Decision **20522-D02-2016**

Alberta Utilities Commission

AltaGas Utilities Inc.

2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application

January 21, 2016

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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. This decision provides the Alberta Utilities Commission's determination of (1) the prudence of AltaGas Utilities Inc.'s (AltaGas or AUI) 2013 and 2014 capital tracker true-up project costs and (2) the reasonableness of AltaGas' forecast 2016-2017 capital tracker project costs. For the reasons outlined in this decision, the Commission has determined that:

- AltaGas' proposed grouping of projects into programs is reasonable.
- The 2013 and 2014 true-up projects and the 2016 and 2017 forecast projects are needed.
- The 2013 true-up projects were prudently incurred and satisfy the project assessment requirement of Criterion 1.
- Except for certain pipeline replacement and gas supply trailing costs, the 2014 true-up projects were prudently incurred and satisfy the project assessment requirement of Criterion 1.
- Except for the BWM Gas Supply project, the 2016-2017 forecast capital tracker projects are reasonable and satisfy the project assessment requirement of Criterion 1.
- The Commission calculated and approved for use by AltaGas a 2016 Gas Supply program placeholder amount based on the historical average of gas supply projects since 2010, including trailing costs and overheads.
- The form of AltaGas' accounting test model is reasonable.
- AltaGas must update the accounting test for forecast capital additions approved in this decision, and for the I-X factor and Q factor determined in Decision 20823-D01-2015.[1]
- The 2013 K factor true-up refund amount of $11,217 is approved, as filed.
- The 2014 K factor true-up amount needs to be corrected to reflect the difference between the true-up adjustment of ($192,806) calculated in this decision and the ($393,854) adjustment included in AltaGas' 2016 annual PBR rate adjustment application.
- The 2016 and 2017 forecast K factors need to be updated to reflect the 2016 I-X index and the Q factor and the BWM Gas Supply placeholder.
- AltaGas has generally complied with previous Commission directions, with the exception of the pipeline replacement trailing costs and the gas supply trailing costs, and minimum filing requirement 1c.

2. On January 7, 2015, the Commission issued a letter that established a preliminary process and schedule that it intended to follow for the 2014 capital tracker true-up and 2016-2017 capital

[1] Decision 20823-D01-2015: AltaGas Utilities Inc.2016 Annual Performance-Based Regulation Rate Adjustment Filing, Proceeding 20823, December 16, 2015.

tracker forecast applications for AltaGas, ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. (the companies).[2]

3. In its letter, the Commission referred to Decision 2013-435[3] in which the Commission provided directions to the companies on the filing process for the 2014 capital tracker true-up and 2016-2017 capital tracker forecast applications. Decision 2013-435 stated:

> 1074. Given that annual actual capital expenditure information may not be publically available until the May AUC Rule 005 filings, the Commission is modifying the direction set out in paragraph 975 of Decision 2012-237 requiring the inclusion of a true-up of the costs of capital tracker projects that have been completed since the prior year's capital tracker filing in the annual March 1 capital tracker application. Commencing in 2015, the companies shall file by May 15th in each year a separate application to true-up the costs of capital tracker projects that have been completed since the prior year's capital tracker filing. For all capital tracker projects that have not been completed, the companies shall also file actual expenditures to December 31 of the prior year and a forecast to completion. The companies shall continue to file their capital tracker applications for the upcoming year by March 1 of the preceding year.

4. In its letter, the Commission also said:

> 2. After processing the 2013 true-up and 2014-2015 forecast capital tracker applications, the Commission has reviewed the procedural timelines established in Decision 2013-435 in light of the compressed procedural and hearing schedule that occurred in 2014, and has decided to modify the application deadlines for true-up applications and forecast capital tracker applications on a go forward basis. The Commission has also considered the concerns expressed by the CCA in its letter of September 23, 2014 with respect to the 2015 annual PBR rate adjustment filings, regarding simultaneous due dates for procedural steps on multiple proceedings.
>
> 3. For regulatory efficiency, the Commission directs the companies to combine the 2014 true-up, 2016 forecast and 2017 forecast capital tracker applications into a single application. Each company's application will continue to be addressed separately from other companies' applications. [Footnotes removed]

5. On March 2, 2015,[4] and May 5, 2015,[5] in response to requests from certain of the companies, the Commission issued letters that included revised schedules. In the May 5, 2015 letter, one of the requested changes that the Commission incorporated into the revised schedule was from AltaGas, who requested an extension to the filing date for its capital tracker application from May 15, 2015 to May 29, 2015 and that the hearing for its proceeding commence no earlier than September 23, 2015.

[2] Proceeding 3558, Exhibit 3558-X0002, Commission letter, submission process for 2014 capital tracker true-up and 2016-2017 capital tracker forecast applications.
[3] Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.
[4] Proceeding 3558, Exhibit 3558-X0011, Commission letter, updating the submission process for 2014 capital tracker true-up and 2016-2017 capital tracker forecast applications.
[5] Proceeding 20176, Exhibit 20176-X002, Commission letter, update to the submission process for 2014 capital tracker true-up and 2016-2017 capital tracker forecast applications.

6. By letter dated May 26, 2015, AltaGas requested a further application filing extension to June 3, 2015.[6] On June 4, and June 5, 2015, AltaGas filed its 2014 capital tracker true-up and 2016-2017 capital tracker forecast application and associated schedules.[7]

7. On June 5, 2015, the Commission issued a filing announcement and a notice for the AltaGas 2014 capital tracker true-up and 2016-2017 capital tracker forecast application, with statements of intent to participate (SIP's) due June 11, 2015.[8]

8. On June 8, 2015, AltaGas filed a revised application.[9]

9. The Commission received SIPs by the specified deadline date from the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA).[10]

10. By letter dated June 12, 2015, the Commission issued a process letter that included an oral hearing from September 28 to October 2, 2015, in the event an oral hearing was required.[11] In response to a July 22, 2015 request by AltaGas for an extension to the filing deadline for its information responses,[12] the Commission again adjusted the schedule in a letter dated July 23, 2015:[13]

Process step	Deadline	Revised deadline
Information requests to AltaGas	July 2, 2015	Complete
Responses to information requests by AltaGas	July 23, 2015	July 28, 2015
Intervener evidence	August 13, 2015	August 18, 2015
Information requests on intervener evidence	August 27, 2015	August 27, 2015
Responses to information requests on intervener evidence	September 11, 2015	September 11, 2015
Rebuttal evidence	September 21, 2015	September 21, 2015
Oral hearing	September 28 to October 2, 2015	September 28 to October 2, 2015

11. On June 23, 2015, AltaGas hosted a technical meeting that was attended by Commission staff and representatives from the CCA and the UCA. AltaGas filed a copy of the technical meeting presentation on the record.[14]

12. On June 26, 2015, AltaGas filed a document reflecting necessary revisions to the application and appendices that were identified as a result of the technical meeting[15] and on

6 Proceeding 20176, Exhibit 20176-X0023.
7 Exhibits 20522-X0001, 20522-X0002, 20522-X0003 and 20522-X0004.
8 Exhibits 20522-X0006 and 20522-X0007.
9 Exhibit 20522-X0010, revised application.
10 Exhibits 20522-X0011 and 20522-X0012.
11 Exhibit 20522-X0013.
12 Exhibit 20522-X0022.
13 Exhibit 20522-X0023.
14 Exhibit 20522-X0016.
15 Exhibit 20522-X0010.01.

August 20, 2015, AltaGas filed a further revised application to incorporate revisions identified during the information response process.[16]

13. On August 18, 2015, the UCA filed evidence[17] and on August 26, 2015, after identifying a material error, the UCA filed a revised version of its evidence.[18]

14. By letter dated August 19, 2015, the Commission requested parties' input on whether there was a continuing need for the oral hearing scheduled to commence on September 28, 2015.[19] In response to the Commission's letter, submissions were received from AltaGas and the UCA.[20] In their submissions, these parties were unable to state definitively that the oral hearing would not be required because the deadlines for interrogatories on the intervener evidence and rebuttal evidence had not yet come due.

15. Subsequently, by letter dated August 27, 2015, AltaGas advised that it would not be filing information requests on the evidence submitted by the UCA nor would it be submitting rebuttal evidence.[21] In its letter, AltaGas also submitted that there was sufficient evidence on the record and an oral hearing was not required, and requested that the Commission dispense with the currently scheduled oral hearing and revise the current schedule to proceed directly to written argument and reply argument. AltaGas suggested September 30, 2015, for argument and October 23, 2015, for reply argument.

16. No information requests were submitted by the Commission regarding the evidence filed by the UCA.

17. By letter dated August 31, 2015, the UCA agreed that a written process would be sufficient to complete the record of this proceeding and accepted AltaGas' proposed dates for argument and reply.[22]

18. On August 31, 2015, the Commission received an email from counsel for the CCA supporting the September 30 and October 23, 2015 dates suggested by AltaGas.[23]

19. By letter dated September 2, 2015, the Commission determined that an oral hearing was not required to complete the evidential record of this proceeding, cancelled the remaining evidential process and advanced the proceeding directly to argument and reply argument to the dates suggested by AltaGas and agreed to by parties.[24]

20. Reply argument was received on October 23, 2015. The Commission considers the record for this proceeding to have closed on October 23, 2015.

21. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of the 2014 capital tracker true-up and

16 Exhibit 20522-X0010.04, application (black line) identifying revisions.
17 Exhibits 20522-X0042 and 20522-X0043.
18 Exhibit 20522-X0042.03.
19 Exhibit 20522-X0044.
20 Exhibits 20522-X0048 and 20522-X0049.
21 Exhibit 20522-X0053.
22 Exhibit 20522-X0054.
23 Exhibit 20522-X0055.
24 Exhibit 20522-X0056.

2016-2017 capital tracker forecast proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the records 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 records with respect to that matter.

2 Background

2.1 Overview of the capital tracker approach under PBR

22. On September 12, 2012, the Commission issued Decision 2012-237,[25] approving performance-based regulation (PBR) plans for the distribution utility services of certain Alberta electric and gas companies, including AltaGas. The PBR plans were approved for a five-year term commencing January 1, 2013. PBR replaced traditional cost-of-service regulation as the annual rate-setting mechanism for distribution utility rates.

23. As set out in Decision 2012-237, the PBR framework provides a formula mechanism for the annual adjustment of rates. In general, AltaGas' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the company can be expected to achieve during the PBR plan period. As a result, with the exception of specified adjustments, a utility's revenues are no longer linked to its costs. Companies subject to a PBR regime must manage their businesses and service obligations with the revenues derived under the PBR indexing mechanism and adjustments provided for in the formula. The PBR framework is intended to provide incentives for productivity increases and cost savings similar to those operating in competitive markets.

24. A company may apply for approval for certain rate adjustments to enable the recovery of specific costs where it can be demonstrated that the costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. These possible adjustments include an adjustment to fund necessary capital expenditures (a K factor), an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (a Y factor), or an adjustment to account for the effect of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan (a Z factor).

25. In Decision 2012-237, the Commission determined that a mechanism to fund certain capital-related costs may be required for some of the approved PBR plans.[26] This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

26. At paragraph 592 of Decision 2012-237, the Commission set out three criteria that any capital project or program would have to satisfy in order to receive capital tracker treatment:

[25] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

[26] Decision 2012-237, paragraph 586.

(1) The project must be outside of the normal course of the company's ongoing operations.
(2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
(3) The project must have a material effect on the company's finances.

27. Further, at paragraph 593 of Decision 2012-237, the Commission indicated that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project or program to be approved as a capital tracker.

28. The implementation and application of the above capital tracker criteria were considered as part of the 2013 capital trackers, Proceeding 2131, leading to Decision 2013-435. The Commission indicated that the implementation methodology established in that decision would be used not only to evaluate the capital tracker projects or programs proposed by the parties for 2013, but also for subsequent capital tracker applications throughout the PBR term.[27]

29. With respect to the first capital tracker criterion, the Commission concluded that, in general, in order for a capital project or program to be considered outside of the normal course of the company's ongoing operations, the increase in associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for this project or program. Accordingly, the Commission found that the concept of normal course is mainly a financial and accounting consideration, rather than strictly an engineering consideration. The Commission referred to this comparison of revenues as the "accounting test" under Criterion 1. At the same time, the Commission indicated an engineering study and a business case would aid the Commission in assessing whether a project proposed for capital tracker treatment is (i) required to provide utility service at adequate levels and, if so, (ii) that the scope, level, timing and costs of a completed project are prudent, and the scope, level, timing and costs of a forecast project are reasonable. The Commission referred to this assessment as the "project assessment" under Criterion 1. An applicant must satisfy the Commission's requirements for both the accounting test and the project assessment in order to satisfy the requirements of Criterion 1.[28]

30. Regarding the accounting test component of Criterion 1, the Commission determined that this test should be based on the project net cost approach, under which the revenue generated under the I-X mechanism for each capital project (or capital program or project category) is compared to the forecast revenue requirement associated with that capital project (or capital program or project category) in a PBR year. No consideration of operating and maintenance costs or savings, or potential productivity offsets above those implied by the approved X factor, are required for the accounting test. The Commission provided further clarification on the weighted average cost of capital (WACC) rate assumptions of the accounting test in Decision 3434-D01-2015.[29]

[27] Decision 2013-435, paragraph 120.
[28] Decision 2013-435, paragraphs 149-150.
[29] Decision 3434-D01-201: Distribution Performance-Based Regulation Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

31. For purposes of the project assessment, the Commission determined that each project or program proposed for capital tracker treatment must generally be supported by a business case and an engineering study. However, the Commission recognized that in some circumstances an engineering study may not be required. In Decision 2013-435, the Commission set out certain minimum filing requirements that a project or program proposed for capital tracker treatment should typically address to assist the Commission's project assessment.[30] These minimum filing requirements were subsequently refined in Decision 3558-D01-2015.[31]

32. At paragraph 615 of Decision 2012-237, the Commission indicated that a company may choose to undertake a capital investment, prior to applying for capital tracker treatment in the subsequent annual capital tracker filing. The Commission further clarified at paragraph 48 of Decision 2013-435:

> 48. It was acknowledged by the Commission that superior incentives for capital trackers would result if the companies were required to spend money on capital expenditures prior to receiving approval for capital tracker recovery of the expenditures. However, given the lack of experience with the capital tracker mechanism, for the first generation PBR plans, it was determined that the companies will be permitted to apply for capital trackers on a forecast basis. The approved forecast cost of a capital tracker project will be included in rates on an interim basis and will be subject to a true-up to prudently incurred actual expenditures, after the project is completed. The true-up process will test the prudence of the actual capital expenditures and imprudent expenditures will be subject to disallowance. As a result, the capital tracker mechanism retains some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred. The true-up mechanism with a prudence review also mitigates somewhat the incentive for companies to overstate the initial capital tracker forecasts. Nonetheless, the companies remained free to incur expenditures prior to applying for capital tracker approval. [footnotes removed]

33. With respect to Criterion 2, in Decision 2013-435, the Commission clarified that, in addition to asset replacement projects and projects required by an external party, in principle, a growth-related project will satisfy the requirements of Criterion 2 where it can be demonstrated that customer contributions, together with incremental revenues allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, are insufficient to offset the revenue requirement associated with the project in a PBR year.[32] Criterion 2 also permits consideration of certain projects for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party related categories.

34. Under Criterion 3, the Commission determined that applying the materiality threshold to that portion of the revenue requirement for a project that is not funded under the I-X mechanism is warranted. The Commission established a two-tier materiality threshold. The first tier of the materiality threshold, a "four basis point threshold" is to be applied at a project level (grouped in the manner approved by the Commission). The second tier of the materiality threshold, a "40 basis point threshold" is to be applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.

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[30] Decision 2013-435, paragraphs 1091-1092.

[31] Decision 3558-D01-2015: Distribution Performance-Based Regulation Commission-initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015.

[32] Decision 2013-435, paragraph 309.

35. Additionally, the Commission recognized the significance of the grouping of projects proposed for capital tracker treatment when it stated in paragraph 601 of Decision 2012-237:

> 601. … The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

36. In Decision 2013-435, the Commission further elaborated that grouping of projects will require close scrutiny, since it will have a direct effect on the results of the accounting test and the project assessment under Criterion 1, as well as the assessment of materiality under Criterion 3. The Commission determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each individual company. The Commission indicated that it will require each company to provide a justification for its grouping of projects proposed for capital tracker treatment.[33]

37. Finally, in Section 4.4 of Decision 2013-435, the Commission set out the K factor calculation methodology. The Commission determined that basing the K factor calculations on the incremental revenue requirement amounts (i.e., above the amounts provided under the I-X mechanism) for each project or program proposed for capital tracker treatment, as is done under the project net cost approach, is commensurate with the Commission's definition of outside the normal course of the company's ongoing operations.

38. In Decision 2012-237, the Commission outlined the capital tracker true-up process as follows:

> 975. … the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.[34]

2.2 Prior AltaGas capital tracker-related proceedings

39. Because the 2013 capital trackers proceeding leading to Decision 2013-435 was ongoing at the time, in Decision 2013-072, the Commission approved, on an interim basis, a 2013 capital tracker placeholder (K factor) for AltaGas, equal to 60 per cent of the applied-for K factor amount. As a result, AltaGas was directed to include in its 2013 PBR rates, a K factor placeholder of $0.60 million on an interim basis.[35]

40. Similar interim K factor placeholders were approved by the Commission for each of 2014, 2015 and 2016. In Decision 2013-465, the Commission approved, on an interim basis, a

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[33] Decision 2013-435, paragraphs 403 and 406.
[34] Decision 2012-237, paragraph 975.
[35] Decision 2013-072: 2012 Performance-Based Regulation Compliance Filings, AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2130, Application 1608826-1, March 4, 2013.

K factor placeholder in the amount of $1.23 million to be included in AltaGas' 2014 PBR rates.[36] In Decision 2014-357, the Commission approved, on an interim basis, a 2015 K factor placeholder in the amount of $3.14 million, based on 90 per cent of the proposed 2015 K factor.[37] In Decision 20823-D01-2015, the Commission approved, on an interim basis, a 2016 K factor placeholder in the amount of $4.86 million based on 90 per cent of the proposed 2016 K factor.[38]

41. In Decision 2013-435, the Commission approved AltaGas' forecast projects for capital tracker treatment, for a 2013 K factor forecast amount of $1.03 million,[39] to be recovered from customers on an interim basis pending future true-up proceedings. In Decision 2014-180, the Commission approved the collection by AltaGas of the $0.43 million difference between the 60 per cent placeholder and the approved K factor forecast amount for 2013.[40]

42. Decision 2014-373 dealt with AltaGas' 2013 true-up and 2014-2015 forecast capital tracker applications.[41] The 2013 K factor true-up amount and 2014-2015 K factor forecast amounts were approved in the compliance filing Decision 20176-D01-2015.[42] As set out in that decision, the Commission approved a total 2013 K factor true-up refund amount of $0.27 million. The Commission also approved the 2014 and 2015 forecast total K factor true-up amounts, a collection of $1.98 million and $3.45 million, respectively.

43. Finally, in Decision 20695-D01-2015,[43] the Commission approved AltaGas' application to refund the $0.09 million 2013 capital tracker K factor true-up adjustment, collect the $0.75 million 2014 capital tracker K factor true-up adjustment and collect the $0.11 million 2015 capital tracker K factor true-up adjustment, as determined in Decision 20176-D01-2015.

3 Commission process for reviewing the 2014 capital tracker true-up and 2016-2017 capital tracker forecast application

44. In Decision 2012-237, the Commission provided direction regarding the manner in which it would assess the prudence of completed projects subject to a capital tracker. The Commission stated:

> 975. …[T]he March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year‘s capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will

36 Decision 2013-465: AltaGas Utilities Inc. 2014 Annual PBR Rate Adjustment Filing, Proceeding 2831, Application 1609923-1, December 23, 2013, paragraphs 99-100.

37 Decision 2014-357: AltaGas Utilities Inc. 2015 Annual PBR Rate Adjustment Filing, Proceeding 3408, Application 1610838-1, December 18, 2014, paragraph 79.

38 Decision 20823-D01-2015, paragraph 65.

39 Paragraph 600.

40 Decision 2014-180: AltaGas Utilities Inc. 2013 Net Deficiency and Rider F, Proceeding 3055, Application 1610297-1, June 20, 2014.

41 Decision 2014-373: AltaGas Utilities Inc. 2014-2015 Capital Tracker Application and 2013 Capital Tracker True-up Application, Proceedings 3152 and 3244, Applications.1610446-1 and 1610600-1, December 24, 2014.

42 Decision 20176-D01-2015: AltaGas Utilities Inc. Compliance Filing Pursuant to Decision 2014-373 (2014-2015 Capital Tracker Forecast and 2013 Capital Tracker True-up), Proceeding 20176, June 25, 2015.

43 Decision 20695-D01-2015: AltaGas Utilities Inc. 2015 Net Deficiency and Rider F, Proceeding 20695, September 24, 2015.

> include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.[44]

45. The Commission has applied this direction to its assessment of the prudence of AltaGas' completed 2014 capital tracker projects, and for the projects that were completed in 2013 but not approved for capital tracker treatment in Decision 2014-373 and were subsequently reapplied for in the current application. Consistent with these determinations, for programs or projects that have already received approval of the need for the project or program, it is not necessary, for the purposes of assessing the prudence of these programs or projects, to demonstrate again that a project or program is needed as set out in Criterion 1. If the program or project is no longer required, the Commission expects that the company will include evidence of this in its application. The company is still required to demonstrate the second part of the project assessment under Criterion 1 that the scope, level and timing of each project was prudent, and the actual costs of the project were prudently incurred.

46. The Commission also considers that for the purposes of the true-up of capital tracker projects or programs previously approved, unless the driver for the project or program has changed, there is no need to undertake a reassessment against the Criterion 2 requirements. However, to the extent that costs have changed from the original approved forecast, the Commission will undertake an assessment with respect to Criterion 3.

47. For any new 2014 projects not previously approved, the Commission will undertake assessments with respect to all three criteria for capital tracker treatment. In the application, there are no AltaGas projects that fall into this category.

48. With respect to forecast capital projects or programs for 2016 and 2017 for which the company is seeking capital tracker treatment, the Commission will undertake assessments with respect to all three criteria for capital tracker treatment. However, if the project or program is part of an ongoing multi-year project or program, or of an annual recurring nature that has been previously approved by the Commission for capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission will undertake assessments with respect to all remaining aspects of the three criteria for capital tracker treatment.

49. The remaining sections of the decision regarding the Commission's assessment of AltaGas' capital tracker projects or programs are organized as follows:

- An overview of the capital tracker projects or programs is provided in Section 4. AltaGas also provided updates to 2015 to provide context for the 2014 capital tracker true-up and 2016 and 2017 capital tracker forecasts.
- The Commission's evaluation of AltaGas' proposed capital project groupings is set out in Section 5.
- The Commission's assessment of whether AltaGas' projects or programs proposed for capital tracker treatment satisfy Criterion 1 is set out in Section 6.

[44] Decision 2012-237, paragraph 975.

- The Commission's assessment of individual projects in each of AltaGas' three capital tracker programs is set out in Section 7.
- The Commission's application of the accounting test requirements to satisfy Criterion 1 is set out in Section 8.
- The Commission's assessment under Criterion 2 is undertaken in Section 9.
- The Commission's assessment under Criterion 3 is set out in Section 10.
- The Commission addresses the K factor calculation methodology, and the resulting approved K factor true-up for 2014 and K factor forecasts for 2016 and 2017 in Section 11.
- Compliances with previous Commission directions are discussed in Section 12.

4 Summary of projects and programs included in the 2014 true-up and 2016-2017 capital tracker forecast application

50. AltaGas has three programs for which it has received prior capital tracker treatment approval. These programs are: Pipeline Replacements, Station Refurbishments and Gas supply.

4.1 Pipeline Replacement program

51. The Pipeline Replacement program is a multi-year program. It was approved in Decision 2012-091[45] for the 2010-2012 test period, approved for 2013 as a capital tracker program in Decision 2013-435, and approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373.

52. AltaGas' Pipeline Replacement program provides for the replacement of three types of pipe: polyvinylchloride (PVC) pipe, non-certified and interim-certified polyethylene (PE) (collectively referred to as non-certified PE) pipe[46] and pre-1957 steel pipe. For each of the three types of pipe, individual projects were provided and differentiated by geographic type (i.e., downtown, town, village, hamlet, rural subdivision and rural).

53. AltaGas' natural gas distribution system currently includes approximately 20,800 kilometres (km) of pipe of various types and ages. AltaGas has stated that all PVC, non-certified PE and pre-1957 steel pipe needs to be replaced. This is because these pipe segments are at, or past, their useful lives, have high leak frequencies and exceed AltaGas' risk tolerance threshold in terms of the likelihood and potential impact from failures.[47]

54. AltaGas described the key steps in its multi-stage project prioritization and staging process for its pipe replacement program, including risk assessment, reconnaissance, pre-engineering and design, contractor selection and construction.[48] AltaGas also described several initiatives it has undertaken with the intention to continue to improve and enhance the level and

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45 Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application – Phase I, Proceeding 904, Application 1606694-1, April 9, 2012.

46 Both non-certified and interim certified PE pipe pose identical risks and their replacement is managed in the same way. AltaGas refers to this pipe, collectively, as "non-certified PE."

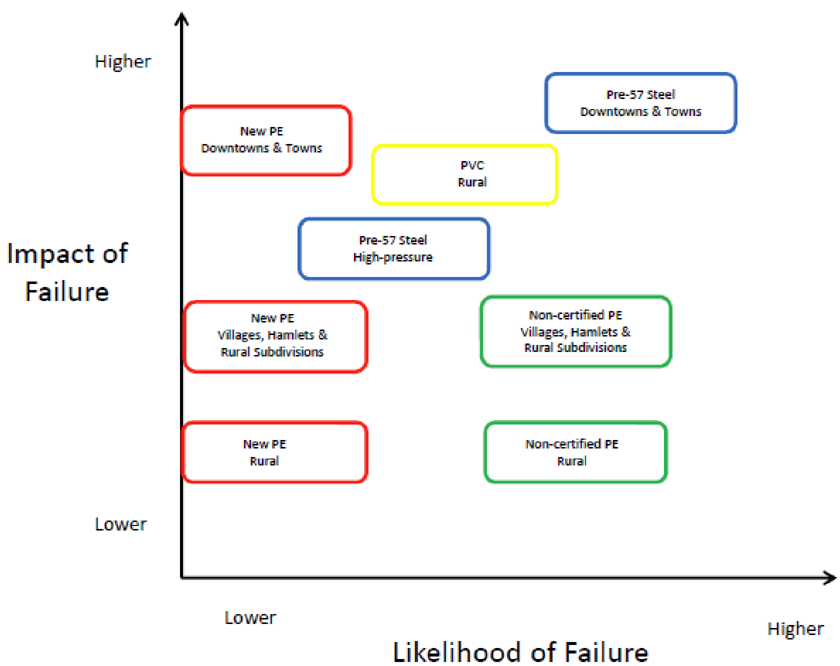
47 Exhibit 20522-X0010, application, paragraph 59.

48 Exhibit 20522-X0010, application, paragraph 69.

quality of information being filed, optimize systems and processes to manage resources and costs prudently, minimize variances and ensure the work is carried out in a timely and systematic manner.[49]

55. Under its risk assessment process steps, AltaGas provided a high level risk assessment matrix (see Table 1 below) to present a more tangible analysis of the overall levels of risk associated with the three types of pipe that it has proposed to replace, based on the likelihood of an incident occurring and the impact of an incident if it occurs. This overview, which was initially provided by AltaGas in its 2014-2015 capital tracker application, has been adjusted to show pre-1957 steel high-pressure pipe as its own category and to compare the relative risk of pre-1957 steel, PVC, and non-certified PE pipe to the best-performing pipe in AltaGas' system, namely new PE pipe.

Table 1. AltaGas risk assessment matrix[50]



56. AltaGas also provided its previously developed detailed risk assessment, which it relied on to prioritize segments of pipeline replacement based on the type and age of pipe, population density, ground cover, leak history and whether the pipe is locatable by tracer wire.[51] The project prioritization process also explicitly considered the extent to which each project would coincide with municipal works and other AltaGas capital projects in the vicinity.[52] AltaGas' detailed risk assessment model, including risk factors, likelihood and impact explanations, weights and scores is set out in Appendix 3 of this decision.

[49] Exhibit 20522-X0010, application, paragraph 3.
[50] Exhibit 20522-X0010, application, paragraph 54, Figure 2.
[51] Exhibit 20522-X0010, application, paragraph 60.
[52] Exhibit 20522-X0010, application, paragraph 62.

57. AltaGas also included a pre-1957 steel high pressure pipe risk assessment matrix to reflect specific factors relevant to pipelines constructed for, and operated at, high pressure, which is defined as pressures larger than 701 kilopascals.[53] Pre-1957 Steel High-Pressure Pipe Replacement projects considerations include how critical the supply line is in terms of customers served, engineering evidence of external coating deterioration (if coated) and corrosion.[54] The high pressure steel detailed risk assessment model, including risk factors, likelihood and impact explanations, weights and scores is set out in Appendix 4 of this decision .

58. AltaGas also provided risk scores and rankings for each type of its planned Pipeline Replacement projects. These risk scores can be found in Appendix 5 of this decision.

59. When the PVC Pipeline Replacement program began in 2010, AltaGas had approximately 625 km of PVC pipe (3.0 per cent) in its system. From 2010 to 2014, AltaGas replaced approximately 217 km (34.7 per cent) of this pipe. Going forward, AltaGas has forecast the replacement of 52.9 km in 2015, 111.9 km in 2016, 131.4 km in 2017 and 126.3 km in 2018. This forecast reflects an acceleration of its initial forecast for replacement of PVC pipe. The initial forecast was to complete replacement by 2021. AltaGas explained that continued improvements in contractor resourcing and internal processes should result in it being able to complete all PVC projects by the end of 2018.[55]

60. When the Non-Certified PE Pipe Replacement program began in 2010, AltaGas had approximately 3,250 km of non-certified PE pipe (15.6 per cent) in its system. From 2010 to 2014, AltaGas replaced approximately 91 km (2.8 per cent) of the non-certified PE pipe. Going forward, AltaGas has forecast the replacement of 27.1 km in 2015, 44.3 km in 2016, 83.6 km in 2017, 114.1 km in 2018, 163.8 km in 2019 and 160 km in 2020, and the remainder to be replaced in subsequent years. At the end of 2015, the remaining pipe to be replaced will all be situated in rural subdivisions and rural areas.[56]

61. When the Pre-1957 Steel Pipe Replacement program began in 2010, there was approximately 275 km of pre-1957 steel pipe (1.3 per cent) in AltaGas' system. To date, AltaGas has completed the replacement of 65 km (23.6 per cent) of pre-1957 steel mains and service lines in downtown, town and hamlet areas. Going forward, AltaGas has forecast the replacement of 32.1 km in 2015, 45.8 km in 2016, 55.2 km in 2017, 39.8 km in 2018 and 66.9 km in 2019. The 2017 lengths do not include 12.4 km of pre-1957 high pressure steel pipe forecast for replacement as part of the Calmar Gas Supply project.

62. AltaGas has approximately 98.8 km of pre-1957 high pressure steel pipe in its system. Of this, 85.6 km is scheduled for completion as part of AltaGas' Pre-1957 Steel Pipe Replacement program. Of the remaining 13.2 km, 12.4 km is included in the Calmar Gas Supply project in 2017, while 0.8 km in the Hanna rural area will be abandoned. Although AltaGas did not originally forecast commencement of high pressure steel pipe work until 2018, it explained that

53 Exhibit 20522-X0010, application, pre-1957 steel pipe business case, executive summary, PDF page 2.
54 Exhibit 20522-X0010, application, paragraph 60.
55 Exhibit 20522-X0010, application, PDF pages 158, 160 and 166 (Table PVC-10.0) of the PVC pipe business case.
56 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 141, 142 (Table NCPE-1.0) and 150 of the non-certified PE pipe business case.

continued improvements in contractor resourcing and internal processes now permit it to forecast completion of all High and Medium Pressure Pre-1957 Steel projects by 2019.[57] [58]

63. Section 7.1 below considers all 2013 Pipeline Replacement projects that were not approved for capital tracker treatment in Decision 2014-373 and subsequently reapplied for in the current application, projects that were approved in Decision 2014-373 for 2014 and fully or partially completed in 2014, and all projects forecast for 2016 and 2017. In some instances, costs were incurred for projects that started in a previous year but were not completely finished in the year they were started. These costs are examples of what AltaGas refers to as trailing costs.

