the absence of a satisfactory explanation for the increase, the Commission directs AG to revise its forecasts for Account 710 to the amount calculated as the actual expenditure for 2010 increased by a five per cent per year, to reflect inflation and growth, for each of 2011 and 2012. The $0.3 million for CC&B benchmarking is also approved in 2012.[114]

118. AG has removed the required amounts from its labor and supplies forecast for the test years, as shown in appendices 3 and 4. AG used the actual expenditures for 2010 and added the five per cent per year to reflect inflation and growth. The Commission has reviewed the adjustments in the application and is satisfied that AG has complied with Direction 34.

4.22.4 Commission Direction 35 – meter reader adjustment – Account 712

119. The Commission issued the following direction to AG:

> The Commission has calculated assuming a mid-year installation in 2012 that 318,000 meters will have been converted to AMR units by the end of 2012. AG stated that the average meter reader will be able to read 4500 meters per year. Theoretically this represents a reduction of approximately 70 meter readers in 2012. AG has forecast an opportunity savings of 12.9 meter readers, which is 57 less than the theoretical reduction based on the number of meters removed. At a fully loaded cost of $76,175 per meter reader an adjustment of approximately $4.3 million would be warranted. The Commission considers the transition factors identified in paragraph 714 and the redeployment of meter readers to other areas or potential severance costs must be considered. Given the lack of detailed information on the record regarding these matters, the Commission recommends a reduction of the estimated $4.3 million by 25 per cent. The Commission directs AG in its compliance filing to reduce the forecast costs for Account 712 by $3.2 million in 2012.[115]

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[113] Decision 2011-450, paragraph 584.
[114] Decision 2011-450, paragraph 691.
[115] Decision 2011-450, paragraph 712.

120. In its compliance filing, AG has reduced costs included in Account 712 by $3.2 million from its labor forecast for 2012, as shown in Appendix 4. The Commission has reviewed this adjustment and is satisfied that AG has complied with Direction 35.

4.22.5 Commission Directions 36, 37 and 38 – VPP – Account 721

121. The Commission issued the following direction to AG:

> 36. AG is directed to revise its 2011 and 2012 forecast for administrative labour, excluding the VPP component, utilizing AG's 2010 actual costs increased by five per cent per year.[116]

122. The Commission has reviewed the tables provided in the application[117] as well the adjustments made to the O&M spreadsheet.[118] The Commission is satisfied that AG has adjusted its 2011 and 2012 forecast for administrative labour, excluding the variable pay program (VPP) component, as directed. In respect to Directions 37 and 38, the Commission stated:

> 37. The Commission finds that the inclusion of net income component within a VPP is reasonable when there is a balance struck between the benefits that customers may receive through reduced costs versus increased earnings for the benefit of shareholders. A net income component greater than 10 per cent for officers and senior managers might result in an inherent conflict between shareholder interests and customers. The Commission finds that setting limits to individual performance objectives will ensure that management is not incented to maximize shareholder value at the expense of customers. If AG wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders. AG is directed to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent in its compliance filing to this decision with a supporting explanation to its revised VPP forecast.[119]
>
> 38. With regard to AG's forecasted increases in 2011 and 2012 for VPP, the Commission concurs with the UCA that AG did not justify an increase to the VPP forecast cost in excess of inflation. In its April 21 update, AG revised its forecast inflation rate for supervisory labour in 2012 to 4.0 per cent. The Commission finds that AG's four per cent inflationary adjustment for supervisory labour for 2012 is reasonable. The Commission directs AG in its compliance filing to revise its forecast VPP for 2011 by utilizing the 2010 forecast cost (which is consistent with the 2009 actual expense) by three per cent for 2011 and increasing the 2011 amount by four per cent for 2012.[120]

123. In accordance with Direction 37, AG has revised the maximum individual net income component of VPP to 10 per cent in its labor forecast for the test years in appendices 3 and 4. AG has changed the 2011 and 2012 forecast costs to reflect the inflation adjustment in Direction 38.

116 Decision 2011-450, paragraph 731.
117 Application, Commission Direction 36, page 1 of 1.
118 Application, Exhibit 8.
119 Decision 2011-450, paragraph 751.
120 Decision 2011-450, paragraph 752.

124. The Commission has reviewed the adjustments to the VPP forecast and finds that the adjustments arising from Directions 37 and 38 have been accurately reflected in appendices 3 and 4. AG has complied with these directions.

4.22.6 Commission Direction 39 – Calgary office lease

125. The Commission issued the following direction to AG:

> AG is directed in the compliance filing to this decision to include in its revenue requirement a rental rate for 2011 of $14.50. For 2012, rent should be forecast based on $14.50 per square foot increased by a three per cent inflation factor.[121]

126. In terms of the rental rate, AG has confirmed that the 2011 revenue requirement has a placeholder amount of $14.50 per square foot and no adjustment was required for 2011 forecast revenue requirement. AG included the $14.50 per square foot rental rate and the three per cent inflation factor in its supplies forecast, as shown in the 2012 summary of O&M Adjustments at Appendix 4.

127. The issue of the Calgary office lease is currently before the Commission in Proceeding ID No. 1698, the Phase II of AG's R&V of Decision 2011-450. In granting a review of the findings, the review panel stated that it is unclear whether the hearing panel rate was aware that AG's existing rental rate was $16 per square foot in reaching the determination that the existing lease rate should be used.[122] Pending the outcome of the Phase II R&V proceeding, AG is directed to maintain a placeholder amount for the Calgary lease rate of $14.50 per square foot for 2011, and a placeholder amount of $14.50 per square foot increased by a three per cent inflation factor for 2012, in its second compliance filing to Decision 2011-450.

4.22.7 Commission Direction 40 – corporate costs – Account 721

128. The Commission issued the following direction to AG:

> The Commission relies on the approval of the corporate cost allocation methodology in Decision 2010-447 for 2011. The Commission has reviewed the corporate costs in Table 42, Administrative expense and notes that actual costs for 2008, 2009 and 2010 exceeded forecasts. However, for 2008 an explanation of the variance is provided. The Commission accepts AG's explanation and considers that the increase, which was with respect to HRX, would be a recurring cost. A comparison of actual 2008 costs to forecast 2011 costs is an increase of 10.5 per cent over a three-year period. The Commission considers an increase of approximately 3.5 per cent per year to be reasonable. However, the Commission agrees that the $73,000 for 2011 and $75,000 for 2012 of allocated corporate advertising, as noted above by the UCA, should not have been included in the corporate costs and directs that this amount should be removed.[123]

129. In its application, AG has removed the corporate adverting costs of $73,000 for 2011 and $75,000 for 2012 from its supplies forecast for the test years, as shown in appendices 3 and 4.

130. The Commission is satisfied that this adjustment has been accurately reflected in the appendices and considers that AG has complied with Direction 40.

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[121] Decision 2011-450, paragraph 769.
[122] Decision 2012-156, page 24, paragraph 99.
[123] Decision 2011-450, paragraph 780.

4.22.8 Commission Direction 41 – mass media and other supplies – Account 721

131. The Commission issued the following direction to AG:

> The Commission therefore approves mass media and other supplies expenses for 2011 and 2012 calculated as 2010 actual costs increased by five per cent per year for inflation and growth. AG is directed to include this revision in its compliance filing.[124]

132. AG provided the five per cent per year adjustment for inflation and growth using the 2010 actual costs. Supporting calculations were included in AG's application and reflected in the supplies forecast for the test years at appendices 3 and 4.

133. The Commission has reviewed AG's adjustments to mass media and other supplies. The Commission is satisfied that AG has complied with Direction 41.

4.22.9 Commission Direction 61 – distribution supervision – Account 670

> 552. For Account 670, distribution supervision, the Commission accepts cost increases of $0.5 million for inflation and $0.3 million for the increased work provided to ATCO Pipelines. As discussed earlier in this decision, the Commission does not accept AG's arguments with respect to cost increases being driven by an aging workforce and retirements. Accordingly, the forecast cost increases of $0.6 million for training, mentoring and coaching related to forecast retirement activity, $0.5 million for safety initiatives related to changes to the workforce and retirements, and $0.2 million in 2012 for the costs of two new occupational health nurses to proactively implement preventative programs to address potential injuries in the aging workforce are denied.[125]

134. AG has removed the distribution supervision adjustments, as directed, from its labor and supplies forecast for the test years. These adjustments have been described and accounted for in the summaries of O&M adjustments in appendices 3 and 4, as separate line items for the years to which the reductions apply, as:

- remove forecast costs related to training, mentoring and coaching
- safety initiatives related to changes in workforce
- remove occupational health nurses

135. The Commission has reviewed the amounts in these line items and concludes that the compliance filing amounts are consistent with the reductions directed in Decision 2011-450 for Account 670 - Distribution Supervision. The Commission is satisfied that AG has complied with this direction.

