AUC
Alberta Utilities Commission

AltaGas Utilities Inc.

2015 Capital Tracker True-Up Application

December 7, 2016

Alberta Utilities Commission
Decision 21627-D01-2016
AltaGas Utilities Inc.
2015 Capital Tracker True-Up Application
Proceeding 21627

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1 Decision

1. This decision provides the Alberta Utilities Commission's determination of AltaGas Utilities Inc.'s (AltaGas or AUI) 2015 capital tracker true-up. For the reasons outlined in this decision, the Commission has determined that:

- AltaGas' proposed grouping of projects into programs is reasonable.
- The 2015 true-up projects or programs are needed.
- The actual scope, level, timing and actual costs of each of the projects or programs included in the 2015 true-up were prudently incurred and satisfy the project assessment requirement of Criterion 1.
- The capital tracker projects or programs included in the 2015 true-up continue to meet the requirements of the accounting test under Criterion 1.
- The capital tracker projects or programs included in the 2015 true-up continue to meet the requirements of Criteria 2.
- The projects or programs included in the 2015 true-up satisfy the materiality requirement under Criterion 3.
- AltaGas has generally complied with previous Commission directions. The exceptions are the provision of descriptions of all non-capital tracker projects or programs, a trailing cost variance explanation for the Blaine Hochstein project, clarification of the costs claimed for the decommissioning of the post-regulator stations (PRS) stations and evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the Canada Revenue Agency (CRA) (item 1.c. from Decision 3558-D01-2015[1]). For purposes of regulatory efficiency, the Commission has determined that a compliance filing to this decision is not required and that each of these instances of non-compliance are to be addressed in a future Rider F deficiency/surplus application or capital tracker true-up application.

2 Introduction and procedural background

2. On April, 27, 2016, the Commission issued a letter that established the preliminary process and schedule it intended to follow for the 2015 capital tracker true-up applications for AltaGas, ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution &

[1] 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.

Transmission Inc. and FortisAlberta Inc. (the companies). The application filing date for AltaGas was set in the letter as May 17, 2016.[2]

3. In a May 10, 2016 letter,[3] AltaGas requested an extension to May 19, 2016, for filing its 2015 capital tracker true-up application, the addition of a technical meeting, and a corresponding adjustment to the other process schedule steps. By letter dated May 13, 2016,[4] the Commission granted AltaGas' request and issued a revised preliminary schedule.

4. On May 24, 2016, AltaGas filed its 2015 capital tracker true-up application and associated schedules.[5]

5. Also on May 24, 2016, the Commission issued a filing announcement and a notice for the AltaGas 2015 capital tracker true-up application, with statements of intent to participate (SIP's) due May 31, 2016.[6]

6. 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).[7]

7. The Commission issued a process letter for this proceeding on June 1, 2016. The process schedule in the letter was consistent with the one issued in the Commission's May 13, 2016 letter, with the exception of the technical meeting date, which had not yet been determined by AltaGas. On June 14, 2016, AltaGas filed a letter with the Commission requesting approval of deadline extensions for information requests (IRs), IR responses and intervener evidence. AltaGas also proposed that the remaining process steps be determined at a future date. By letter dated June 15, 2016, the Commission approved AltaGas' request and issued a revised schedule as set out below. The Commission also requested the UCA and the CCA, following the receipt of AltaGas' IR responses, to advise whether they would be filing intervener evidence and to indicate which remaining process steps would be necessary. The process schedule also included a placeholder for an oral hearing, in the event an oral hearing was required:[8]

2 Proceeding 20414, Exhibit 20414-X0154.
3 Proceeding 20414, Exhibit 20414-X0307.
4 Proceeding 20414, Exhibit 20414-X0336.
5 Exhibits 21627-X0001 to 21627-X0007.
6 Exhibits 21627-X0009 and 21627-X0010.
7 Exhibits 21627-X0011 and 21627-X0012.
8 Exhibit 21627-X0017.