4.2 Station Refurbishment program

64. The Station Refurbishment program is also a multi-year program and consists of partial, through to complete, replacement of a particular station. It was approved in Decision 2012-091 for the 2010-2012 test period, approved for 2013 as a capital tracker program in Decision 2013-435, and approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373.

65. As of December 31, 2014, AltaGas operated and maintained approximately 686 stations in Alberta. Approximately 30 per cent of these stations were installed in the 1950s, 1960s and 1970s and are currently equipped with obsolete parts or do not conform to the new pipe configurations used by AltaGas. The Station Refurbishment program will replace and refurbish station facilities presenting the greatest risk, as determined by consideration of the risks associated with worker safety issues and failure, and by obsolescence to AltaGas' design standards to ensure the equipment is supported by the manufacturer. Refurbishments are only viable when no more than two major components can be readily changed out. Otherwise, the time and costs to refurbish only partially tend to be greater than those applicable to a replacement.

66. AltaGas' Station Refurbishment program provides for the replacement or refurbishment of three station types – purchase meter stations (PMS), town border stations (TBS) and post regulator stations (PRS). PMS are the largest and most complex stations that AltaGas operates. These sites have metering, odourization, line heaters, automatic meter reading and other specialized equipment. TBS are mid-size stations and have sophisticated equipment, such as alarms, line heaters and, in some cases, custom buildings to suit municipal requirements. PRS are smaller scale pressure regulating sites.

67. AltaGas provided a risk assessment model, which was based on the same principles as the detailed pipeline risk assessment to illustrate its prioritization of station refurbishment and replacement projects based on criteria specific to stations. The model quantifies the risk factors identified by AltaGas' engineers as the key drivers of the station refurbishment program. Risk factors are considered in terms of the likelihood of failure, and the potential impact of a failure if one occurs. Data for the risk factors in the model was collected from various AltaGas systems and supplemented by on-site inspections and input from district managers responsible for

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[57] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 82 and 99-100 of the pre-1957 steel pipe business case.

[58] As explained in response to AUI-UCA-2015JUL02-004, (Exhibit 20522-X0030), apparent discrepancies between lengths of pipe being replaced are due to the need to replace incidental lengths of post-1957 steel (and to a lesser extent PVC and non-certified PE), in addition to the pre-1957 steel, plus or minus lengths require for routing changes from the original pipe layouts.

operating the stations. In this model, AltaGas focused on the more complex PMS and TBS infrastructure and, in particular, the 39 PMS and 40 TBS stations that are over 25 years old.[59]

68. The factors considered in the model are volume throughput, criticality (sole source of supply or not), proximity to public, station vintage, piping and obsolescence issues, site issues (instability, flood prone, security, building condition), gas quality, level of pressure cuts performed, frost issues, and design (vent gas to atmosphere or not). A description of the detailed risk assessment, including risk factors, likelihood and impact explanations, and weights was provided in the Station Refurbishment business case in the application.[60]

69. AltaGas also provided risk scores and ranking for planned PMS and TBS Station Refurbishment projects. These risk scores can be found in Appendix 6 of this decision.

70. AltaGas planned to complete approximately 232 station refurbishments over the nine year period from 2010 to 2018 and since commencement of the program in 2010, it has completed 131 stations or 56 per cent of the total stations currently forecast for replacement (26 PMS, 16 TBS and 89 PRS). Over the period 2015-2018, AltaGas has forecast the completion of the majority of the more extensive and higher cost PMS and TBS stations (41 PMS, 33 TBS and 27 PRS) and is planning to complete all refurbishments by the end of 2018.

71. Section 7.2 considers all station refurbishment projects that were not approved for capital tracker treatment in Decision 2014-373 and subsequently reapplied for in the current application, projects that were approved in Decision 2014-373 for 2014 and fully or partially completed in 2014, and all projects forecast for 2016 and 2017. In some instances, trailing costs were incurred.

4.3 Gas Supply program

72. The Gas Supply program is AltaGas' third multi-year program. It was approved in Decision 2012-091 for the 2010-2012 test period, approved for 2013 as a capital tracker program in Decision 2013-435, and approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373.

73. AltaGas assesses gas supply across its system to identify any significant risks to service quality and safety. Several projects have been identified as priorities to be completed over a period of up to 10 years. AltaGas also anticipates that it may need to address other gas supply constraints or issues arising from the termination of third-party suppliers or as a result of deteriorating gas supply or quality. These gas supply constraints or issues are difficult to predict and result in unique projects that vary for several reasons, including:

- the cause of the supply issue
- the configuration of the system in the affected area
- the types of remedial action available
- project timing
- available resources

[59] Exhibit 10.04, application (black line) identifying revisions, paragraphs 127-128.
[60] Exhibit 10.04, application (black line) identifying revisions, Appendix II(d), Section 2.2, pages 19-21.

74. In 2014, AltaGas completed the St. Paul Gas Supply project. This project addressed declining supply pressure arising from Nova Gas Transmission Ltd.'s installation of a natural gas compression facility immediately upstream of AltaGas' receipt point, and established a new source of supply for the St. Paul area.

75. In the application, AltaGas identified the gas supply to the Barrhead/Westlock/Morinville (BWM) area as a critical and emerging issue that needs to be addressed over the 2015-2016 period. Specifically, one of AltaGas' third-party suppliers intends to discontinue operation of the high pressure supply line servicing a large portion of the BWM area, likely before the end of 2016. To ensure continued service to approximately 6,150 AltaGas customers served off this line, AltaGas identified a number of alternatives ranging from the purchase of the existing line to complete bypass through additions to existing AltaGas infrastructure and connections to other third-party suppliers.[61]

76. For 2017, AltaGas has proposed the replacement of the Calmar Gas Supply as another high priority gas supply project. AltaGas supplies natural gas to the Town of Calmar and nearby rural area through a combination of uncoated pre-1957 high pressure steel pipeline, pre-1957 steel distribution pipeline, and non-certified PE and PVC service pipelines. AltaGas submitted that the uncoated, pre-1957 steel pipelines are experiencing severe soil-side corrosion and the cathodic protection achieved through a number of rectifiers on the line is becoming less effective as the pipe material continues to deteriorate.

77. Section 7.3 considers all gas supply projects that were approved in Decision 2014-373 for 2014 and constructed in 2014, all projects forecast for 2016 and 2017, and trailing costs.

5 Grouping of projects for capital tracker purposes

78. In Decision 2013-435, the Commission determined that the accounting test and the first tier of the materiality test will generally be applied to the approved level of grouping (i.e., either at a project or at a program level). The Commission will however, where it determines it to be necessary, consider the individual component projects comprising the approved groupings in order to assess the need for the capital expenditures and the reasonableness of the forecast costs. The second tier of the materiality test will be applied at the level of all capital tracker projects, in aggregate.[62] The Commission also determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each individual company.[63]

79. AltaGas identified two previous Commission decisions that approved its approach to project grouping for capital tracker purposes[64] and submitted that the capital tracker project or program groupings in the application continue to be consistent with those approved in Decisions 2013-435 and 2014-373.[65]

[61] Exhibit 20522-X0010, application, paragraphs 148-149 and 154-155.
[62] Decision 2013-435, paragraph 407.
[63] Decision 2013-435, paragraph 406.
[64] Decision 2013-435, paragraph 512; Decision 2014-373, paragraph 79.
[65] Exhibit 20522-X0010, application, paragraph 32.

80. In Decision 3558-D01-2015, the Commission stated the following:

> 50. The Commission considers that a short description outlining the nature, scope and timing of non-capital tracker projects and programs will be of assistance in understanding the proposed grouping of capital projects and programs for capital tracker treatment. A requirement for a limited description should not be unduly onerous and may reduce the need for information requests from the Commission and parties. Accordingly, the companies are directed in their future capital tracker applications, starting with the 2014 true-up and 2016-2017 forecast applications, to provide descriptions of the types of capital for non-capital tracker projects or programs. The Commission has added this requirement to its revised minimum filing requirements in Appendix 3.[66]

81. In the application, AltaGas provided a brief description of all non-capital tracker projects or programs, showing actual and forecast capital additions from 2014 to 2017.[67] Interveners did not object to any of the groupings for the projects proposed by AltaGas in this proceeding.

Commission findings

82. The Commission finds that AltaGas' proposed groupings for projects into programs is consistent with the groupings approved by the Commission in previous decisions. The Commission continues to find these groupings to be reasonable.

83. The Commission has also reviewed AltaGas' description of the nature, scope and timing of non-capital tracker projects, provided for better understanding of the proposed grouping of capital projects and programs for capital tracker treatment, and finds that AltaGas has complied with the direction at paragraph 50 of Decision 3558-D01-2015.

6 Project assessment under Criterion 1 – the project must be outside of the normal course of the company's ongoing operations

84. As discussed in Section 3 of this decision, consistent with paragraph 841 of Decision 2013-435, each of AltaGas' projects or programs proposed for capital tracker treatment will be evaluated against the project assessment requirements of Criterion 1. The purpose of the project assessment is to demonstrate that a project proposed for capital tracker treatment is required in order to maintain utility service at adequate levels, as required by paragraph 594 of Decision 2012-237. In addition, if approval is being sought for an already-completed project that has not received prior approval for capital tracker treatment, the applicant must demonstrate that the actual scope, level, timing and costs of the project were prudent. If approval is being sought for a project that has not yet been completed, the applicant must demonstrate that the forecast scope, level, timing and costs of the project are reasonable. As noted in paragraphs 974 and 975 of Decision 2012-237, when applying to true up the costs of a completed project that has previously been approved by the Commission for capital tracker treatment, the applicant must be able to demonstrate that the actual costs were prudent.

85. In the application, AltaGas did not apply for any new capital tracker programs and has applied for approval of specific projects within each of the three existing programs. These projects have been divided into three categories:

66 Decision 3558-D01-2015, paragraph 50.
67 Exhibit 20522-X0010, Appendix III.

- projects completed in 2013, not approved for capital tracker treatment in Decision 2014-373[68] and reapplied for in the application on an actual basis
- projects previously approved in Decision 2014-373 for 2014 on a forecast basis and fully or partially completed in 2014
- projects to be implemented in 2016 or 2017 that have not been previously approved for capital tracker treatment

86. AltaGas provided a business case and engineering study (where AltaGas considered either to be applicable) for each of its projects proposed for capital tracker treatment in 2016 and 2017. In its business cases, as supplemented by other evidence filed in the proceeding, AltaGas assessed its proposed capital tracker projects in relation to the minimum filing requirement guidelines set out in Decision 2013-435, and subsequently refined in Decision 3558-D01-2015.

87. AltaGas maintained that all of its capital tracker programs continue to be of an ongoing or recurring nature and, based on previous Commission determinations and in accordance with the minimum filing requirements, there should be no requirement to reassess the need for these programs.[69] AltaGas submitted that each of its capital tracker programs satisfies the project assessment criteria set out in Decision 2013-435 because its ability to provide safe, reliable service would be compromised in the absence of each of these programs, and the programs could not have been undertaken previously.

88. With respect to its Pipeline Replacement programs, AltaGas submitted that its evidence demonstrates the pipe replacement program is required to prevent deterioration in safety and service quality. In AltaGas' view, the risks outlined from the outset of this program will continue to exist until these replacements are complete. Station refurbishments are required since those stations scheduled for refurbishment have now aged to the point where maintenance performed in the normal course of business is not possible or no longer effective. Consequently, large scale refurbishments or complete station replacements, are required to maintain station operability and serviceability within acceptable safety parameters. Finally, with respect to AltaGas' Gas Supply program, the company stated that projects within this program arise as a result of the actions of third-party suppliers (e.g., termination of supply) or deterioration of the volume or quality of supply that would compromise safety and service quality, if the program is not undertaken.[70]

Commission findings

89. The Commission finds no evidence on the record of this proceeding, which includes, specifically, no evidence submitted by interveners, demonstrating that any of the 2013 projects not approved for capital tracker treatment in Decision 2014-373 were not needed in 2013. The Commission also finds no evidence on the record of this proceeding demonstrating that any of the capital tracker projects previously approved for 2014 on a forecast basis and now proposed for true-up, were not needed in 2014. Therefore, the need for these projects is confirmed.

90. With respect to projects proposed for capital tracker treatment in 2016 or 2017 on a forecast basis, the applicant must satisfy all of the Commission's requirements for the project assessment under Criterion 1. To that end, a business case and an engineering study, if

68 The need for these projects was approved in Decision 2014-373 but insufficient cost information was provided for the Commission to make a determination on prudence.
69 Exhibit 20522-X0010, application, paragraphs 2 and 7-9.
70 Exhibit 20522-X0010, application, sections 2.1.1, 3.1.1 and 4.1.1; Decision 2013-435, paragraph 1092.

applicable, are to be provided to aid the Commission in conducting project assessments under Criterion 1.

91. There was no evidence on the record of this proceeding that any of the projects that were included in AltaGas' 2016-2017 forecast are not required to maintain service reliability, quality and safety at adequate levels in 2016 and 2017, which constitutes the assessment of need under Criterion 1. The Commission has reviewed AltaGas' evidence demonstrating that each of the projects included in the 2016-2017 forecast is required and finds that each of the proposed projects is needed.

7 Assessment of individual projects within programs under Criterion 1

92. The Commission has evaluated AltaGas' business cases, engineering studies, cost related information, and related evidence and argument against each of the project assessment minimum filing requirements. For the purposes of this decision, the Commission has commented only on those aspects of the minimum filing requirements that the Commission considers to be insufficiently addressed by AltaGas' evidence or were otherwise raised as an issue in the proceeding. In future capital tracker applications, AltaGas should continue to provide similar information with respect to each of the minimum filing requirements, including business cases, engineering studies and cost related information, including costs by cost category, unit costs and historical cost comparators, in sufficient detail to allow an evaluation of the reasonableness of its forecasts and the prudence of its incurred costs.

93. The Commission's Criterion 1 assessment of AltaGas' projects or programs previously approved for capital tracker treatment in Decision 2013-435 or in Decision 2014-373, or for projects not previously approved for capital tracker treatment is set out in sections 7.1 through 7.3 below.

7.1 Projects in the Pipeline Replacement program

7.1.1 Projects completed in 2013, not approved for capital tracker treatment in Decision 2014-373 and reapplied for in the application

94. In 2013, AltaGas completed four pipeline replacement projects that had not been previously approved for capital tracker treatment on a forecast basis in Decision 2013-435. As part of its 2013 capital tracker true-up application, AltaGas applied for these projects after they had been completed. The need for these four projects was approved in Decision 2014-373.

95. With respect to the scope, level, timing and costs for each project, the Commission determined that there was insufficient evidence on the record of the 2013 capital tracker true-up proceeding to conclude that the costs for each project were prudent. Accordingly, the Commission did not approve these four projects for capital tracker treatment at that time. However, at paragraph 184 of Decision 2014-373, the Commission provided an allowance AltaGas to reapply for capital tracker treatment for these projects:

> 184. Because AltaGas applied for capital tracker treatment for these projects after they were completed, and this was the first time a company has applied for a project after its completion, the Commission will allow AltaGas to reapply for capital tracker treatment for these projects with revised information at the time of its next capital tracker true-up

application. If approved at that time, the Commission would allow the company to receive capital tracker treatment for these projects effective 2013 on a mid-year basis.

96. In this application, AltaGas reapplied for capital tracker treatment for these projects. The projects consist of three Non-Certified PE Pipeline projects and one Pre-1957 Steel Pipeline project. AltaGas submitted:

> 93. As the 2013 projects were undertaken subsequent to Decision 2013-435, AUI provides a 2013 forecast to compare with actual results to demonstrate the project costs were prudently incurred.
>
> 94. The 2013 forecast represents the project cost estimate, as approved by AltaGas' senior management, in the applicable Authorization for Expenditures (AFE) process, together with project justification. AUI considers the 2013 AUI AFE Estimate to be an appropriate baseline to assess the prudence of project costs, as the AFE process serves as a key component for cost control and monitoring of AUI's capital projects.[71]

97. The 2013 AFE forecast represents the project costs, as approved by senior management staff in the AFE process, together with a project justification. For each pipeline replacement project, the 2013 AFE estimate details the costs for labour, materials, contractors and overhead.[72]

98. AltaGas provided forecast and actual costs, pipeline length (km) and unit cost (total cost per km), as well as a variance analysis for each pipeline replacement project, summarized in the table provided below.

Table 2. Pipeline projects completed in 2013, not approved for capital tracker treatment in Decision 2014-373 and reapplied for in the application[73]

	Capital additions ($)				Pipe length (km)				Unit cost ($/km)			
	2013 AFE estimate ($)	Actual ($)	Variance ($)	Variance (%)	2013 AFE estimate (S)	Actual ($)	Variance ($)	Variance (%)	2013 AFE estimate ($)	Actual ($)	Variance ($)	Variance (%)
Non-certified PE												
Morinville (rural)	285,443	248,893	37,717	13	4.6	4.7	(0.1)	-2	62,053	52,956	9,907	15
Pincher Creek (rural)	29,793	28,719	1,073	4	1.5	1.5	0.0	3	19,246	19,146	100	1
Stettler (town)	62,739	69,788	(3,140)	-5	0.5	0.6	(0.1)	-33	138,803	116,313	22,490	16
Pre-1957 steel												
Drumheller (downtown)	241,951	237,361	4,590	1.9	0.8	0.7	0.1	16	291,157	339,088	(47,931)	-16

71 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 313.

72 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 314, Table 2.5.1-1, 2013 Morinville (NCPE); PDF page 316, Table 2.5.1.2, 2013 Pincher Creek Rural (NCPE); PDF page 318, Table 2.5.1-3, 2013 Stettler (Town) (NCPE); PDF page 320, Table 2.5.2-1, 2013 Drumheller (Downtown) (Steel).

73 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 314, Table 2.5.1-1, 2013 Morinville (NCPE); PDF page 316, Table 2.5.1.2, 2013 Pincher Creek Rural (NCPE); PDF page 318, Table 2.5.1-3, 2013 Stettler (Town) (NCPE); PDF page 320, Table 2.5.2-1, 2013 Drumheller (Downtown) (Steel).

7.1.1.1 Non-Certified PE Pipe

Morinville (rural)

99. For the Morinville (rural) project, AltaGas provided a 2013 AFE forecast cost of $285,443, a forecast pipeline length of 4.6 km and a forecast unit cost of $62,053/km. AltaGas completed this project in 2013, replacing 4.7 km of pipe at an actual cost of $248,893 and a unit cost of $52,956/km. As mentioned above, AltaGas provided a cost variance of $37,717 (13 per cent) below forecast, a pipeline length variance of 0.1 km (two per cent) above forecast, and a unit cost variance of $9,097/km (15 per cent) below forecast.[74]

100. AltaGas explained that the lower actual costs compared to the AFE forecast costs were primarily due to drier than normal weather and field conditions, resulting in a shorter timeframe required to complete the project. Specifically, drier conditions allowed the contractors to plow pipeline trenches in several areas, rather than use the more costly horizontal directional drilling method. The drier than normal ground conditions also resulted in lower contract inspection hours and costs. However, these lower costs were offset by costs associated with land work and line locates completed by contractors. The other factor that contributed to lower costs was the fact that contractors were already in the area, which reduced mobilization and de-mobilization costs.[75]

Pincher Creek Mole Line (rural)

101. For the Pincher Creek Mole Line (rural) project, AltaGas provided a 2013 AFE forecast cost of $29,793, a forecast pipeline length of 1.5 km and a forecast unit cost of $19,246/km. AltaGas completed this project in 2013, replacing 1.5 km of pipe at an actual cost of $28,719, for a total unit cost of $19,146/km. AltaGas provided a cost variance of $1,073 (four per cent) below forecast, a pipeline length variance of zero km (zero per cent) and a total unit cost variance of $100/km (one per cent) below forecast. No material variances occurred because this project was competed in a timely manner and within the forecast.[76]

Stettler (town)

102. For the Stettler (town) project, AltaGas provided a 2013 AFE forecast cost of $62,739, a forecast pipeline length of 0.5 km and a forecast unit cost of $138,803/km. AltaGas completed this project in 2013, replacing 0.6 km of pipe at an actual cost of $69,788, for a total unit cost of $116,313/km. AltaGas provided a cost variance of $3,140 (5 per cent) above forecast, a pipeline length variance of 0.1 km (33 per cent) above forecast and a unit cost variance of $22,490/km (16 per cent) below forecast.[77]

103. AltaGas explained that the increase in pipeline length was the result of a landowner request to alter the proposed pipeline alignment in order to accommodate current and future land use. The increase in cost variance was the result of increasing the length of pipe installed

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[74] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 314, Table 2.5.1-1, 2013 Morinville (NCPE).

[75] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 314-315, paragraphs 99-100.

[76] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 316, Table 2.5.1.2, 2013 Pincher Creek Rural (NCPE), paragraph 104.

[77] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 318, Table 2.5.1-3, 2013 Stettler (Town) (NCPE).

compared to forecast, which resulted in higher than forecast aggregate costs for materials and labour, in addition to higher than anticipated contractor inspection costs.[78]

7.1.1.2 Pre-1957 Steel Pipe

Drumheller (downtown) project

104. For the Drumheller (downtown) project, AltaGas provided a 2013 AFE forecast cost of $241,951, a forecast pipeline length of 0.8 km, and a forecast unit cost of $291,157/km. AltaGas completed this project in 2013, replacing 0.7 km of pipe at an actual cost of $237,361, for a unit cost of $339,088/km. AltaGas provided a cost variance of $4,590 (1.9 per cent) below forecast, a pipeline length variance of 0.1 km (16 per cent) below forecast and a unit cost variance of $47,931/km (16 per cent) above forecast.[79]

105. In paragraph 187 of Decision 2014-373, the Commission stated its concerns with the unit cost difference between the 2013 Leduc (downtown) steel project and the 2013 Drumheller (downtown) steel project:

> 187. … However, the Commission has reviewed the costs for this project, and notes that the unit costs were 23 per cent higher than the Leduc project, even though the project was coordinated with the town of Drumheller. The Commission finds that there is insufficient evidence on the record of the proceeding to conclude that the costs for this project were prudent. Accordingly, this project is not approved for capital tracker treatment at this time.

106. AltaGas responded that this project is located in a congested two block commercial area of the Drumheller downtown core where there is full asphalt cover on the entire project area. In addition, the town of Drumheller requires 100 per cent compaction testing on all road and street excavations, whereas in Leduc no compaction testing is required due to other road fill specifications. Furthermore, the number of services/meter of main are higher in Drumheller than in Leduc, contributing to higher actual costs.[80]

107. AltaGas attributed the 0.1 km decrease in the amount of pipe installed to final field alignment changes. AltaGas also explained that the lower costs are due to a shorter project timeframe, reduced contractor inspection time and costs, and lower than expected engineering and land costs due to project documents taking less time to complete than expected.[81]

108. No intervener filed argument opposing the costs for these four projects.

Commission findings

109. For each of these four projects , the Commission has reviewed the 2013 AFE estimates, 2013 actual costs and the variance explanations. For the purposes of this decision, and noting that no intervenor filed argument opposing the costs of these four projects, the Commission finds that the 2013 AFE estimates submitted by AltaGas provide sufficient evidence for the Commission to consider whether the costs for each project were prudent.

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78 Exhibit 20522-X0028, AUI-AUC-2015JUL02-055(c).
79 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 320, Table 2.5.2-1, 2013 Drumheller (Downtown) (Steel).
80 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 321, paragraph 115.
81 Exhibit 20522-X0028, AUI-AUC-2015JUL02-056(b) and (c).

110. The Commission has reviewed AltaGas' evidence explaining the differences between the 2013 AFE estimates and the actual costs, and finds the variance explanations to be reasonable. The Commission finds that the actual scope, level, timing and costs of the work undertaken by AltaGas in 2013 to be prudently incurred. The Commission finds that these four projects satisfy the project assessment requirement of Criterion 1 for 2013. AltaGas is directed to calculate and include the revenue requirement for these projects, on a 2013 mid-year basis, in its K factor calculations.

7.1.2 Projects approved in Decision 2014-373 for 2014 and fully or partially completed in 2014

111. AltaGas provided the actual and approved forecast costs, and pipeline lengths for each of the PVC, Non-Certified PE and Pre-1957 Steel Pipe projects that were fully or partially completed in 2014. This information is reproduced in the following three tables.

Table 3. 2014 PVC Pipe – actual versus approved forecast and variances by project[82]

		2014 approved			2014 actual			Variances - approved to actual		
Line	Location	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)
1	Barrhead Area 1, 2, 3 (rural)	2,230,700	47.9	46,570	2,279,004	49.2	46,351	(48,304)	(1.3)	219
2	Morinville Area 1 (rural)	1,170,900	20.4	57,397	1,390,241	19.7	70,722	(219,341)	0.7	(13,325)
3	Leduc Area 4 (rural)	559,321	8.2	67,969	409,229	5.0	81,700	150,092	3.2	(13,731)
4	Trailing costs	-	-		14,340	-		(14,340)	-	
5	**Total PVC**	**3,960,921**	**76.5**		**4,092,814**	**73.8**		**(131,893)**	**2.7**	

Table 4. 2014 Non-Certified PE Pipe – actual versus approved forecast and variances by project[83]

		2014 approved			2014 actual			Variances - approved to actual		
Line	Location	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)
1	Pigeon Lake	3,945,855	18.7	211,008	4,125,169	19.8	208,342			
2	Ma-Me-O Beach	1,633,055	7.9	206,716	1,576,766	7.6	207,469	(179,314)	(1.1)	2,666
3	Trailing costs	-	-		39,760	-		56,289	0.3	(753)
4	**Total non-certified PE**							(39,760)	-	-
		5,578,910	**26.6**		**5,741,695**	**27.4**		**(162,785)**	**(0.8)**	

Table 5. 2014 Pre-1957 Steel Pipe – actual versus approved forecast and variances by project[84]

		2014 approved			2014 actual			Variances - approved to actual		
Line	Location	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)	Capital additions ($)	Pipe length (km)	Unit cost ($/km)
1	Athabasca (town/downtown)	3,526,790	13.2	268,034	3,079,969	12.2	252,915	446,821	1.0	15,119
2	Bonnyville (town)	364,900	1.2	297,150	338,361	1.0	325,035	26,539	0.2	(27,885)
3	Drumheller (downtown)	966,500	3.0	323,677	1,054,166	3.1	343,937	(87,666)	(0.1)	(20,260)
4	Trailing costs	-	-		(4,200)	-		4,200		
5	**Total pre-1957 steel**	**4,858,190**	**17.4**		**4,468,296**	**16.3**		**389,894**	**1.1**	

82 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 296, Table 2.3-1.
83 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 305, Table 2.4-1.
84 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 288, Table 2.2-1.

7.1.2.1 PVC Pipe

Barrhead Area 1, 2, 3 (rural)

112. In Decision 2014-373, the Commission approved the Barrhead Area (rural) 1, 2 and 3 projects as three separate projects.[85] Taking advantage of logistics, and after completion of a final bid tendering process, AltaGas awarded, managed and completed the Barrhead Area 1, 2 and 3 projects as a single project in 2014. Consequently, the variance analysis was provided on a combined basis for this project. AltaGas provided a cost variance of $48,304 (two per cent) above forecast, a pipeline length variance of 1.3 km (three per cent) above forecast and a unit cost variance of $219/km (one per cent) below forecast.

113. AltaGas explained that the additional 1.3 km of pipe was required because of the discovery of some PVC pipe that was initially identified as PE pipe in the ESRI geographic information system (GIS) database. This additional segment of PVC pipe was replaced using contractor resources already on site.[86]

Morinville Area 1 (rural)

114. In Decision 2014-373, the Commission approved the Morinville Area 1 (rural) project. AltaGas completed the project in 2014 and provided a cost variance of $219,341 (19 per cent) above forecast, a pipe length variance of 0.7 km (three per cent) below forecast and a unit cost variance of $13,325/km (23 per cent) above forecast.

115. AltaGas explained that the actual pipe length installed was 0.7 km below forecast and attributed this variance to route realignments. After the project had commenced, landowner concerns arose relating to alleged transmission of the "clubroot virus."[87] Although the rerouting reduced the required pipeline length, it resulted in additional costs for a road crossing and extra mainline tie-ins.[88]

Leduc Area 4 (rural)

116. In Decision 2014-373, the Commission approved the Leduc Area 4 (rural) project. AltaGas did not complete this project in 2014 and provided a cost variance of $150,092 (27 per cent) below forecast, a pipeline length variance of 3.2 km (39 per cent) below forecast and a total unit cost variance of $13,731/km (20 per cent) above forecast.

117. AltaGas explained that it was able to complete 5.0 km of the 8.2 km planned for replacement in 2014 but was not able to complete the remaining 3.2 km. AltaGas explained that the completion delays were due to wetter than normal weather conditions in the early summer, work that was required to confirm the extent of additional PVC pipe discovered, and delays to the original start date caused by contractor delay on another project. Ultimately, the decision to suspend work was based on safety issues related to working near brittle PVC pipe in deep frost conditions.

85 Decision 2014-373, paragraph 198.
86 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 296-297, Table 2.3.1-1, 2014 PVC Barrhead Area 1, 2, 3 (rural), paragraphs 58-61.
87 Exhibit 20533-X0028, AUI-AUC-2015JUL02-051(b).
88 Exhibit20522-X0010.04, application (black line) identifying revisions, PDF page 299, Table 2.3.1-2, 2014 PVC – Morinville Area 1 (rural), paragraphs 64-65.

118. An additional 0.4 km of pipe was required to be replaced because of a Ducks Unlimited requirement to realign a portion of the proposed pipeline route that was on its land. Consequently, the total project length was revised to 3.6 km. AltaGas plans to complete the remaining 3.6 km of pipe in 2015.[89]

119. Due to the issues discussed above and a Ducks Unlimited requirement that horizontal directional drilling be used on its land, as opposed to the cheaper trenchless plow method, costs were revised from the approved forecast of $559,000 to a new forecast total of $783,000.[90]

7.1.2.2 Non-Certified PE Pipe

Pigeon Lake (village)

120. In Decision 2014-373, the Commission approved the Pigeon Lake (village) project. AltaGas completed the project in 2014 and provided a cost variance of $179,314 (five per cent) above forecast, a pipeline length variance of 1.1 km (one per cent) above forecast and a unit cost variance of $2,666/km (one per cent) below forecast.

121. AltaGas provided explanations for the higher than forecast pipe length and costs. Subsequent to the approval of this project for capital tracker treatment, the municipality requested the company to identify potential conflicts with future sewer installations. AltaGas conducted supplemental field reconnaissance work, which resulted in the identification of additional required pipe and utility crossings. In addition, further site investigations identified certain areas requiring a change from the pipe insertion method of replacement to a method requiring horizontal directional drilling.[91]

Ma-Me-O Beach (village)

122. In Decision 2014-373, the Commission approved the Ma-Me-O Beach (village) project. AltaGas partially completed this project in 2014 and provided a cost variance of $56,289 (three per cent) below the approved forecast, a pipeline length variance of 0.3 km (four per cent) below the approved forecast and a unit cost variance of $753/km (four per cent) above the approved forecast.

123. In 2014, AltaGas completed 7.6 km of the approved 7.9 km of pipe. AltaGas explained that at the end of the 2014 construction period, approvals were still required to complete 1.9 km of pipe located on First Nations land. The 1.9 km of remaining pipe is due to 0.3 km of outstanding pipe that was not replaced in 2014 and an additional 1.6 km of pipe subsequently identified for replacement. Most of the 1.6 km of pipe is located on private lands, with the remainder on First Nation lands and within Alberta Transportation rights- of-way. At the time, AltaGas had only received two of the four required approvals to access and construct on these lands. AltaGas stated that it had no contingency plan in place to complete the remaining portion of pipe but indicated that it would continue its efforts to obtain all requisite approvals. It explained that rerouting was not an option because AltaGas is required to cross Alberta

[89] Exhibit20522-X0010.04, application (black line) identifying revisions, PDF page 303, paragraph 71.