4.23 Commission Direction 62 – line heater inspections - Account 677

> 578. The evidence submitted by AG with respect to the line heater inspection program has not persuaded the Commission that these inspections are required during the test period. The Commission notes that AG stated that line heaters on well sites have a legal requirement for inspection every five years but AG is not legally bound to abide by this same inspection requirement. Further AG has not inspected its line heaters in the past and AG has not supplied any evidence to suggest that it should begin inspecting line heaters during the test period. Given the above, the Commission denies the line heater inspection

[124] Decision 2011-450, paragraph 797.
[125] Decision 2011-450, paragraph 552.

> costs of $0.9 million per year. The Commission also observes that it has approved the forecast costs associated with AG's line heater improvements program to meet OH&S standards and improved reliability enhancements on noncompliant meters during the test years. [126]

136. AG has removed line heater inspection costs for each of the test years from its labor and supplies forecast in appendices 3 and 4. The Commission is satisfied that AG has complied with this direction.

4.24 Commission Directions 30, 31 and 32 – the BFK and Centennial Anniversary

137. The Commission issued the following directions to AG:

> 30. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK while the forecast for the test period for the BFK is $2 million per year. The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre. The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied.[127]
>
> 31. The Commission does, however, continue to support the expenditure of $50,000 per year on safety messaging that the BFK has provided in the past. AG may add this expenditure to its Customer Relations and Communications forecast for the test years. AG is directed to advise the Commission in the compliance filing to this decision as to the mechanism it will use to promote natural gas safety matters and gas distribution education information to customers.[128]
>
> 32. Similar to the Commission's finding with respect to AG's BFK program above, the Commission is of the view that the increase in costs for the purpose of the Centennial Anniversary celebration is not justified as a cost effective means to communicate safety matters and is unnecessary for the provision of safe and reliable delivery of natural gas. Accordingly AG is directed to remove the forecast costs associated with the Centennial Anniversary from the sales and transportation promotions function for the 2011 and 2012 test years.[129]

138. The proposed treatment of the BFK in opening rate base is addressed within the findings of Commission Direction 1 above. In relation to the removal of the BFK costs in Direction 30, AG has removed the costs for the BFK in each of the test years, $1.9 million for 2011, and $2.1 million for 2012.[130] The Commission has reviewed the tables provided in AG's compliance

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[126] Decision 2011-450, paragraph 578.
[127] Decision 2011-450, paragraph 610.
[128] Decision 2011-450, paragraph 611.
[129] Decision 2011-450, paragraph 616.
[130] Application, Exhibit 1, page 191 of 238 PDF.

application and the O&M summary of adjustments included as appendices 3 and 4 of this decision. AG also reduced other utility revenue relating to the BFK by $0.6 million on 2011, and $0.7 million in 2012.[131] The Commission is satisfied that AG has complied with the direction to remove the BFK costs from its revenue requirement.

139. For safety messaging, AG stated in its application that it has added $50,000 for each test year to the Customer Relations and Communications forecast expenditures from the BFK operating expenditures. AG stated that it will use media, such as television, print, and radio to promote safety matters and gas distribution education.[132] The Centennial Anniversary forecast costs have been similarity removed from the sales and transportation promotions function for the test years.[133] The Commission considers that AG has complied with directions 31 and 32. These adjustments have been reflected in the summary of O&M adjustments in appendices 3 and 4, and therefore, AG has complied with these directions.

4.25 Commission Direction 33 - DSM

140. The Commission issued the following direction to AG:

> 680. The Commission denies AG’s request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base.[134]

141. The proposed treatment of the DSM in opening rate base was addressed within the findings under Commission Direction 1 above.

142. AG noted in its application that a correction was required regarding the inclusion of expenditures related to natural gas load building activities and it adjusted the DSM O&M amounts to reflect the correction of this error.[135] The Commission has reviewed the revisions reflected in the tables in the application as well as the capital and O&M adjustment spreadsheets.[136] Also in relation to DSM, AG stated that it has reduced other utility revenue by $1.2 million in 2011, and $1.4 million in 2012.[137] The Commission confirms that AG has complied with the direction to remove the DSM related capital expenditures and O&M costs for the test years from its rate base and revenue requirement.

4.26 Commission Direction 42 – corporate governance

143. The Commission issued the following direction to AG:

> As noted above, AG has not fully described which accounts, O&M or capital, include corporate governance costs. The Commission directs AG in its compliance filing to indicate the allocation of the governance costs identified above to specific capital and

131 Application, Exhibit 1, page 192 of 238 PDF.
132 Application, Exhibit 1, page 193 of 238 PDF.
133 Application, Exhibit 1, page 194 of 238 PDF.
134 Decision 2011-450, paragraph 686.
135 Application, Exhibit 1, page 195 of 238 PDF.
136 Application, Exhibits 7 and 8.
137 Application, Exhibit 1, page 196 of 238 PDF.

> O&M accounts, including the corresponding amounts approved in Decision 2011-228 and the actual amounts incurred in 2010.[138]

144. In its response to this direction AG clarified that IT Governance and Office of the Chief Information Officer (CIO) costs are allocated to Account 721 – Administrative Expenses, and CC&B is allocated to governance to Account 710 – Supervision. AG also provided the amounts for CC&B and IT costs for 2008 and 2009 that were approved in Decision 2011-228.[139] AG also provided the 2010 actual amounts for CC&B, IT and CIO costs. The Commission has reviewed the allocation of these governance costs and finds that AG has sufficiently explained the allocation of these costs. AG has complied with this direction.

4.27 Commission Direction 43 – IT placeholders

145. The Commission issued the following direction to AG:

> 810. Calgary brought forward issues with respect to the Evergreen Strategy Report, O&M IT volumes and the lack of comparability due to the differences in structure and terms of the two MSAs. The Commission is satisfied that Exhibit 180 provided sufficient detail of volumes in a standardized format to allow the Commission to assess the reasonability of the forecast volumes. The Commission accepts the O&M forecast volumes as filed. The Commission notes the dollars are placeholders and directs AG to use the amounts provided in Table 42 above for the test years.[140]

146. AG noted in the application that final forecast costs will be determined by applying the approved O&M volumes to rates approved in the Evergreen 2010 proceeding.[141] The Commission agrees with AG that the forecast O&M volumes are placeholders and considers that AG has complied with this direction.

4.28 Commission Direction 44 – late payment settlement costs

147. The Commission issued the following direction to AG:

> 842. AG's request for a recovery of $1.8 million related to the settlement and associated legal expenses is denied. The Commission therefore directs AG to remove the settlement and associated legal expenses from AG's forecast for reserve for injuries and damages and revenue requirement in its compliance filing. The $300,000 balance of the proposed $2.1 million recovery in order to maintain a reserve balance of $600,000 is approved.[142]

148. AG confirmed in its application that it had removed the late payment settlement costs and legal expenses in the amount of $1.8 million from the forecast for reserve for injuries and damages.[143]

149. The Commission granted a review and variance of late payment settlement costs in Decision 2012-156.[144] The issue of late payment settlement costs is therefore, currently before the

138 Decision 2011-450, paragraph 805.
139 Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011.
140 Decision 2011-450, paragraph 810.
141 Application, Commission Direction 43, page 1 of 1.
142 Decision 2011-450, paragraph 842.
143 Application, Exhibit 1, page 209 of 238 PDF.
144 Decision 2012-156, paragraphs 87 to 89.

Commission in Proceeding ID No. 1698, the Phase II R&V proceeding of Decision 2011-450. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount of zero for late payment penalty settlement costs in its second compliance filing to Decision 2011-450.

4.29 Commission Direction 45 – pension funding placeholders

150. The Commission issued the following direction to AG:

> 852. The Commission is satisfied that AG has adequately explained why employee benefits are increasing for the test years. Further the Commission notes that the largest component of employee benefits is the pension funding which is subject to a placeholder. In Decision 2011-391 the Commission made a determination of pension funding for AG to be included in revenue requirement for 2011 and 2012. AG is directed to maintain the current placeholders for pension funding, pending a decision in relation to the compliance filing for Decision 2011-391 noted above. AG is directed to submit an application to replace the placeholders within a reasonable time following the issuance of the decision in the compliance filing. With the exception of the placeholder for pension funding, the Commission approves the forecast costs for employee benefits.[145]

151. AG has stated it will file an application to replace the placeholders for pension funding following the Commission issuing its decision in the compliance filing of Decision 2011-391.[146] The Commission notes that the pension compliance filing Decision 2012-166[147] was released on June 14, 2012. In Decision 2012-166, the Commission directed AG to file a second compliance filing with respect to revised placeholder amounts for 2011 and 2012.[148] The Commission is satisfied that AG has maintained the current placeholders for pension funding and has complied with this direction.