Process step	Deadline
Application submission	Completed May 24, 2016
Notice	Completed May 24, 2016
Statements of intention to participate	Completed May 31, 2016
Technical meeting – AltaGas offices or remote participation using GoToMeeting	Completed June 9, 2016
IRs to AltaGas	June 21, 2016
IR responses from AltaGas	July 18, 2016
Intervener evidence	August 2, 2016
IRs to interveners	TBD
IR responses from interveners	TBD
Submissions regarding the need for an oral hearing	TBD
Rebuttal evidence	TBD
Oral hearing	TBD

8. On June 9, 2016, AltaGas hosted a technical meeting with respect to the application. The meeting 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.[9]

9. By letter dated July 26, 2016,[10] the UCA submitted that it did not intend to file evidence and, if no other parties filed evidence, considered that a written process of argument and reply argument would be sufficient to dispose of the issues in the proceeding. In a letter dated August 3, 2016,[11] the CCA advised that it would not be filing evidence. Based on these submissions, by letter dated August 4, 2016, the Commission determined that argument and reply argument would be sufficient to conclude the record development portion of the proceeding and set August 25, 2016 and September 1, 2016, respectively, as the dates for argument and reply argument.[12]

10. AltaGas and the UCA filed their respective arguments on August 25, 2016.[13] The CCA filed its argument on August 31, 2016.[14]

11. Also on August 25, 2016, the CCA filed a letter requesting an extension to the deadline to file IRs to September 1, 2016.[15]

12. By letter dated August 26, 2016, the Commission requested input from AltaGas on the CCA's requested extension.[16] On August 29, 2016, AltaGas filed a letter indicating no objection to the CCA's extension request, as long as the CCA undertook not to utilize submissions from

[9] Exhibit 21627-X0016.
[10] Exhibit 21627-X0037.
[11] Exhibit 21627-X0038.
[12] Exhibit 21627-X0039.
[13] Exhibits 21627-X0043 and 21627-X0042.
[14] Exhibit 21627-X0047.
[15] Exhibit 21627-X0040.
[16] Exhibit 21627-X0044.

AltaGas' argument in the preparation of the CCA's argument.[17] Also on August 29, 2016, the Commission issued a letter granting the CCA's extension request and directing the CCA not to utilize submissions from AltaGas' argument in the preparation of the CCA's argument.[18] In a follow-up letter issued on September 1, 2016, the Commission extended the reply argument deadline to September 8, 2016.[19]

13. In a letter dated September 1, 2016, the UCA advised that it had reviewed AltaGas' and the CCA's argument and had nothing further to add in reply argument.[20] The CCA filed a letter on September 8, 2016 stating that it would not be filing reply argument. Reply argument was received from AltaGas on September 8, 2016.[21] The Commission considers the record for this proceeding to have closed on September 8, 2016.

14. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, as well as relevant portions of the records considered by the Commission in prior AltaGas capital tracker proceedings as referenced throughout this decision. 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 a particular matter.

3 Background

3.1 Overview of the capital tracker approach under PBR

15. On September 12, 2012, the Commission issued Decision 2012-237,[22] which set out the performance-based regulation (PBR) framework and approved PBR plans for the distribution utility services of certain Alberta electric and gas companies (collectively the distribution utilities), including AltaGas. Within these PBR plans, the Commission approved a rate adjustment mechanism to fund certain capital-related costs. 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.

16. At paragraph 592 of Decision 2012-237, the Commission set out the criteria that a capital project or program would have to satisfy in order to receive capital tracker treatment approval. The implementation and application of these criteria, and the K factor calculation methodology were considered in a 2013 capital trackers proceeding, leading to Decision 2013-435.[23] The implementation methodology established in Decision 2013-435 is, and has been, used to evaluate

[17] Exhibit 21627-X0045.
[18] Exhibit 21627-X0046.
[19] Exhibit 21627-X0048.
[20] Exhibit 21627-X0049.
[21] Exhibit 21627-X0051.
[22] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.
[23] Decision 2013-435: Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

the capital tracker projects or programs proposed by the parties throughout the five-year PBR term over the 2013 to 2017 year period.

17. Subsequent to the release of Decision 2013-435, each distribution utility has filed separate capital tracker applications on an annual basis for its specific capital trackers. AltaGas' last such proceeding was filed in 2015 and led to the release of Decision 20522-D02-2016,[24] which dealt with AltaGas' 2014 capital tracker true-up and 2016-2017 capital tracker forecast. Section 2.1 of that decision provides a comprehensive overview of the capital tracker approach under PBR. A summary of AltaGas' prior capital tracker-related decisions and resulting approved K factor amounts is attached as Appendix 3 to this decision.