[90] Exhibit20522-X0010.04, application (black line) identifying revisions, PDF pages 302-303, Table 2.3.1-3, 2014 PVC – Leduc Area 4 (rural), paragraphs 69-71; Exhibit 20522-X0028, AUI-AUC-2015JUL02-051(c)(ii)-(v).

[91] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 306, Table 2.4.1-1, 2014 Non-Certified PE – Pigeon Lake (village), paragraphs 78-79.

Transportation Highway 13, which is located on First Nations lands.[92] AltaGas proposed to replace 9.5 km of pipeline for a total cost of $1.79 million in 2015 or later, depending on when the necessary approvals are received.[93]

7.1.2.3 Pre-1957 Steel Pipe

Athabasca (town/downtown)

124. In Decision 2014-373, the Commission approved the Athabasca (town/downtown) project. AltaGas did not complete the project in 2014 and provided a cost variance of $446,821 (13 per cent) below the approved forecast, a pipeline length variance of 1.0 km (eight per cent) below the approved forecast and a unit cost variance of $15,119/km (six per cent) below the approved forecast.

125. In 2014, AltaGas completed 12.2 km of the approved 13.2 km of pipe. AltaGas explained that the actual pipe length was less than forecast primarily due to minor realignments and the abandonment of some service lines. In response to a Commission IR, AltaGas confirmed that it had received an Alberta Road Transport crossing permit required for the construction of the remaining 0.2 km section of pipe, which would enable it to complete the project in 2015.[94]

126. AltaGas explained that the actual cost of the project was lower than forecast because of the use of horizontal directional drilling, as opposed to the originally planned open cut trenching method. Horizontal directional drilling enabled AltaGas to reduce expensive asphalt and site restoration costs, save on materials costs, including sand normally required to fill open trenches, and minimize the construction impacts on customers.[95]

Bonnyville (town)

127. In Decision 2014-373, the Commission approved the Bonnyville (town) project. AltaGas completed this project in 2014, and provided a cost variance of $26,539 (seven per cent) below its approved forecast, a pipeline length variance of 0.2 km (15 per cent) below the approved forecast and a total cost per km variance of $27,885 (nine per cent) above the approved forecast. AltaGas attributed the decrease in pipeline length of 0.2 km below forecast due to the removal of three service line replacements from the project as they were no longer required. The higher actual cost per km was a result of higher site restoration costs and greater asphalt replacement costs.[96]

Drumheller (downtown)

128. In Decision 2014-373, the Commission approved the Drumheller (downtown) project. AltaGas completed this project in 2014 and provided a cost variance of $87,666, (nine per cent) above the approved forecast, a pipeline length variance of 0.1 km (two per cent) above the

92 Exhibit 20522-X0028, AUI-AUC-2015JUL02-052(a) and (b).
93 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 309, paragraphs 84-85.
94 Exhibit 20522-X0028, AUI-AUC-2015JUL02-050(a).
95 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 288-289, Table 2.2.1-1, 2014 Pre-1957 Steel - Athabasca (town/downtown), paragraphs 43-45.
96 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 292-292, paragraphs 47-49, Table 2.2.1-2, 2014 Pre-1957 Steel - Bonnyville (town).

approved forecast and a total unit cost variance of $20,260/km (six per cent) above the approved forecast.

129. The actual pipe installed was 0.1 km higher than forecast, reflecting the difference between final engineering drawings and preliminary field reconnaissance work. The cost variance resulted from higher site restoration costs for asphalt replacement and greater material costs, and was offset by lower pipeline installation costs and labour.[97]

130. No intervener filed argument or opposed the costs for any of these projects.

Commission findings

131. The Commission finds the evidence explaining the differences between the forecast costs and the actual costs to be persuasive and finds the variance explanations to be reasonable. For each PVC, Non-Certified PE and Pre-1957 Steel Pipe project that was completed or partially completed in 2014, the Commission has reviewed the actual scope, level, timing and costs of the work undertaken by AltaGas, and finds that, with the exception of the trailing costs for the PVC and Non-Certified PE Pipe Projects (as set out in Section 7.1.3 below), each of the projects was prudently incurred. The Commission finds that these projects, with the exception of certain trailing costs discussed in Section 7.1.3 below, satisfy the project assessment requirement of Criterion 1 for 2014.

132. For projects partially completed in 2014 with outstanding work required to be completed in a future year, the Commission expects AltaGas to provide detailed variance explanations in a future capital tracker true-up application.

7.1.3 Pipeline Replacement project trailing costs

133. AltaGas provided three tables detailing the pipeline replacement program trailing costs for PVC, non-certified PE and pre-1957 steel pipe that were incurred in 2014, as shown below.[98]

Table 6. PVC Pipe trailing costs – 2014

PVC - trailing costs		Cost component ($)				
Line	Project/project year	Labour	Land payments	Tendered contractor	Overhead	Total
1	Stettler (2012)	1,238	1,200	-	(434)	2,004
2	Morinville (2013)	1,508	9,125	-	587	11,220
3	Morinville Rural Phase 1 (2013)	4,865	12,754	51	1,374	19,044
4	Morinville Rural Phase 2 (2013)	(449)	-	(20,176)	(1,732)	(22,358)
5	Morinville Rural Phase 3 (2013)	5,992	2,519	-	(4,636)	3,875
6	Other* (2012)	556	-	-	(1)	554
7	**Total**	**13,710**	**$25,598**	**(20,126)**	**(4,842)**	**14,340**

*Minor adjustments for four prior period projects.

97 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 293-294, paragraphs 51-52, Table 2.2.1-3, 2014 Pre-1957 Steel - Drumheller (downtown).

98 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 304, Table 2.3.2-1, PVC Trailing Costs, PDF page 312, Table 2.4.2-1, Non-Certified PE Trailing Costs and PDF page 295, Table 2.2.2-1, Pre-1957 Steel Trailing Costs.

134. AltaGas explained that $14,340 of prior year PVC project trailing costs were incurred for final clean-up costs related to overall civil site work and other miscellaneous costs. AltaGas also explained that the credit for the Morinville Phase 2 project was related to an accrual reversal in 2014. The 'other' category identified in the table consists of insignificant adjustments under $1,000 for other prior period projects.[99]

135. In response to a Commission IR, AltaGas provided additional information for the Stettler trailing costs, explaining that this project included 2014 adjustments to 2013 labour allocations.[100]

Table 7. Non-Certified PE Pipe trailing costs – 2014

Non-Certified PE - trailing costs		Cost component ($)					
Line	Project/project year	Labour	Other contractor	Land payments	Tendered contractor	Overhead	Total
1	Irvine (2013)	125	-	-	-	13	138
2	Looma (2013)	37	-	-	1,655	95	1,786
3	Tiebeke (2013)	20	-	-	877	55	952
4	Pibroch (2013)	595	-	-	-	27	622
5	Pincher Creek Mole Line (2013) [101]	1,245	-	4,500	-	140	5,884
6	Kavanagh (2013)	75	608	-	2,769	190	3,643
7	Carbondale (2013)	-	-	940	-	95	1,035
8	Green Acres (2013)	422	-	-	18,963	1,010	20,396
9	Morinville Phase 1 (2013) [102]	2,686	-	5,796	-	318	8,800
10	Sturgeon View Estates (2013)	-	-	-	-	(50)	(50)
11	Red Willow (2013)	-	-	-	-	(84)	(84)
12	Westlock Rural (2013)[103]	-	-	-	-	(1,074)	(1,074)
13	Pincher Creek Rural (2013) Morinville	-	-	-	-	(0)	(0)
14	Phase 3 (2013) [104]	-	-	-	-	(1,485)	(1,485)
15	Stettler - Remaining Piece (2013)	-	-	-	-	(802)	(802)
16	**Total**	**5,205**	**608**	**11,236**	**24,264**	**(1,552)**	**39,760**

136. AltaGas explained that $39,760 of prior year Non-Certified PE Pipe project trailing costs relate to final clean-up costs for overall civil site work, and other miscellaneous costs.[105]

99 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 305.
100 Exhibit 20522-X0028, AUI-AUC-2015JUL02-057(c).
101 Originally referred to as 10-05-29-W4.
102 Originally referred to as 2-55-25-W4-12-55-25-W4.
103 Originally referred to as SW36-SW35-58-27-W4.
104 Originally referred to as 01-55-24-W4-05-55-23-W4.
105 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 312.

Table 8. Pre-1957 Steel Pipe trailing costs – 2014

Pre-1957 Steel - trailing costs		Cost component ($)			
Line	**Project/project year**	**Labour**	**Other contractor**	**Overhead**	**Total**
1	Calmar (2012)	-	-	(5)	(5)
2	Leduc (2013)	4,555	2,125	(10,874)	(4,195)
3	**Total**	**4,555**	**2,125**	**(10,879)**	**(4,200)**

137. AltaGas explained that the credit amount of $4,200 for prior year Pre-1957 Steel Pipe project trailing costs was largely due to an adjustment in 2014 to correct the over-allocation of overheads applied in 2013. In total, $56,000 was over-allocated to all capital projects, including approximately $35,000 to capital tracker projects. AltaGas identified that the costs incurred for labour and other contractors were related to final clean-up for overall civil site work and other miscellaneous items.[106]

138. AltaGas further submitted that the trailing costs for 2012 projects for both PVC and pre-1957 steel pipe should qualify for capital tracker treatment because they relate to costs applicable to assets within the capital tracker rate base that were not identifiable at the time the 2013 true-up application was submitted.[107]

139. No intervener party opposed nor submitted argument regarding the trailing costs claimed.

Commission findings

140. At paragraph 113 of Decision 2014-373, the Commission directed:

> 113. In order to demonstrate the prudence of the trailing costs, the Commission agrees with the UCA that the company should be required to show the prior year trailing costs clearly in its capital tracker true-up applications. In future capital tracker true-up applications, the Commission directs AltaGas to identify the specific prior-year project to which the trailing costs relate, identify the activities that give rise to the trailing costs, and fully support the prudence of the requested amounts.

141. The 2014 trailing costs reflect:

- 2012 projects that were previously approved in Decision 2012-091
- 2013 projects that were previously approved on a forecast basis by the Commission in Decision 2013-435
- 2013 non-certified PE pipe projects that were not approved for capital tracker treatment in Decision 2014-373 and reapplied for in the application

142. For the 2012 and 2013 projects, AltaGas provided trailing costs, the specific year to which those trailing costs relate, trailing cost explanations on a program level and some explanations for certain projects on an individual level, but not all projects. Trailing costs explanations were not provided for the following projects:

[106] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 295, paragraph 55.
[107] Exhibit 20522-X0028, AUI-AUC-2015JUL02-057(c).

- the 2013 PVC Morinville (rural) project costs of $11,220, $19,044, $ (22,358) and $3,875, as shown in Table 6 above
- all of the 2013 Non-Certified PE Pipe projects, in the total amount of $39,760, as shown in Table 7 above

143. With the exception of the projects listed above for which trailing cost explanations were not provided, the Commission considers that AltaGas has complied with the above direction and finds that there is sufficient evidence on the record of the proceeding to conclude that the trailing costs for the projects in this program were prudently incurred. Accordingly, the Commission approves the inclusion of the trailing costs as part of project total costs for the purposes of the K factor calculation.

144. With respect to the projects listed above for which trailing cost explanations were not provided at a project level, at paragraph 113 of Decision 2014-373, the Commission requested that AltaGas identify the specific prior-year project to which the trailing costs relate, the activities that give rise to the trailing costs, and that it fully support the prudence of the requested amounts. AltaGas identified the specific prior-year projects but did not provide specific explanations of the costs incurred to each of these projects. Instead, it provided a generic explanation for the program. The Commission is prepared to accept that AltaGas did not consider its direction for an explanation to also be at the project level and on this basis, it will conditionally approve the trailing costs for these projects. However, AltaGas is directed to provide the missing trailing cost explanations in the compliance filing to this decision. If approved at that time, the Commission would allow the company to include these trailing costs as part of project total costs for the purposes of the K factor calculation.

7.1.4 2016-2017 forecast capital tracker projects

145. AltaGas stated that the optimal timing for site reconnaissance, including landowner negotiations, is during the 12 to 18 month window prior to the start of construction. If site reconnaissance is done too far in advance, changes may occur that could materially affect the nature and cost of the project. AltaGas stated that final review and selection of pipeline routes should typically be complete by the end of March in the year of construction, and contractors should begin work as soon as weather conditions allow, which is generally before the end of May.

146. AltaGas explained that site reconnaissance will identify most above-grade conditions. However, sub-surface issues will not be fully evident until construction begins. Unforeseen conditions may require extra directional drilling, hydrovac excavation or rerouting of existing lines. As AltaGas' cost estimates also assume optimal routing, any change will generally result in increased costs. Consequently, actual costs have a greater probability of being higher rather than lower than forecast.

147. In response to a Commission IR, AltaGas explained that it had made improvements to its cost estimation process. The cost estimation method used depends on the level of engineering precision that has been completed at the time the particular forecast is prepared. AltaGas' cost

estimating methods for any given project now include initial (regression) analysis, desktop reconnaissance and field reconnaissance.[108]

148. AltaGas stated that prior to using regression-based analysis, cost estimates were based on an average cost of projects completed in previous years. However, this led to inaccuracies because previous years' projects differed from future forecast work. The use of regression analysis by cost and project type is an example of an estimating enhancement that was implemented since the 2014-2015 capital tracker application.[109]

149. AltaGas described its regression process in further detail in response to an information request from the Commission. The initial cost estimate is prepared using a linear regression model based on historical costs by project type where up to three years of comparable cost data are utilized. AltaGas uses a separate linear model for each pipe type (PVC, non-certified PE and pre-1957 steel) and each geographic type (downtown, town, hamlets and villages, rural subdivisions and rural), and a separate linear regression equation for each financial component of the project cost estimate (labour, materials, land damages, tendered contractors). It updates all of its regression results annually to incorporate the latest historical data. The regression analysis, based on historical data, is applied to arrive at an aggregate cost per meter.[110]

150. To calculate the cost estimate using the linear regression approach, AltaGas inputs the total pipe length to be installed into the regression formula for each project cost component. AltaGas determines line-of-best-fit regression formulas for each major cost type (engineering, land, labour, tendered contractors, land payments, materials) with the Y variable as the cost per meter and the X variable as the total pipe length in meters.

151. A regression analysis was provided for each major cost type with the following regression formulas and R-squared (R^2) statistical measures, showing how close the data fits to the regression line. The associated linear regression model graphs are provided in Appendix 7.

Table 9. Linear regression costing approach[111]

Major cost type	Estimated regression formula	R^2
Engineering	y = 0.6142x + 11310	0.4405
Land	y = 0.2549x + 6077.9	0.0688
Labour	y = 0.9439x + 12172	0.8612
Tendered contractor	y = 24.573x + 170073	0.9232
Other	y = 5.7197x + 75532	0.8957
Land payments	y = 3.2147x + 11743	0.9427
Material	y = 8.2824x + 11999	0.9857

152. AltaGas submitted that its regression formulas generally fit the data very well, particularly for the largest cost components. For example, the tendered contractor R^2 is over 92 per cent. The formulas are less reliable for engineering and land. Land cost, which is highly variable, has an R^2 of only six per cent.

108 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 157.
109 Exhibit 20522-X0028, AUI-AUC-2015JUL02-031(a) and (f).
110 Exhibit 20522-X0025, AUI-AUC-2015JUL02-031(c).
111 Exhibit 20522-X0025, AUI-AUC-2015JUL02-031(c).

153. AltaGas explained that at the time a project area is defined, little is known about the project from a cost perspective except for the length of the mains and services involved. Therefore, linear regression provides the best estimate of project costs because desktop reconnaissance and field reconnaissance, which ultimately affect actual project costs, have not yet been completed. As more information is gathered on the project through reconnaissance, project costs are revised from the regression-based costs to direct pay items estimates, including forecast quantities and estimated rates based on historical costs adjusted for inflation. Once tenders are received and contractors are selected, pay items are adjusted to actual.[112]

154. AltaGas' desktop reconnaissance process was also described in further detail. During the desktop reconnaissance phase, maps are obtained from AltaGas' GIS database and are overlaid with aerial photos or Google Earth imagery to identify the amount of replacement work required and all general surface conditions. Rough estimates of the amount of pipe to be installed by horizontal directional drilling or by plow are then obtained by AltaGas' estimators, taking into account the amount of square metres of asphalt to be replaced, the removal of crops and trees, the identification of the number of services affected, and any road, creek and pipeline crossings. The estimated quantities are then entered under each appropriate pay item, together with estimated unit costs, to arrive at the total project cost. AltaGas stated that the estimated unit rates are based on the most recent tendered prices, adjusted for inflation. At this stage, on-site field reconnaissance has not been completed and all approvals with all relevant regulatory agencies, municipalities and/or landowners, which can influence final pipe alignment and the resulting cost of the project, have not been received.[113]

155. Once a project moves to field reconnaissance, the estimator further refines the proposed pipe alignments and confirms pay items. Specifically, the estimator applies the analyzed historical data to determine the average contractor pay item rates for AltaGas' tendered contractor pay items, and together with regression analysis, this is used to estimate other major cost types, such as engineering, land damages, project management and materials.[114]

[112] Exhibit 20522-X0025, AUI-AUC-2015JUL02-031(c).
[113] Exhibit 20522-X0010, application, PDF page 164.
[114] Exhibit 20522-X0028, AUI-AUC-2015JUL02-031(a) and (f).

7.1.4.1 PVC Pipe

156. AltaGas provided a breakdown of the costs and pipeline length for each of the 2016, and 2017 projects, as shown in the following two tables.

Table 10. PVC Pipe Replacement – 2016 forecast[115]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	2016 projects						
1	Leduc Area 2	Rural	4.4	387,668	20,792	408,459	91,913
2	Leduc Area 9	Rural	35.0	2,303,275	123,426	2,426,701	69,354
3	Morinville Area 3	Rural	37.9	2,590,729	138,947	2,729,677	72,083
4	Morinville Area 4	Rural	3.1	239,562	12,848	252,410	82,360
5	Westlock Area 5	Rural	9.0	712,772	38,228	751,000	83,592
6	Westlock Area 4	Rural	22.6	1,539,542	82,569	1,622,112	71,904
7	**Total**		**111.9**	**7,773,548**	**416,810**	**8,190,358**	

157. AltaGas proposed to complete two projects in the Leduc rural area that were first started in 2011. The 2016 forecast costs were developed using desktop reconnaissance and an assessment of pipeline hydraulics. The costs for each pay item were based on estimated quantities identified through desktop reconnaissance and pay item unit rates adjusted for inflation.[116]

158. AltaGas proposed to complete four projects in the Morinville and Westlock rural areas, based on their connection to the BWM Gas Supply project, as further discussed in Section 7.3.3. The 2016 forecast costs reflect a preliminary estimate that was developed through desktop reconnaissance and costed by major components using AltaGas' linear regression model. These costs are based on aggregated (cost/meter) historical data using linear regression.[117]

159. The 2016 forecast costs also include an inflation factor of 4.56 per cent using the Alberta Average Weekly Earnings (AB AWE).[118] AltaGas' inflation factor reflects a 70 per cent weighting of the AB AWE earnings of 5.58 per cent and a 30 per cent weighting of the Alberta Consumer Price Index of 2.16 per cent.[119] In response to a Commission IR, AltaGas submitted that the 70:30 ratio of contractor to non-contractor costs is reasonable because it provides a conservative approach reflecting AltaGas' view that costs associated with Pipeline Replacement projects are largely driven by market demand in industries competing for the same labour and equipment resources in the oil and gas sectors.[120]

115 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 45, Table 2.6.2-1, PVC 2016 Forecast Additions.
116 Exhibit 20522-X0010, application, PVC pipeline replacement business case, PDF page 163.
117 Exhibit 20522-X0010, application, PVC pipeline replacement business case, PDF page 164.
118 Exhibit 20522-X0024, AUI-AUI-2015JUL02-032(a) - CANSIM Table 218-0063 (also used in the 2015 I factor calculation) for the subcategory of Mining, Quarrying and Oil and Gas Extraction.
119 Exhibit 20522-X0010, application, PVC pipeline replacement business case, PDF page 164.
120 Exhibit 20522-X0028, AUI-AUC-2015JUL02-032(b).

Table 11. PVC Pipe Replacement – 2017 forecast[121]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	2017 projects						
1	Leduc Area 10A	Rural	7.1	571,098	27,487	598,585	84,870
2	Leduc Area 10B	Rural	20.8	1,571,763	75,649	1,647,412	79,271
3	Leduc Area 6	Rural	2.0	142,533	6,860	149,393	74,510
4	Leduc Area 7	Rural	2.8	195,262	9,398	204,659	74,179
5	Westlock Area 2	Rural	37.2	2,653,363	127,706	2,781,069	74,812
6	Westlock Area 1	Rural	19.9	1,478,172	71,144	1,549,317	78,023
7	Westlock Area 3	Rural	11.7	875,525	42,139	917,664	78,483
8	Westlock Rural (Remainder)	Rural	8.6	728,816	35,078	763,894	88,978
9	Barrhead Rural (Remainder)	Rural	13.5	1,015,477	48,875	1,064,352	78,829
10	Barrhead Area 5	Rural	8.0	635,089	30,567	665,656	83,280
11	**Total**		**131.4**	**9,867,099**	**474,903**	**10,342,001**	

160. AltaGas proposed to complete 10 PVC projects in 2017. The 2017 forecast costs for the Leduc Area 10A, Leduc Area 10B, Leduc Area 6, Leduc Area 7, Barrhead Area 5 and Westlock Area 2 rural projects were developed through desktop reconnaissance and the costs for each pay item are based on quantities identified using desktop reconnaissance and pay item unit rates.

161. The 2017 forecast costs for the Westlock Area 1, Westlock Area 3, Barrhead (Remainder) and Westlock (Remainder) rural projects reflect a preliminary estimate developed through desktop reconnaissance and costed by major components using AltaGas' linear regression model. The costs are based on aggregated (cost/meter) historical data using linear regression.

162. Forecast costs in 2017 also reflect AltaGas' inflation factor of 4.56 per cent.

163. AltaGas explained that because of the requirement to construct the 2016 BWM Gas Supply project, four PVC projects previously identified to be replaced in 2016 were rescheduled to either 2017 or 2019. The Leduc Area 6 and 7 rural projects were deferred to 2017, and the Morinville Area 2 rural project was deferred to 2019. In response to a Commission IR, AltaGas explained that these three PVC projects could be deferred due to their relatively low risk scores.[122] With respect to the Westlock Area 2 rural project, AltaGas deferred this project to 2017, explaining that, despite this project having a relatively high risk score, AltaGas needed to ensure that sufficient contractor resources would be available in 2016 to complete 72.5 km of other PVC Pipe Replacement and 20.6 km of Non-Certified PE Pipe Replacement projects that have emerged in the BWM area.[123]

164. In Appendix IV and Appendix V of the business case, AltaGas provided 2016 and 2017 cost estimates broken down by labour, materials, contractor costs, overhead costs, total project costs, pipe length and total cost per km.[124] In addition, in Appendix VI of the business case,

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[121] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 46, Table 2.6.2-2, PVC, 2017 Forecast Additions.
[122] Exhibit 20522-X0028, AUI-AUC-2015JUL02-029(a).
[123] Exhibit 20522-X0028, AUI-AUC-2015JUL02-029(b).
[124] Exhibit 20522-X0010, application, PVC pipeline replacement business case, PDF pages 192-194.

AltaGas provided historical information for the period 2010-2014 for each PVC project completed, including area type, km completed, costs and cost per km.[125]

7.1.4.2 Non-Certified PE Pipe

165. AltaGas provided a breakdown of the costs and pipeline length for each of the 2016, and 2017 projects, as shown the following two tables:

Table 12. Non-Certified PE Pipe Replacement – 2016 forecast[126]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	2016 projects						
1	Beau Vista	Rural Sub.	6.8	414,662	22,239	436,901	64,194
2	Kadavista	Rural Sub.	2.2	278,559	14,940	293,499	132,147
3	Southwood	Rural Sub.	1.9	274,076	14,699	288,775	155,842
4	Kay wood	Rural Sub.	1.1	154,171	8,269	162,439	148,754
5	Valleyview	Rural Sub.	4.3	365,212	19,587	384,800	89,467
6	Westlock Area 5	Rural	1.5	130,784	7,014	137,798	93,170
7	Morinville	Rural	19.1	1,468,534	78,499	1,547,032	81,086
8	**Subtotal**		**36.8**	**3,085,997**	**165,247**	**3,251,245**	
	2015 approved projects						
9	Looma Estates SW22	Rural Sub.	3.1	337,601	18,279	355,881	113,410
10	Gateway	Rural Sub.	2.7	377,015	20,134	397,148	145,157
11	Looma Estates NE22	Rural Sub.	1.5	204,939	11,165	216,104	139,512
12	**Subtotal**		**7.4**	**919,555**	**49,578**	**969,133**	
13	**Total**		**44.3**	**4,005,553**	**214,825**	**4,220,378**	

166. The 2016 forecast costs for the Beau Vista, Kadavista, Southwood and Kaywood Rural Subdivision projects were developed using field reconnaissance and land work previously completed. Project cost estimates reflect the major cost types and are based on pay items and unit rates, adjusted for inflation. The 2016 forecast cost for the Valleyview Rural Subdivision project was developed using desktop reconnaissance and an assessment of pipeline hydraulics, with component costs based on unit rates adjusted for inflation.[127]

167. AltaGas also proposed to replace the Westlock Area 5 and Morinville rural projects in conjunction with the 2016 BWM project. The 2016 forecast costs for these projects are a preliminary estimate developed through desktop reconnaissance and were costed by major components using AltaGas' linear regression model. The costs are based on aggregated (cost/meter) historical data using linear regression, adjusted for inflation.[128]

[125] Exhibit 20522-X0010, application, PVC pipeline replacement business case, PDF page 195.
[126] Exhibit 20522-X0010.04, application (black line) identifying revisions, Table 2.6.3-1, Non-Certified PE, 2016 Forecast Additions, PDF page 47.
[127] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 157.
[128] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 158.

168. In Decision 2014-373, the Commission approved the Looma Estates SW, Gateway and Looma Estates NE (rural subdivision) projects for completion in 2015.[129] However, AltaGas proposed to defer these projects to 2016 to allow for the BWM project to proceed.[130] AltaGas updated its forecast to reflect quantities developed through field reconnaissance work and using major cost types based on unit rates adjusted for inflation.[131]

169. Similar to the PVC projects, AltaGas applied an inflation factor of 4.56 per cent.

Table 13. Non-Certified PE Pipe Replacement – 2017 forecast[132]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	<u>2017 projects</u>						
1	Irvine	Rural	3.6	329,085	15,839	344,924	96,753
2	Peace Hills Heights	Rural Sub.	2.7	375,783	18,086	393,870	144,116
3	Rural sub 34	Rural Sub.	3.8	455,650	21,930	477,581	124,988
4	Helm	Rural Sub.	1.0	184,932	8,901	193,833	197,587
5	King	Rural Sub.	1.4	201,069	9,677	210,746	148,832
6	Namao Ridge Estates	Rural Sub.	4.8	744,179	35,817	779,996	162,975
7	Richdale Estates	Rural Sub.	1.0	171,283	8,244	179,527	175,149
8	Clearwater	Rural Sub.	0.9	169,879	8,176	178,055	198,723
9	Barrhead Area 1 (Mains Only)	Rural	19.1	1,446,391	69,615	1,516,006	79,360
10	Westlock Area 1 (Mains Only)	Rural	20.2	1,534,762	73,868	1,608,630	79,659
11	Westlock Area 2 (Mains Only)	Rural	25.1	1,902,455	91,565	1,994,020	79,472
12	**Total**		**83.6**	**7,515,469**	**361,719**	**7,877,188**	

170. The 2017 forecast costs for the Irvine, Barrhead Area 1 and Westlock Area 2 rural projects, and for the Peace Hills Heights, Rural Sub 34, Helm, King, Namao Ridge Estates, Richdale Estates, and Clearwater rural subdivision projects were developed using desktop reconnaissance. Similar to its PVC projects, the 2017 forecast costs include an inflation factor of 4.56 per cent.[133]

171. AltaGas deferred the Irvine, Peace Hills Heights, Rural Sub 34, Helm, King, Namao Ridge Estates, Richdale Estates and Clearwater projects, originally identified in the 2016 forecast to 2017 because of their relatively low risk scores.[134]

172. In Appendix IV and Appendix V of the business case, AltaGas provided 2016 and 2017 cost estimates broken down by labour, materials, contractor costs, overhead costs, total project costs, pipe length and total cost per km.[135] Further, in Appendix VI of the business case, AltaGas

[129] Decision 2014-373, paragraph 203.
[130] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 151.
[131] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 158.
[132] Exhibit 20522-X0010.04, application (black line) identifying revisions, Table 2.6.3-2, Non-Certified PE, 2017 Forecast Additions, PDF page 48.
[133] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 159.
[134] Exhibit 20522-X0028, AUI-AUC-2015JUL02-029(c).
[135] Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF pages 188-191.

provided historical information for the period 2010-2014 for each Non-Certified PE Pipe project completed, including area type, km completed, costs and cost per km.[136]

7.1.4.3 Pre-1957 Steel Pipe

173. AltaGas provided a breakdown of the costs and pipeline length for each of the 2016 and 2017 projects, as shown below:

Table 14. Pre-1957 Steel Pipe Replacement – 2016 forecast[137]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	2016 projects						
	Mains and services						
1	Barrhead	Town	8.9	2,429,297	130,289	2,559,586	288,665
2	Drumheller Phase 2, 3, 4	Town	9.7	3,325,899	178,758	3,504,657	361,640
3	Drumheller Phase 5	Town	9.9	2,618,287	140,425	2,758,712	279,902
4			**28.4**	**8,373,483**	**449,473**	**8,822,955**	
	High pressure (HP) pipe						
5	Pickardville HP supply line	Rural	10.4	1,756,556	94,208	1,850,765	178,542
6	Morinville HP steel	Rural	1.6	290,365	15,573	305,938	196,744
7	Westlock HP steel	Town	1.5	429,048	23,011	452,059	309,418
8	Drumheller HP supply line	Town	4.0	700,963	37,594	738,557	182,856
9			**17.4**	**3,176,932**	**170,387**	**3,347,319**	
10	**Total**		**45.8**	**11,550,414**	**619,859**	**12,170,274**	

174. The 2016 forecast costs for the Barrhead, Drumheller Phase 2, 3 and 4, and Drumheller Phase 5 town projects for medium pressure steel pipe were developed using field reconnaissance and land work previously completed. Cost forecasts reflect the major cost types and are based on pay items and unit rates.

175. As discussed in Section 4.1, AltaGas proposed to begin the replacement of high pressure steel pipe starting in 2016. The 2016 forecast costs for the Pickardville HP Supply Line and the Morinville HP Steel rural projects, and the Westlock HP Steel and the Drumheller HP Supply Line town projects are preliminary estimates developed through desktop reconnaissance and are costed by major cost types using AltaGas' linear regression model. The costs are based on aggregated (cost/meter) historical data using linear regression.[138]

176. The Pickardville HP Supply Line project and the Westlock HP Steel project are forecast to be replaced in 2016 in conjunction with the BWM Gas Supply project. AltaGas also forecast the replacement of the Morinville HP Steel and the Drumheller HP Supply Line in 2016 because AltaGas is replacing critical supply line segments that comprise the sole source of supply to the major urban centres of Morinville and Drumheller.[139]

136 Exhibit 20522-X0010.04, application (black line) identifying revisions, non-certified PE pipe replacement business case, PDF page 192.

137 Exhibit 20522-X0010.04, application (black line) identifying revisions, Table 2.6.1-1: Pre-1957 Steel: 2016 Forecast Additions, PDF page 43.

138 Exhibit 20522-X0010.04, application (black line) identifying revisions, pre-1957 steel pipe business case, PDF page 107.

139 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 44.