4.30 Commission Direction 46 – credit facility and standby fees placeholder

152. The Commission issued the following direction to AG:

> The Commission is satisfied with AG's explanation that credit facility costs and standby fees have increased as a result of the recent economic crisis. Further, the Commission recognizes that ensuring liquidity levels are maintained at levels required by bond rating agencies results in CU Inc. being able to maintain its existing credit rating and allows AG access to lower market rates for financing its operations. The forecast bank charges are consistent in total with the 2009 charges and the Commission finds the amounts to be reasonable. As these costs are allocated using the ATCO Utilities corporate cost allocation methodology approved in Decision 2010-447 the Commission accepts the allocation methodology for 2011. As noted earlier, ATCO Utilities corporate cost allocation methodology is subject to review in 2012. As a result, all costs for 2012 including "bank and short term financing costs" are subject to a placeholder pending the outcome of the aforementioned proceeding. AG is directed to maintain a placeholder for 2012.[149]

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[145] Decision 2011-450, paragraph 852.

[146] Decision 2011-391: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.) - 2011 Pension Common Matters, Application No. 1606850, Proceeding ID No. 999, September 27, 2011.

[147] Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2011 Pension Common matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

[148] Decision 2012-166, page 14, paragraphs 70 and 71.

[149] Decision 2011-450, paragraph 858.

153. AG stated that it will maintain placeholders for credit facility and standby fees pending the outcome of the review of ATCO Utilities corporate cost allocation methodology in 2012.[150] The Commission is satisfied that AG has complied with this direction.

4.31 Commission Direction 47 – financing costs

154. The Commission issued the following direction to AG:

> The Commission directs AG in its compliance filing to reclassify bank and short-term financing costs as financing costs.[151]

155. AG indicated in its application that it has removed bank and short term financing costs of $1 million in 2011, and $0.9 million in 2012, from operating expenses and has included them in financing costs. The Commission has reviewed Schedule 3.2-C which adjusts 2011 and 2012 forecast GRA updates[152] to reflect the Commission's direction on financing costs, and is satisfied that AG has complied with this request.

4.32 Commission Directions 48, 49, 50 and 52 – depreciation adjustments

156. The Commission issued the following directions to AG:

> 48. AG is directed in the compliance filing to calculate depreciation expense using a 57-R2.5 Iowa curve for Account 47300, Services.[153]
>
> 49. AG is directed in the compliance filing to calculate depreciation using an Iowa curve of 51-R3 for Account 47400, Regulator & Meter Installations.[154]
>
> 50. AG is directed to calculate depreciation using an Iowa curve for 66-R2.5 for account 47500, mains in the compliance filing to this decision.[155]
>
> 52. AG is directed in the compliance filing to calculate depreciation using the 11-R2 Iowa curve for Account 48400, Transportation Equipment.[156]

157. AG provided the depreciation adjustments in its compliance application regarding the above referenced accounts. The UCA indicated in argument that after review of AG's responses to information requests that it was satisfied that the depreciation adjustments were reasonable and correct.[157]

158. The Commission has reviewed the tables in the application as well as the depreciation expense adjustments spreadsheet[158] and the depreciation expense sheets are attached as appendices 5 and 6, respectively. The Commission is satisfied that AG has complied with these directions.

150 Application, Commission Direction 46, page 1 of 1.
151 Decision 2011-450, paragraph 860.
152 Application, Exhibit 2.
153 Decision 2011-450, paragraph 915.
154 Decision 2011-450, paragraph 921.
155 Decision 2011-450, paragraph 941.
156 Decision 2011-450, paragraph 947.
157 Exhibit 40.02, UCA argument, page 13.
158 Application, Exhibit 10.

4.33 Commission Direction 51 – segregation of depreciation accounts

159. The Commission issued the following direction to AG:

> 942. The Commission considers that the determination of a depreciation rate for this account has been particularly difficult given the size of the account and the mix of non-homogeneous assets of different vintages. The Commission notes the discussion at the hearing about the possibility of introducing accounting mechanisms to segregate the account into multiple accounts of a more homogeneous nature. The lack of detailed historical records was an impediment to further segregation at this time. The Commission directs AG to report in the compliance filing to this application on the feasibility of further segregation of significant accounts on a go-forward basis.[159]

160. AG confirmed in its application that it will complete a study looking into the further segregation of significant depreciation accounts on a go-forward basis. The study will then be brought to the Commission in a future application.[160] For the purposes of this application, AG has complied with this direction, as a further study will be conducted and provided to the Commission in a future application.

4.34 Commission Direction 53 – removal of non-utility assets from depreciation calculation

161. The Commission issued the following direction to AG:

> 952. The Commission will consider Account 48400 separately from the other accounts. With respect to the balance of the "other depreciation accounts" identified above, the Commission notes that the interveners did not file evidence with respect to these accounts and that the aggregate net change in depreciation expense is $1,990,539 in the test period. The Commission has denied a number of programs in other parts of this Decision which may have assets reflected in some of these accounts. Accordingly, the Commission directs that the assets associated with denied programs be removed from these accounts and reflected in the compliance filing to this decision. Subject to the removal of the denied assets, the Commission approves the depreciation expense for these other depreciation accounts.[161]

162. The Commission has reviewed the table in the application as well as the depreciation expense adjustments spreadsheet.[162] Given the findings in Direction 1 of this decision, the Commission directs AG to provide a schedule detailing the removal of the DSM and the Calgary BFK assets from opening rate base, and any accompanying impact on depreciation in its second compliance filing.

4.35 Commission Direction 54 – net salvage rates

163. The Commission issued the following direction to AG:

> 971. The Commission agrees with the UCA and the evidence of Mr. Pous that AG has failed to provide sufficient justification for the proposed changes to the net salvage rates. Neither Mr. Kennedy nor AG have provided a reasonable explanation for the large changes in net salvage percentages calculated by Mr. Kennedy in his analysis. The

[159] Decision 2011-450, paragraph 942.
[160] Application, Commission Direction 51, page 1 of 1.
[161] Decision 2011-450, paragraph 952.
[162] Application, Exhibit 10.

> explanation provided by Mr. Kennedy for the proposed modified net salvage rates, based on the calculated percentages, lacks the robustness and precision necessary to support the determination of the proposed net salvage rates. In the absence of probative evidence the Commission is inclined to deny the requested increase in net salvage rates for the test period. However, the Commission is concerned that should the current net salvage rates be insufficient, continuation of existing rates for an extended period of time may result in intergenerational inequity for ratepayers and unfairness to the utility. Accordingly, the Commission would entertain a timely separate application outside of the compliance filing process on net salvage rates for the test period. AG is directed to indicate in the compliance filing to this decision whether it will be submitting a separate application and if proceeding, the anticipated filing date. If AG chooses not to submit a separate application the existing net salvage rates will remain in place for the test years. If AG chooses to file a separate application, the compliance filing will use the existing salvage rates as placeholders pending a decision on the separate application.[163]

164. AG has advised that it will not be filing a separate application to deal with net salvage rates in the test years.[164] AG explained that a study cannot be completed in time to allow for a separate application for the test years. Consistent with Direction 54 in Decision 2011-450, the Commission therefore directs AG to use the existing net salvage rates for the test years and to reflect the corresponding change in the compliance filing.

4.36 Commission Direction 55 – depreciation reserve deficiency account update

165. The Commission issued the following direction to AG:

> 983. The collection from customers of a depreciation reserve deficiency or the refund to customers of a depreciation reserve surplus does not amount to retroactive rate making, rather it is a prospective rate setting mechanism designed to ensure that the costs of an asset are recovered over its anticipated service life. The Commission directs AG in its compliance filing to this Decision to update it depreciation reserve deficiency account in accordance with the revised depreciation rates.[165]

166. AG indicated that it has updated its depreciation reserve deficiency account in its compliance filing, and in accordance with the revised depreciation rates[166] as a result of Decision 2011-450. The Commission has reviewed the depreciation expense adjustments spreadsheet[167] and is satisfied that AG has complied with this direction.

4.37 Commission Direction 56 – production abandonment costs

167. In Decision 2011-450, the Commission addressed the issue of production abandonment costs as follows:

> [A]ssets which no longer have an operational purpose are no longer used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* should be retired and removed from rate base. Further, if the asset is not disposed of at the time of retirement, it should be moved to a non-utility account whether or not the asset has been fully consumed in providing utility service or whether it had residual value at the time it was retired. Accordingly, all ongoing costs of any nature, including operational

163 Decision 2011-450, paragraph 971.
164 Application, Commission Direction 54, page 1 of 2.
165 Decision 2011-450, paragraph 983.
166 Application, Exhibit 1, page 221 of 238 PDF.
167 Application, Exhibit 10.