4 Commission process for reviewing the 2015 capital tracker true-up application

18. The Commission's process for reviewing the 2015 capital tracker true-up application followed the same steps as those set out in Section 3 of Decision 20522-D02-2016. The Commission indicated it would generally undertake assessments with respect to all three criteria for capital tracker treatment for all capital projects or programs that the Commission has not considered in prior capital tracker decisions.

19. For projects or programs for which the Commission has previously confirmed the need under the project assessment component of Criterion 1 in prior capital tracker decisions, the Commission did not undertake a reassessment of need under Criterion 1 in the absence of evidence that the project or program was no longer required. However, the Commission did assess the scope, level and timing of each project or program for prudence, and whether the actual costs of the project or program were prudently incurred, as required by the second part of the project assessment under Criterion 1.

20. The Commission also considered that for the purposes of the true-up of the 2015 capital tracker programs or projects for which the Commission undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, there was no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program had changed. An assessment of the 2015 capital tracker projects and programs with respect to the accounting test under Criterion 1 and materiality test under Criterion 3 was conducted.

21. The remaining sections of this decision are organized as follows:

- Section 5 of this decision provides an overview of the programs or projects for which AltaGas has sought capital tracker true-up in 2015 on an actual basis.
- The evaluation of AltaGas' proposed capital project groupings is set out in Section 6.
- Section 7 deals with AltaGas' proposal for a variance explanation materiality threshold to be used in future applications.

[24] Decision 20522-D02-2016: AltaGas Utilities Inc. 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.

- The assessment of AltaGas' programs or projects proposed for capital tracker treatment under Criterion 1 is set out in sections 8 and 9 dealing with the project assessment and the accounting test, respectively.
- The Commission's assessment under Criterion 2 is undertaken in Section 10 and the assessment under Criterion 3 is set out in Section 11.
- Section 12 deals with other matters raised in the proceeding.
- Section 13 deals with the K factor calculation methodology and the K factor true-up for 2015.
- Finally, compliances with previous Commission directions are discussed in Section 14 and Appendix 5.

5 Summary of programs included in the 2015 capital tracker true-up:

22. AltaGas has three programs for which it has previously received capital tracker treatment approval: Pipeline Replacements, Station Refurbishments and Gas Supply. As part of the 2015 capital tracker true-up, AltaGas applied for a number of projects under these programs, most of which were previously approved for capital tracker treatment on a forecast basis in Decision 2014-373.[25] A few projects were not previously approved on a forecast basis. Each of these projects are assessed in Section 8 below.

23. The programs included in the 2015 capital tracker true-up and the resulting variance from approved forecast, resulting in a K factor true-up for 2015, are set out in the table below.

Table 1. Applied-for 2015 K factor true-up adjustments

Program name	2015 approved forecast K factor	2015 actual K factor	K factor true-up
	($)		
Pipeline Replacement	2,617,747	2,584,174	33,573
Station refurbishment	499,844	387,712	112,131
Gas supply	332,154	329,063	3,091
2015 K factor total	3,449,744	3,300,949	148,796

5.1 Pipeline Replacement program

24. The Pipeline Replacement program is a multi-year program that 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[26] and pre-1957 steel pipe. The Pipeline Replacement program was first approved in Decision 2012-091,[27] for the 2010-2012 test period. The need for this program, as part of the project assessment under capital

[25] 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.

[26] 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."

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

tracker Criterion 1, was approved in Decision 2013-435 for 2013. It was also approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373, and for 2016 and 2017 forecast capital tracker purposes in Decision 20522-D02-2016.

25. AltaGas provided approved forecast and actual costs, and pipeline length (km) and unit cost (total cost per km) for each of the PVC, Non-Certified PE and Pre-1957 Steel Pipe projects. This information is reproduced in the following tables:

Table 2. Pipeline Replacement program (Pre-1957 Steel Pipe) – 2014 and 2015 actual versus approved forecast, and variances by project