Table 15. Pre-1957 Steel Pipe Replacement – 2017 forecast[140]

Line		Area type	Pipe length (km)	Direct costs ($)	Overhead costs ($)	Total additions ($)	Unit cost ($/km)
	2017 projects						
	Mains and Services						
1	Barrhead	Town	11.7	3,419,899	164,599	3,584,499	305,090
2	Hanna	Town	18.7	5,703,801	274,523	5,978,324	319,014
3			**30.5**	**9,123,700**	**439,123**	**9,562,823**	
	High pressure (HP) pipe						
4	Hanna HP steel	Town	1.6	467,524	22,502	490,025	311,364
5	Stettler HP supply line	Town	5.5	1,431,010	68,874	1,499,884	271,571
6	Hanna- HP supply line	Rural	17.6	3,057,500	147,157	3,204,657	182,425
7			**24.7**	**4,956,033**	**238,533**	**5,194,566**	
8	**Total**		**55.2**	**14,079,733**	**677,656**	**14,757,389**	

177. The 2017 cost forecast for the Barrhead and Hanna Pre-1957 Medium Pressure Steel Pipe town projects were developed using field reconnaissance and land work previously completed. The costs reflect the major cost types and are based on pay items and unit rates.

178. The 2017 cost forecasts for the Hanna HP Steel and Stettler HP Supply Line town projects, and for the Hanna HP Supply Line High Pressure Steel Pipe rural project are preliminary estimates developed through desktop reconnaissance and were costed by major cost types using AltaGas' linear regression model. The costs are based on aggregated (cost/meter) historical data using linear regression.[141]

179. Similar to PVC and Non-Certified PE Pipe, the 2016 and 2017 projects included an inflation factor of 4.56 per cent.

180. In Appendix IV and Appendix V of the business case, AltaGas provided 2016 and 2017 cost estimates broken down by labour, materials, contractor costs, overhead costs, total project costs, pipe length and total cost per km.[142] Further, in Appendix VI of the business case, AltaGas provided historical information for the period 2010-2014 for each Pre-1957 Steel Pipe project completed, including area type, km completed, costs and cost per km.[143]

181. No other party opposed nor submitted argument regarding the forecast 2016-2017 pipeline replacement projects identified by AltaGas. No party submitted any comments regarding the changes made by AltaGas' to its updated cost estimation methodology.

[140] Exhibit 20522-X0010.04, application (black line) identifying revisions, Table 2.6.1-2, Pre-1957 Steel, 2017 Forecast Additions, PDF page 44.
[141] Exhibit 20522-X0010.04, application (black line) identifying revisions, pre-1957 steel pipe business case, PDF page 107.
[142] Exhibit 20522-X0010.04, application (black line) identifying revisions, pre-1957 steel pipe business case, PDF pages 134-137.
[143] Exhibit 20522-X0010.04, application (black line) identifying revisions, pre-1957 steel pipe business case, PDF page 138.

Commission findings

182. As mentioned above, AltaGas has updated the cost estimation methodology it uses to prepare its forecasts for its pipeline replacement program.

183. When there is a change in methodology used to produce forecasts, such as is the case here with the introduction of a regression analysis, it is often worthwhile to compare the results obtained using the previous and current methodologies, where possible. Regression analysis, as used by AltaGas, can be a useful tool to model, and subsequently forecast, cost or cost per km. However, if parties are to understand and test AltaGas' forecasts, then the regression analysis needs to be well-documented. A complete understanding of the method and results is not possible if the regression models, the data used in the regression analyses, accurate detailed descriptions of the variables used, and the analysis used by AltaGas to produce forecasts for replacement of pre-1957 steel pipe, of non-certified PE pipe, or of PVC pipe, is not provided and cannot be reproduced. For example, in a reliable regression analysis, the substitution of forecast pipe lengths, provided in Table 2.6.2-1 of the application, in the estimated regression equations for PVC pipe replacement, as provided in the response to AUI-AUC-2015JUL02-031 c), would yield forecast costs per km that match those forecasts provided in Table 2.6.2-1.

184. With this in mind, it would be helpful to all parties if AltaGas were to provide the regression models and accompanying analysis for each type of pipe, and for each geographic area, for which the analysis is conducted separately. A more complete presentation for each of the regression models for specific types of costs might then include regression diagnostic statistics beyond the goodness of fit statistic provided. For example, for each regression model parties would benefit from being provided with the number of observations used, the time period used, estimated standard errors of all the estimated parameters as well as the estimated standard error of the regression, and tests of parameter significance.

185. AltaGas might also consider including the aggregate cost model (sum of the individual cost regressions) so that the forecast of aggregate cost can be reproduced by substituting in the (provided) forecast values of the explanatory variable(s). If this is done, then the estimated standard errors for these forecasts could also be provided so that the uncertainty associated with these forecasts can be evaluated. In addition, if cost data include values from different years, then for consistent comparability between years, the data is usually inflation-adjusted using a method that is described and justified.

186. Finally, interested parties, as well as AltaGas, might benefit from an evaluation of alternative regression models that employ standard regression diagnostic procedures such as individual and joint tests of significance of parameters. For example, these alternatives could include models with multiple explanatory variables rather than just pipeline length in metres, where additional variables may also include service density, or number of services. For projects where some associated costs, such as land costs, are zero, as identified in Appendix 8, standard regression models may not apply, and alternative regression models that reflect whether or not a non-zero cost was observed may be considered.

187. In summary, while there is potential to improve on the regression model, in order to make it more useful for AltaGas and for interveners and the Commission when assessing the validity of the forecast, the Commission considers AltaGas' initiative to improve on its forecasting accuracy to be reasonable and it is approved for the purposes of this decision.

188. The Commission has reviewed the information provided on forecast program scope and costs for 2016 and 2017, including the forecast costs for each pipeline replacement, and finds that the forecast information provided by AltaGas supports a finding that the scope, level, timing and forecast costs for the projects in the pipeline replacement program are reasonable. Accordingly, the Commission finds that this program satisfies the project assessment requirement of Criterion 1.

7.2 Projects in the Station Refurbishment program

7.2.1 Projects completed in 2013, not approved for capital tracker treatment in Decision 2014-373 and reapplied for in the application

189. AltaGas undertook three Station Refurbishment projects in 2013 that were not approved for capital tracker treatment on a forecast basis in Decision 2013-435. As part of its 2013 capital tracker true-up application, AltaGas applied for these projects after they had been completed. The Commission accepted that stations PMS LE069 and MN017 became priorities because certain operational issues made them safety concerns. The Commission also accepted that it became necessary to refurbish MN032 partially in order to ensure that AltaGas' gas pipeline performance was within specified operating parameters. Accordingly, the need for these projects was approved in Decision 2014-373.

190. In Decision 2014-373, the Commission reviewed the scope, level, timing and costs of these stations and, even though some comparability evidence was provided with respect to the costs for two of the stations, the Commission determined that there was insufficient evidence on the record of AltaGas' 2013 capital tracker true-up application to conclude that the costs for these three projects were prudent. As a result, these stations were not approved for capital tracker treatment at that time. However, at paragraph 262 of Decision 2014-473 the Commission left provision for AltaGas to reapply for capital tracker treatment for these projects:

> 262. Because AltaGas applied for capital tracker treatment for these projects after they were completed, and this was the first time a company has applied for a project after its completion, the Commission will allow AltaGas to reapply for capital tracker treatment for these projects with revised information at the time of its next capital tracker true-up application. If approved at that time, the Commission would allow the company to receive capital tracker treatment for these projects effective 2013 on a mid-year basis.

191. In addition, the Commission directed AltaGas as follows:

> 280. … Therefore, in future capital tracker applications, when there is a difference in forecast or actual costs between a particular station and the standard station, AltaGas is directed to include a table similar to the one provided in AUC-AUI-11 showing the build-up of project costs for each station and comparing it to the build-up of project costs in a standard station. The Commission also directs AltaGas to include information that explains the difference between the variance in costs from a standard station.
>
> …
>
> 284. … However, since the scope of each station refurbishment or replacement varies, where in some cases regulators and valves are replaced, while in others, the entire above-ground facilities require replacement, the Commission finds that the alternatives for replacement or refurbishment, including all costs, should be explored in the business case for each station so that the Commission is assured that each station is being refurbished or replaced prudently. For each of the 2014-2015 station refurbishments or replacements,

> AltaGas is directed to provide this type of information in the applications where the costs are trued-up to actual.[144]

192. AltaGas reapplied for capital tracker treatment for all three stations in this application. PRS stations LE069 and MN032 were completed in 2013 and will be discussed in this section. PMS MN017 was completed in 2014 and is discussed in Section 7.2.2, which focusses on station projects completed in 2014.

193. Since PRS stations LE069 and MN032 were undertaken subsequent to the issuance of Decision 2013-435, no forecast was approved for these projects. AltaGas, therefore, provided its 2013 AFE forecast as a proxy for the missing 2013 forecast costs in order to be able to have a comparison to actual costs and to demonstrate that the project costs were prudently incurred. The 2013 forecast consists of the project costs approved by AltaGas' senior management in its AFE process, together with the project justification, categorized by engineering, labour, materials, contractors and overheads costs.

194. No interested party opposed nor filed argument regarding the prudence of the costs claimed by AltaGas for these projects.

7.2.1.1 PRS LE069

195. AltaGas explained that PRS LE069 required complete replacement due to multiple failures on old, obsolete plug valves that were not repairable and virtually inoperable, preventing the timely gas flow stoppage under an emergency situation.[145]

196. AltaGas provided a 2013 AFE forecast of $57,451 and actual costs of $54,854, resulting in a variance of five per cent. The variance analysis showed that contactor costs were much lower than forecast and material costs were higher than forecast. AltaGas attributed the contactor cost variance to less time required to complete the project, and the variance in material costs to required additional miscellaneous parts, such as valves and fittings.[146]

7.2.1.2 PRS MN032

197. PRS MN032 was a partial refurbishment. AltaGas explained that MN032 is located in a remote area, making it difficult or impossible to monitor performance on a timely basis, particularly if it were to be done manually and during winter conditions. For reliability and safety reasons, it was necessary for AltaGas to install a communication system, including alarms, to monitor station performance on a continuous basis, ensuring reliable supply to customers.[147]

198. AltaGas provided a 2013 AFE forecast of $11,636 and actual costs of $13,384. AltaGas explained that the 15 per cent variance from forecast was due to winter conditions requiring more time for fence installation by AltaGas field personnel.[148]

[144] Decision 2014-373, paragraphs 280 and 284.
[145] AUI-AUC-2015JUL02-059.
[146] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 351, paragraph 197.
[147] Exhibit 20522-X0028, AUI-AUC-2015JUL02-059.
[148] Ibid., PDF page 352, paragraph 200.

Commission findings

199. The Commission accepts AltaGas' explanations for choosing a complete replacement for PRS LE069 and a partial refurbishment of PRS MN032, and finds AltaGas to have complied with the Commission's direction in paragraph 284 of Decision 2014-373.

200. For these two stations, the Commission has reviewed the 2013 AFE estimates, 2013 actual costs and the variance explanations. Similar to the pipeline replacement program, the Commission finds that the 2013 AFE forecasts provided by AltaGas will suffice for the purposes of this decision, in order for the Commission to consider whether the costs for each individual project were prudent.

201. The Commission has reviewed the evidence explaining the differences between the 2013 AFE estimates and the actual costs, and finds the variance explanations to be reasonable. However, for these two projects AltaGas has not included information that compares the build-up of project costs for each station to those of a standard 2013 PRS station, as directed in paragraph 280 of Decision 2014-373. Nonetheless, for the purposes of this decision, the Commission is prepared to overlook this omission. Accordingly, the Commission finds that the actual scope, level, timing and costs of the work undertaken by AltaGas in 2013 were prudently incurred.

202. The Commission finds that these two projects satisfy the project assessment requirement of Criterion 1 for 2013. AltaGas is directed to calculate and include the revenue requirement for these projects, on a 2013 mid-year basis, in its K factor calculations. AltaGas is reminded in future capital tracker applications, when there is a difference in forecast or actual costs between a particular station and the standard station, to include a table showing the build-up of project costs for each station and to compare them to the build-up of project costs in the standard station.

7.2.2 Projects approved in Decision 2014-373 for 2014 and completed in 2014

203. In its 2014 true-up application, AltaGas provided forecast costs, including direct and overhead costs of $265,300, $185,700 and $21,200 for standard 2014 PMS, TBS and PRS Station Refurbishments, respectively. The standard 2014 PMS Station Refurbishment cost includes the removal of an existing station, addition of a new station with gas regulation components (i.e., piping, regulator), new fencing, new line heater and new odourization. The cost of a standard 2014 TBS refurbishment is similar to a PMS station, but excludes the line heater and associated costs. The cost of a standard 2014 PRS station is based on the replacement of the smallest size PRS.[149]

204. AltaGas also provided actual costs, forecast costs and variances for each station project being requested for true-up approval, and information that explained the difference between each station's cost variance and the cost of a standard station refurbishment.

205. No interested party opposed nor filed argument related to the prudence of the costs claimed by AltaGas for these projects.

[149] Decision 2014-373, paragraph 264.

206. The following table provides a comparison, for 2014 stations, of approved forecast costs to actual costs, and approved number of stations to forecast number of stations.

Table 16. 2014 Station projects – actual versus approved forecast costs, and variances by project[150]

Line	Station type	Project name	Approved	Actual	Variance
			($)	($)	($)
	2014 additions				
1	PMS	LE081	659,977	263,023	396,954
2	PMS	SP014	265,300	325,280	(59,980)
3	PMS	SP252	318,300	248,102	70,198
4	PMS	MN017	262,425	274,086	(11,661)
5			1,506,002	1,110,491	395,511
	2014 approved[1]				
6	PMS	HL005	424,400	-	424,400
7	PMS	LE077	201,600	-	201,600
8	PMS	LE327	169,800	-	168,800
9		**Total PMS**	**2,301,802**	**1,110,491**	**1,191,311**
	2014 additions				
10	TBS	DR009	185,700	147,043	38,657
11	TBS	HA005	185,700	162,630	23,070
12	TBS	SP316	53,000	51,827	1,173
13	TBS	ST004	185,700	122,449	63,251
14			610,100	483,949	126,151
	2014 approved[1]				
15	TBS	LE909	185,600	-	185,600
16		**Total TBS**	**795,700**	**483,949**	**311,751**
	2014 additions				
17	PRS	DR017	212,200	300,165	(87,965)
18	PRS	LE214	21,200	28,902	(7,702)
19	PRS	MN008	21,200	39,017	(17,817)
20	PRS	LE310	21,200	46,371	(25,171)
21	PRS	LE060	21,200	40,054	(18,854)
22		**Total PRS**	**297,000**	**454,509**	**157,509**
23	**Prior period trailing costs**		**(815)**	**52,030**	**(52,845)**
24		**Grand total**	**3,393,687**	**2,100,978**	**1,292,709**

		Number of stations		
Line	**Station type**	**Approved**	**Actual**	**Variance**
1	PMS	7	4	3
2	TBS	5	4	1
3	PRS	5	5	-
4	**Total number of stations**	**17**	**13**	**4**

Note 1: Projects approved in Decision 2014-373 and not in service at December 31, 2014.

150 Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 326, Table 3.3-1.

7.2.2.1 PMS Stations – LE081, SP014, SP252, and MN017

207. PMS Stations LE081, SP014, SP252, and MN017 were all managed as complete station replacements because all major equipment components were obsolete and AltaGas concluded that there was no other alternative but to replace each station completely.[151]

208. In Decision 2014-373, the Commission approved a proposal by AltaGas, based on an Alberta Ministry of Transportation request, to relocate PMS LE081. Subsequently, AltaGas was notified by the Alberta Ministry of Transportation that the relocation would no longer be required, which enabled AltaGas to use the original design and fabricated station to complete and place the station into service in 2014. The approved $659,977 forecast cost for LE081 was based on standard direct PMS station costs of $250,000 plus $363,400 for land, a TCPL tap and 200 m of high pressure pipe due to the relocation of the station, plus overhead costs. The actual cost of $263,023 is slightly less than the cost of a standard PMS station ($265,300) and 60 per cent less than the approved forecast because AltaGas did not require the additional features that were associated with the originally requested station relocation.[152]

209. For PMS Station SP014, the approved forecast cost was for a standard PMS station. However, the actual cost was $325,280, resulting in a 23 per cent variance. AltaGas explained that the cost increase was primarily because of inclement weather conditions adversely affecting the site conditions during construction. Additional time was required for the field crew to get on site and additional site work was required to prevent potential flooding.[153]

210. For PMS Station SP252, the approved forecast cost was $318,300. The actual cost was $248,102, resulting in a 22 per cent variance. The $318,300 forecast was based on standard direct PMS station costs of $250,000, plus $40,000 for a larger line heater and miscellaneous station, plus site materials of $10,000, plus overhead. Actual costs were lower than forecast for three reasons. First, AltaGas discovered that the existing odorant facility was in good working condition and did not need to be replaced. Second, it was determined that a standard line heater would be sufficient. Third, less time was required for engineering design and construction work.

211. With respect to PMS Station MN017, the approved forecast cost was $262,425 and the actual cost was $274,086, resulting in a four per cent variance. The approved forecast was based on the direct costs for a standard PMS station of $250,000 without standard features such as a line heater and an odorant tank, but with the addition of an odourizer injection kit. Actual costs were higher than the approved forecast due to additional time requirements from the engineering and field crews.[154]

7.2.2.2 TBS Stations – DR009, HA005, ST004, and SP 316

212. TBS Stations DR009, HA005, and ST004 were managed as complete station replacements because all major equipment components were obsolete and AltaGas concluded that there was no other alternative but to replace each station completely. TBS Station SP 316 was not a complete replacement because only the replacement of an obsolete regulator was required.

[151] Exhibit 20522-X0028, AUI-AUC-2015JUL02-059.
[152] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 329, paragraph 130.
[153] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 330, paragraph 135.
[154] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 335, paragraph 148.

213. The actual cost for each of TBS Stations DR009, HA005, and ST004 was less than the approved forecast cost, which was based on the approved standard TBS station refurbishment cost of $185,700. The actual cost for TBS Station DR009 was $147,043 which was 21 per cent less than the approved forecast. AltaGas explained that the lower actual cost was due to a modification made to the station design that eliminated the need for the gas measurement component. This resulted in significantly less time required for engineering design and by the field crew for installation work.[155] Similarly, modifications made to the design for TBS Station HA005 resulted in less time required for design, fabrication and installation. The actual cost of that station was $162,630, which is 12 per cent less than the approved forecast. With respect to TBS Station ST004, the actual cost was $122,449, or 34 per cent less than forecast. Because of the configuration of this station, AltaGas was able to complete the work without line stopping operations, resulting in lower labour costs. In addition, the standard station design was used, resulting in lower engineering costs.[156]

214. The actual cost of TBS Station SP 316 was $51,827, which was two per cent less than the approved forecast cost of $53,000. Because this station only required replacement of an obsolete regulator, the costs were much less than the cost of a standard TBS station refurbishment.[157]

7.2.2.3 PRS Stations – DR017, LE214, MN008, LE310, LE060

215. PRS Stations DR017, LE214, MN008, LE310 and LE060 were all managed as complete station replacements because all major equipment components were obsolete and AltaGas concluded that there was no other alternative but to replace each station completely.

216. For PRS Station DR017, the approved forecast cost was $212,200 and the actual cost was $300,165, resulting in a 41 per cent variance. Because this station is located within a town boundary and has a considerable load requirement, AltaGas considered it to be generally equivalent to a TBS station, but for the fact that it did not have a line heater and metering. Consequently, the forecast cost for a complete station replacement was much higher than that of a standard PRS station. In addition, AltaGas explained that because of unseasonably wet conditions, installation was slower and required more labour and equipment than planned. In addition, extra contractor costs were incurred to modify a related metering facility and additional time and resources were required by construction and maintenance personnel to alter the site to bore a laneway into the site, connect new pipes, remove a cement pad and install full stopper fittings and a new inlet riser.

217. The approved forecast cost for each of PRS Stations LE214, MN008, LE310 and LE060 was $21,200, which was the approved average cost of a standard station refurbishment. The actual costs for these four stations were $28,902, $39,017, $46,371 and $40,054, respectively. This equates to 36, 84, 119 and 89 per cent respective variances. Standard PRS stations are small scale, pressure-regulating sites with non-compliant, obsolete equipment , threaded fittings rather than welded joints, and include above-ground equipment only. Unlike these standard PRS stations, PRS Stations LE214, MN008, LE310 and LE060 included both above and below-ground equipment. AltaGas explained that a review of the cost estimate for each of the stations revealed that the costs for dismantling part of the below-ground equipment were inadvertently missed from the forecast, resulting in higher actual materials, labour and other contractor costs.

155 Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 339, paragraph 165.
156 Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 342, paragraph 173.
157 Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 341, paragraph 171.

Additionally, for PRS Stations LE310 and LE060, additional contractor costs were incurred because AltaGas' field labour crews were not available because of delays in other projects.

Commission findings

218. The Commission finds that AltaGas has complied with paragraph 284 of Decision 2014-373 explaining why it chose complete replacement or partial refurbishment for each station. All of the station refurbishments undertaken in 2014 were complete replacements with the exception of TBS SP 316, which was a partial refurbishment. After reviewing the explanations provided, the Commission is satisfied that AltaGas made reasonable choices between complete replacement and partial refurbishment for each station.

219. For each of the PMS, TBS and PRS stations that were completed in 2014, the Commission has reviewed the evidence explaining the differences between the forecast costs and the actual costs, including the information which illustrates how each individual station varies from a standard station in terms of its features and resulting costs, and accepts the variance explanations as reasonable. The Commission has reviewed the actual scope, level, timing and costs of the work undertaken by AltaGas, and finds that each of the projects was prudently incurred. The Commission finds that these projects satisfy the project assessment requirement of Criterion 1 for 2014.

7.2.3 Station Refurbishment project trailing costs

220. AltaGas provided the following table with respect to trailing costs incurred in 2014:

Table 17. Station trailing costs – 2014[158]

Line	Station	2014 approved ($)	2014 actual additions ($)					Variance ($)
			Labour	Contractor	Materials	Overhead	Total	
1	MN020	(127)	26,865	12,479	8,648	3,110	51,102	(51,229)
2	BO002	(1,093)	-	-	-	(1,093)	(1,093)	-
3	AT036	(70)	358	-	-	(70)	288	(358)
4	DR009	448	591	-	-	(144)	448	-
5	AT042	27	115	1,096	-	74	1,285	(1,258)
6	**Total**	**(815)**	**27,929**	**13,575**	**8,648**	**1,877**	**52,030**	**(52,845)**

221. In response to a Commission IR, AltaGas provided a detailed list of functions for which additional labour, contractor and materials costs were incurred for Station MN020. AltaGas explained that the trailing costs for MN020 are related to final clean-up costs for overall civil site work and other miscellaneous costs. AltaGas submitted that, "All the trailing costs were incurred as part of the normal construction process of any station, particularly when that construction spans seasons or encounters weather delays."[159]

222. No interested party filed argument or objected to the prudence of the costs claimed by AltaGas for trailing costs.

[158] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 348, paragraph 191.
[159] Exhibit 20522-X0028, AUI-AUC-2015JUL02-063, PDF page 227.

Commission findings

223. The Commission accepts the evidence of AltaGas and finds that the trailing costs for this program were prudently incurred. Accordingly, the Commission approves the inclusion of the trailing costs for the station refurbishment projects as part of project total costs for the purposes of the K factor calculation.

7.2.4 2016-2017 forecast capital tracker projects

224. AltaGas developed forecast costs for its 2016 and 2017 Station projects from initial site reconnaissance and preliminary pre-engineering work. It also provided cost estimates for standard PMS, TBS and PRS stations. For 2016, these costs were $312,200, $211,200 and $34,600, respectively.

225. The 2016 cost estimates for standard PMS, TBS and PRS stations were calculated by escalating the 2015 standard cost by an inflation rate of 2.65 per cent and adding an overhead rate of 5.36 per cent. For PMS and TBS stations, the calculation also includes price increases related to line heaters, valves, metering and instrumentation equipment and higher labour costs for welding, instrumentation and fabrication.[160] AltaGas also explained that the cost of a standard 2016 PRS station is higher than most PRS stations completed in 2015 and earlier years because stations with above-ground risks were completed first in order to maximize program coverage while the majority of PRS stations to be refurbished or replaced in 2016 and 2017 have subsurface issues (e.g., uneven ground settling or flooding risk) that will require additional site and foundation work.[161]

226. The 2017 cost estimates for standard PMS, TBS and PRS stations are $318,800, $215,700 and $35,200, respectively and were calculated by applying an inflation rate of 2.65 per cent to the 2016 direct unit costs and adding an overhead rate of 4.80 per cent.[162]

227. AltaGas expects to complete 19 stations in 2016 for a total cost of $3.9 million and 24 stations in 2017 for a total cost of $3.8 million.

228. AltaGas also provided information on how each individual station is different from the standard station and the consequential difference in costs. The cost estimates were broken down into five major cost categories namely: internal labour resources, external contractors, site work, fabrication and assembly and major components, such as odorant and line-heater systems.

[160] Exhibit 20522-X0028, AUI-AUC-2015JUL02-039.
[161] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 229.
[162] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF pages 231-233.

7.2.4.1 PMS Stations

229. AltaGas provided the following 2016 PMS Station forecast cost information:

Table 18. PMS Stations – 2016 forecast costs[163]

Line	Cost element	Typical	GC002P	TH001P	AT074P	WS038P ($)	MN027	AT052P	AT081P	SE095
1	AUI labour	78,300	72,400	71,400	82,800	79,700	61,400	52,400	61,400	10,100
2	External contractors	7,400	11,900	9,000	30,700	10,000	8,000	30,200	8,500	-
3	Site work	14,300	16,000	11,000	50,600	22,400	23,400	18,000	21,800	-
4	Fabrication & assembly	32,600	42,400	36,200	39,600	44,100	38,400	37,400	37,300	5,100
	Major components	-	-	-	-	-	-	-	-	-
5	Building	14,000	23,700	17,000	14,300	25,800	15,400	15,600	14,300	1,300
6	Odorant system	14,900	-	-	-	14,900	14,900	14,900	14,900	-
7	Lineheater system	56,500	56,700	56,500	57,200	56,700	56,700	56,700	56,700	-
8	Valving, piping, fittings	29,100	29,100	29,100	29,100	29,100	31,800	42,100	42,100	22,700
9	Regulators & pressure controls	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500
10	Meters & instrumentation	36,700	36,700	36,700	36,700	36,700	36,700	36,700	36,700	-
11	Direct costs	296,300	301,600	279,500	353,500	331,900	299,400	316,600	306,300	51,700
12	Overhead	15,900	16,200	15,000	18,900	17,800	16,000	17,000	16,400	2,800
13	**Total costs**	**312,200**	**317,700**	**294,500**	**372,400**	**349,700**	**315,400**	**333,500**	**322,700**	**54,500**

Note: Costs include 2.65 per cent annual inflation over 2015 rates plus overhead at 5.36 per cent.

230. AltaGas explained that all of the 2016 PMS Stations will be complete station replacements except for SE095, which will be a partial station refurbishment due to multiple component issues, making refurbishment impractical. As noted in Section 4 above, AltaGas has generally found that refurbishments are only viable when no more than two major components can be readily changed out. Otherwise, the time and costs to refurbish partially tend to be greater than those applicable to a replacement.[164]

231. AltaGas provided a brief explanation on how each 2016 PMS Station Refurbishment project differs from the standard one. In particular, two of the PMS Stations, AT074 and SE095, have forecast costs that are significantly different from the standard 2016 PMS station. PMS Station AT074, a 38-year-old station will require additional costs relative to a standard station for labour and site work to add fill to raise the station foundation and put a culvert in the access road to allow water to flow away from the site. PMS Station SE095, at 24 years old, is a relatively newer station, but has a run-splitting regulator configuration and requires partial refurbishment. PMS Station SE095 was included in AltaGas' 2016 forecast because of its significance to AltaGas' network operations.

[163] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 225, Table 3.2-2.
[164] Exhibit 20522-X0028, AUI-AUC-2015JUL02-038.

232. AltaGas provided the following 2017 PMS Station forecast cost information:

Table 19. PMS Stations – 2017 forecast costs[165]

Line	Cost element	Typical	ST025	AT105 ($)	LE080	PC022
1	AUI labour	80,400	59,000	40,600	113,100	67,300
2	External contractors	7,600	8,700	8,500	10,500	7,600
3	Site work	14,600	33,500	12,600	26,800	14,600
4	Fabrication & assembly	33,500	34,900	33,200	64,200	33,500
	Major components					
5	Building	14,300	14,700	15,000	19,800	14,300
6	Odorant system	15,300	-	-	-	15,300
7	Lineheater system	58,000	58,200	58,500	58,200	58,000
8	Valving, piping, fittings	29,900	29,900	29,900	29,900	29,900
9	Regulators & pressure controls	12,800	12,800	12,800	12,800	12,800
10	Meters & instrumentation	37,700	37,700	37,700	37,700	37,700
11	Direct costs	304,200	289,500	248,900	373,100	291,100
12	Overhead	14,600	13,900	11,900	17,900	14,000
13	**Total costs**	**318,800**	**303,400**	**260,800**	**391,000**	**305,100**

Note: Costs include 2.65 per cent annual inflation over 2016 rates plus overhead at 4.80 per cent.

233. AltaGas explained that all of the 2017 PMS Stations will be complete station replacements because they all have run-splitting regulators and numerous gate valves in their piping configuration. In response to a Commission IR, AltaGas explained why partial refurbishment is not a viable solution for such stations:

> Current station designs use regulators requiring specific piping configurations (minimum lengths & minimum diameter dimensions for example) to achieve designed performance. Refurbishing an existing station with new regulators, in conjunction with the old piping configuration, is not viable and jeopardizes the operational performance. This, in turn, could lead to pressure disturbances in the gas distribution supply, with negative impacts on gas delivery.[166]

234. AltaGas provided a brief explanation on how each 2017 PMS Station Refurbishment differs from its 2017 standard. In particular, the forecast costs for LE080 and AT105 were significantly different from that of a standard 2017 PMS station. LE080 is a 32-year-old station that leaks gas by design. AltaGas explained that the higher than standard costs forecast for LE080 are driven by the significantly higher fabrication and assembly costs that include additional welding services required to excavate, remove and dispose of the substantial amount of old infrastructure at this station.[167] AT105 is a 28-year-old station that has equipment that leaks by design and outlet risers, which are causing frost heaving, thereby requiring a new line-

165 Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 231, Table 3.2-6.
166 Exhibit 20522-X0028, AUI-AUC-2015JUL02-041.
167 Exhibit 20522-X0028, AUI-AUC-2015JUL02-043(c).

heater. However, unlike a standard PMS station replacement, AT105 does not require a new odorant system. In addition to the cost of the odorant system, installation costs are avoided.

7.2.4.2 TBS Stations

235. AltaGas provided the following 2016 TBS Station forecast cost information:

Table 20. TBS Stations – 2016 forecast costs[168]

Line	Cost element	Typical	MN019	TW001	BA041 ($)	LE088	LE089	TH002
1	AUI labour	78,300	48,200	66,800	86,800	71,800	69,800	61,900
2	External contractors	7,400	14,100	6,900	42,200	6,900	5,900	6,900
3	Site work	14,300	19,200	26,900	39,300	18,300	23,200	13,000
4	Fabrication & assembly	32,600	34,200	37,900	29,000	33,900	33,900	32,200
	Major components							
5	Building	14,000	22,000	23,100	23,700	23,900	23,500	23,800
6	Lineheater system	-	-	-	43,000	-	-	-
7	Valving, piping, fittings	27,400	27,400	27,400	13,500	27,400	27,400	27,400
8	Regulators & pressure controls	12,500	12,500	12,500	10,400	12,500	12,500	12,500
9	Meters & instrumentation	14,000	14,000	14,000	10,400	14,000	14,000	14,000
10	Direct costs	200,500	191,700	215,600	298,400	208,800	210,200	191,800
11	Overhead	10,700	10,300	11,600	16,000	11,200	11,300	10,300
12	**Total costs**	**211,200**	**202,000**	**227,200**	**314,000**	**219,900**	**221,500**	**202,100**

Note: Costs include 2.65 per cent annual inflation over 2015 rates plus overhead at 5.36 per cent.

236. AltaGas explained that all of the 2016 TBS Stations will be complete station replacements because they also have multiple component issues, including run-splitting regulators and numerous gate valves in their piping configurations.

237. AltaGas provided a brief explanation respecting why each 2016 TBS Station Refurbishment differs from its 2016 standard. In particular, BA041 has considerably higher forecast costs because it requires a line heater which requires, in addition to the cost of the line heater, installation costs related to labour, external contractors and site work.

[168] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 226, Table 3.2-3.