> and remediation costs (except to the extent that remediation costs are notionally offset by the net salvage component of depreciation expense previously included in rates an collected from ratepayers) associated with the asset after it creases to have an operational purpose should be removed from revenue requirement and be for the account of the utility shareholder.[168]

168. The Commission issued the following direction to AG:

> 10004. Given the above determination, all production abandonment costs applied for during the test period are disallowed and shall be removed from forecast revenue requirement in the compliance filing to this decision. Similarly, the deferral account in respect of these costs will be discontinued as of January 1, 2011. The closing deferral account balances in the north and south for 2010 are $0.76 million and $0.24 million respectively. Given that these balances relate to prior periods and the decisions that relate to those periods, AG will be permitted to include a one time recovery of those balances in 2011 revenue requirement.[169]
>
> The Commission directs AG to remove the 2011 and 2012 production abandonment costs of $2.18 and $1.5 million respectively from revenue requirement.[170]

169. In respect to production abandonment costs, AG noted in its application that the 2011 amount of $2.18 million included a one time adjustment of $0.68 million, which was approved in paragraph 1004 of Decision 2011-450.[171] AG removed the 2011 and 2012 annual expense amounts for production abandonment costs from its revenue requirement. The adjustments have been reflected in the depreciation expense adjustments spreadsheet.[172]

170. The issue of production abandonment costs was included in Decision 2012-156. In granting the Phase I R&V on the issue of production abandonment costs, the review panel granted a further review of production abandonment and AG's settlement agreements and stated that this issue would be better suited for the Utility Asset Disposition Rate Review Proceeding (Proceeding ID No. 20) or the generic proceeding on asset disposition and stranded assets following Proceeding ID No. 556.[173] The review panel determined:

> In the interim, the Commission directs AG to maintain a placeholder of zero with respect to these costs, to be adjusted upon completion of either Proceeding ID No. 20 or the generic proceeding.[174]

171. As the issue of production abandonment costs will be subject to a further proceeding and given the direction of the Commission in Decision 2012-156 that a placeholder is warranted for production abandonment costs, the Commission directs AG in its second compliance filing to use a placeholder of zero for production abandonment costs for the 2011 and 2012 test years.

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168 Decision 2011-450, page 207, paragraph 1000.
169 Decision 2011-450, page 208, paragraph 1004.
170 Decision 2011-450, paragraph 1005.
171 Application, Commission Direction 56, page 1 of 1.
172 Application, Exhibit 10.
173 Decision 2012-156, paragraphs 110 and 113.
174 Decision 2012-156, paragraph 110.

4.38 Commission Direction 57 – gas price regression model variable

172. The Commission issued the following direction to AG:

> 1018. The Commission notes that in the presentation provided during its SPC Forecast Workshop on June 14, 2010, AG made mention that gas price has not been included in the regression models in past GRA's. In its compliance filing AG is directed to provide information on why it has added gas price as a variable into the regression model and the impact the gas price variable has on its revenue forecast.[175]

173. AG stated in its application that:

> Prior to the 2011/2012 GRA, the gas price variable has never resulted in a statistically significant variable, and for that reason, it was never previously used. For the 2011-12 GRA, the 12 month lagged gas cost recovery rate was found to be statistically significant for one model – the South High Use Industrial Model. The inclusion of gas price in the South High Use Industrial model has no impact on the revenue forecast for the test years because the High Use GJPC model forecasts are not used in the calculation of the revenue forecast. The High Use rate group is applied a fixed charge and a demand charge and not a variable charge.[176]

174. The Commission finds that AG has sufficiently explained why the gas price variable has not been used for regression analysis in the test years. The Commission concludes that AG has complied with this direction.

4.39 Commission Direction 58 – other revenue

175. The Commission issued the following direction to AG:

> 1021. The Commission notes that 2010 actual revenue was very close to the forecast for 2011. Further the Commission notes that the largest component of other revenue is services provided to AP. The Commission directs AG in its compliance filing to discuss if the recently approved integration of AP with NGTL will have an impact on its other revenue from AP including any change to the basis on which the work will be priced. The Commission accepts the revenue forecast for the rest of the components of other revenue for the test years.[177]

176. In its response to Direction 58, AG requested in the compliance filing that the Commission approve the use of a deferral account related to the impacts of the NGTL/AP Integration. The deferral account would have included the effect of changes to services between AG and AP as a result of integration. Any integration impact related to 2011 revenues and expenses from AP has been addressed in AG's response to Direction 64. For 2012, AG stated that it "does not anticipate any significant changes to its 2012 other revenue as a result of NGTL/AP Integration, however that was the reason why a deferral account was requested, because ATCO Gas is unable to control or properly forecast the effect of Integration on its costs and revenues. However, any change in service agreement revenues would also be accompanied by a change in operating costs so it would be inappropriate to only address the revenue aspect."[178]

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[175] Decision 2011-450, paragraph 1018.
[176] Application, Exhibit 1, page 223 of 238 PDF.
[177] Decision 2011-450, paragraph 1021.
[178] Application, Exhibit 1, page 224 of 238 PDF.

177. The Commission notes that in AG's 2011-2012 GRA, AG provided an "Other Revenue Forecast"[179]. AG forecast $18.9 million for 2011 and $19.8 for 2012. In the compliance application, AG stated that it did not anticipate any significant changes to its 2012 other revenue forecast.

178. The Commission considers that AG has not provided any new information in the compliance filing to support an impact on other revenue that would change the basis on which the work will be priced. The Commission has previously denied a deferral account to capture the potential impacts related to integration in Decision 2011-450 and Decision 2012-156. In this application, AG reiterated the need for the deferral account to address the impacts and indicated that at the current time, it did not anticipate any significant changes to its 2012 other revenue as a result of integration of AP with NGTL. Accordingly, the Commission considers that since no new information has been provided on the effect of integration on other revenue and given that AG does not expect any significant changes to its 2012 other revenue, that no changes to other revenue is required. The Commission finds that AG has complied with this direction and that the original forecast amounts for other revenue approved in Decision 2011-450 remain unchanged.

4.40 Commission Direction 59 – IFRS deferral account

179. The Commission issued the following direction to AG:

> 1037. The Commission considers the establishment of the requested deferral account is consistent with the above principle because it establishes a mechanism to monitor and address any shifting of risk between customers and shareholders with respect to the unanticipated differences. Accordingly the Commission approves the establishment of a deferral account in accordance with AG's proposal provided however that the deferral account shall include only unanticipated differences that are within the scope of Rule 026. The Commission directs that this deferral account be closed and an application filed along with AG's proposal for the method for settling each deferral account adjustment within three months of the public release of the 2011 annual financial statements for Canadian Utilities Limited.[180]

180. In its application, AG stated it will close the IFRS deferral account and file an application to address settlement of each deferral account adjustment within three months of the public release of 2011 Canadian Utilities Limited financial statements.[181] The Commission notes that no application regarding this deferral account has been filed to date. The Commission directs AG to provide an update in its second compliance filing regarding the status of its application for the closure and settlement of the IFRS deferral account.

4.41 Commission Direction 60 – UMR adjustment

181. The Commission issued the following direction to AG:

> Given all the above the Commission approves a capital expenditure based on a status quo urban mains replacement program during the test years based on the actual expenditures in 2010 increased each year by an inflation factor of three per cent. The amounts approved for inclusion in revenue requirement are $12.0 million and $12.4 million in 2011 and 2012, respectively.[182]

[179] Decision 2011-450, Table 54, page 211, paragraph 1019.
[180] Decision 2011-450, paragraph 1037.
[181] Application, Commission Direction 59, page 1 of 1.
[182] Decision 2011-450, paragraph 135.

182. AG has adjusted its forecast for the Urban Mains Replacement program to reflect the approved amounts of $12 million in 2011 and $12.4 million in 2012. The Commission has reviewed the capital adjustments spreadsheet[183] and is satisfied that AG has complied with this direction.

4.42 Commission Direction 63 – NEB costs

183. The Commission issued the following direction regarding forecast costs for AG's participation in National Energy Board (NEB) hearings:

> The Commission has not been persuaded that the $150,000 forecast costs in each of the test years for potential involvement in hearings before the NEB relating to integration are justified because no supporting rationale was provided. The Commission is satisfied that the balance of AG's forecast costs for its audit, legal and consulting fees is reasonable based on AG's explanation that it is an average of its previous three-year costs. AG's forecast with regard to legal and consulting expenses is approved, subject to the above reduction.[184]

184. In its application, AG provided an update to its 2011 costs with respect to NEB hearings including legal and consulting expenses, to $128,000 for 2011. The 2012 forecast costs of $150,000 were not amended.[185] AG provided further rationale for the inclusion of these costs as AG considered it important for it to act in the best interests of its customers and take the position in the TransCanada (TCPL) Business and Services Restructuring Proposal NEB proceeding (RH-003-2011) that its customers should not be allocated costs for which they bear no cost responsibility and from which they receive no benefit.

185. The UCA stated that it is prepared to accept that AG has or will incur the additional costs and that AG's participation in the RH-003-2011 proceeding is appropriate.[186] However, the UCA questioned whether the inclusion of these costs in AG's revenue requirement was appropriate. In the UCA's opinion,

> The procedure adopted by the Commission in relation to these issues is unusual, in the sense that AG is effectively being allowed to request increases in its allowed expenses after the hearing and without the normal scrutiny provided by the hearing process.[187]

186. The UCA also stated that it was not clear if the costs associated with AG's participation in the NEB proceeding were genuinely integration costs because they were not associated with implementing integration. However, the UCA stated that if AG is allowed to recover these costs, then it should be allowed to do so only as a one-time for those years and not as an on-going expense embedded in base rates.