	Capital additions ($)			Pipe length (km)			Unit cost ($/km)		
Pre-1957 Steel	**Approved**	**Actual**	**Approved vs. actual variance**	**Approved**	**Actual**	**Approved vs. actual variance**	**Approved**	**Actual**	**Approved vs. actual variance**
2015 approved, completed									
Drumheller (downtown)	1,163,000	1,962,526	(799,526)	3.8	5.2	(1.4)	304,100	374,564	(70,464)
Hanna (downtown)	909,300	1,193,286	(283,986)	3.0	3.9	(0.9)	304,100	306,552	(2,452)
Stettler (downtown)	472,900	1,147,856	(674,956)	1.6	2.6	(1.0)	304,100	443,753	(139,653)
Barrhead (downtown)	861,100	1,421,963	(560,863)	2.8	3.9	(1.1)	304,200	365,449	(61,249)
Westlock (downtown)	1,197,400	1,684,250	(486,850)	3.9	5.5	(1.6)	304,100	306,712	(2,612)
Morinville (downtown)	889,600	1,304,818	(415,218)	3.0	4.2	(1.2)	299,000	313,327	(14,327)
St. Paul (downtown)	591,200	1,013,042	(421,842)	1.9	2.8	(0.9)	304,100	360,205	(56,105)
2015 approved, partially completed									
Drumheller (town)	1,606,600	240,705	1,365,895	6.9	0.4	6.5	233,000	685,575	(452,575)
2014 approved, remaining work									
Athabasca (town)	-	55,980	(55,980)	-	0.2	(0.2)	-	237,305	(237,305)
2015 not approved, completed									
St. Paul (town)	-	563,901	(563,901)	-	1.7	(1.7)	-	329,555	(329,555)
Morinville (town)	-	256,827	(256,827)	-	0.6	(0.6)	-	402,488	(402,488)
Trailing costs									
Athabasca (downtown/town)	-	102,966	(102,966)	-	-	-	-	-	-
Bonnyville (town)	-	2,030	(2,030)	-	-	-	-	-	-
Drumheller (town)	-	(3,470)	3,470	-	-	-	-	-	-
Total	**7,691,100**	**10,946,683**	**(3,255,583)**	**27.0**	**31.0**	**(4.1)**			

Source: Exhibit 21627-X0007, application, Table 2.2-1, paragraph 74.

Table 3. Pipeline Replacement program (Non-Certified PE Pipe) – 2015 actual versus approved forecast, and variances by project

	Capital additions ($)			Pipe length (km)			Unit cost ($/km)		
Non-Certified PE	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance
2015 approved, completed									
Alcomdale (Hamlet)*[28]	290,600	350,582	(59,982)	1.5	1.7	(0.2)	197,300	209,753	(12,453)
Ashmont (Hamlet)	376,400	597,561	(221,161)	2.1	2.5	(0.4)	181,600	240,758	(59,158)
Colinton (Hamlet)	574,300	748,256	(173,956)	3.4	3.8	(0.3)	167,800	198,666	(30,866)
Duvernay (Hamlet)	110,500	150,106	(39,606)	0.7	0.7	(0.0)	167,900	226,849	(58,949)
Fort Assiniboine (Hamlet)	692,900	1,068,390	(375,490)	3.0	3.9	(0.9)	234,600	274,976	(40,376)
Hairy Hill (Hamlet)	652,000	509,492	142,509	3.3	3.1	0.2	196,800	164,660	32,140
Meanook (Hamlet)	102,300	128,160	(25,860)	0.6	0.7	(0.1)	167,700	173,965	(6,265)
Pincher Station (Hamlet)	280,100	243,573	36,527	1.7	1.5	0.2	168,300	161,853	6,447
Rosedale (Hamlet)	576,800	665,308	(88,508)	3.4	2.8	0.5	171,200	236,000	(64,800)
Seven Persons (Hamlet)	128,700	189,335	(60,635)	0.8	0.7	0.1	167,800	271,176	(103,376)
Allarco (Rural Sub.)	313,000	290,593	22,407	2.0	2.1	(0.1)	155,400	138,728	16,672
Munson (Village)	612,400	731,551	(119,151)	2.6	3.5	(0.9)	239,900	209,373	30,527
2015 approved, deferred to 2016									
Gateway (Rural Sub.)	458,500	-	458,500	2.9	-	2.9	155,500		
Looma Estates NE (Rural Sub.)	336,700	-	336,700	2.2	-	2.2	155,400		
Patterson Estates (was Looma) (Rural Sub.)	640,500	-	640,500	4.1	-	4.1	155,500		
Trailing costs									
Total	-	4,590	(4,590)	-	-	-			
Total	**6,145,700**	**5,677,496**	**468,204**	**34.1**	**26.9**	**7.2**			

Source: Exhibit 21627-X0007, application, Table 2.4.1-1, paragraph 177.

[28] In Decision 2014-373, Table 14. Non-certified PE Pipe replacement - 2015 forecast reflects an incorrect 2014 expenditure amount for the Alcomdale (Hamlet) project. The correct amount should be $25,800, thereby making the total project cost $290,600.