238. AltaGas provided the following 2017 TBS Station forecast cost information:

Table 21. TBS Stations – 2017 forecast costs[169]

Line	Cost element	Typical	SP098	AT031	HL004	SE009	HL001	SP265	TW003	BO001	MN002	DR004	AT007
		($)											
1	AUI labour	80,400	67,300	66,000	67,300	31,500	73,600	42,500	45,000	76,500	67,300	67,300	67,300
2	External contractors	76,000	7,600	7,100	7,600	3,900	11,800	7,100	7,100	10,200	7,600	7,600	7,600
3	Site work	14,600	14,600	18,000	14,600	17,100	7,000	12,900	21,400	13,800	14,600	14,600	14,600
4	Fabrication & assembly	33,500	33,500	37,700	33,500	17,800	45,500	26,000	31,000	44,500	33,500	33,500	33,500
	Major components												
5	Building	14,300	14,300	23,700	14,300	900	15,300	22,700	23,800	22,700	14,300	14,300	14,300
6	Lineheater system	-	-	-	-	-	-	-	-	58,000	-	-	-
7	Valving, piping, fittings	28,100	28,100	28,100	28,100	28,100	28,100	28,100	28,100	28,100	28,100	28,100	28,100
8	Regulators & pressure controls	12,800	12,800	12,800	12,800	12,800	12,800	12,800	12,800	12,800	12,800	12,800	12,800
9	Meters & instrumentation	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400
10	Direct costs	205,800	192,700	207,900	192,700	126,600	208,700	166,700	183,600	281,100	192,700	192,700	192,700
11	Overhead	9,900	8,300	10,000	9,300	6,100	10,000	8,000	8,800	13,500	9,300	9,300	9,300
12	**Total costs**	**215,700**	**202,000**	**217,900**	**202,000**	**132,600**	**218,700**	**174,700**	**192,400**	**294,600**	**202,000**	**202,000**	**202,000**

Note: Costs include 2.65 per cent annual inflation over 2016 rates plus overhead at 4.80 per cent.

239. AltaGas explained that all of the 2017 TBS Stations will be complete station replacements because they have multiple component issues, including run-splitting regulators and piping configurations that are incompatible with new regulator systems. In addition, TBS Station AT031 needs to be relocated because it is located near the bank of the Muskeg Creek in Athabasca and ground indications are that it is sloughing towards the creek. In addition, TBS Station AT007 requires a new building because the existing one is structurally unsound, and TBS Station MN002 needs a new building as the existing one has become mouse-infested.[170]

240. AltaGas provided a brief explanation on how each 2017 TBS Station Refurbishment differs from its 2017 standard. In particular, the forecast costs for TBS Stations BO001 and SE009 are significantly different from the standard. TBS Station BO001 is a 32-year-old station that suffers from frost heaving. AltaGas proposed to remedy this issue with the installation of a line heater, a feature that is not included in the standard. TBS Station SE009, a 46-year-old station, has been classified as a TBS station because it serves a small hamlet (Irvine). However, it is relatively smaller than most TBS stations and does not require a new building structure. Therefore, its forecast replacement costs are expected to be lower than its 2017 standard.[171]

[169] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 232, Table 3.2-7.
[170] Exhibit 20522-X0028, AUI-AUC-2015JUL02-041(b).
[171] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF pages 232-233.

7.2.4.3 PRS Stations

241. AltaGas provided the following 2016 PRS Station forecast cost information:

Table 22. PRS Stations – 2016 forecast costs[172]

Line	Cost element	Typical	TW006	TW007	TW008	SE046	SE060
		($)					
1	AUI labour	17,000	17,000	17,000	17,000	17,000	17,000
2	Site work	2,600	5,100	5,100	5,100	5,100	5,100
3	Fabrication & assembly	5,500	5,500	5,500	5,500	5,500	5,500
	Major components						
4	Valving, piping, fittings	6,000	6,000	6,000	6,000	6,000	6,000
5	Regulators & pressure controls	1,700	1,700	1,700	1,700	1,700	1,700
6	Direct costs	32,800	35,300	35,300	35,300	35,300	35,300
7	Overhead	1,800	1,900	1,900	1,900	1,900	1,900
8	**Total costs**	**34,600**	**37,200**	**37,200**	**37,200**	**37,200**	**37,200**

Note: Costs include 2.65 per cent annual inflation over 2015 rates plus overhead at 5.36 per cent.

242. AltaGas indicated that all five 2016 PRS stations require complete replacement. These stations range from 35 to 53 years old and have obsolete features including numerous threaded fittings in their piping configuration.

243. In response to a Commission IR, AltaGas explained why partial refurbishment of a standard PRS station is not considered a practical or viable option:

> i. The stations are older (i.e. 28 to 49 years) and were constructed using threaded fittings. Over time, many of these threaded fittings leak gas, and repair becomes difficult as the threads deteriorate and are no longer able to provide a leak proof seal. To alleviate this, new stations are constructed with welded joints to eliminate potential leaks at those junctures. To refurbish existing threaded stations with welded fittings would require replacement of the pipe. However, in most instances the old threaded pipe material no longer conforms to present standard specifications and pipe sizing. Consequently, replacement of the station is considered the most practical and cost effective alternative.
>
> ii. In AUI's experience, it is more cost-effective to replace a PRS with a new pre-fabricated unit than to try and change out the piping and regulator(s) in the field. It is also more efficient and safer for AUI personnel to assemble the PRSs in a fabrication shop than to reassemble and attempt to fabricate portions of old piping in the field. For these reasons, most PRS station projects are full replacements.[173]

244. The cost estimates for all of the 2016 PRS stations are uniform and slightly greater than the cost of its 2016 standard PRS station because of additional site work required at each of these stations.

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[172] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 228, Table 3.2-4.
[173] Exhibit 20522-X0028, AUI-AUC-2015JUL02-041(c).

245. AltaGas provided the following table identifying 2017 PRS Station forecast cost information:

Table 23. PRS Stations – 2017 forecast costs[174]

Line	Cost element	Typical	SP277	SP278	BA032	MN009	MN012	MN032	MN040	WS010	WS013
						($)					
1	AUI labour	17,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400
2	Site work	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600
3	Fabrication & assembly	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600
	Major components										
4	Valving, piping, fittings	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100
5	Regulators & pressure controls	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
6	Direct costs	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600
7	Overhead	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
8	**Total costs**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**	**35,200**

Note: Costs include 2.65 per cent annual inflation over 2016 rates plus overhead at 4.80 per cent.

246. AltaGas explained that all nine 2017 PRS Stations Refurbishments also need to be complete station replacements. These stations range from 28 to 49 years old and, similar to the 2016 PRS stations, have obsolete features including numerous threaded fittings in their piping configuration.

247. All of the 2017 PRS Stations Refurbishments are expected to be standard.

248. No other party opposed nor submitted argument relating to the forecast costs of the 2016-2017 Station Replacement projects identified by AltaGas.

Commission findings

249. The Commission finds the detailed unit cost breakdown for a standard PMS, TBS and PRS station to be comparable to the forecasts approved in Decision 2014-373, after adjusting for inflation. Based on the information provided by AltaGas regarding its forecast program scope and costs for 2016 and 2017, including the estimates for each of the stations to be replaced or partially refurbished and the explanations provided by AltaGas regarding the forecast variances to the 2016 and 2017 standards, including the response to AUI-AUC-2015JUL02-039,[175] the Commission accepts the forecast costs of the station refurbishments for 2016 and 2017 as reasonable.

250. Given the above, the Commission finds that the forecast information provided by AltaGas supports a finding that the scope, level, timing and forecast costs for the projects in the station refurbishment program are reasonable, as proposed for 2016 and 2017 and that this program satisfies the project assessment requirement of Criterion 1.

[174] Exhibit 20522-X0010.04, (black line) identifying revisions, PDF page 228, Table 3.2-8.
[175] Exhibit 20522-X0028.

7.3 Projects in the Gas Supply program

7.3.1 Projects approved in Decision 2014-373 for 2014 and completed in 2014

251. In Decision 2014-373, the Commission approved the St. Paul Gas Supply project on a forecast basis. The project was completed in 2014, with a variance of $160,574 (22.8 per cent) above forecast.

252. The actual and approved forecast costs are reproduced in the following table:

Table 24. 2014 Gas Supply program – actual vs. approved forecast[176]

Line	Location	2014 additions		
		Approved	Actual	Variance
		($)		
1	St. Paul - Cork Hall	703,300	863,874	(160,574)

253. AltaGas provided a table detailing the St. Paul approved costs, actual costs and cost variances. This table has been reproduced below:

Table 25. 2014 St. Paul Gas Supply project variances[177]

Line	Description	Approved	Actual ($)	Variance	Variance (%)
1	AUI labour	108,900	200,356	(91,456)	-84
2	Materials	155,500	174,646	(19,146)	-12
3	Land payments	-	15,093	(15,093)	
4	Contractor	398,500	424,392	(25,892)	-6
5	Total direct costs	662,900	814,487	(151,587)	-23
6	Overhead	40,400	49,387	(8,987)	-22
7	Total project costs	**703,300**	**863,874**	**(160,574)**	-23

254. AltaGas attributed the increase in costs to circumstances outside of its control, including:

- wet weather conditions resulting in the need for additional time to complete the work
- a required new PRS station block valve to connect aluminum pipe to steel high pressure pipeline
- an unexpected price increase from the line heater supplier
- land access payments caused by higher than anticipated site damage related to the wet weather
- land acquisition costs not originally identified in the project estimate to accommodate the new station[178]

255. No interested party opposed nor submitted argument related to the costs of this project.

[176] Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraph 202, Table 4.1.
[177] Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraph 202, Table 4.1-1.
[178] Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraphs 208-214.

Commission findings

256. The Commission accepts AltaGas' evidence explaining the differences between the forecast costs and the actual costs, and finds the variance explanations to be reasonable. The Commission has reviewed the actual scope, level, timing and costs of the work undertaken by AltaGas on the St. Paul Gas Supply project, and finds that it was prudently incurred. Accordingly, the Commission finds that this project satisfies the project assessment requirement of Criterion 1 for 2014.

7.3.2 Gas Supply project trailing costs

257. AltaGas provided a table detailing the Gas Supply program trailing costs incurred in 2014, which is reproduced below.

Table 26. 2014 Gas Supply program trailing costs[179]

Gas Supply - Trailing Costs		2014	2014 actual additions ($)							
Line	Project	approved ($)	Labour	Other contractor	Land payments	Materials	Tendered contractor	overhead	Total	Variance ($)
1	Morinville AT078	-	767	19,287	-	-	-	236	20,290	(20,290)
2	(Suncor) WS081	-	5,206	36,203	2,600	3,457	(6,835)	2,390	43,020	(43,020)
3	(Westlock) total	97,229	37,204	24,895	-	5,938	-	5,981	74,018	23,211
4		97,229	43,177	80,385	2,600	9,395	(6,835)	8,607	137,328	(40,099)

258. AltaGas explained that the $137,238 of prior year Gas Supply project trailing costs were incurred for final clean-up costs, overall civil site work, and other miscellaneous costs for final adjustments to equipment, fencing and paint touch ups.[180]

259. In response to Commission IRs, AltaGas provided additional information on each of the three trailing cost projects. When providing its response, AltaGas discovered an error respecting the trailing costs reported for Morinville and proposed a solution to address the error:

> The trailing costs identified in the above Tables for the Morinville Gas Supply Project were coded to the incorrect work order and are not related to this 2012 project. The costs are for a station building and should have been coded to the MN017 station project completed in 2014. AUI proposes to reflect the corrected adjustments as part of its Compliance Filing for this Application. As the same utility account would be affected, there should be little, if any, impact on the net K Factor adjustment for 2014.[181]

260. The Suncor trailing costs were due to:

- AltaGas labour related to site final cleanup, backfilling of all underground piping, snow removal and final commissioning.
- Materials costs including miscellaneous small fittings and tubing for instruments, gravel for final site grading, and nitrogen for purging all systems of natural gas prior to commissioning and final abandonment of retired piping.

179 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraph 202, Table 4.2-1.
180 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraph 215.
181 Exhibit 20522-X0028, AUI-AUC-2015JUL02-015 b).

- Tendered contractor costs credit adjustment, as work was completed by AltaGas labour rather than third-party contractors.
- Other contractor costs including work-related fence supply and installation, heavy equipment rental for unloading and installing station, building installation, hydrovac truck to expose underground piping, onsite X-ray inspection of welded steel piping joints, fence supply and installation, and commissioning and site testing of all equipment.
- Final land payment to a landowner for land access and damages.

261. The Westlock trailing costs were due to:

- AltaGas labour related to site preparation/snow removal/site cleanup after all work was completed, excavation of existing underground infrastructure, install new PRS and new risers on site, backfill open excavations, commission and test all equipment, connect portable/mobile CNG trailers to maintain gas delivery to customers and continuous monitoring of distribution system while working on site.
- Other contractor costs including data-logging equipment rental for monitoring gas system during installation, fence supply and installation, fabrication of PRS, hydrovac truck rental to expose underground piping, site welding services for PRS and block valve installation, specialized X-ray of onsite welded steel pipe joints, heavy equipment rental for PRS and block valve installation, and final site cleanup and sand bedding for all underground piping, commissioning/testing and portable CNG trailer rentals.
- Materials costs including miscellaneous steel fittings, piping to fabricate PRS, and sand for site preparation and final grading.[182]

262. No interested party opposed nor provided argument related to these trailing costs.

Commission findings

263. The Morinville project was a 2012 project and the costs were approved in Decision 2013-435. The Commission accepts AltaGas' explanation for the Morinville trailing costs error and considers that the compliance filing is a suitable venue to address the error. AltaGas is directed to correct the error in its compliance filing and provide a full explanation and financial calculations and schedules, as needed, for any potential K factor adjustments.

264. The Suncor project spanned 2013 and 2014. In the application leading to Decision 2014-373, AltaGas requested recovery of 2013 actual costs of $741,536 and indicated that an additional $13,117 was incurred in January of 2014. The 2013 costs of $741,536 for the Suncor project were approved in Decision 2014-373.

265. The Westlock project also spanned 2013 and 2014. In the application leading to Decision 2014-373, AltaGas requested recovery of 2013 actual costs of $286,088 and indicated that an additional $99,700 was incurred in January of 2014 for additional work required to complete the facility that could not be done until gas was flowing through the new interconnection, and for final site clean-up. The 2013 costs of $286,088 for the Westlock project were approved in Decision 2014-373.

[182] Exhibit 20522-X0028, AUI-AUC-2015JUL02-015 and 016.

266. With respect to the Suncor and Westlock trailing costs, at paragraph 302 of Decision 2014-373, the Commission said:

> 302. The Commission assumes that the $13,117 of the Suncor Athabasca gas supply costs and the $99,700 of Westlock gas supply site clean-up work that was completed in 2014 will be presented as 2013 trailing costs in AltaGas' 2014 capital tracker true-up application.

267. In the application, the actual costs for Suncor and Westlock were $43,020 and $74,018, respectively. The Suncor costs were $29,903 higher than forecast and the Westlock costs were $25,682 lower than forecast.

268. At paragraph 113 of Decision 2014-373, the Commission directed:

> 113. In order to demonstrate the prudence of the trailing costs, the Commission agrees with the UCA that the company should be required to show the prior year trailing costs clearly in its capital tracker true-up applications. In future capital tracker true-up applications, the Commission directs AltaGas to identify the specific prior-year project to which the trailing costs relate, identify the activities that give rise to the trailing costs, and fully support the prudence of the requested amounts.

269. AltaGas explained the Westlock trailing costs in the proceeding leading to Decision 2014-373 but did not explain the variance in the forecast costs and the actual costs presented in the current application. AltaGas has yet to explain the Suncor project trailing costs and did not provide a variance explanation for the difference between the forecast and actual costs.

270. With respect to the projects listed above for which trailing cost explanations were not provided at a project level, at paragraph 113 of Decision 2014-373, the Commission requested that AltaGas identify the specific prior-year project to which the trailing costs relate, the activities that give rise to the trailing costs, and that it fully support the prudence of the requested amounts. AltaGas identified the specific prior-year projects but did not provide specific explanations of the costs incurred to each of these projects. Instead, it provided a generic explanation for the program. The Commission is prepared to accept that AltaGas did not consider its direction for an explanation to also be at the project level and on this basis, it will conditionally approve the trailing costs for these projects. However, AltaGas is directed to provide the missing trailing cost explanations in the compliance filing to this decision. If approved at that time, the Commission would allow the company to include these trailing costs as part of project total costs for the purposes of the K factor calculation.

7.3.3 2016-2017 forecast capital tracker projects

271. AltaGas stated that the timing and priority of gas supply projects is subject to change based on emerging circumstances generally driven by third-party actions or circumstances outside AltaGas' control.

272. In general, the particulars of projects in this program are not as readily known as those identified in AltaGas' other two programs (Pipeline Replacement and Station Refurbishment) because AltaGas is usually not aware in advance what gas supply projects may arise or the scope of what the projects may entail. In this application, AltaGas was able to identify two projects that it anticipates having to undertake during the forecast period. The first project, the BWM project,

is expected to arise due to the anticipated loss of a third-party gas supply. Given the resource requirements anticipated under any of the alternatives it examined, AltaGas expected to commence work on this project in 2015 and to continue work into 2016.

273. The second project, the Calmar project, expected to be required in 2017 would address a loss of gas supply to the Town of Calmar and nearby rural area. This loss of gas supply is driven by the occurrence of severe soil-side pipeline corrosion and the declining effectiveness of the existing cathodic protection on the pre-1957 steel high pressure pipeline as the pipe material continues to deteriorate.[183]

274. AltaGas was able to provide forecast capital additions amounts for the BWM and Calmar Gas Supply projects. As AltaGas explained, a 2015 update was provided for true-up and forecast context purposes. In Decision 2014-373, a placeholder was approved for potential 2015 Gas Supply projects. In the application, AltaGas explained that the BWM project had been identified for the timeframe 2015 to 2016. $1,777,500 of capital additions are projected to be spent on the BWM project in 2015 and a further $1,317,000 of capital additions are forecast to complete the project in 2016. For 2017, $2,069,894 of capital additions were forecast for the Calmar project.[184] The actual and expected flow of these capital additions are summarized in the table below.

Table 27. BWM and Calmar Gas Supply projects capital additions

Item	2015 approved	2015 update	2016 forecast	2017 forecast
	($)			
Opening work in progress	-	-	1,777,500	-
Add: current year expenditures	531,000	1,777,500	1,317,000	2,069,894
Less: transfer to completed plant	(531,000)	-	(3,094,500)	(2,069,894)
Closing work in progress	-	1,777,500	-	-
Total capital additions	531,000	-	3,094,500	2,069,894

7.3.3.1 BWM Gas Supply

275. AltaGas submitted that in order to ensure continued service to the customers in the BWM area, it is exploring all reasonable alternatives, ranging from purchase of the existing supply line to complete bypass through additions to existing AltaGas infrastructure and connections to other third-party suppliers. AltaGas provided its forecast costs as temporary placeholders, pending the outcome of negotiations.[185]

276. AltaGas stated that denial of capital tracker treatment approval for its forecast $3.1 million expenditure for this project will have an adverse effect on its finances. AltaGas argued that its proposed placeholder approach is reasonable because it provides funding to address gas supply issues in a timely manner, recognizing that the project will be required because the third-party suppliers' intention to discontinue operation of a high pressure supply line to the BWM service area by the end of 2016 is unequivocal. AltaGas is requesting the funding now because waiting to apply for funding of the required project as part of a capital tracker true-up application process may take as long as three years from the time the project is

183 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraphs 170-171.
184 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraphs 169 and 173, and Appendix II(e), Calmar Gas Supply project.
185 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraphs 155-156.

completed and placed into service, the true-up application and approval process in 2017 and collection of the shortfall, likely in 2018 rates. In addition, one-time true-up effects, in the absence of forecast costs included in interim rates, will likely result in lumpy effects to customer rates. Further, AltaGas explained that the difference between the approved 2015 K factor placeholder for projects in the Gas Supply projects program of $531,000 and its estimated $1.778 million BWM expenditure in 2015 will already require it to bear a significant funding shortfall.[186]

277. The UCA requested further explanation from AltaGas regarding its forecast. However, in response to a UCA IR, AltaGas indicated that negotiations currently suggest full disclosure may not be possible or permissible before completion of the record for this proceeding. AltaGas, however, anticipated it should be in a position to disclose the business case, 2015 forecast, 2015 actual and 2016 forecast costs as part of its 2015 capital tracker true-up application.[187]

278. The Commission also sought an update on the negotiation process underway and the status of the project. In response to a Commission IR, AltaGas advised:

> AUI continues to conduct a due diligence engineering assessment in accordance with CSA Z662, Annex N. AUI has identified three alternatives for ensuring gas supply to over 6,500 customers in the area currently served by the third-party. AUI considers the placeholders reasonable as they reflect anticipated expenditures based on the least-cost alternative. However, further details cannot be provided at this time to protect the confidentiality of the process and AUI's negotiating position.[188]

279. As of the close of record, AltaGas was still in negotiations with the third-party supplier and, as such, was unable to determine which alternative it had selected. It submitted that the lowest cost option requires total capital investment of $3.1 million, of which approximately 57 per cent would be spent in 2015, with the remainder completed and brought into service in 2016. This option was included in AltaGas' 2016 capital tracker forecast as a BWM placeholder. AltaGas acknowledged that it had yet to file a business case for this project but explained that disclosure of the required information would breach the confidentiality provisions under which the negotiations are taking place and potentially prejudice its negotiating position. AltaGas argued that the requested placeholder is not unreasonable and is consistent with paragraph 304 of Decision 2014-373, in which the Commission recognized the financial effect on the company in the event all recovery was deferred to the applicable true-up filing.

280. AltaGas summarized its position as follows:

> In this instance, there is an identified project which will be required. Even based on the information AUI is able to provide, it is evident this project is entirely consistent with previous gas supply projects. It is outside the normal course, as demonstrated in AUI's Financial Schedules, is driven by the actions of a third party (supplier), is required to sustain safe and reliable service to several thousand customers and, even using the least cost alternative, as reflected in the proposed placeholder, it is clear it will have a material impact on AUI's finances. Accordingly, AUI submits the BWM placeholder should be approved, as filed.[189]

[186] Exhibit 20522-X0030, AUI-UCA-2015JUL02-010(d).
[187] Exhibit 20522-X0030, AUI-UCA-2015JUL02-010(a).
[188] Exhibit 20522-X0028, AUI-AUC-2015JUL02-013.
[189] Exhibit 20522-X0057, AltaGas argument, paragraphs 126 and 128-130.

281. Both the UCA and the CCA opposed the placeholder request of AltaGas for the BWM project.

282. Mr. Shymanski, on behalf of the UCA, submitted that the BWM project should not be approved for capital tracker treatment given that AltaGas had not submitted a business case and, therefore, had not satisfied the project assessment component of capital tracker Criterion 1. In Mr. Shymanski's view, using a placeholder amount until further justification is provided defeats the purpose of the requirement outlined in paragraph 1092 of Decision 2013-435 under Criterion 1 for capital tracker treatment.

283. Mr. Shymanski made the following comment on materiality and financial effect to the company:

> While AUI has stated that denial of Capital Tracker treatment will have a material and adverse impact on AUI's finances, it has not provided any evidence of the impact of a full or partial denial of this project on AUI's earnings, and whether such impact would result in undue financial hardship, including a downgrade in AUI's ability to borrow money.

284. The UCA submitted:

> … The UCA recognizes that AUI has indicated that it cannot provide information respecting the BWM Gas Supply Project due to confidentiality issues. However, it is unclear why AUI is unable to indicate the associated costs for each of the alternatives it has identified ("ranging from purchase of the existing line to complete bypass through additions to existing AUI infrastructure"), or provide at least a general overview of why the proposed alternative (with a cost of approximately $3.1 million) is appropriate.[190] [footnotes removed]

285. Mr. Shymanski recommended that if this project was necessary from the point of view of AltaGas and its customers, AltaGas should complete the project as proposed and apply for capital tracker treatment once it is completed or once a complete business case can be provided that supports the alternative selected by AltaGas and the associated costs.[191]

286. The CCA supported the evidence and the conclusions of the UCA on this matter, arguing that apart from AltaGas' statement that denial of the placeholder would affect AltaGas' finances, there was no evidence supporting this assertion. It argued that the placeholder requested by AltaGas for the BWM project should be rejected and AltaGas should be directed, in the capital tracker compliance filing, to remove the BWM project costs because it had failed to:

- provide a business case and engineering study
- support its assertion that there would be significant financial effects to the company if the placeholder was not approved
- provide the nature, scope, location, timing and cost of the project as required by Decision 2013-435

190 Exhibit 20522-X0060, UCA argument, paragraph 13.
191 Exhibit 20522-X0042.03, UCA revised evidence, A20.

- provide a detailed forecast of costs for the project or project components, in sufficient detail to allow an evaluation of the reasonableness of the forecast as required by Decision 2013-435
- provide a discussion of any reasonable alternatives, including the rationale for recommending the proposed solution as required by Decision 2013-435
- identify the assets in question
- provide other information required in paragraph 1092 of Decision 2013-435
- take advantage of confidentiality processes available before the AUC[192]

287. Additionally, the CCA argued that because AltaGas did not know the outcome of the negotiations, it did not know whether all three of the alternatives it had identified are available.[193]

288. In response, AltaGas argued:

> … AUI has made it very clear why it is unable to indicate the associated costs for each of the alternatives it has identified. The basic reason, as stated in AUI's Application, several Information Responses and Argument, is because the alternatives under consideration involve buy-or-build decisions for several segments of the gas supply pipeline infrastructure. [e.g. AUI-UCA-2015JUL02-009, AUI-UCA-2015JUL02-010].
> The alternative selected will ultimately depend on the physical condition of certain assets owned by third parties. The price third parties will charge for such assets is likely to be influenced by their perception of the amount AUI may be willing to pay for them relative to AUI's cost to construct such facilities. Therefore, disclosing detailed forecast costs of every option at this time is premature and would negatively impact AUI's bargaining position, potentially resulting in higher project costs and adversely affect customer rates.[194]

7.3.3.2 Calmar Gas Supply

289. AltaGas provided the following background on the Calmar pipeline:

> … This pipeline was constructed in the early 1950's, using uncoated steel with no cathodic protection. Cathodic protection was not applied until about 1957, when the industry adopted the practice of installing rectifiers to minimize the effects of external soil-side corrosion. However, degradation of the bare pipe wall had already begun.
>
> Since 1957, AltaGas has continued to add rectifiers and increase current on this line in an effort to minimize, or at least slow, the corrosion of this bare steel pipeline. Severe corrosion, pipe wall material loss, weld corrosion and failures have caused AUI to repair corrosion leaks and replace short sections of the most severely corroded pipe in this area.
>
> Pre-1957 steel HP and distribution pipe was installed using welding techniques methods inferior to modern industry standards. As a result, many welds are porous, further increasing the risks of corrosion and weld failure.[195]

192 Exhibit 20522-X0058, CCA argument, paragraph 13.
193 Exhibit 20522-X0058, CCA argument, paragraph 13.
194 Exhibit 20522-X0063, AltaGas reply argument, paragraph 7.
195 Exhibit 20522-X0010, application, Appendix II(e), Calmar Gas Supply project, Section 2.0, background.

290. AltaGas submitted that it had considered the relative merits of four alternatives to replace the gas supply that will be lost due to the unacceptable corrosion problems being experienced on the pipeline that serves the Town of Calmar and nearby rural area. The first alternative is the status quo, which AltaGas submitted is not a viable option because the existing pipelines have deteriorated to a point where continued reliable service is no longer possible. The second alternative, derating the pipeline to a lower pressure, is not viable because the pipeline would not have the capacity to support AltaGas' 884 residential and commercial customers in the Town of Calmar and the 436 rural customers southwest of the City of Leduc at distribution pressures. The third alternative, replacing the existing pre-1957 high pressure steel pipelines and associated noncertified PE and PVC services, was a possible technical solution but is not the most cost effective solution as it had an estimated cost of around $4.26 million. The fourth alternative, moving gas supply and replacing selected sections of the pipeline, estimated at $2.07 million, is the most cost effective solution that also met its technical requirements and obligation to provide safe, secure, reliable gas supply to the Town of Calmar and nearby rural customers. This is the alternative proposed by AltaGas for acceptance.

291. AltaGas further described its proposed alternative. AltaGas owns a high-pressure steel pipeline near the south boundary of the Town of Calmar with the capacity to serve the Town for the foreseeable future. Calmar would be served from the southern high pressure pipeline and the uncoated, corroded pre-1957 high pressure pipeline would be abandoned, with only a small section being replaced to maintain supply to rural customers between Calmar and Leduc.[196]

292. AltaGas provided a breakdown of the cost estimates for the third and fourth alternatives in the business case.[197] In response to a Commission IR, AltaGas provided some additional information for these two alternatives. This information, for the fourth alternative, the preferred alternative, is reproduced in the two tables below. The first table provides the available details supporting the cost estimate for Alternative 4 of $2.07 million (in 2015 dollars, excluding overheads) and the second table provides the breakdown between the capital additions and cost of removal/retirements:

[196] Exhibit 20522-X0010, application, Appendix II(e), Calmar Gas Supply project, Section 3, alternatives.
[197] Exhibit 20522-X0010, application, Appendix II(e), Calmar Gas Supply project, Section 3.5, financial analysis.

Table 28. Cost estimate for Calmar Gas Supply project alternative number 4[198]

Table 3					
Alternative 4 - Move Gas Supply & Replace Selected Sections	**Pipe length**	**Cost per meter**	**Total pipe replacement cost**	**Land**	**Total project cost**
New pipe, replacements and abandonments	(m)	($/m)	($)	($)	(2015 $)
Replace HP steel between LE332 and LE013 with HP steel	2,000	230	460,000	154,350	614,350
Abandon HP steel from LE006 to LE091	6,200	4	23,250	-	23,250
Replace HP steel between LE012 and LE006 with distribution PE	4,320	75	324,000	13,590	337,590
Construct new distribution PE to accommodate new configuration	4,000	75	300,000	12,570	312,570
Replace bare steel / PVC / non-cert PE lines tapped to Calmar high pressure	5,800	75	435,000	18,240	453,240
Total new pipe, replacements and abandonments					**1,741,000**
	Quantity	**Cost per station**	**Total station cost**		**Total project cost**
Station modifications		($)	($)		(2015 $)
Move LE091 to high pressure line south of Calmar and add line heater	1	192,800	192,800		192,800
Modify LE012 to accommodate new configuration	1	32,000	32,000		32,000
Retire stations feeding customers being transferred to local utility	2	11,566	23,132		23,132
Retire stations no longer required with new configuration	7	11,566	80,962		80,962
Total station modifications					**328,894**
Total project cost (in 2015 $, excluding overheads)					**2,069,894**

Table 3 Assumptions: Pipe replacement cost for high pressure steel of $230/m based on historical combined town steel and rural PE installation costs and other pipe types based $75/m on pipe replacement in rural areas (plowing method).

Table 29. Cost breakdown for Calmar Gas Supply project alternative number 4[199]

Table 4			
Alternative 4 - Move Gas Supply & Replace Selected Sections	**Capital additions**	**Cost of removal / retirements**	**Total project cost**
New pipe, replacements and abandonments	(2015 $)	(2015 $)	(2015 $)
Replace HP steel between LE332 and LE013 with HP steel	591,350	23,000	614,350
Abandon HP steel from LE006 to LE091	-	23,250	23,250
Replace HP steel between LE012 and LE006 with distribution PE	321,390	16,200	337,590
Construct new distribution PE to accommodate new configuration	297,570	15,000	$312,570
Replace bare steel / PVC / non-cert PE lines tapped to Calmar high pressure line	431,490	21,750	453,240
Total new pipe, replacements and abandonments	**1,641,800**	**99,200**	**1,741,000**
Station modifications			
Move LE091 to high pressure line south of Calmar and add line heater	183,160	9,640	192,800
Modify LE012 to accommodate new configuration	32,000	-	32,000
Retire stations feeding customers being transferred to local utility	-	23,132	23,132
Retire stations no longer required with new configuration	-	80,962	80,962
Total station modifications	215,160	113,734	328,894
Total project cost (in 2015 $, excluding overhead)	**1,856,960**	**212,934**	**2,069,894**

Table 4 Assumptions: Cost of removal / retirements for pipe projects is based on 5% of total project costs.