183 Application, Exhibit 7.
184 Decision 2011-450, paragraph 813.
185 Application, Commission Direction 64, Response to UCA-AG-131.
186 Exhibit 40.02, UCA argument, pages 11 to 13.
187 Ibid, page 12, paragraph 50.

187. The CCA stated that given the potential harm to customers as a result of the possible outcomes of the TCPL mainline hearing, it was not opposed to including some of the hearing costs into AG's hearing cost reserve account if AG can demonstrate a benefit to customers and not to the utility or its parent company.[188]

188. In Proceeding ID No. 1698, 2012 General Rate Application R&V application, AG submitted that the hearing panel's determination in Decision 2011-450 to deny AG's ability to recover legal and consulting expenses related to the NEB proceeding on the basis that AG provided no supporting rationale should be reviewed. AG stated that it did in fact support its claim in its response to information request AUC-AG-83.[189] In that response, AG stated that it was not familiar with NGTL's rate design and cost allocation methodologies, and there are also cost risks associated with export deliveries and TransCanada mainline costs that may have an effect on Alberta customers. AG made similar arguments in its compliance filing application.[190]

189. The Commission has reviewed the O&M adjustments spreadsheet and is satisfied that AG has removed $150,000 in forecast costs related to participating in NEB proceedings for each of 2011 and 2012, in compliance with the Commission's direction. However, the Commission notes that in Decision 2012-156, the review panel has granted a review of the decision to deny AG's request to recover $300,000 in forecast costs for participation in the NEB NGTL hearings.[191] The issue of the recovery of 2011 and 2012 forecast costs related to AG's participation in NEB hearings related to integration is properly before the Commission in Proceeding ID No. 1698. Pending the outcome of the Phase II R&V proceeding in Proceeding ID No. 1698, AG is directed to use a placeholder amount of zero for forecast hearing costs related to integration hearings for 2011 and 2012. The Commission directs AG to reflect the zero placeholder for these costs in its second compliance filing to Decision 2011-450.

4.43 Commission Direction 64 – integration deferral account

190. The Commission issued the following direction regarding forecast costs for integration between AP and NGTL:

> 1040. The Commission does not consider that the proposed deferral account satisfies the materiality factor criterion for the establishment of a new deferral account and accordingly denies AG's request. However, the Commission is sensitive to the concerns raised by AG with respect to possible unknown costs of integration and the difficulty of forecasting these costs prior to integration occurring. Contract integration between ATCO Pipelines and NGTL occurred October 1, 2011. While the Commission denies the requested deferral account, the Commission will permit AG in the compliance filing to this decision to identify any additional specific costs that AG has incurred due to integration and to include a request for approval of such costs in revenue requirement.[192]

188 Exhibit 42.01, CCA argument, page 5.
189 Exhibit 84.01.
190 Application, Exhibit 1, footnote 4 on pages 236 and 237 PDF.
191 Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, page 19, paragraph 74.
192 Decision 2011-450, paragraph 1040.

191. In the 2011-2012 AG GRA filing, AG proposed to use a deferral account to address the impact of any changes on its revenues, capital and operating costs directly related to integration. The table below provides these costs,[193] with the removal of legal costs as discussed in Direction 63:

Table 5. AG Costs for Integration Deferral from AG 2011-2012 GRA

O&M	2011 (000s)	2012 (000s)
New Contract Analyst (50% of salary allocated to O&M)	$14	$14
New Admin. Coordinator (50% of salary allocated to O&M)	$20	$20
Increased meter maintenance for meters transferred to AG. Two additional FTEs in 2011, one additional FTE in 2012	$90	$170
Total	$124	$204
Capital	**2011 (000s)**	**2012 (000s)**
CNG Tube Trailers	$40	$80
Enhancements to Imbalance Reporting Information System	$55	$0
New Contract Analyst (50% of salary allocated to Capital)	$14	$14
New admin. Coordinator (50% of salary allocated to Capital)	$20	$20
Purchase of non SCADA equipment from AP	$0	$6,500
Total	$489	$6,568

192. AG stated that it expected it would be required to manage approximately 60 contracts for FT-D3 service.[194] In its compliance application, AG commented that NGTL required it to hold contracts at approximately 1,150 summary points, significantly increasing staff requirements. The original estimate of $170,000 for technologists to visit non SCADA meter sites was increased to $235,000 based on better information. The survey costs are unforeseen post integration rights-of-way costs. AG assets within rights-of-way assumed by NGTL require new rights-of-way agreements. The following table identifies updated costs provided by AG:

Table 6. Costs for integration from compliance filing update

O&M	2011 (000s)	2012 (000s)
New Analyst, Contract Demand Quantity (75% allocated to O&M)	$13	$56
New Supervisor, Contract Demand Quantity (75% allocated to O&M)	$45	$93
Contract Management System Maintenance and Support	$0	$4
New contract mgmt. system to manage FT-D3 Service Contracts	$0	$18
Increased meter maintenance/reading for meters transferred to AG. Two additional FTEs in 2012 plus travel costs.	$0	$235
Survey Costs	$120	$180
Total	$178	$586

Capital	2011 (000s)	2012 (000s)
CNG Tube Trailers	$47	$0
Enhancements to Imbalance Reporting Information System	$110	$4
New Analyst, Contract Demand Quantity (25% allocated to Capital)	$4	$19
New Supervisor, Contract Demand Quantity (25% allocated to Capital)	$15	$31
Purchase of non SCADA metering equipment from AP	$0	$7,600
Total	$176	$7,654

193 Proceeding ID No. 969 AG 2011-2012 GRA, Exhibit 83.01, UCA-AG-131(a)(b).

194 Application, Commission Direction 64, page 6.

193. In the opinion of the UCA,

> there is a difference between identifying “additional specific costs” in the sense of discovering new and previously unforeseen types or categories of costs, on the one hand, and identifying such costs in the sense of discovering that the company’s original forecast was simply wrong. The UCA is unclear about whether the Commission intended in paragraph 1040 to simply give ATCO Gas an opportunity to identify new types or categories of integration related costs (of which the survey costs might be an example), or whether it intended to go further and give ATCO Gas something like a short-run deferral account to protect it against bad forecasting of costs it had already identified.[195]

194. In the UCA’s view, if the Commission meant it will allow AG to correct its forecasts for integration related activities by saying it will permit AG to identify any additional specific costs that AG has incurred due to integration broad brush opportunity, then AG’s forecast must be accepted. If a narrower definition of additional costs was intended by the Commission, UCA submits that there is a question of what should be approved.[196]

195. Calgary stated that AG should not be allowed to revise the number of positions for staff administering the NGTL contracts as AG has not met its onus as to why a Supervisor is required as compared to a Contract Analyst and an Administrative Coordinator. Increased complexity does not require a Supervisor and AG has provided no evidence of the abilities required for the different positions.[197]

196. The Commission agrees with Calgary that the need for increased manpower in addition to the requested enhancements to the Imbalance Reporting System has not been supported in this compliance filing. The reporting system should increase efficiency in imbalance reporting and AG has not made a case for personnel additions in this area.

197. As the Commission stated in Decision 2011-450, unknown costs associated with integration were identified as an issue for the test years, and AG was given the opportunity to request approval for these unknown costs. The UCA points out that AG’s integration costs submitted in this application could be reviewed for an approval on a more limited or narrow basis. However, upon review of the information provided in the compliance filing, the Commission considers that integration with NGTL has changed AG’s requirements with respect to the number of FT-D3 contracts AG is required to manage. This is an unexpected consequence of integration that has lead to additional specific costs for AG. The Commission approves AG’s request for increases to O&M and capital costs related to contracts for FT-D3 service outside of the personnel additions identified in the paragraphs below.

198. The Commission finds that AG has not justified why a Supervisor and a Contract Analyst are required rather than a Contract Analyst and an Administrative Coordinator. Increasing complexity does not necessarily require a Supervisory position be established. AG stated in response to AUC-AG-4(c),[198]

> …by the time commercial integration took place in October 2011, NGTL determined that ATCO Gas would be required to contract for service by Summary Point instead of sub-group. ATCO Gas has approximately 1,150 Summary Points of service off the NGTL

[195] Exhibit 41.02, UCA argument, page 12, paragraph 51.
[196] Exhibit 41.02, UCA argument page 12, paragraph 52.
[197] Exhibit 41.01, City of Calgary argument, page 3.
[198] Exhibit 34.01.

> system. Additionally, any additional changes due to growth or shifts in forecast demand between points will require a new contract resulting in multiple contracts being held at a single summary point. It is expected that the number of contracts will increase to over 1,500 in 2012 and will continue to increase in the future. This twenty five fold increase in the number of contracts to be managed obviously increases the level of complexity and the capability of staff to ensure due diligence is maintained with the respect to the cost of transmission service and equally importantly ensuring that NGTL has adequate transmission capacity to meet the ATCO Gas peak requirements.