198 Exhibit 20522-X0028, AUI-AUC-2015JUL02-045(a), Table 3.
199 Exhibit 20522-X0028, AUI-AUC-2015JUL02-045(a), Table 4.

293. AltaGas also submitted that it had previously identified PVC and non-certified PE replacements in the same area, and construction would be coordinated to address these replacements during the same period to limit potential interruptions and inconvenience to customers and potentially reduce costs related to mobilization/demobilization, where possible.[200]

294. The main risk associated with this project would be AltaGas' ability to secure a suitable TBS station site and right-of-way to connect the new supply to the Town of Calmar distribution network but it did not consider this risk to be significant.[201] In response to a Commission IR regarding this risk, AltaGas further explained that there are several sites south of Calmar, in the area of the high-pressure line, that are viable for this project. In the event that one of those alternative locations is required, there would be no additional associated costs.[202]

295. No other party opposed nor filed argument related to the Calmar project.

Commission findings

296. In Decision 2014-373, the AUC approved a requested forecast placeholder for AltaGas' 2015 Gas Supply program. As explained in that proceeding, the use of a placeholder forecast amount for the Gas Supply program was a reasonable approach and reflective of AltaGas' experience that at least one Gas Supply project is likely to arise in any given year although the particulars related to the Gas Supply project may not be known sufficiently in advance for AltaGas to provide detailed costing information or a business case at the time the placeholder for this program is established.

297. The placeholder amount approved for the 2015 gas supply program in Decision 2014-373 was $531,000. It was determined on the basis of reviewing the costs of similar projects from 2010 to 2013 and calculating the historical average. It was not calculated on the basis of forecast project costs, since in the Gas Supply program, those costs are often not known. The actual Gas Supply program expenditures are then trued-up against actual project costs in subsequent capital tracker true-up proceedings.

298. In the current application, AltaGas was able to provide additional detail respecting the costs of Gas Supply projects it had identified in the Gas Supply program. With respect to the BWM project, the Commission accepts AltaGas' evidence that the project will be required but that it did not file a business case on the basis that doing so could affect its negotiating leverage. The Commission also accepts the evidence of AltaGas that a project cost of $3.1 million, which is the minimum amount that AltaGas has forecast to spend on this project, would impose some level of financial hardship on AltaGas. In addition, the Commission accepts AltaGas' evidence that some spending in 2015 will have been conducted for this program and that the amount will exceed the 2015 placeholder amount already approved for this program.

299. Although AltaGas was able to identify two specific projects for its Gas Replacement program for this test period, the Commission continues to hold the view that, with the exception of the Calmar project, placeholder funding for this program should be based on an averaging methodology, as approved by the Commission in Decision 2014-373. This finding is made

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200 Exhibit 20522-X0010.04, application (black line) identifying revisions, paragraph 172; Exhibit 20522-X0010, application, Appendix II, Calmar business case.

201 Exhibit 20522-X0010, application, Appendix II(e), Calmar Gas Supply project, Section 3.7, risk assessment.

202 Exhibit 20522-X0028, AUI-AUC-2015JUL02-046.

having considered the evidence of AltaGas that at least one gas supply project is typically required every year and that these costs could be potentially significant for some gas supply projects.

300. With respect to the Calmar Gas Supply project, AltaGas was able to provide a business case that includes an explanation of the need for this specific gas supply project, the alternatives examined, and a forecast of the project cost. The Commission has reviewed the information supporting the Calmar forecast and finds it to be reasonable. Therefore, for the purposes of funding the 2017 program, the Commission is prepared to approve a placeholder of $2.07 million, which represents the forecast cost of the lowest alternative presented.

301. With regard to approval of a placeholder amount for 2016, the Commission has calculated a 2016 Gas Supply program placeholder amount using the historical average of Gas Supply projects since 2010, as shown in the table below. Trailing costs have been included for all projects, including those that have not yet been approved, for simplicity purposes for this calculation, and should not be considered at this time as any indication that these trailing costs will be approved. An overhead rate of 5.36 per cent was applied to the 2016 calculation, based on the 2016 overhead rate provided in the application.[203]

Table 30. Gas supply placeholder for 2016

Project year	Gas supply projects	Direct costs ($)	Trailing costs ($)	Total costs ($)
2010	Verdant Valley	303,843	-	303,843
2011	Athabasca	194,679	-	194,679
2012	Morinville	1,364,431	(20,290)	1,344,141
2012	Stettler	867,913	-	867,913
2012	Battle Lake	373,765	-	373,765
2013	Suncor (Athabasca)	691,498	43,020	734,518
2013	Westlock	264,147	74,018	338,165
2014	St. Paul	863,874	-	863,874
Totals		4,924,150	96,748	5,020,898
Average cost per project		627,612		
Overhead at 5.36 per cent		33,640		
Placeholder amount		**661,250**		

302. The Commission approves a 2016 Gas Supply program placeholder in the amount of $661,250, as calculated above. The Commission finds that the Gas Supply program, as proposed for 2016 and 2017, satisfies the project assessment requirement of Criterion 1.

8 Accounting test under Criterion 1

8.1 Accounting test for the 2014 true-up, and 2016-2017 forecast

303. As explained in Decision 2013-435, the purpose of the accounting test is to determine whether a project or program (depending on the approved level of grouping) proposed for capital

[203] Exhibit 20522-X0001, Schedule 7.6.

tracker treatment is outside the normal course of the company's ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project.[204]

304. In Decision 2013-435, the Commission determined that the accounting test should be based on a "project net cost approach," which is sufficient to satisfy the Commission that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy Criterion 1. Under this approach, the extent to which a project is underfunded by the I-X mechanism is calculated by comparing the forecast or actual revenue requirement for that project to the going-in revenue historically associated with a similar type of capital expenditures escalated by I-X and including the impact on revenue of any changes in billing determinants.[205] The Commission referred to the latter component, the impact on revenue of any changes in billing determinants, calculated as the forecast percentage change in billing determinants in any given PBR year as "Q."[206]

305. In the accounting test for the 2014 capital tracker true-up, AltaGas used the 2014 I-X index of 1.59 per cent and the 2014 Q factor of 1.70 per cent,[207] which was approved in Decision 2013-465.[208]

306. In the accounting test for 2016, AltaGas used 1.49 per cent as a placeholder for the I-X index based on the 2015 I-X index, which was approved in Decision 2014-357. In the accounting test for 2017, AltaGas also used the 2015 I-X index value of 1.49 per cent on a placeholder basis. AltaGas submitted that it used 2015 I-X placeholders because the Commission had not approved the 2016 or 2017 I-X index at the time AltaGas submitted the capital tracker application.[209]

307. AltaGas used a 2016 forecast Q factor of 1.72 per cent and a 2017 forecast Q factor of 1.78 per cent:

> 25. AUI has used the most current billing determinants to calculate the customer growth component of the PBR formula and to allocate K Factor adjustments to rate classes. To ensure consistency between the approved 2015 Annual PBR filing and the current 2016-2017 Capital Tracker Application, AUI applied the 2015 billing determinants approved in AUC Decision 2014-357. The 2015 billing determinants incorporate 2014 actual data and 2015 outlook data in forecasting customer billings. The forecast use per customer incorporates actuals from 2012- 2014, as per Decision 2012-237.[210]

308. AltaGas' accounting test model for the 2013 and 2014 capital tracker true-ups and the 2016-2017 capital tracker forecast was provided in Appendix VII to the application.[211] For its accounting test and K factor calculations, AltaGas applied the project net cost approach,

204 Decision 2013-435, paragraphs 149-150.
205 Decision 2013-435, paragraphs 262-263.
206 Decision 2013-435, paragraph 499.
207 Exhibit 20522-X0010, application, Appendix VII, Schedule 9.0.
208 Decision 2013-465: AltaGas Utilities Inc., 2014 Annual PBR Rate Adjustment Filing, Proceeding 2831, Application 1609923-1, December 23, 2013.
209 Exhibit 20522-X0010, application, paragraph 26.
210 Exhibit 20522-X0010, application, paragraph 25.
211 Exhibit 20522-X0010, application, Appendix VII.

excluding the cash working capital component of the calculation, as directed by the Commission in Decision 2013-435.[212]

309. No intervener objected to the I factor or the billing determinants used to calculate the Q factor used in AltaGas' accounting test calculations.

Commission findings

310. The Commission has reviewed AltaGas' schedules that make up its accounting test analysis and finds them to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435.

311. The accounting test and K factor calculations use the I-X index and Q factor as inputs. It is the Commission's preference to use an I-X index that has previously been approved in a separate annual PBR rates adjustment proceeding and a Q factor based on an approved billing determinants forecast, whenever possible. For other aspects of the PBR plans where the I-X index and billing determinant forecasts are used, the values are not subsequently updated to reflect actuals when they become available.

312. The Commission has reviewed the 2014 true-up I-X indices and Q factors used in the accounting test, and finds that AltaGas has correctly used the values approved in the 2014 and 2015 annual PBR rate adjustment proceedings.

313. Regarding the I-X index and Q factor values used for purposes of capital tracker forecast years, the Commission acknowledges that, because the capital tracker applications are typically filed before the September 10 date of the annual PBR rate adjustment filings, a company may be required to estimate the I factor and Q factor for forecast years. This is the case for the accounting test for both the 2016 and 2017 capital tracker forecast. Therefore, in the accounting tests for 2016 and 2017, AltaGas used a placeholder for the I factor based on the approved 2015 I factor. AltaGas' 2016 and 2017 Q factors of 1.72 per cent and 1.78 per cent, respectively, were based on 2014 actual data and 2015 outlook data in forecasting customer billings, and the forecast usage per customer incorporates actuals from 2012-2014. The Commission accepts, in principle, the use of such forecasting methods when the final approved numbers are not available.

314. AltaGas filed its 2016 annual PBR rate adjustment application on September 10, 2015. The filing included AltaGas' 2016 I-X index and billing determinant forecast. In Decision 20823-D01-2015,[213] released on December 16, 2015, the Commission stated that it had reviewed AltaGas' calculation of the 2016 I-X index and AltaGas' forecast 2016 billing determinants and the supporting calculations, and found that the forecasting methodology used is consistent with previous PBR-related applications, and that the resulting 2016 I-X index and forecast billing determinants are reasonable. The 2016 I-X index and billing determinants were, therefore, approved as filed. In order to minimize future true-ups, the Commission directs AltaGas, in its compliance filing to this decision, to use the approved 2016 I-X index and the Q factor based on the forecast billing determinants approved in Decision 20823-D01-2015 for purposes of its 2016 capital tracker forecast accounting test.

212 Exhibit 20522-X0010, application, paragraph 20 and Appendix VII.
213 Decision 20823-D01-2015: AltaGas Utilities Inc. 2016 Annual PBR Rate Adjustment Filing, Proceeding 20823, December 16, 2015.

315. Section 8.2 below addresses the WACC rates used by AltaGas in the accounting test. Subject to determinations on these issues, the Commission is satisfied that AltaGas' accounting test model can be used to demonstrate that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy Criterion 1.

8.2 WACC rate

316. As set out in Section 4.4 of Decision 2013-435, the accounting test, as it relates to revenue calculations, consists of two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. The second component is the revenue requirement calculations based on the forecast or actual capital additions for that project or program for a given PBR year.

317. In the first component of the accounting test for both its 2014 true-up and 2016-2017 forecast capital trackers, AltaGas used the approved going-in WACC rates. In order to determine the portion of the debt requirement funded through I-X, which is reflected in its WACC rate, AltaGas escalated the associated going-in revenue requirement for debt (using the approved weighted average cost of debt of 5.168 per cent) by I-X multiplied by customer growth for the prior and current PBR years, respectively.[214]

318. Consistent with the directions in Decision 3434-D01-2015, for the calculation of its WACC rate, in the second component of its accounting test for the 2014 true-up AltaGas used the 2014 actual weighted average cost of debt of 4.90 per cent, the approved equity thickness of 42 per cent and the approved return on equity (ROE) of 8.3 per cent from Decision 2191-D01-2015.[215] The 2014 actual weighted average cost of debt of 4.90 per cent is a blend of AltaGas' new $20 million and $40 million long-term debt issuances in 2014 with coupon rates of 5.21 per cent and 4.48 per cent, respectively, and its four prior debt issuances dating back to 2009, as shown in supporting rate Schedule 9.1[216] and AltaGas' 2014 Rule 005 filing.

319. The debt issuances in 2014 of $20 million and $40 million were inter-company debt issued by AltaGas to its direct corporate parent, AltaGas Utility Holdings Inc. (AUHI), and were approved in Decision 2014-057.[217] It is AltaGas' practice to obtain long-term debt financing from its ultimate corporate parent, AltaGas Ltd. (AL), through its direct corporate parent, AUHI. In keeping with the finding in Decision 2009-176,[218] AltaGas mirrored the debt rate of its parent, because it was obtaining inter-company debt financing, which in this case was 5.21 per cent for the $20 million debt issuance and 4.48 per cent for the $40 million debt issuance.

320. For the purpose of forecasting its WACC rate in its 2016 and 2017 capital tracker forecast, AltaGas forecast a weighted average cost of debt of 4.637 per cent and 4.538 per cent for 2016 and 2017, respectively. The forecast 2016 and 2017 weighted average costs of debt were based on AltaGas' forecast of its 2015, 2016 and 2017 long-term debt issuances, and all of

214 Exhibit 20522-X001, Schedule 7.2; Exhibit 20522-X003, Schedule 9.1.
215 Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.
216 Exhibit 20522-X0003.
217 Decision 2014-057: AltaGas Utilities Inc., Application for Approval to Issue a Debenture in the Principal Amount of $60,000,000, Proceeding 3035, Application 1610264-1, March 11, 2014.
218 Decision 2009-176: AltaGas Utilities Inc. 2008-2009 General Rate Application Phase I, Proceeding 88, Application 1579247-1, October 29, 2009, paragraph 387.

its prior debt issuances, as shown in supporting rate Schedule 7.2.[219] For the calculation of its 2016 and 2017 weighted average costs of debt, AltaGas assumed that in each of 2015, 2016 and 2017, it will issue new debt at a cost of 4.48 per cent, based on the rate resulting from its most recent actual debt issuance in 2014,[220] in accordance with the Commission's direction in Decision 3434-D01-2015.[221]

321. The CCA opposed AltaGas' calculation of its weighted average cost of debt in the second component of its accounting test in the 2014 true-up. The CCA submitted that AltaGas should be directed to update the rates for its 2014 and 2015 debt issuances to reflect the actual rates of 3.84 per cent plus issue costs that arose from its last issuances. The CCA also recommended that AltaGas' 2016 and 2017 debt issuances should be based on the last actual rates of 3.84 per cent plus issue costs.[222]

322. In support of its position, the CCA referred to paragraph 77 of Decision 3434-D01-2015, where the Commission gave the Alberta distribution utilities the following direction with respect to developing utility forecasts for debt:

> 77. The debt forecasts to be used in the second component of the accounting test for 2016 and 2017 should be based on the best information that is known by the companies at the time they make their forecasts, meaning that they should include the impacts of their most recent actual debt and preferred share issuances in developing their forecasts, along with all outstanding historical debt and preferred share issuances, but the companies are not required to forecast the movement of interest rates in the future.[223]

323. The CCA further argued:

> As referenced in Decision 20590-D01-2015,[[224]] AUI submitted it issued a November 10, 2014 $300 million medium term issue with a coupon rate of 3.84% and a 0.07% issue cost. The application considered a request of AltaGas to issue a 2015 related party intercompany debenture of $15 million at the 3.84% and 0.07% issue cost.[225]

324. AltaGas rejected the CCA's recommendation for actual debt rates for 2014 stating:

> In response, AUI notes the 2014 debt costs used for the true-up already reflect all outstanding issuances for 2014. Therefore, no update of the 2014 actual debt issues is required. In this regard, it appears the CCA's Argument mistakenly suggests the underlying AltaGas Ltd. MTN, issued in November 2014, was mirrored down to AUI that same year. However, as the timing of AUI's debt issuances are driven by the timing of its own capital and working capital requirements, capital structure and operating purposes, it was not necessary for AUI to issue debt after the AltaGas Ltd. MTN was issued in 2014 or in the period prior to August 2015. [Proceeding ID 20823, AUC.CCA-2015OCT05-001] As the November 2014 issuance was the most recent AltaGas Ltd.

219 Exhibit 20522-X0001.
220 Decision 2014-057.
221 Paragraph 77.
222 Exhibit 20522-X0058, CCA argument, paragraph 9.
223 Decision 3434-D01-2015, paragraph 77.
224 Decision 20590-D01-2015: AltaGas Utilities Inc., 2015 Debenture and Common Shares Issue Applications, Proceeding 20590, August 25, 2015.
225 Exhibit 20522-X0058, CCA argument, paragraph 7.

issuance, the $15M debenture issued at the end of August 2015, reflects the tenor and rate of that MTN as and from August 31, 2015.[226]

325. AltaGas also submitted that the CCA's recommendation to update the forecast cost of debt for its 2016 and 2017 debt issuances is not in keeping with the Commission's direction in paragraph 77 of Decision 3434-D01-2015. The rates used for AltaGas' 2016 and 2017 debt issuances were based on the best information available at the time. Since AltaGas did not know the rate or tenor of future debt issuances that would be available at that time, it used the debt rate of 4.48 per cent from its most recent issuance as a proxy. Further, AltaGas argued that the CCA's recommended approach to update selectively one component of the forecast to reflect the 2015 debenture issuance is arbitrary and inappropriate and fails to take into consideration the fact that the forecast cost of debt for 2016 and 2017 will ultimately be subject to true up. Last, it argued that updating only one factor in its forecasts at this point was premature and unwarranted.[227]

Commission findings

326. For the calculation of its 2014 weighted average cost of debt AltaGas used a cost of debt of 5.21 per cent and 4.48 per cent, respectively, for its $20 million and $40 million debt issuances in 2014. The Commission notes that in Decision 2014-057, it approved an inter-company debenture issuance for AltaGas for the amounts of $20 million and $40 million. The Commission also observes that, consistent with the finding in Decision 2009-176, AltaGas mirrored the debt rate of its parent, which in this case was 5.21 per cent for the $20 million debt issuance and 4.48 per cent for the $40 million debt issuance.

327. In Decision 20590-D01-2015, the Commission approved an inter-company debenture issuance of $15 million by AltaGas to AUHI. Although AltaGas' corporate parent, AL, had issued the debentures in November 10, 2014, it had not been mirrored down to AltaGas until August 25, 2015.[228] The reason for this delay was that "as the timing of AUI's debt issuances are driven by the timing of its own capital and working capital requirements, capital structure and operating purposes, it was not necessary for AUI to issue debt after the AltaGas Ltd. MTN was issued in 2014 or in the period prior to August 2015."[229]

328. Based on the above, the Commission accepts AltaGas' evidence that the underlying AL debenture issuance in November 2014 was not mirrored down to AltaGas that same year. Moreover, the Commission approved the issuance of the $20 million and $40 million long-term debt in Decision 2014-057 at the rate of 5.21 per cent and 4.48 per cent, respectively, which was mirrored down to AltaGas for its 2014 debt issuance.

329. At paragraph 89 of Decision 3434-D01-2015, the Commission determined that "…the embedded debt rate used in the second component of the accounting test in the true-up process should match the rate that appears on the company's Rule 005 filing from the associated year, and if it does not match, the Commission directs the company to provide an explanation of why it does not match, in its capital tracker true-up application." Therefore, the Commission will accept, in the absence of any evidence that the actual incurred cost of debt was not reasonable, the company's embedded debt rate that appears on the company's Rule 005 filing from the

[226] Exhibit 20522-X0063, AltaGas reply argument, paragraph 10.
[227] Exhibit 20522-X0063, AltaGas reply argument, paragraphs 11-13.
[228] Decision 20590-D01-2015, paragraph 15.
[229] Exhibit 20522-X0063, AltaGas reply argument, paragraph 10.

associated year for purposes of the second component of the accounting test in the capital tracker true-up process. This approach recognizes the PBR incentives provided in Decision 2012-237, which allow companies to manage their businesses during the PBR term, to be followed by a prudence review upon re-basing or in a future rate application. Accordingly, the prudence of the debt rates reported in the company's Rule 005 filing during the PBR term will be included in the prudence review at the time of rebasing for purposes of establishing the going-in rates on a go-forward basis for the next generation PBR plan or in a general rate application.

330. AltaGas' 2014 weighted average cost of debt of 4.90 per cent is a blend of AltaGas' $20 million and $40 million long-term debt issuances in 2014 with coupon rates of 5.21 per cent and 4.48 per cent, respectively, and its four prior debt issuances dating back to 2009, as set out in AltaGas' 2014 Rule 005 filing. The Commission has dismissed the CCA's objections with respect to the 2014 debt rates and no other objections have been received regarding the reasonableness of the 2014 debt issuances from parties in this proceeding. Accordingly, based on the evidence filed in this proceeding, the Commission finds that for the purposes of the 2014 capital tracker true-up accounting test, it is reasonable for AltaGas to use the cost of debt of 5.21 per cent and 4.48 per cent for its $20 million and $40 million 2014 long-term debt issuances, in the calculation of the weighted average cost of debt.

331. With regards to the forecast cost of debt for 2016 and 2017, the Commission finds the directive given by the Commission in paragraph 77 of Decision 3434-D01-2015 to be instructive. In that decision, the Commission directed utilities to use their most recent actual debt and preferred share issuances in developing their forecasts. At the time of filing this application, AltaGas had not received approval for its 2015 debt issuance, which was granted in Decision 20590-D01-2015 and released on August 25, 2015. Consequently, the 2014 debt rate of 4.48 per cent, which the Commission found to be reasonable earlier in this section, was AltaGas' most recent rate at the time of developing its forecasts for the application. Therefore, for the purposes of this accounting test, the Commission finds it reasonable for AltaGas to use the weighted average cost of debt of 4.637 per cent and 4.538 per cent in its 2016 and 2017 forecast capital tracker accounting tests, respectively, based on the assumption that in each of 2015, 2016 and 2017, it will issue new debt at a cost of 4.48 per cent.

332. While this cost of debt is higher than the cost of debt discussed in Decision 20590-D01-2015, the Commission in that decision did not approve the coupon rates of 3.84 per cent and a 0.07 per cent issue cost and made the following finding:

> 25. However, the onus still resides with AUI to demonstrate that the actual debt issuance was obtained prudently. Given the changing market conditions between November 2014 and August 2015, the Commission is concerned that mirroring the coupon rate of the AL $300 million 10-year MTN to the AUI 2015 Debenture may not be reflective of the market conditions in August 2015. The Commission previously commented on a similar issue in Decision 2012-091, when it stated "The Commission considers that the relevant test associated with interest rates for debentures is an assessment of the prudence of the interest rates at the time that AltaGas received the proceeds, not when AL received the proceeds." Consequently, AUI is directed to discuss the prudence of mirroring the coupon rate incurred by AL for its $300 million 10-year MTN to the AUI 2015 Debenture in its next cost of service application where the full revenue requirement of the company is considered for rate-setting purposes, whether that be a performance-based

> regulation rebasing, a full general rate application (GRA) or some other application.[230] [footnote removed]

333. Earlier in this section, the Commission indicated that in the absence of any evidence that the actual incurred cost of debt was not reasonable, it will accept the company's embedded debt rate that appears on the company's Rule 005 filing from the associated year for purposes of the second component of the accounting test in the capital tracker true-up process. Given an issue with respect to AltaGas' 2015 debt issuance noted by the Commission in Decision 20590-D01-2015, referenced above, the Commission will review the reasonableness of AltaGas' 2015 debt costs at the time of its 2015 capital tracker true-up application. Accordingly, AltaGas is directed to provide in its 2015 capital tracker true-up application, information supporting the actual weighted average cost of debt included in the capital tracker true-up accounting test for 2015, including information relating to the particulars of debt issuances by AltaGas within that year. This information should be consistent in form and content with the information filed by AltaGas in previous general rate applications in support of its application for approval of its weighted average cost of debt.

334. Having considered all of the evidence on record, the Commission finds that by reflecting the going-in, actual and forecast debt rates, ROEs and capital structures, in the first and second component of its accounting test, AltaGas has conformed with the directions given in Decision 3434-D01-2015 and Decision 2191-D01-2015.

8.3 Commission's conclusions on Criterion 1

335. In Section 8.1 of this decision, the Commission found the form of AltaGas' accounting test model to be reasonable and consistent with the accounting test methodology approved in Decision 2013-435. However, the Commission directed some changes with respect to AltaGas' accounting test assumptions related to the I-X index and Q factor values for 2016.

336. In Section 8.2, the Commission confirmed that AltaGas accurately reflected the WACC rate assumptions resulting from Decision 3434-D01-2015 and the updated equity thickness and ROE as determined in Decision 2191-D01-2015. Also in Section 8.2, the Commission found it reasonable for AltaGas to use the forecast cost of debt of 4.48 per cent for its 2015, 2016 and 2017 debt issuances in the calculation of the weighted average cost of debt for the 2016 and 2017 capital tracker forecast.

337. Although the Commission finds the general form of AltaGas' accounting test model to be reasonable and consistent with the methodology approved in Decision 2013-435, until the accounting test assumptions related to the I-X index and Q factor values for 2016 are updated, the Commission cannot make a determination in this decision as to whether any of AltaGas' projects or programs proposed for capital tracker treatment in 2016-2017 on a forecast basis satisfy the accounting test requirement of Criterion 1 and accordingly, whether any of AltaGas' projects or programs satisfy Criterion 1 in its entirety.

338. The Commission directs AltaGas, in its compliance filing to this decision, to revise its accounting test for 2016-2017, based on approved final forecast or actual capital additions approved in this decision (for example, the reduction to the applied-for 2016 BWM Gas Supply project forecast amount) and the 2016 accounting test model assumptions.

[230] Decision 20590-D01-2015, paragraph 25.

9 Criterion 2 – Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

339. With respect to Criterion 2, the Commission clarified in Decision 2013-435 that, in addition to asset replacement projects and projects required by an external party, a growth-related project will satisfy the requirements of Criterion 2 where it can be demonstrated that customer contributions, together with incremental revenues allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, are insufficient to offset the revenue requirement associated with the project in a PBR year.[231] Certain projects for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party related categories might also satisfy Criterion 2 in certain circumstances as discussed in Section 3.2.4 of Decision 2013-435.[232]

340. As set out in Section 3 of this decision, for the purposes of the true-up of the 2013 and 2014 capital tracker projects or programs for which the Commission undertook the assessment against the Criterion 2 requirements in Decision 2014-373, unless the driver (replacement of existing assets, external party, growth, other) for the project or program has changed, there is no need to undertake a reassessment against the Criterion 2 requirements. AltaGas confirmed that the drivers of its capital tracker program have not changed.[233] As such, AltaGas did not provide any additional evidence on how the previously approved capital tracker projects or programs included in the 2014 true-up satisfy the requirements of Criterion 2.

341. AltaGas provided information in support of how the projects or programs proposed for capital tracker treatment in 2016-2017 on a forecast basis satisfy the requirements of Criterion 2. Table 31 below provides a summary of AltaGas' evidence with respect to Criterion 2 in support of the 2016-2017 capital tracker forecast.

Table 31. Applied-for 2016-2017 capital tracker projects or programs and Criterion 2 requirements

Project name	Criterion 2 project type	Application paragraph
Applied-for projects or programs previously approved for capital tracker treatment		
Pipe replacement program	Replacement	48-50
Stations	Replacement	122-124
Gas supply	External party driven/replacement	162-164

342. No party took issue with AltaGas' evidence referenced in the table above in support of how the projects or programs proposed for capital tracker treatment in 2016-2017 on a forecast basis satisfy the requirements of Criterion 2.

Commission findings

343. Upon review of the 2013 actual cost information and variance explanations, the Commission concludes that the drivers have not changed for any of AltaGas' projects or programs approved in Decision 2014-373, so as to warrant a reassessment under Criterion 2. The

[231] Decision 2013-435, paragraph 309.
[232] Decision 2013-435, paragraph 314.
[233] Exhibit 20522-X0010, application, Appendix IV, paragraph 25.

Commission finds that these 2013 projects or programs continue to satisfy the requirements of Criterion 2.

344. Similarly, the Commission also finds that the driver or drivers for each project or program included in AltaGas' 2014 capital tracker true-up have not changed and there is no need to undertake a reassessment of these projects or programs against the Criterion 2 requirements.

345. With regard to the forecast capital projects for 2016 and 2017 proposed for capital tracker treatment, as summarized in Table 31 above, the Commission finds that the driver for each of AltaGas' proposed capital tracker projects and programs falls into one or more of the following Criterion 2 categories: asset replacement or refurbishment; or requirement by an external party. Accordingly, the Commission finds that AltaGas' programs presented in Table 31 above satisfy the requirements of Criterion 2.

10 Criterion 3 – The project must have a material effect on the company's finances

346. Section 8 of this decision addressed AltaGas' accounting test, which determines whether all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy Criterion 1. This is established by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program proposed for capital tracker treatment.

347. In accordance with the Commission determinations set out in Decision 2013-435, the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test, is then assessed against the two-tiered materiality test under Criterion 3. The first tier of the materiality threshold, a "four basis point threshold," is applied at a project level, grouped in the manner approved by the Commission. The second tier of the materiality threshold, a "40 basis point threshold," is applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.[234]

348. In Decision 2013-435, the Commission calculated the four basis point threshold and the 40 basis point threshold based on a respective dollar value of AltaGas' ROE in 2012. The Commission indicated that in subsequent PBR years, the four basis point threshold and the 40 basis point threshold are to be calculated by escalating the dollar value of a respective amount in 2012 by I-X.[235]

349. For the 2014 true-up, AltaGas used a four basis point threshold of $31,816 and a 40 basis point threshold of $318,156, calculated by escalating the 2012 amount by the approved 2013 and 2014 I-X index values.[236] AltaGas then assessed each of capital tracker projects included in the 2014 true-up against the four basis point threshold, in accordance with the requirements set out in paragraphs 503 to 506 of Decision 2013-435. AltaGas submitted, based on the same groupings

[234] Decision 2013-435, paragraphs 382-385.
[235] Decision 2013-435, paragraphs 378 and 384.
[236] Exhibit 20522-X0010, application, paragraph 33; Exhibit 20522-X0003, schedules 8.1 and 9.0.

of projects previously approved, the 2014 actual additions for each of the 2014 capital tracker programs exceeded the materiality thresholds for K factor treatment.[237]

350. For the 2016-2017 capital tracker forecast, AltaGas calculated the materiality thresholds following the methodology set out in Decision 2013-435. However, as discussed in Section 8.1, since at the time of the filing of the application AltaGas did not have the approved I factors for either 2016 or 2017, it used the 2015 I-X of 1.49 per cent, which was approved in Decision 2014-357, as a placeholder.

351. AltaGas calculated the four basis point threshold for 2016 to be $32,771 and the 40 basis point threshold to be $327,707 by escalating the 2012 amounts by the approved I-X index values for 2013, 2014 and 2015 as well as the forecast I-X index values for 2016. Using the same methodology, AltaGas calculated the 2017 four basis point threshold to be $33,259 and the 40 basis point threshold to be $332,590.[238]

352. AltaGas then assessed each of its capital tracker programs included in the 2016 and 2017 forecast against the four basis point threshold, and the total K factor amount associated with all capital tracker projects or programs in each of those years against the 40 basis point threshold. AltaGas submitted that its proposed capital tracker projects or programs exceed the materiality thresholds for K factor treatment.[239]

353. No party took issue with AltaGas' calculation of its materiality thresholds under Criterion 3.

Commission findings

354. As discussed in Section 8.1, the Commission accepts AltaGas' forecasting methodology. As the 2016 I-X index of 0.90 per cent was approved in Decision 20823-D01-2015, in order to minimize future true-ups, the Commission directs AltaGas, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent and approved Q factor to calculate the first and second tier materiality thresholds for 2016.