199. The Commission is aware that contracting for firm delivery service on the NGTL system is done on a yearly basis. NGTL offers variable pricing dependent on the length of term with a longer term contract resulting in a lower toll. While the choice of which product meets AG system requirements may require some analysis, the Commission considers that this will most likely be an annual occurrence. AG has not presented any evidence that the day-to-day management of its NGTL business is any more difficult or onerous to require additional staff. The Commission considers that the original organizational plan of having the Contract Analyst and Administrative Coordinator under the supervision of the existing Distribution Planning, Supervising Engineer[199] is a much more reasonable utilization of resources. The Commission denies the request for the Supervisor, Contract Demand Quantity position. AG is directed in its second compliance filing to only include in revenue requirement the capital and labor components for the Contract Analyst and Administrative Coordinator which were filed as part the GRA application for the test years.

4.44 Commission Direction 65 – MRRP costs

200. The Commission issued the following direction to AG:

> 160. The Commission approves the relocation of meters classified as Tier 3 with low risk factors in conjunction with other work such as meter recalls.[200]

201. AG stated in its application:

> In compliance with Commission Direction 3, AG removed the relocation of meters classified as Tier 3 with low risk from its MRRP program, which is scheduled to be completed by 2014. ATCO Gas has reviewed its meter recall program and notes that 316 of its 2011 meter recalls and 900 of its 2012 meter recalls involve locations identified as Tier 3 with low risk factors.

202. The total capital costs associated with these meter relocations is $690,000 and $1,985,000 respectively for 2011 and 2012.[201] The Commission approves these additional meter relocations and the capital costs for the test years as a result of AG's removal Tier 3 meters with low risk from its MRRP consistent with Direction 3 of this decision.

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[199] Ibid, AUC-AG-4(c).
[200] Decision 2011-450, paragraph 160.
[201] Application, Exhibit 1, page 238 of 238.

5 Order

203. It is hereby ordered that:

(1) AG shall re-file its 2011-2012 General Rate Compliance Application including its placeholder summary to reflect the findings, conclusions and directions in this decision.

(2) AG shall re-file its 2011-2012 General Rate Compliance Application by September 10, 2012.

Dated on July 20, 2012.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

Name of Organization (Abbreviation) **Counsel or Representative (APPLICANTS)**
ATCO Gas (AG) D. Cook L. Fink
Office of the Utilities Consumer Advocate (UCA) M. Stauft R. Daw T. Marriot K. Kellgren
Consumers' Coalition of Alberta (CCA) J. Wachowich J. Jodoin
The City of Calgary D. Evanchuk H. Johnson M. Rowe

Alberta Utilities Commission Commission Panel M. Yahya, Commission Member Commission Staff A. Sabo (Commission Counsel) B. Whyte C. Burt M. McJannet C. Taylor

Appendix 2 – 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. With respect to the BFK and DSM, the Commission finds that these costs are related to entire programs which have been disallowed by the Commission, and costs associated with these programs are not required for utility service, unlike SIBS and HRX costs which were split between utility and non-utility service. On this basis the Commission directs AG to remove the BFK and DSM reductions accounted in for its opening rate base in its second compliance filing to Decision 2011-450............................ Paragraph 44

2. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount for 90 per cent of the actual costs of HRX in its second compliance filing to Decision 2011-450..Paragraph 45

3. The Commission finds that there was limited evidence provided by AG in the compliance filing with regard to increased labour requirements or travel costs to support a premium in the 2011 and 2012 test years. However, the Commission recognizes that potential inefficiencies may have resulted due to AG's required exclusion of Tier 3 low risk meter replacements as per Commission Direction 2. As a result, the Commission directs AG in its second compliance filing to provide a detailed justification of any premium that should be applied to AG's forecast due to the above noted inefficiencies.. .... Paragraph 60

4. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the remaining costs of HRX in opening rate base was addressed in paragraph 43 of Direction 1 above. As stated in Direction 1, the issue of Oracle HRX is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V and pending the outcome of the Phase II R&V and any appeals on this issue, AG is directed to include a placeholder amount for Oracle HRX of 90 per cent of the actual cost in its second compliance filing to Decision 2011-450……………………….Paragraph 76

5. AG has removed the CIS enhancement program, forecast amounts of $1 million and $0.6 million, in 2011 and 2012, respectively, determining its revised revenue requirement [MH1]. The Commission has confirmed that this amount has been reflected in the capital adjustment sheet.[202] The issue of the CIS enhancement program forecast costs is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V of Decision 2011-450. In the Phase I R&V, the review panel found that it was unclear whether the hearing panel considered AG's response to the business case in AUC-AG-43(b).[203] Pending the outcome of the Phase II R&V, AG is directed to include a placeholder amount for CIS of zero in its second compliance filing to Decision 2011-450………………..Paragraph 87

[202] Application, Exhibit 7.
[203] Decision 2012-156, paragraph 48, pages 12 and 13.

6. AG stated in its application that it will provide a comparative analysis of the alternative of issuing debt in its next preferred share application and prepare an updated analysis of whether the optimal range of AG's capital structure should include five to ten per cent of preferred shares concurrent with or prior to AG's next preferred share application.[204] For the purposes of this application, the Commission finds that Directions 21 and 22 have been complied with. AG is directed to include the alternatives and analysis as directed in Decision 2011-450 in its next preferred share application……………………………………………………...……….Paragraph 91

7. AG argued that AMR meter exchange costs should continue to be capitalized as they relate to meters that may be damaged or otherwise cannot be retrofitted with the AMR device. The Commission agrees with this approach and directs AG to continue to capitalize meter exchange costs associated with the AMR program. The Commission considers that AG has explained the discrepancy in metering costs and that the additional $4.2 million in O&M for 2011 and 2012 is consistent with Commission direction. AG has complied with this direction…………………………………..………...Paragraph 111

8. The issue of the Calgary office lease is currently before the Commission in Proceeding ID No. 1698, the Phase II of AG's R&V of Decision 2011-450. In granting a review of the findings, the review panel stated that it is unclear whether the hearing panel rate was aware that AG's existing rental rate was $16 per square foot in reaching the determination that the existing lease rate should be used.[205] Pending the outcome of the Phase II R&V proceeding, AG is directed to maintain a placeholder amount for the Calgary lease rate of $14.50 per square foot for 2011, and a placeholder amount of $14.50 per square foot increased by a three per cent inflation factor for 2012, in its second compliance filing to Decision 2011-450.………………….....……......Paragraph 127

9. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount of zero for late payment penalty settlement costs in its second compliance filing to Decision 2011-450.………………………………..….Paragraph 149

10. The Commission has reviewed the table in the application as well as the depreciation expense adjustments spreadsheet.[206] Given the findings in Direction 1 of this decision, the Commission directs AG to provide a schedule detailing the removal of the DSM and the Calgary BFK assets from opening rate base, and any accompanying impact on depreciation in its second compliance filing. .... Paragraph 162

11. AG has advised that it will not be filing a separate application to deal with net salvage rates in the test years.[207] AG explained that a study cannot be completed in time to allow for a separate application for the test years. Consistent with Direction 54 in Decision 2011-450, the Commission therefore directs AG to use the existing net salvage rates for the test years and to reflect the corresponding change in the compliance filing.…………………………………………………………………....Paragraph 164

204 Application, Exhibit 1, pages 157 and 158 of 238 PDF.
205 Decision 2012-156, page 24, paragraph 99.
206 Application, Exhibit 10.
207 Application, Commission Direction 54, page 1 of 2.

12. As the issue of production abandonment costs will be subject to a further proceeding and given the direction of the Commission in Decision 2012-156 that a placeholder is warranted for production abandonment costs, the Commission directs AG in its second compliance filing to use a placeholder of zero for production abandonment costs for the 2011 and 2012 test years. .... Paragraph 171

13. In its application, AG stated it will close the IFRS deferral account and file an application to address settlement of each deferral account adjustment within three months of the public release of 2011 Canadian Utilities Limited financial statements.[208] The Commission notes that no application regarding this deferral account has been filed to date. The Commission directs AG to provide an update in its second compliance filing regarding the status of its application for the closure and settlement of the IFRS deferral account………………………………………………………………....Paragraph 180

14. The Commission has reviewed the O&M adjustments spreadsheet and is satisfied that AG has removed $150,000 in forecast costs related to participating in NEB proceedings for each of 2011 and 2012, in compliance with the Commission’s direction. However, the Commission notes that in Decision 2012-156, the review panel has granted a review of the decision to deny AG’s request to recover $300,000 in forecast costs for participation in the NEB NGTL hearings.[209] The issue of the recovery of 2011 and 2012 forecast costs related to AG’s participation in NEB hearings related to integration is properly before the Commission in Proceeding ID No. 1698. Pending the outcome of the Phase II R&V proceeding in Proceeding ID No. 1698, AG is directed to use a placeholder amount of zero for forecast hearing costs related to integration hearings for 2011 and 2012. The Commission directs AG to reflect the zero placeholder for these costs in its second compliance filing to Decision 2011-450.………………………………….Paragraph 189

15. The Commission considers that the original organizational plan of having the Contract Analyst and Administrative Coordinator under the supervision of the existing Distribution Planning, Supervising Engineer[210] is a much more reasonable utilization of resources. The Commission denies the request for the Supervisor, Contract Demand Quantity position. AG is directed in its second compliance filing to only include in revenue requirement the capital and labor components for the Contract Analyst and Administrative Coordinator which were filed as part the GRA application for the test years. ……………………………………………………………………..Paragraph 199

[208] Application, Commission Direction 59, page 1 of 1.