355. The Commission has reviewed AltaGas' calculations, and finds that AltaGas has interpreted and reasonably applied the Criterion 3 test for the purpose of its 2014 true-up and 2016-2017 capital tracker forecast. However, as discussed earlier, the two-tiered materiality test under Criterion 3 is applied to the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test. In Section 8.3, the Commission directed AltaGas, in its compliance filing to this decision, to revise its accounting test based on approved 2016-2017 forecast capital additions and the 2016 model assumptions. Accordingly, because AltaGas' accounting test for each of 2016 and 2017 needs to be revised, the Commission cannot determine in this decision whether any of AltaGas' projects or programs proposed for capital tracker treatment in 2016-2017 on a forecast basis satisfy the materiality test requirement of Criterion 3.

356. Given these findings, the Commission directs AltaGas, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in

237 Exhibit 20522-X0010, application, paragraph 34; Exhibit 20522-X0003, schedules 8.0 and 8.1.
238 Exhibit 20522-X0010, application, paragraph 33; Exhibit 20522-X0001, schedules 7.0 and 7.1.
239 Exhibit 20522-X0010, application, paragraph 34; Exhibit 20522-X0001, schedules 1.0, and 2.0.

2016-2017 on a forecast basis satisfy the two-tiered materiality test requirement of Criterion 3. For this reassessment, AltaGas will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above.

11 K factor calculations for 2013 true-up, 2014 true-up, and 2016-2017 forecast

357. Table 32 below details the 2013 and 2014 approved and actual K factors by program, and resulting variances applied for in this application as K factor adjustments. The 2013 K factor calculations reflect the 2013 projects that were not approved for capital tracker treatment in Decision 2014-373 and were reapplied for in the current application. The resulting net adjustment to the K factor is an $11,217 refund to customers. This amount was included in AltaGas' 2016 annual PBR rate application and approved in Decision 20823-D01-2015.

358. For the 2014 capital tracker true-up, AltaGas calculated an actual 2014 K factor of $1,790,620. In Decision 2014-373, the Commission approved an AltaGas forecast K factor of $2,184,474, on an interim basis. AltaGas included this amount in the application and calculated ($393,854) as the required K factor adjustment. Subsequent to the filing of the application, the Commission issued compliance Decision 20176-D01-2015, incorporating several adjustments to the 2014 forecast K factor, and approving an updated K factor forecast in the amount of $1,983,426. This amount was included in AltaGas' Rider F application and approved in Decision 20695-D01-2015. The Commission has reflected this in column F of Table 32 below and calculated an updated K factor adjustment of $192,806. AltaGas included the $393,854 in its 2016 annual PBR interim rates and the Commission approved this amount in Decision 20823-D01-2015.

Table 32. Applied-for 2013 and 2014 K factor true-up adjustments

		2013 K factor adjustment			2014 K factor adjustment			
Line	Program	2013 approved forecast K factor[240]	2013 actual K factor[241]	2013 K factor adjustment	2014 approved forecast K factor[242]	2014 updated approved forecast[243]	2014 actual K factor[244]	2014 K factor adjustment
		A	B	C = A - B	D	E	F	G = F - E
		($)						
1	Pipe Replacement	509,195	499,350	(9,845)	1,629,510	1,477,128	1,392,492	(84,636)
2	Station Refurbishment	68,270	66,898	(1,372)	246,273	217,941	118,917	(99,024)
3	Gas Supply	179,810	179,810	-	308,691	288,357	279,211	(9,146)
4	Total	757,275	746,057	(11,217)	2,184,474	1,983,426	1,790,620	(192,806)

359. As summarized in Table 33 below, AltaGas calculated the 2016 and 2017 forecast K factors to be $5,854,585 and $8,483,831, respectively.

240 Proceeding 20176, Exhibit X0002.01, Schedule 1.0.
241 Exhibit 20522-X0003, Schedule 11.0.
242 Exhibit 20522-X0003, Schedule 1.0.
243 Proceeding 20176, Exhibit 20176-X0003.01, Schedule 1.0.
244 Exhibit 20522-X003, Schedule 1.0.

Table 33. Applied-for 2016 and 2017 K factor amounts

Program	2016 forecast K factor ($)[245]	2017 forecast K factor ($)[246]
Pipe replacement	4,576,133	6,691,069
Station refurbishment	834,824	1,158,493
Gas supply	443,628	634,269
Total	5,854,585	8,483,831

360. For purposes of allocation to rate classes, AltaGas used the same methodology previously approved in Decision 2014-373.

361. There were no objections by interveners to AltaGas' K factor proposals.

Commission findings

362. The Commission has reviewed AltaGas' calculations and finds that AltaGas' methodology to determine the 2013 K factor true-up amount, the 2014 K factor true-up amount and the 2016-2017 K factor forecast amounts to meet the requirements set out in Decision 2012-237 and Decision 2013-435.

363. The 2013 K factor true-up refund amount of $11,217 is approved, as filed.

364. With respect to the 2014 true-up, the difference between the recalculated true-up adjustment of ($192,806) and the ($393,854) adjustment included in AltaGas' 2016 annual PBR rate adjustment application will need to be corrected. Accordingly, AltaGas is directed to file an application for an adjustment to Rate Rider F to collect refund amounts that were approved in Decision 20823-D01-2015 related to the 2014 capital tracker true-up that are in excess of the 2014 capital tracker true-up refund amount that will be approved in the compliance filing to this decision. This Rate Rider F application should be made after AltaGas' compliance filing to this decision is approved.

365. With respect to the 2016 and 2017 forecast K factors, the Commission finds that AltaGas has used the correct inputs in its calculations. The Commission has also reviewed the K factor calculations and is satisfied that the calculations have generally been performed correctly and in accordance with previous Commission directions. The Commission directs AltaGas to update the 2016 and 2017 forecast amounts of $5,854,585 and 8,483,831, respectively, in the compliance filing to this decision to give effect to:

- The 2016 I-X index and the Q factor, as per recently released Decision 20823-D01-2015, as directed in Section 8.1 of this decision.
- The revised BWM gas supply placeholder as calculated by the Commission in Section 7.3.3 of this decision.

366. Because K factor placeholder values in AltaGas' 2016 PBR rates are different from the amounts approved in this decision. AltaGas is directed to include in its next Rider F application,

245 Exhibit 20522-X0001, Schedule 1.0.
246 Exhibit 20522-X0001, Schedule 2.0.

on an interim basis, the 2016 forecast amounts approved in the compliance filing to this decision that are different than the K factor placeholder amounts that have been included in AltaGas' 2016 PBR rates.

12 Compliance with previous Commission directions

367. In Appendix IV to the application, AltaGas provided responses to the Commission's directions from Decision 2014-373, Decision 3434-D01-2015 and Decision 3558-D01-2015. In its filing, AltaGas has identified those directions that have already been responded to in other applications, directions that have been responded to elsewhere in this application and directions that will be responded to in future applications. In this section, the Commission will, therefore, only address responses that have not yet or will not be addressed in another future forum.

Decision 2014-373, paragraph 391

> 391. In future capital tracker applications, in order to demonstrate the reasonableness and prudence of overhead costs, AltaGas is directed to provide its overhead calculations separately, identifying a line item for each of the specific items indicated in its response to CCA-AUI-2(b) in Proceeding No. 3244. The company must also be prepared to explain any significant year-over-year changes in the items that make up the overhead pool. To the extent that a company limits the year-over-year increases to an item in the overhead pool to I-X, as AltaGas has done with inter-affiliate costs, the Commission considers that to be a reasonable approach for capital tracker purposes. However, a company is not required to limit its increases to its overhead items to I-X if it can demonstrate that an increase in excess of this amount is prudent.

368. AltaGas submitted that it complied with this direction, referring to Schedule 7.6 of Appendix VII(c), 2016-2017 Capital Tracker Schedules, to the application. No intervener objected to AltaGas' overhead amounts or calculations.

369. The Commission reviewed the overhead information and calculations provided and finds that AltaGas has complied with this direction.

Decision 2014-373, paragraph 407

> 407. PBR encourages a company to seek out and realize process, operational and capital efficiencies continually with respect to those functions and activities funded under the IX mechanism in order to enhance overall profitability. These activities will in turn benefit ratepayers immediately through the X factor and over the longer term through lower costs than might otherwise be the case. Capital projects funded through capital tracker treatment with a true-up to actual costs are not, however, subject to the same incentives. Accordingly, the Commission requires sufficient information in capital tracker forecast and true-up applications on the proposed capital tracker projects themselves, as well as the processes in place to manage those projects, in order to confirm the need for the project in the manner that is proposed, and to ensure the prudence of the costs incurred. The Commission considers that formal project management policies and procedures are necessary to ensure the Commission understands that the scope, level, timing and costs of forecast capital projects are reasonable and actual costs are prudently incurred. The Commission directs AltaGas to describe fully its formal project management policies and procedures in its next capital tracker application.

370. AltaGas submitted that it complied with this direction and referred to Appendix V of the application where it provided a description of its project management procedures.

371. The Commission has reviewed Appendix V and AltaGas' responses to the Commission's IRs. The Commission finds that AltaGas has implemented and is following formal project management policies and procedures. Specifically, AltaGas' adoption of PRINCE2 (projects in a controlled environment) as its platform for company-wide project management, the detailed description of PRINCE2's principles and its five formal project execution stages, the scalability capability of PRINCE2 to projects ranging from very simple to highly complex, the focus of the PRINCE2 platform on project manager responsibilities, project governance and accountability through the life of the project, compatibility of PRINCE2 with other project management methods, and the description of how PRINCE2 has been integrated into AltaGas' construction and management functions all assisted the Commission in its determination of the reasonableness of AltaGas' forecasts and the prudence of the scope, level, timing and costs of AltaGas' capital projects.

Decision 3558-D01-2015, Appendix 3

372. At paragraph 1092 of Decision 2013-435, the Commission set out a list of minimum filing requirements for capital tracker projects. On December 5, 2014, the Commission initiated proceeding 3558 to review some of the filing requirements for capital tracker applications. This proceeding arose as the result of the various positions advocated on the level of information required to be filed in a capital tracker application by parties in the 2013 true-up and 2014-2015 forecast capital tracker proceedings. In Decision 3558-D01-2015, amongst other things, the Commission established a revised set of minimum filing requirements for the distribution companies. In Appendix 3 to the decision, the Commission set out the revised minimum filing requirements companies must comply with in their capital tracker true-up and capital tracker forecast applications.

373. AltaGas responded to this direction by referring to a table in Appendix I to the application that sets out each of the filing requirements prescribed in Decision 3558-D01-2015 and the location of the applicable information or data.[247] With respect to the revised minimum filing requirements set out in Appendix 3 to Decision 3558-D01-2015, item 1c., evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the CRA, AltaGas stated "AUI will submit evidence of reconciliation when 2014 amounts have been filed with the CRA (due June 30, 2015.)."

374. With the exception of the Commission's conditional approvals of the pipeline replacement trailing costs and the gas supply trailing costs in Sections 7.1.3 and 7.3.2, respectively, and the non-compliance with respect to the CRA materials discussed in this section, the Commission finds that AltaGas has complied with the minimum filing requirements. No evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the CRA has been filed on the record of this proceeding. Accordingly, AltaGas is directed to fulfill this requirement in the compliance filing to this decision.

[247] Exhibit 20522-X0010, application, paragraphs 5 and 10, and Appendix I (reference table for where each minimum filing requirement is addressed in the application), and business cases.

13 Order

375. It is hereby ordered that:

(1) AltaGas Utilities Inc. is directed to file a compliance filing application in accordance with the directions contained within this decision by February 29, 2016.

Dated on January 21, 2016.

The Alberta Utilities Commission

(original signed by)

Neil Jamieson
Panel Chair

(original signed by)

Henry van Egteren
Commission Member

(original signed by)

Kate Coolidge
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
AltaGas Utilities Inc. (AltaGas)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP

Alberta Utilities Commission Commission panel N. Jamieson, Panel Chair H. van Egteren, Commission Member Kate Coolidge, Acting Commission Member Commission staff C. Wall (Commission counsel) P. Howard P. Genderka N. Mahbub G. Nadeau D. Ryan

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. The Commission has reviewed AltaGas' evidence explaining the differences between the 2013 AFE estimates and the actual costs, and finds the variance explanations to be reasonable. The Commission finds that the actual scope, level, timing and costs of the work undertaken by AltaGas in 2013 to be prudently incurred. The Commission finds that these four projects satisfy the project assessment requirement of Criterion 1 for 2013. AltaGas is directed to calculate and include the revenue requirement for these projects, on a 2013 mid-year basis, in its K factor calculations. .... Paragraph 110

2. With respect to the projects listed above for which trailing cost explanations were not provided at a project level, at paragraph 113 of Decision 2014-373, the Commission requested that AltaGas identify the specific prior-year project to which the trailing costs relate, the activities that give rise to the trailing costs, and that it fully support the prudence of the requested amounts. AltaGas identified the specific prior-year projects but did not provide specific explanations of the costs incurred to each of these projects. Instead, it provided a generic explanation for the program. The Commission is prepared to accept that AltaGas did not consider its direction for an explanation to also be at the project level and on this basis, it will conditionally approve the trailing costs for these projects. However, AltaGas is directed to provide the missing trailing cost explanations in the compliance filing to this decision. If approved at that time, the Commission would allow the company to include these trailing costs as part of project total costs for the purposes of the K factor calculation. .... Paragraph 144

3. The Commission finds that these two projects satisfy the project assessment requirement of Criterion 1 for 2013. AltaGas is directed to calculate and include the revenue requirement for these projects, on a 2013 mid-year basis, in its K factor calculations. AltaGas is reminded in future capital tracker applications, when there is a difference in forecast or actual costs between a particular station and the standard station, to include a table showing the build-up of project costs for each station and to compare them to the build-up of project costs in the standard station. .... Paragraph 202

4. The Morinville project was a 2012 project and the costs were approved in Decision 2013 435. The Commission accepts AltaGas' explanation for the Morinville trailing costs error and considers that the compliance filing is a suitable venue to address the error. AltaGas is directed to correct the error in its compliance filing and provide a full explanation and financial calculations and schedules, as needed, for any potential K factor adjustments. .... Paragraph 263

5. With respect to the projects listed above for which trailing cost explanations were not provided at a project level, at paragraph 113 of Decision 2014-373, the Commission requested that AltaGas identify the specific prior-year project to which the trailing costs relate, the activities that give rise to the trailing costs, and that it fully support the prudence of the requested amounts. AltaGas identified the specific prior-year projects but did not provide specific explanations of the costs incurred to each of these projects. Instead, it provided a generic explanation for the program. The Commission is prepared

to accept that AltaGas did not consider its direction for an explanation to also be at the project level and on this basis, it will conditionally approve the trailing costs for these projects. However, AltaGas is directed to provide the missing trailing cost explanations in the compliance filing to this decision. If approved at that time, the Commission would allow the company to include these trailing costs as part of project total costs for the purposes of the K factor calculation. .... Paragraph 270

6. AltaGas filed its 2016 annual PBR rate adjustment application on September 10, 2015. The filing included AltaGas' 2016 I-X index and billing determinant forecast. In Decision 20823-D01-2015, released on December 16, 2015, the Commission stated that it had reviewed AltaGas' calculation of the 2016 I-X index and AltaGas' forecast 2016 billing determinants and the supporting calculations, and found that the forecasting methodology used is consistent with previous PBR-related applications, and that the resulting 2016 I-X index and forecast billing determinants are reasonable. The 2016 I-X index and billing determinants were, therefore, approved as filed. In order to minimize future true-ups, the Commission directs AltaGas, in its compliance filing to this decision, to use the approved 2016 I-X index and the Q factor based on the forecast billing determinants approved in Decision 20823-D01-2015 for purposes of its 2016 capital tracker forecast accounting test. .... Paragraph 314

7. Earlier in this section, the Commission indicated that in the absence of any evidence that the actual incurred cost of debt was not reasonable, it will accept the company's embedded debt rate that appears on the company's Rule 005 filing from the associated year for purposes of the second component of the accounting test in the capital tracker true-up process. Given an issue with respect to AltaGas' 2015 debt issuance noted by the Commission in Decision 20590-D01-2015, referenced above, the Commission will review the reasonableness of AltaGas' 2015 debt costs at the time of its 2015 capital tracker true-up application. Accordingly, AltaGas is directed to provide in its 2015 capital tracker true-up application, information supporting the actual weighted average cost of debt included in the capital tracker true-up accounting test for 2015, including information relating to the particulars of debt issuances by AltaGas within that year. This information should be consistent in form and content with the information filed by AltaGas in previous general rate applications in support of its application for approval of its weighted average cost of debt. .... Paragraph 333

8. The Commission directs AltaGas, in its compliance filing to this decision, to revise its accounting test for 2016-2017, based on approved final forecast or actual capital additions approved in this decision (for example, the reduction to the applied-for 2016 BWM Gas Supply project forecast amount) and the 2016 accounting test model assumptions. .... Paragraph 338

9. As discussed in Section 8.1, the Commission accepts AltaGas' forecasting methodology. As the 2016 I-X index of 0.90 per cent was approved in Decision 20823-D01-2015, in order to minimize future true-ups, the Commission directs AltaGas, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent and approved Q factor to calculate the first and second tier materiality thresholds for 2016. .... Paragraph 354

10. Given these findings, the Commission directs AltaGas, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in 2016-2017 on a forecast basis satisfy the two-tiered materiality test

requirement of Criterion 3. For this reassessment, AltaGas will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above. .... Paragraph 356

11. With respect to the 2014 true-up, the difference between the recalculated true-up adjustment of ($192,806) and the ($393,854) adjustment included in AltaGas' 2016 annual PBR rate adjustment application will need to be corrected. Accordingly, AltaGas is directed to file an application for an adjustment to Rate Rider F to collect refund amounts that were approved in Decision 20823-D01-2015 related to the 2014 capital tracker true-up that are in excess of the 2014 capital tracker true-up refund amount that will be approved in the compliance filing to this decision. This Rate Rider F application should be made after AltaGas' compliance filing to this decision is approved. .... Paragraph 364

12. With respect to the 2016 and 2017 forecast K factors, the Commission finds that AltaGas has used the correct inputs in its calculations. The Commission has also reviewed the K factor calculations and is satisfied that the calculations have generally been performed correctly and in accordance with previous Commission directions. The Commission directs AltaGas to update the 2016 and 2017 forecast amounts of $5,854,585 and 8,483,831, respectively, in the compliance filing to this decision to give effect to:

    - The 2016 I-X index and the Q factor, as per recently released Decision 20823-D01-2015, as directed in Section 8.1 of this decision.
    - The revised BWM gas supply placeholder as calculated by the Commission in Section 7.3.3 of this decision. .... Paragraph 365

13. Because K factor placeholder values in AltaGas' 2016 PBR rates are different from the amounts approved in this decision. AltaGas is directed to include in its next Rider F application, on an interim basis, the 2016 forecast amounts approved in the compliance filing to this decision that are different than the K factor placeholder amounts that have been included in AltaGas' 2016 PBR rates. .... Paragraph 366

14. With the exception of the Commission's conditional approvals of the pipeline replacement trailing costs and the gas supply trailing costs in Sections 7.1.3 and 7.3.2, respectively, and the non-compliance with respect to the CRA materials discussed in this section, the Commission finds that AltaGas has complied with the minimum filing requirements. No evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the CRA has been filed on the record of this proceeding. Accordingly, AltaGas is directed to fulfill this requirement in the compliance filing to this decision. .... Paragraph 374

15. (1).. AltaGas Utilities Inc. is directed to file a compliance filing application in accordance with the directions contained within this decision by February 29, 2016. ... Paragraph 375

Appendix 3 – Detailed risk assessment model[248]

Risk Factor	Scoring										Likelihood of Failure	Impact of Failure	Weighting
Pipe material	0	Certified PE	1	Aluminum	2	Non-certified PE Interim certified PE	3	PVC	4	Bare Steel Mains	Likelihood of failure increases based on susceptibility of the pipe to failure (i.e. by virtue of its composition, age or condition)	Impact of failure is proportionate to the amount of gas released when failure occurs, which is a function of failure mechanics (e.g. shatter vs crack) and line pressure.	1
Population Density (# services/ km within 20 meters of the main)	0	< 50 services/km^2	1	50 - 100 services/km^2	2	100 - 200 services/km^2	3	200 - 500 services/km^2	4	500+ services/km^2	More customers = more fittings and activity around pipe = high propensity for leakage.	Higher population density in proximity to the pipe increases health & safety risk to the public.	= (Pipe Material x .5) multiplied by Population Density
Ground Cover (extent to which pipe is covered by asphalt, concrete or structures)	0	0% - 20% (e.g. Rural)	1	20% - 40% (e.g. Rural subdivisions)	2	40% - 60% (e.g. Hamlets and Villages, paved streets with gravel alleyways)	3	60% - 80% (e.g. Towns, paved streets and alleyways)	4	80% - 100% (e.g. Downtown cores)	Ground coverage generally increases the impact, but not likelihood, of failure.	If leak occurs, detection is more difficult. More ground cover (e.g. pavement) results in more migration of the gas to unfavorable places. Ground cover also increases time to complete repairs.	= (Pipe Material x .5) multiplied by Ground Cover
Locatable	0	Insignificant - tracer wire good	1	Moderate - tracer wire has gaps/breaks	2	Significant - no tracer wire	3		4		Pipe that cannot be easily located poses a damage risk when work occurs near the pipe.	Pipe that cannot be easily located increases time to complete repairs.	1
Logistics (aligment with municipal works or other AUI activity in the area)	0	Stand alone project	1	Aligns with municipal works or other AUI project	2	Critical to be completed with another AUI project	3		4		This is not a failure indicator, but is significant in project planning. Higher score indicates efficiency gains due to shared costs, single mobilization, economies of scale, and reduced disruption to the public.		2
15-year Leak Rate (# leaks/ km)	0	< 0.050 leaks/km^2 score equivalent to AUI's best pipe (i.e. certified PE)	1	.050 - .125 leaks/km^2	2	.125 - .200 leaks/km^2	3	.200 - .275 leaks/km^2	4	> .275 leaks/km^2	Historical leak rate is a key indicator of probability of leaks in future. Squeezing to repair a leak on non-certified PE typically causes subsequent leaks adjacent to the squeeze location.	Leak rate directly affects the amount of gas that may be released if a leak occurs. Leaks disrupt customer service when repairs are performed.	1.5

248 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 28.

Appendix 4 – Pre-1957 Steel High Pressure Pipe detailed risk assessment model[249]

Risk Factor	Scoring										Likelihood of Failure	Impact of Failure	Weighting
Population Density (# services/ km within 200 meters of the main)	0	<50 services/km²	1	50 - 100 services/km²	2	100 - 200 services/km²	3	200 - 500 services/km²	4	500+ services/km²	More customers = more fittings and activity around pipe = high propensity for leakage.	High population density indicates relatively more customers depend on this pipe. Higher population density in proximity to the pipe increases health & safety risk to the public.	2
Criticality (degree of dependence on supply)	0	multiple or redundant sources of supply available	1	other sources available but sustained service depends on this supply	2	sole or main source of supply to customers affected by failure					Criticality increases the impact, but not likelihood, of failure.	The impact to customers of failue of a high-pressure pipeline is directly correlated to the degree of dependence customers have the gas flowing from that pipeline.	2
Customers Affected (volume of gas flowing through the pipe used as proxy)	0	0-10 customers affected	1	10-50 customers affected	2	over 50 customers affected					The number of Customers Affected increases the impact, but not likelihood, of failure.	The total magnitude of a pipeline failure is directly correlated to the number of customers directly affected by loss of service	2
Stress (ratio of Maximum Operating Pressure to pipe SMYS yield strength)	0	MOP = 0-20% of SMYS	1	MOP = 20-40% of SMYS	2	MOP > 40% of SMYS					Pipe at or near the end of its useful life that is operated, or licensed to operate, at pressures closer to its yield strength has greater likelihood of failure.	Pipe that exceeds its yield strength (e.g. through wall loss due to corrosion) is more likely to result in catastrophic failure and blowing gas.	1
Coating Condition (cathodic protection amps/km as proxy for coating loss)	0	0 - .25 amps/km (equivalent to new coated steel)	1	.25 - .50 amps/km	2	.50 - .75 amps/km	3	> .75 amps/km	4		Higher amps/km to maintain target pipe-to-ground electric potential (i.e. 1000 millivolts) indicates higher likelihood of coating loss which increases the risk of pipe corrosion.	Coating condition affects the likelihood, but not the imapct, of pipe failure.	1
Ground Cover (extent to which pipe is covered by asphalt, concrete or structures)	0	0% - 20% (e.g. Rural)	1	20% - 40% (e.g. Rural subdivisions)	2	40% - 60% (e.g. Hamlets and Villages, paved streets with gravel alleyways)	3	60% - 80% (e.g. Towns, paved streets and alleyways)	4	80% - 100% (e.g. Downtown cores)	Ground coverage generally increases the impact, but not likelihood, of failure.	If leak occurs, detection is more difficult. More ground cover (e.g. pavement) allows migration of the gas to unfavorable places. Ground cover also increases time to complete repairs.	0.5
15-year Leak Rate (# leaks/ km)	0	< 0.050 leaks/km equal to AUI's best pipe (new coated steel)	1	.050 - .125 leaks/km	2	.125 - .200 leaks/km	3	.200 - .275 leaks/km	4	> .275 leaks/km	Historical leak rate is a key indicator of probability of leaks in future.	Leak rate directly affects the amount of gas that may be released if a leak occurs. Leaks disrupt customer service when repairs are performed.	1
Logistics (aligment with municipal works or AUI activity in the area)	0	Stand alone project	1	Aligns with municipal works or other AUI project	2	Critical to be completed with another AUI project					This is not a failure indicator, but is significant in project planning. Higher score indicates efficiency gains due to shared costs, single mobilization, economies of scale, and reduced disruption to the public.		2

249 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 98.

Appendix 5 – Risk scores and rankings for 2016 and 2017 Pipeline projects

2016 PVC projects[250]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	Barrhead	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 2	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 3	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 5	TOWN	21	4	3	0	2	0
STEEL	Drumheller Phase 4	TOWN	18	4	3	0	0	0
NCPE	Morinville Rural	RURAL	13	0	0	0	4	2
PVC	Morinville PVC Area 3	RURAL	11	0	0	1	2	2
PVC	Westlock PVC Area 5	RURAL	8	0	0	1	0	2
PVC	Morinville PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Westlock PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 9	RURAL	5.5	0	0	1	1	0
PVC	Leduc PVC Area 2	RURAL	4	0	0	1	0	0
NCPE	Looma Estates NE22-50-23-W4	RURAL SUB	3	1	0	0	0	0
NCPE	Southwood	RURAL SUB	3	1	0	0	0	0
NCPE	Valleyview	RURAL SUB	3	1	0	0	0	0
NCPE	Beau Vista	RURAL SUB	2	0	0	0	0	0
NCPE	Gateway	RURAL SUB	2	0	0	0	0	0
NCPE	Kadavista	RURAL SUB	2	0	0	0	0	0
NCPE	Kaywood	RURAL SUB	2	0	0	0	0	0
NCPE	Looma Estates SW23-50-23-W4	RURAL SUB	2	0	0	0	0	0

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2017 PVC projects[251]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	2017 Steel - Town of Hanna Steel Ma	TOWN	24	4	3	0	4	0
STEEL	2017 Barrhead Town Steel Replacem	TOWN	19.5	4	3	0	1	0
PVC	Barrhead Rural (Remainder)	RURAL	10.5	0	0	1	3	1
PVC	Westlock PVC Area 2	RURAL	10.5	0	0	1	3	1
NCPE	BA NCPE Area 1 Mains Only	RURAL	10	0	0	0	4	1
NCPE	WS NCPE Area 2 Mains Only	RURAL	10	0	0	0	4	1
PVC	Barrhead PVC Area 5	RURAL	9	0	0	1	2	1
PVC	Leduc Area 10A	RURAL	9	0	0	1	2	1
PVC	Westlock PVC Area 3	RURAL	9	0	0	1	2	1
NCPE	WS NCPE Area 1 Mains Only	RURAL	8.5	0	0	0	3	1
PVC	Westlock PVC Area 1	RURAL	7.5	0	0	1	1	1
PVC	Westlock Rural (Remainder)	RURAL	7.5	0	0	1	1	1
PVC	Leduc PVC Area 10B	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 6	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 7	RURAL	6	0	0	1	0	1
NCPE	Namao Ridge Estates	RURAL SUB	4	2	0	0	0	0
NCPE	Richdale Estates	RURAL SUB	3	1	0	0	0	0
NCPE	Clearwater	RURAL SUB	2	0	0	0	0	0
NCPE	Helm	RURAL SUB	2	0	0	0	0	0
NCPE	Irvine SE Rural NCPE	RURAL	2	0	0	0	0	0
NCPE	King	RURAL SUB	2	0	0	0	0	0
NCPE	Peace Hills Heights	RURAL SUB	2	0	0	0	0	0
NCPE	Rural sub 34	RURAL SUB	2	0	0	0	0	0

[251] Exhibit 20522-X0010, application, PDF page 157.

2016 Non-Certified PE Pipe projects[252]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	Barrhead	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 2	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 3	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 5	TOWN	21	4	3	0	2	0
STEEL	Drumheller Phase 4	TOWN	18	4	3	0	0	0
NCPE	Morinville Rural	RURAL	13	0	0	0	4	2
PVC	Morinville PVC Area 3	RURAL	11	0	0	1	2	2
PVC	Westlock PVC Area 5	RURAL	8	0	0	1	0	2
PVC	Morinville PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Westlock PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 9	RURAL	5.5	0	0	1	1	0
PVC	Leduc PVC Area 2	RURAL	4	0	0	1	0	0
NCPE	Looma Estates NE22-50-23-W4	RURAL SUB	3	1	0	0	0	0
NCPE	Southwood	RURAL SUB	3	1	0	0	0	0
NCPE	Valleyview	RURAL SUB	3	1	0	0	0	0
NCPE	Beau Vista	RURAL SUB	2	0	0	0	0	0
NCPE	Gateway	RURAL SUB	2	0	0	0	0	0
NCPE	Kadavista	RURAL SUB	2	0	0	0	0	0
NCPE	Kaywood	RURAL SUB	2	0	0	0	0	0
NCPE	Looma Estates SW23-50-23-W4	RURAL SUB	2	0	0	0	0	0

[252] Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 148.

2017 Non-Certified PE Pipe projects[253]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	2017 Steel - Town of Hanna Steel Ma	TOWN	24	4	3	0	4	0
STEEL	2017 Barrhead Town Steel Replacem	TOWN	19.5	4	3	0	1	0
PVC	Barrhead Rural (Remainder)	RURAL	10.5	0	0	1	3	1
PVC	Westlock PVC Area 2	RURAL	10.5	0	0	1	3	1
NCPE	BA NCPE Area 1 Mains Only	RURAL	10	0	0	0	4	1
NCPE	WS NCPE Area 2 Mains Only	RURAL	10	0	0	0	4	1
PVC	Barrhead PVC Area 5	RURAL	9	0	0	1	2	1
PVC	Leduc Area 10A	RURAL	9	0	0	1	2	1
PVC	Westlock PVC Area 3	RURAL	9	0	0	1	2	1
NCPE	WS NCPE Area 1 Mains Only	RURAL	8.5	0	0	0	3	1
PVC	Westlock PVC Area 1	RURAL	7.5	0	0	1	1	1
PVC	Westlock Rural (Remainder)	RURAL	7.5	0	0	1	1	1
PVC	Leduc PVC Area 10B	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 6	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 7	RURAL	6	0	0	1	0	1
NCPE	Namao Ridge Estates	RURAL SUB	4	2	0	0	0	0
NCPE	Richdale Estates	RURAL SUB	3	1	0	0	0	0
NCPE	Clearwater	RURAL SUB	2	0	0	0	0	0
NCPE	Helm	RURAL SUB	2	0	0	0	0	0
NCPE	Irvine SE Rural NCPE	RURAL	2	0	0	0	0	0
NCPE	King	RURAL SUB	2	0	0	0	0	0
NCPE	Peace Hills Heights	RURAL SUB	2	0	0	0	0	0
NCPE	Rural sub 34	RURAL SUB	2	0	0	0	0	0

253 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 149.

2016 Pre-1957 Medium Pressure Steel Pipe projects[254]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	Barrhead	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 2	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 3	TOWN	24	4	3	0	4	0
STEEL	Drumheller Phase 5	TOWN	21	4	3	0	2	0
STEEL	Drumheller Phase 4	TOWN	18	4	3	0	0	0
NCPE	Morinville Rural	RURAL	13	0	0	0	4	2
PVC	Morinville PVC Area 3	RURAL	11	0	0	1	2	2
PVC	Westlock PVC Area 5	RURAL	8	0	0	1	0	2
PVC	Morinville PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Westlock PVC Area 4	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 9	RURAL	5.5	0	0	1	1	0
PVC	Leduc PVC Area 2	RURAL	4	0	0	1	0	0
NCPE	Looma Estates NE22-50-23-W4	RURAL SUB	3	1	0	0	0	0
NCPE	Southwood	RURAL SUB	3	1	0	0	0	0
NCPE	Valleyview	RURAL SUB	3	1	0	0	0	0
NCPE	Beau Vista	RURAL SUB	2	0	0	0	0	0
NCPE	Gateway	RURAL SUB	2	0	0	0	0	0
NCPE	Kadavista	RURAL SUB	2	0	0	0	0	0
NCPE	Kaywood	RURAL SUB	2	0	0	0	0	0
NCPE	Looma Estates SW23-50-23-W4	RURAL SUB	2	0	0	0	0	0

254 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 91.

2017 Pre-1957 Medium Pressure Steel Pipe projects[255]

Type	Project	Geo Type	RISK SCORE	POP DENSITY	GROUND COVER	LOCATABLE	15YR LEAK RATE	LOGISTICS
STEEL	2017 Steel - Town of Hanna Steel Ma	TOWN	24	4	3	0	4	0
STEEL	2017 Barrhead Town Steel Replacem	TOWN	19.5	4	3	0	1	0
PVC	Barrhead Rural (Remainder)	RURAL	10.5	0	0	1	3	1
PVC	Westlock PVC Area 2	RURAL	10.5	0	0	1	3	1
NCPE	BA NCPE Area 1 Mains Only	RURAL	10	0	0	0	4	1
NCPE	WS NCPE Area 2 Mains Only	RURAL	10	0	0	0	4	1
PVC	Barrhead PVC Area 5	RURAL	9	0	0	1	2	1
PVC	Leduc Area 10A	RURAL	9	0	0	1	2	1
PVC	Westlock PVC Area 3	RURAL	9	0	0	1	2	1
NCPE	WS NCPE Area 1 Mains Only	RURAL	8.5	0	0	0	3	1
PVC	Westlock PVC Area 1	RURAL	7.5	0	0	1	1	1
PVC	Westlock Rural (Remainder)	RURAL	7.5	0	0	1	1	1
PVC	Leduc PVC Area 10B	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 6	RURAL	6	0	0	1	0	1
PVC	Leduc PVC Area 7	RURAL	6	0	0	1	0	1
NCPE	Namao Ridge Estates	RURAL SUB	4	2	0	0	0	0
NCPE	Richdale Estates	RURAL SUB	3	1	0	0	0	0
NCPE	Clearwater	RURAL SUB	2	0	0	0	0	0
NCPE	Helm	RURAL SUB	2	0	0	0	0	0
NCPE	Irvine SE Rural NCPE	RURAL	2	0	0	0	0	0
NCPE	King	RURAL SUB	2	0	0	0	0	0
NCPE	Peace Hills Heights	RURAL SUB	2	0	0	0	0	0
NCPE	Rural sub 34	RURAL SUB	2	0	0	0	0	0

2016-2019 Pre-1957 High Pressure Steel projects[256]

Project	Type	Year	km	Risk Score	Pop Density	Criticality	# Customers	Stress	Coating	Ground cover	15-year Leak Rate	Logistics
Stettler Town	TOWN	2017	5.5	18.5	3	2	2	1	0	3	2	0
Westlock Town (BWM Gas Supply)	TOWN	2016	1.5	13.5	1	1	2	0	0	3	0	2
Hanna Town	TOWN	2017	1.6	14.5	2	1	2	1	0	3	0	1
Drumheller supply line	RURAL	2016	4.0	12.0	0	2	2	1	0	0	3	0
Leduc City (Calmar Gas Supply)	TOWN	2017	1.9	10.5	0	1	2	1	0	3	0	1
Westlock Rural (BWM Gas Supply)	RURAL	2016	10.4	10.0	0	1	2	0	0	0	0	2
Morinville supply line	RURAL	2016	1.6	9.0	0	2	2	1	0	0	0	0
Leduc Rural (Calmar Gas Supply)	RURAL	2017	10.5	8.0	0	1	0	1	3	0	0	1
Barrhead Rural	RURAL	2019	21.6	10.0	0	1	1	1	3	0	0	1
Stettler Rural	RURAL	2019	15.1	6.0	0	1	1	0	0	0	2	0
Leduc Rural "Imperial Oil line"	RURAL	2018	8.4	5.0	0	1	1	1	0	0	0	0
Hanna Rural	RURAL	2017	16.8	5.0	0	1	0	1	0	0	0	1
TOTAL			98.8									

255 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 92.
256 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF page 99.

Appendix 6 – Risk scores and rankings for Station Refurbishment projects[257]

	Type	FacilityID	Vintage	2014	2015	2016	2017	2018	2019	Risk Score	Consequence Score	Volume Throughput	Single Supply	Proximity	Probability Score	Vintage Score	Obsolete equipment	Run Splitting	Gate valves	Proximity	Instability or flooding	Safety Security	Building condition	Gas Quality	Pressure Cut	Frost balls/ heave (risers/ building)	Leaks by design
1	TBS	LE085	1970		X					47.5	10	4	1	1	4.75	2	0	1	1	1	0	0	1	0	0	0	1
2	PMS	GC002	1976			X				31.9	7.5	3	1	1	4.25	2	0	1	1	1	0	0	0	0	0	0	0
3	PMS	HL005	1979		X					30.0	8	4	1	0	3.75	2	0	1	1	0	0	0	0	0	1	0	1
4	TBS	PC024	1982		X					24.4	7.5	3	1	1	3.25	1	0	1	0	1	1	0	0	0	0	0	0
5	TBS	MN019	1978			X				22.5	5	2	1	1	4.5	2	0	0	1	1	0	0	0	0	0	1	0
6	TBS	LE090	1968		X					20.3	3	2	0	1	6.75	3	0	1	1	1	1	0	1	0	0	1	0
7	TBS	TW001	1963			X				18.8	5	2	1	1	3.75	3	0	0	1	1	0	0	0	0	0	0	0
8	TBS	LE092	1968		X					18.0	3	2	0	1	6	3	0	1	1	1	0	0	0	0	0	1	0
9	TBS	PC001	1960		X					17.3	3	2	0	1	5.75	3	0	1	0	1	1	1	0	0	0	1	0
10	PMS	TH001	1975			X				17.0	4	2	1	0	4.25	2	0	1	1	0	0	0	0	0	0	1	0
11	PMS	AT074	1977			X				15.0	2.5	1	1	1	6	2	0	1	0	1	1	0	1	0	1	1	1
12	TBS	LE088	1975			X				15.0	2.5	1	1	1	6	2	0	1	1	1	0	0	0	0	1	1	0
13	TBS	LE089	1973			X				15.0	2.5	1	1	1	6	2	0	1	1	1	0	0	0	0	1	1	0
14	TBS	TH002	1959			X				13.8	5	2	1	1	2.75	3	0	0	0	1	0	0	0	0	0	0	0
15	PMS	MN017	1982	X						13.5	4.5	3	0	1	3	1	0	1	0	1	0	0	0	0	0	0	1
16	TBS	WS036	1980							13.5	4.5	3	0	1	3	1	0	1	0	1	0	1	0	0	0	0	0
17	PMS	WS038	1980			X				13.5	6	3	1	0	2.25	1	0	1	0	0	0	0	0	0	1	0	1
18	TBS	AT031	1973				X			12.0	3	2	0	1	4	2	0	1	0	1	1	0	1	0	0	0	0
19	TBS	SP250	1967					X		12.0	3	2	0	1	4	3	1	0	0	1	0	0	0	0	0	0	0
20	PMS	ST025	1972				X			12.0	2	1	1	0	6	2	1	1	1	0	0	0	0	0	1	1	0
21	PMS	AT105	1988				X			11.9	2.5	1	1	1	4.75	1	0	1	0	1	0	0	0	0	1	1	1
22	TBS	SE009	1969				X			11.9	2.5	1	1	1	4.75	3	0	1	1	1	0	0	0	0	0	0	0
23	TBS	HL001	1979				X			11.3	3	2	0	1	3.75	2	0	1	0	1	1	0	0	0	0	0	0
24	TBS	SP265	1972				X			11.3	2.5	1	1	1	4.5	2	1	0	1	1	0	0	0	0	0	0	0
25	TBS	TW003	1970				X			11.3	2.5	1	1	1	4.5	2	1	0	1	1	0	0	0	0	0	0	0
26	PMS	BA060	1972					X		11.0	4	2	1	0	2.75	2	0	1	0	0	0	0	0	0	1	0	1
27	PMS	LE080	1983				X			11.0	4	4	0	0	2.75	1	0	1	0	0	0	0	0	1	0	0	1
28	PMS	MN027	1969			X				11.0	4	2	1	0	2.75	3	0	1	0	0	0	0	0	0	0	0	1
29	TBS	BA010	1982					X		10.5	6	3	1	0	1.75	1	0	1	0	0	0	0	0	0	0	0	1
30	TBS	BO001	1983				X			10.5	3	2	0	1	3.5	1	0	0	0	1	0	0	0	0	1	1	0
31	PMS	PC028	1960		X					10.5	6	3	1	0	1.75	3	0	0	0	0	0	0	0	0	0	0	1
32	PMS	WB001	1985					X		10.5	3	2	0	1	3.5	1	0	1	0	1	0	0	0	0	1	0	1

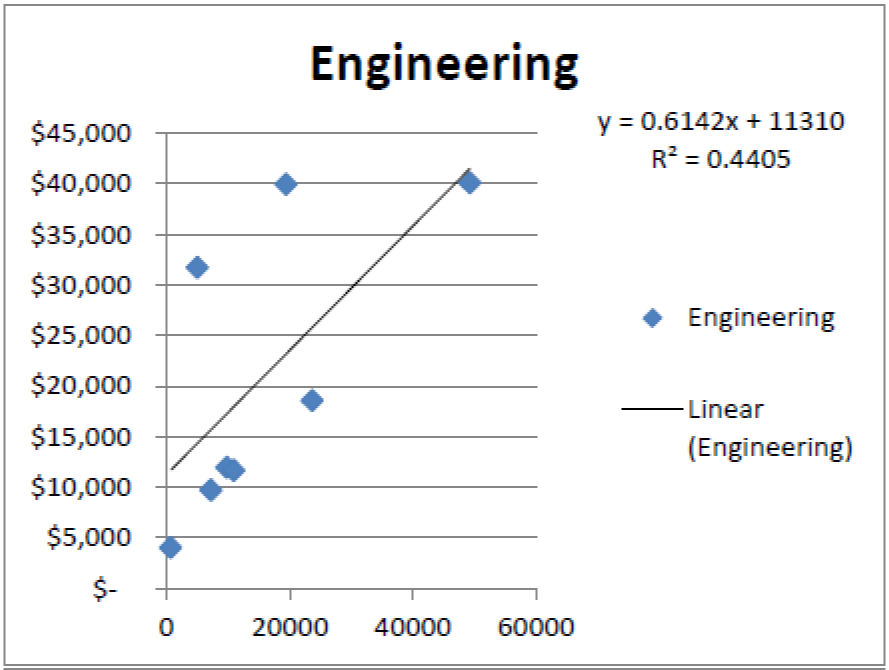
257 Exhibit 20522-X0010.04, application (black line) identifying revisions, PDF pages 240-242.

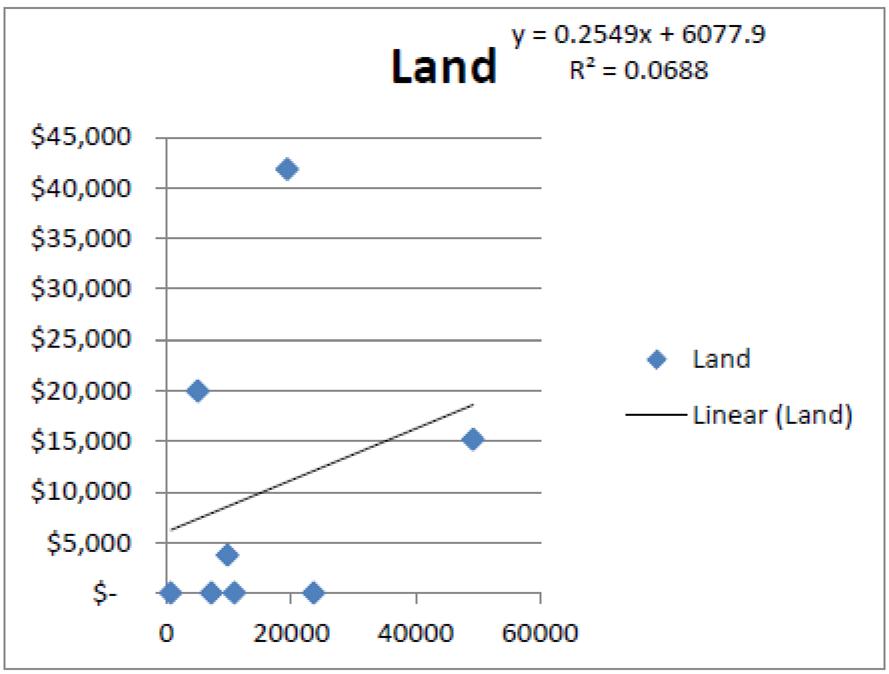
	Type	FacilityID	Vintage	2014	2015	2016	2017	2018	2019	Risk Score	Consequence Score	Volume Throughput	Single Supply	Proximity	Probability Score	Vintage Score	Obsolete equipment	Run Splitting	Gate valves	Proximity	Instability or flooding	Safety Security	Building condition	Gas Quality	Pressure Cut	Frost balls/ heave (risers/ building)	Leaks by design
33	PMS	WS044	1975							10.0	2	1	1	0	5	2	1	1	0	0	0	0	0	0	1	1	0
34	TBS	MN002	1971				X			9.8	3	2	0	1	3.25	2	0	1	0	1	0	0	0	0	0	0	0
35	TBS	DR004	1967				X			9.4	2.5	1	1	1	3.75	3	0	0	1	1	0	0	0	0	0	0	0
36	PMS	AT091	1977					X		8.5	2	1	1	0	4.25	2	0	1	0	0	0	0	1	0	1	1	1
37	PMS	DR013	1969					X		8.5	2	1	1	0	4.25	3	0	1	1	0	0	0	0	0	1	0	1
38	PMS	SP263	1979					X		8.5	2	1	1	0	4.25	2	0	1	0	0	0	0	1	0	1	1	1
39	TBS	HA004	1971		X					8.3	1.5	1	0	1	5.5	2	1	1	1	1	0	0	0	0	0	0	0
40	TBS	DR003	1971					X		8.1	2.5	1	1	1	3.25	2	0	1	0	1	0	0	0	0	0	0	0
41	PMS	TW004	1973					X		8.0	4	2	1	0	2	2	0	0	1	0	0	0	0	0	0	0	0
42	TBS	BA041	1982			X				7.5	2	2	0	0	3.75	1	0	1	0	0	0	0	0	1	0	1	0
43	TBS	SE007	1969							7.5	2.5	1	1	1	3	3	0	0	0	1	0	1	0	0	0	0	0
44	PMS	ST002	1975		X					7.0	2	2	0	0	3.5	2	0	1	1	0	0	0	1	0	0	0	1
45	TBS	AT106	1988					X		6.9	2.5	1	1	1	2.75	1	0	1	0	1	0	0	0	0	0	0	0
46	TBS	SE008	1973							6.9	2.5	1	1	1	2.75	2	0	0	0	1	0	1	1	0	0	0	0
47	TBS	BA012	1971					X		6.8	3	2	0	1	2.25	2	0	0	0	1	0	0	0	0	0	0	0
48	TBS	LE043	1974							6.8	1.5	1	0	1	4.5	2	0	0	1	1	0	0	0	0	0	1	0
49	PMS	AT052	1978			X				6.5	2	1	1	0	3.25	2	0	1	0	0	0	1	1	0	1	0	1
50	PMS	AT081	1977			X				6.0	2	1	1	0	3	2	0	1	0	0	0	0	1	0	1	0	1
51	PMS	AT086	1978					X		6.0	2	1	1	0	3	2	0	1	0	0	0	0	1	0	1	0	1
52	PMS	TW002	1972					X		6.0	2	1	1	0	3	2	0	1	1	0	0	0	0	0	0	0	0
53	TBS	WS061	1989					X		6.0	3	2	0	1	2	1	0	0	0	1	0	1	0	0	0	0	0
54	PMS	ST014	1976		X					5.5	2	2	0	0	2.75	2	0	1	0	0	0	0	0	0	1	0	1
55	PMS	WS043	1975							5.5	2	1	1	0	2.75	2	0	0	0	0	0	0	0	0	1	1	0
56	PMS	AT068	1977					X		5.0	2	1	1	0	2.5	2	0	0	0	0	0	0	1	0	0	1	0
57	TBS	BA038	1972					X		4.9	1.5	1	0	1	3.25	2	0	1	0	1	0	0	0	0	0	0	0
58	TBS	DR001	1970					X		4.9	1.5	1	0	1	3.25	2	0	0	1	1	0	0	0	0	0	0	0
59	TBS	AT006	1982					X		4.5	1.5	1	0	1	3	1	0	1	0	1	0	1	0	0	0	0	0
60	PMS	WS058	1989					X		4.5	2	2	0	0	2.25	1	0	1	0	0	0	0	0	0	1	0	1
61	TBS	DR025	1983							4.4	2.5	1	1	1	1.75	1	0	0	0	1	0	0	0	0	0	0	0
62	TBS	WS039	1981							4.4	2.5	1	1	1	1.75	1	0	0	0	1	0	0	0	0	0	0	0
63	TBS	WS051	1987							4.4	2.5	1	1	1	1.75	1	0	0	0	1	0	0	0	0	0	0	0
64	TBS	WS052	1987							4.4	2.5	1	1	1	1.75	1	0	0	0	1	0	0	0	0	0	0	0

	Type	FacilityID	Vintage	2014	2015	2016	2017	2018	2019	Risk Score	Consequence Score	Volume Throughput	Single Supply	Proximity	Probability Score	Vintage Score	Obsolete equipment	Run Splitting	Gate valves	Proximity	Instability or flooding	Safety Security	Building condition	Gas Quality	Pressure Cut	Frost balls/ heave (risers/ building)	Leaks by design
65	PMS	SP253	1979		X					4.3	1	1	0	0	4.25	2	0	1	0	0	0	0	1	0	1	1	1
66	PMS	WB002	1985					X		3.8	1.5	1	0	1	2.5	1	0	0	0	1	0	0	0	0	1	0	1
67	TBS	AT007	1974				X			3.4	1.5	1	0	1	2.25	2	0	0	0	1	0	0	0	0	0	0	0
68	PMS	MN031	1973					X		3.3	1	1	0	0	3.25	2	0	1	1	0	0	0	0	0	0	0	1
69	PMS	ST007	1976					X		3.0	2	1	1	0	1.5	2	0	0	0	0	0	0	1	0	0	0	1
70	PMS	WS041	1975					X		3.0	2	1	1	0	1.5	2	0	0	0	0	0	0	0	0	1	0	0
71	TBS	SE066	1983							2.6	1.5	1	0	1	1.75	1	0	0	0	1	0	0	0	0	0	0	0
72	PMS	BA026	1986					X		2.3	1	1	0	0	2.25	1	0	1	0	0	0	0	0	0	1	0	1
73	PMS	BA046	1981					X		2.0	2	1	1	0	1	1	0	0	0	0	0	0	0	0	1	0	0
74	PMS	PC022	1970				X			2.0	1	1	0	0	2	2	0	1	0	0	0	0	0	0	0	0	0
75	PMS	BA001	1987					X		1.8	1	1	0	0	1.75	1	0	0	1	0	0	0	0	0	0	0	1
76	PMS	MN030	1969							1.8	1	1	0	0	1.75	3	0	0	0	0	0	0	0	0	0	0	1
77	PMS	MN029	1973							1.3	1	1	0	0	1.25	2	0	0	0	0	0	0	0	0	0	0	1
78	TBS	SP098	1982				X			1.0	2	1	1	0	0.5	1	0	0	0	0	0	0	0	0	0	0	0
79	PMS	ST016	1989							1.0	2	2	0	0	0.5	1	0	0	0	0	0	0	0	0	0	0	0
80	PMS	AT113	1993		X					7.5	2	2	0	0	3.75	0	1	1	1	0	0	0	1	0	0	0	1
81	PMS	LE346	2012*		X					1.3	1	1	0	0	1.25	0	0	0	0	1	0	0	0	0	0	0	0
82	PMS	SE095	1991			X				2.8	1	1	0	0	2.75	1	0	1	0	1	0	0	0	0	0	0	0
83	TBS	HL004	1979				X			3.3	1	1	0	0	3.25	2	0	0	1	1	0	0	0	0	0	0	0
84	TBS	MN003	2005*					X		4.9	1.5	1	0	1	3.25	0	0	1	1	1	0	0	0	0	0	0	0
85	PMS	SP254	1990					X		3.8	1	1	0	0	3.75	0	1	1	0	0	0	0	1	0	0	1	0
86	PMS	SE100	1992					X		3.5	1	1	0	0	3.5	0	1	1	0	0	0	0	0	0	0	1	0
										Weighting ->		1	1	0.5		0.5	1.25	1	1	1.25	0.5	0.25	0.25	1	0.5	1.25	0.25

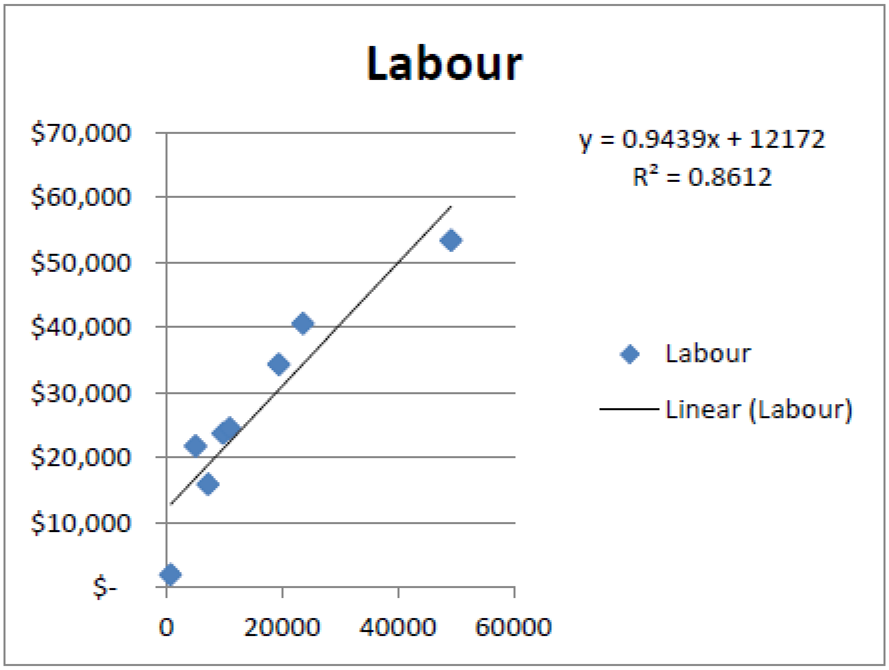
Orange indicates final calculated risk score
Yellow indicates calculated consequence and probability scores
Light Purple indicates vintages derived from station listing review
Light Green indicates scores based on throughput volumes derived from hydraulic analysis
Teal indicates research and review by Integrity Management team using GIS, instrument records, station maintenance records
Light Orange indicates scores based on asset data from Maximo
Remainder of data is from original station list from GIS system (ESRI)

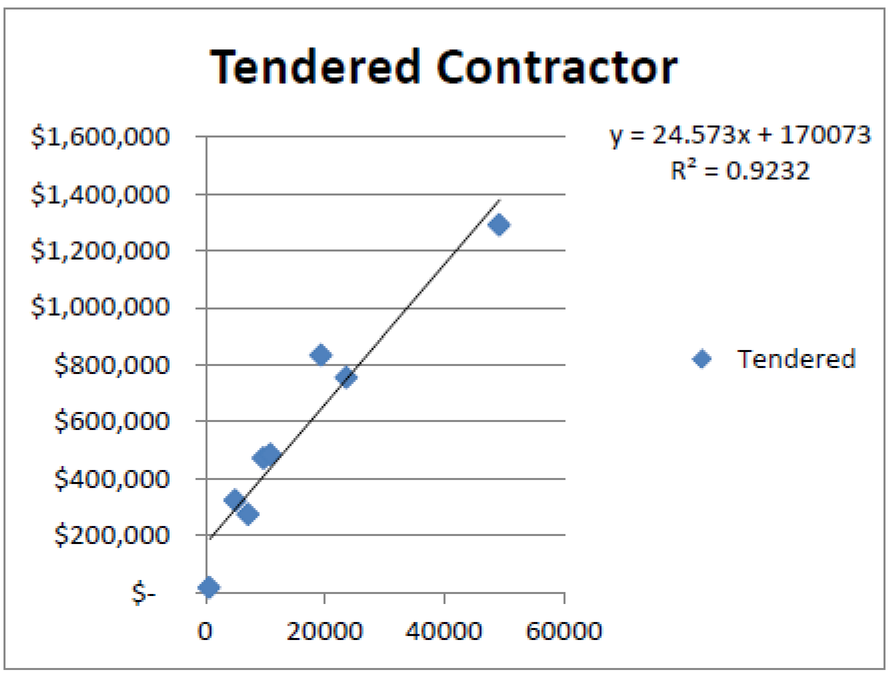
Appendix 7 – Pipeline linear regression model graphs for the 2016-2017 forecast[258]

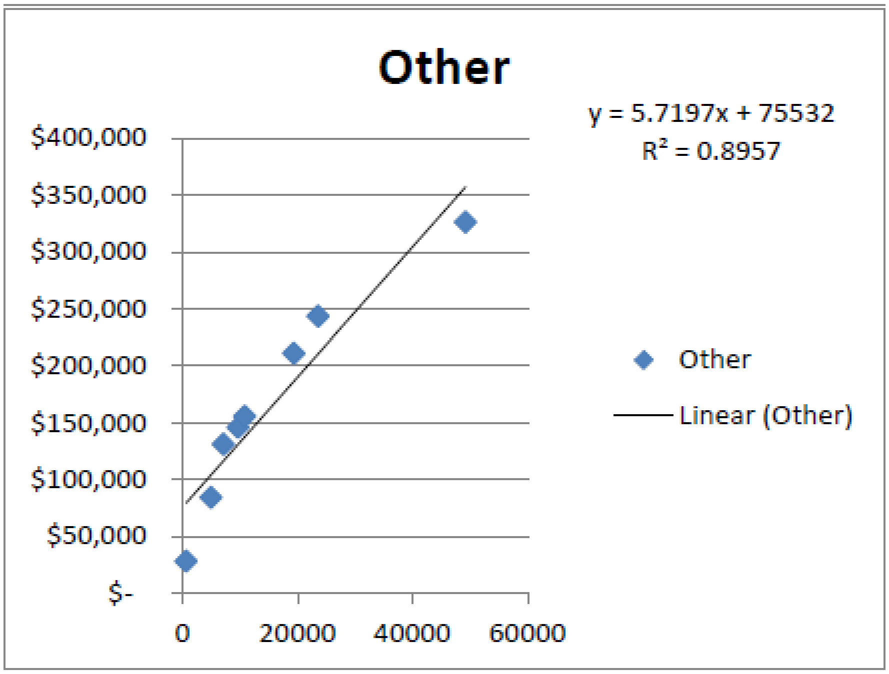


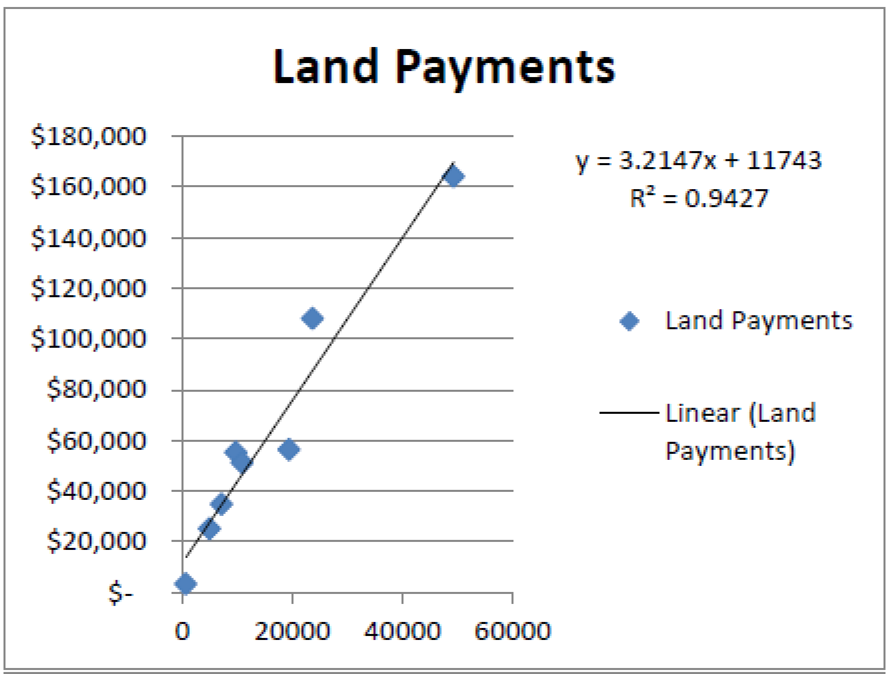


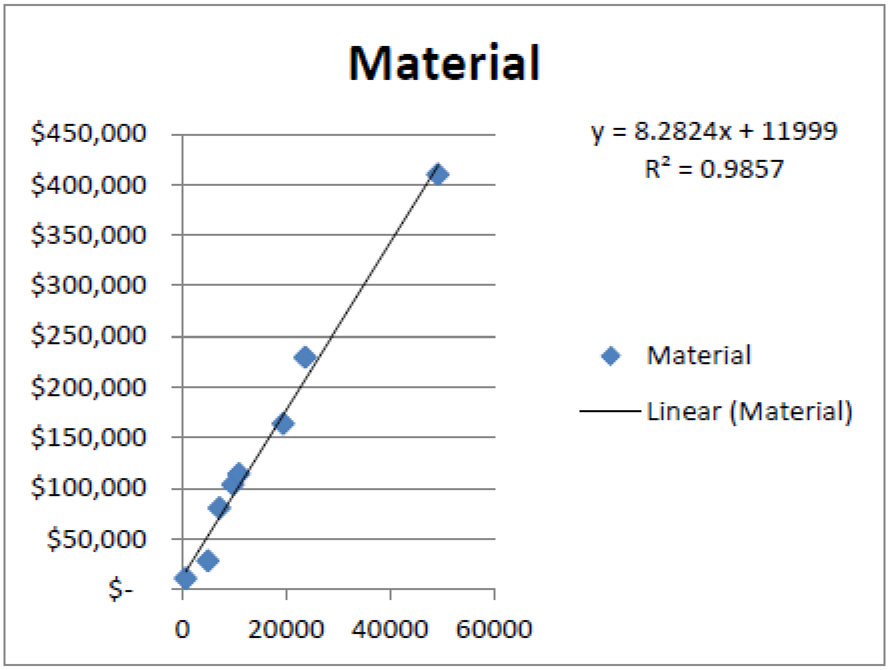
[258] Exhibit 20522-X0025, AUI-AUC-2015JUL2-031(c).


Labour
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
0
20000
40000
60000
y = 0.9439x + 12172
R² = 0.8612
Labour
Linear (Labour)


Tendered Contractor
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
0
20000
40000
60000
y = 24.573x + 170073
R² = 0.9232
Tendered


Other
y = 5.7197x + 75532
R^2 = 0.8957
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$-
0
20000
40000
60000
Other
Linear (Other)


Land Payments
y = 3.2147x + 11743
R^2 = 0.9427
$180,000
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
0
20000
40000
60000
Land Payments
Linear (Land Payments)


Material
y = 8.2824x + 11999
R^2 = 0.9857
$450,000
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$-
0
20000
40000
60000
Material
Linear (Material)