[209] Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, page 19, paragraph 74.

[210] Ibid, AUC-AG-4(c).

Appendix 3 – Summary of 2011 O&M adjustments

SUMMARY OF 2011 O&M ADJUSTMENTS

Description	Reference	Gas Management	Transmission	Distribution	General	Sales & Transportation Promotion	Customer Accounting	Administrative	Total
O&M Labour as Filed	4.2	593	-	57,791	1,905	3,927	20,317	17,245	101,778
Updated for April 21 Adjustments		-	-	(100)	-	-	(300)	-	(400)
VPP Net Income reduction to 10% - Transcript Response - D Wilson - Volume 2, page 344		-	-	-	-	-	-	(531)	(531)
VPP Net Income adjustment to 10% max per participant	CD37	-	-	-	-	-	-	(119)	(119)
Vacancy Allowance Increase to 8.3%	CD25	(13)	-	-	(42)	(30)	(38)	-	(123)
Meter Recalls recorded as O&M	CD27	-	-	1,725	-	-	-	-	1,725
Reduce forecasted costs in Account 674 by 1.2%	CD28	-	-	(166)	-	-	-	-	(166)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(140)	-	-	-	-	(140)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(1,375)	-	-	(1,375)
Remove DSM costs	CD33	-	-	-	-	(1,205)	-	-	(1,205)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(281)	-	(281)
Adjust foreasted costs for admin labour excluding VPP to 2010 actuals increased by 5% per year	CD36	-	-	-	-	-	-	(2,146)	(2,146)
Remove forecasted costs related to training, mentoring, and coaching	CD61	-	-	(600)	-	-	-	-	(600)
Line heater inspection costs	CD62	-	-	(200)	-	-	-	-	(200)
NEB Integration labour for additional supervisor and analyst	CD64	-	-	(66)	-	-	-	-	(66)
Labour adjustments		(13)	-	553	(42)	(2,610)	(319)	(2,265)	(4,696)
Adjusted O&M Forecast - Labour		**580**	**-**	**58,244**	**1,863**	**1,317**	**19,699**	**14,449**	**96,152**
O&M Supplies as Filed	4.2	19	107,898	24,870	5,474	4,624	31,423	92,316	266,624
Updated for April 21 Adjustments		-	-	400	(400)	(600)	(300)	(700)	(1,600)
Meter Recalls recorded as O&M	CD27	-	-	2,475	-	-	-	-	2,475
Reduce forecasted costs in Account 674 by 1.2%	CD28	-	-	(24)	-	-	-	-	(24)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(128)	-	-	-	-	(128)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(574)	-	-	(574)
BFK safety messaging moved to Customer Relations & Communications	CD31	-	-	-	-	50	-	-	50
Remove Centennial Anniversary costs	CD32	-	-	-	-	(250)	-	-	(250)
Remove DSM costs	CD33	-	-	-	-	(1,927)	-	-	(1,927)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(92)	-	(92)
Allocated corporate advertising	CD40	-	-	-	-	-	-	(73)	(73)
Adjust foreasted costs for mass media & other supplies to 2010 actuals increased by 5% per year	CD41	-	-	-	-	-	-	(1,045)	(1,045)
Reclassify bank and short-term financing as financing costs	CD47	-	-	-	-	-	-	(1,000)	(1,000)
Safety initiatives related to changes in workforce	CD61	-	-	(500)	-	-	-	-	(500)
Line heater inspection costs	CD62	-	-	(700)	-	-	-	-	(700)
NEB Integration legal costs	CD63	-	-	-	-	-	-	(150)	(150)
NEB Integration legal costs	CD64	-	-	-	-	-	-	128	128
Transmission Approved Rate		-	(9,755)	-	-	-	-	-	(9,755)
ATCO I-Tek Placeholder Update to 2010 Utilities Evergreen Proceeding		-	-	-	-	-	(1,025)	-	(1,025)
Supplies adjustments		-	(9,755)	1,123	-	(2,701)	(1,117)	(2,140)	(14,590)
Adjusted O&M Forecast - Supplies		**19**	**98,143**	**26,393**	**5,074**	**1,323**	**30,006**	**89,476**	**250,434**
Total Adjustments - April 21 Update		-	-	300	(400)	(600)	(600)	(700)	(2,000)
Total Adjustments - Hearing Update		-	-	-	-	-	-	(531)	(531)
Total Adjustments - Decision 2011-450		(13)	(9,755)	1,676	(42)	(5,311)	(1,436)	(4,405)	(19,286)
Total Adjustments		(13)	(9,755)	1,976	(442)	(5,911)	(2,036)	(5,105)	(21,286)
Adjusted O&M Forecast - Total		**599**	**98,143**	**84,637**	**6,937**	**2,640**	**49,705**	**103,925**	**346,586**

Appendix 4 – Summary of 2012 O&M adjustments

SUMMARY OF 2012 O&M ADJUSTMENTS

Description	Reference	Gas Management	Transmission	Distribution	General	Sales & Transportation Promotion	Customer Accounting	Administrative	Total
O&M Labour as Filed	4.2	611	-	61,232	2,024	4,432	21,301	17,804	107,404
Updated for April 21 Adjustments		-	-	100	-	-	(300)	100	(100)
VPP Net Income reduction to 10% - Transcript Response - D Wilson - Volume 2, page 344		-	-	-	-	-	-	(531)	(531)
VPP Net Income adjustment to 10% max per participant	CD37	-	-	-	-	-	-	(119)	(119)
Vacancy Allowance Increase to 8.3%	CD25	(13)	-	-	(45)	(32)	(41)	-	(131)
Meter Recalls recorded as O&M	CD27	-	-	1,700	-	-	-	-	1,700
Reduce forecasted costs in Account 674 by 1.7%	CD28	-	-	(250)	-	-	-	-	(250)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(223)	-	-	-	-	(223)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(1,492)	-	-	(1,492)
Remove DSM costs	CD33	-	-	-	-	(1,505)	-	-	(1,505)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(358)	-	(358)
Reduce Meter Reading costs	CD35	-	-	-	-	-	(3,200)	-	(3,200)
Adjust foreasted costs for admin labour excluding VPP to 2010 actuals increased by 5% per year	CD36	-	-	-	-	-	-	(2,019)	(2,019)
Remove forecasted costs related to training, mentoring, and coaching	CD61	-	-	(800)	-	-	-	-	(800)
Remove occupational health nurses	CD61	-	-	(200)	-	-	-	-	(200)
Line heater inspection costs	CD62	-	-	(200)	-	-	-	-	(200)
NEB Integration labour for additional supervisor and analyst	CD64	-	-	115	-	-	-	-	115
Labour adjustments		(13)	-	142	(45)	(3,029)	(3,599)	(2,138)	(8,682)
Adjusted O&M Forecast - Labour		**598**	**-**	**61,474**	**1,979**	**1,403**	**17,402**	**15,235**	**98,091**
O&M Supplies as Filed	4.2	19	109,349	26,898	5,741	5,073	32,433	91,926	271,439
Updated for April 21 Adjustments		-	-	400	(400)	-	(300)	(300)	(600)
Okotoks Operating Costs	CD11				(8)	-	-	-	(8)
Consultant costs moved to one-time adjustment	CD26	-	-	(500)	-	-	-	-	(500)
Meter Recalls recorded as O&M	CD27	-	-	2,500					2,500
Reduce forecasted costs in Account 674 by 1.7%	CD28	-	-	(35)	-	-	-	-	(35)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(202)	-	-	-	-	(202)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(636)	-	-	(636)
BFK safety messaging moved to Customer Relations & Communications	CD31	-	-	-	-	50	-	-	50
Remove Centennial Anniversary costs	CD32	-	-	-	-	(1,100)	-	-	(1,100)
Remove DSM costs	CD33	-	-	-	-	(2,018)	-	-	(2,018)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(338)	-	(338)
CC&B Benchmarking	CD34	-	-	-	-	-	300	-	300
Office rent based on $14.50 inflated by 3%	CD39	-	-	-	-	-	-	24	24
Allocated corporate advertising	CD40	-	-	-	-	-	-	(75)	(75)
Adjust foreasted costs for mass media & other supplies to 2010 actuals increased by 5% per year	CD41	-	-	-	-	-	-	(1,182)	(1,182)
Reclassify bank and short-term financing as financing costs	CD47	-	-	-	-	-	-	(900)	(900)
Line heater inspection costs	CD62	-	-	(700)	-	-	-	-	(700)
NEB Integration legal costs	CD63	-	-	-	-	-	-	(150)	(150)
NEB Integration legal costs	CD64	-	-	-	-	-	-	150	150
NEB Integration for meter maintenance/reading	CD64	-	-	65	-	-	-	-	65
NEB Integration for system maintenance & support	CD64	-	-		-	-	-	22	22
Transmission Approved Rate		-	(2,769)	-	-	-	-	-	(2,769)
ATCO I-Tek Placeholder Update to 2010 Utilities Evergreen Proceeding		-	-	-	-	-	(1,056)	-	(1,056)
Supplies adjustments		-	(2,769)	1,128	(8)	(3,704)	(1,094)	(2,111)	(8,558)
Adjusted O&M Forecast - Supplies		**19**	**106,580**	**28,426**	**5,333**	**1,369**	**31,039**	**89,515**	**262,281**
Total Adjustments - April 21 Update		-	-	500	(400)	-	(600)	(200)	(700)
Total Adjustments - Hearing Update		-	-	-	-	-	-	(531)	(531)
Total Adjustments - Decision 2011-450		(13)	(2,769)	1,270	(53)	(6,733)	(4,693)	(4,249)	(17,240)
Total Adjustments		(13)	(2,769)	1,770	(453)	(6,733)	(5,293)	(4,980)	(18,471)
Adjusted O&M Forecast - Total		**617**	**106,580**	**89,900**	**7,312**	**2,772**	**48,441**	**104,750**	**360,372**

Appendix 5 – Summary of 2011 depreciation adjustments

SUMMARY OF 2011 UTILITY DEPRECIATION EXPENSE ADJUSTMENTS

Description	Reference	Distribution	General Plant	Gross Depreciation	Amortization of Contributions	Capitalized Depreciation	Net Depreciation	Production Abandonments	Total Depreciation Expense
North									
Depreciation Expense as Filed	5.1-9 & 10	**53.3**	**16.8**	**70.1**	**(5.5)**	**(2.7)**	**61.9**	**0.5**	**62.4**
Account 473 - Services	CD 48	0.2	-	0.2	(0.1)	-	0.1	-	0.1
Account 474 - Regulator and Meter Installations	CD 49	(1.8)	-	(1.8)	0.1	-	(1.8)	-	(1.8)
Account 475 - Mains	CD 50	(3.2)		(3.2)	0.2	-	(3.0)	-	(3.0)
Account 484 - Transportation Equipment	CD 52	-	(2.0)	(2.0)	-	0.9	(1.1)	-	(1.1)
Other Depreciation Accounts	CD 53	(0.1)	(0.8)	(0.9)	0.6	(0.4)	(0.7)	-	(0.7)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(0.5)	(0.5)
Total Adjustments		(4.9)	(2.8)	(7.7)	0.7	0.5	(6.5)	(0.5)	(7.0)
Adjusted Depreciation Expense Forecast		**48.4**	**14.0**	**62.4**	**(4.8)**	**(2.2)**	**55.4**	**-**	**55.4**
South									
Depreciation Expense as Filed	5.1-9 & 10	**45.9**	**13.4**	**59.3**	**(5.0)**	**(2.0)**	**52.3**	**1.0**	**53.3**
Account 473 - Services	CD 48	0.3	-	0.3	(0.1)	-	0.2	-	0.2
Account 474 - Regulator and Meter Installations	CD 49	(1.3)	-	(1.3)	0.0	-	(1.3)	-	(1.3)
Account 475 - Mains	CD 50	(3.3)	-	(3.3)	0.2	-	(3.1)	-	(3.1)
Account 484 - Transportation Equipment	CD 52	-	(1.7)	(1.7)	-	0.8	(0.9)	-	(0.9)
Other Depreciation Accounts	CD 53	(0.5)	(0.5)	(1.0)	(0.6)	(0.2)	(1.8)	-	(1.8)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.0)	(1.0)
Total Adjustments		(4.8)	(2.2)	(7.0)	(0.4)	0.6	(6.8)	(1.0)	(7.8)
Adjusted Depreciation Expense Forecast		**41.1**	**11.2**	**52.3**	**(5.4)**	**(1.4)**	**45.5**	**-**	**45.5**
Total									
Depreciation Expense as Filed	5.1-9 & 10	**99.2**	**30.2**	**129.4**	**(10.5)**	**(4.7)**	**114.2**	**1.5**	**115.7**
Account 473 - Services	CD 48	0.5	-	0.5	(0.2)	-	0.3	-	0.3
Account 474 - Regulator and Meter Installations	CD 49	(3.1)	-	(3.1)	0.1	-	(3.0)	-	(3.0)
Account 475 - Mains	CD 50	(6.5)	-	(6.5)	0.4	-	(6.1)	-	(6.1)
Account 484 - Transportation Equipment	CD 52	-	(3.7)	(3.7)	-	1.7	(2.0)	-	(2.0)
Other Depreciation Accounts	CD 53	(0.6)	(1.3)	(1.9)	-	(0.6)	(2.5)	-	(2.5)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.5)	(1.5)
Total Adjustments		(9.6)	(5.0)	(14.6)	0.3	1.1	(13.3)	(1.5)	(14.8)
Adjusted Depreciation Expense Forecast		**89.6**	**25.2**	**114.8**	**(10.2)**	**(3.6)**	**100.9**	**-**	**100.9**

Appendix 6 – Summary of 2012 depreciation adjustments

SUMMARY OF 2012 UTILITY DEPRECIATION EXPENSE ADJUSTMENTS

Description	Reference	Distribution	General Plant	Gross Depreciation	Amortization of Contributions	Capitalized Depreciation	Net Depreciation	Production Abandonments	Total Depreciation Expense
North									
Depreciation Expense as Filed	5.1-9 & 10	**58.9**	**18.0**	**76.9**	**(5.9)**	**(2.9)**	**68.1**	**0.6**	**68.7**
Account 473 - Services	CD 48	(0.1)	-	(0.1)	(0.1)	-	(0.2)	-	(0.2)
Account 474 - Regulator and Meter Installations	CD 49	(2.1)	-	(2.1)	0.1	-	(2.0)	-	(2.0)
Account 475 - Mains	CD 50	(3.9)	-	(3.9)	0.2	-	(3.7)	-	(3.7)
Account 484 - Transportation Equipment	CD 52	-	(2.2)	(2.2)	-	1.0	(1.2)	-	(1.2)
Other Depreciation Accounts	CD 53	(0.2)	(0.8)	(1.0)	0.7	(0.4)	(0.7)	-	(0.7)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(0.6)	(0.6)
Total Adjustments		(6.2)	(3.0)	(9.2)	0.8	0.6	(7.8)	(0.6)	(8.4)
Adjusted Depreciation Expense Forecast		**52.7**	**15.0**	**67.7**	**(5.1)**	**(2.3)**	**60.3**	**-**	**60.3**
South									
Depreciation Expense as Filed	5.1-9 & 10	**50.4**	**14.4**	**64.8**	**(5.4)**	**(2.1)**	**57.3**	**1.0**	**58.3**
Account 473 - Services	CD 48	0.3	-	0.3	(0.1)	-	0.2	-	0.2
Account 474 - Regulator and Meter Installations	CD 49	(1.4)	-	(1.4)	0.0	-	(1.4)	-	(1.4)
Account 475 - Mains	CD 50	(3.9)	-	(3.9)	0.2	-	(3.7)	-	(3.7)
Account 484 - Transportation Equipment	CD 52	-	(1.8)	(1.8)	-	0.8	(1.0)	-	(1.0)
Other Depreciation Accounts	CD 53	(0.5)	(0.7)	(1.2)	(0.6)	(0.1)	(1.9)	-	(1.9)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.0)	(1.0)
Total Adjustments		(5.6)	(2.5)	(8.1)	(0.4)	0.7	(7.8)	(1.0)	(8.8)
Adjusted Depreciation Expense Forecast		**44.8**	**11.9**	**56.7**	**(5.8)**	**(1.4)**	**49.5**	**-**	**49.5**
Total									
Depreciation Expense as Filed	5.1-9 & 10	**109.3**	**32.4**	**141.7**	**(11.3)**	**(5.0)**	**125.4**	**1.6**	**127.0**
Account 473 - Services	CD 48	0.2	-	0.2	(0.2)	-	(0.0)	-	(0.0)
Account 474 - Regulator and Meter Installations	CD 49	(3.5)	-	(3.5)	0.1	-	(3.4)	-	(3.4)
Account 475 - Mains	CD 50	(7.8)	-	(7.8)	0.4	-	(7.4)	-	(7.4)
Account 484 - Transportation Equipment	CD 52	-	(4.0)	(4.0)	-	1.8	(2.2)	-	(2.2)
Other Depreciation Accounts	CD 53	(0.7)	(1.5)	(2.2)	0.1	(0.5)	(2.6)	-	(2.6)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.6)	(1.6)
Total Adjustments		(11.8)	(5.5)	(17.3)	0.4	1.3	(15.6)	(1.6)	(17.2)
Adjusted Depreciation Expense Forecast		**97.5**	**26.9**	**124.4**	**(10.9)**	**(3.7)**	**109.8**	**-**	**109.8**