Table 4. Pipeline Replacement program (PVC Pipe) – 2014 and 2015 actual versus approved forecast, and variances by project

	Capital additions ($)			Pipe length (km)			Unit cost ($/km)		
PVC	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance
2015 approved, completed									
Leduc Area 1 (Rural)	770,300	897,022	(126,722)	11.0	10.1	0.9	70,200	88,679	(18,479)
Leduc Area 3 (Rural)	742,800	1,041,385	(298,585)	10.6	11.5	(0.9)	70,200	90,874	(20,674)
Leduc Area 5 (Rural)	476,200	524,467	(48,267)	6.8	7.3	(0.5)	70,200	71,668	(1,468)
Leduc Area 8 (Rural)	1,548,300	1,723,102	(174,802)	22.1	26.5	(4.5)	70,200	64,948	5,252
Ashmont (Rural)	41,100	60,592	(19,492)	0.6	0.7	(0.1)	70,100	91,695	(21,595)
2014 approved, remaining work									
Leduc Area 4 (Rural)	-	469,156	(469,156)	-	3.2	(3.2)	-	146,437	(146,437)
Trailing costs									
Barrhead Area 1,2,3 (Rural)	-	47,417	(47,417)	-	-	-			
Morinville Area 1 (Rural)	-	16,153	(16,153)	-	-	-			
Other (Rural)	-	(32,417)	32,417	-	-	-			
Total	**3,578,700**	**4,746,878**	**(1,168,178)**	**51.0**	**59.3**	**(8.3)**			

Source: Exhibit 21627-X0007, application, Table 2.3.1-1, paragraph 140.

5.2 Station Refurbishment program

26. The Station Refurbishment program is also a multi-year program that provides for partial, through to complete, replacement of a particular station. The Station Refurbishment program was first approved in Decision 2012-091, for the 2010-2012 test period. The need for this program, as part of project assessment under capital tracker Criterion 1, was approved in Decision 2013-435 for 2013. It was also approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373, and for 2016 and 2017 forecast capital tracker purposes in Decision 20522-D02-2016.

27. 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, remote 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 meet municipal requirements. PRS are smaller scale pressure regulating sites.

28. AltaGas provided forecast and actual costs, and cost variance information for each PMS, TBS and PRS project:

Table 5. Station Refurbishment program – 2014 and 2015 actual versus approved forecast, and variances by project

		A	B	C	D=B-C
Station type	**Project name**	**2014 approved**	**2015 approved**	**2015 actual**	**2015 approved vs. actual**
		($)			
	2015 projects				
PMS	AT113[29]	-	458,300	435,927	22,373
PMS	LE346	-	272,800	24,943	247,857
PMS	PC028	-	327,400	384,044	(56,644)
PMS	SP253	-	300,100	385,000	(84,900)
PMS	ST002	-	191,000	-	191,000
PMS	ST014	-	327,400	347,320	(19,920)
	Total		**1,877,000**	**1,577,236**	**299,764**
	2014 approved[30]				
PMS	HL005	424,400	-	849,634	(849,634)
PMS	LE077	201,600	-	300,506	(300,506)
PMS	LE327	169,800	-	308,199	(308,199)
	Total PMS	**795,800**	**1,877,000**	**3,035,575**	**(1,158,575)**
	2015 projects				
TBS	BA041	-	327,400	-	327,400
TBS	HA004	-	191,000	323,649	(132,649)
TBS	LE085	-	523,700	615,186	(91,486)
TBS	PC024	-	-	684,312	(684,312)
TBS	PC001	-	436,400	-	436,400
TBS	**LE092**	-	-	442,808	(442,808)
	Total		**1,478,500**	**2,065,955**	**(5,87,455)**
	2014 approved[31]				
TBS	LE090	185,600	-	652,229	(652,229)
	Total TBS	**185,600**	**1,478,500**	**2,718,184**	**(1,239,684)**
	2015 projects				
PRS	LE251	-	21,800	67,624	(45,824)
PRS	LE302	-	21,800	167,015	(145,215)
PRS	PC018	-	10,900	-	10,900
PRS	SP094	-	54,600	120,249	(65,649)
PRS	SP124	-	21,800	71,296	(49,496)
PRS	ST006	-	21,800	2,793	19,007
PRS	SP Stations (11)[32]	-	144,000	-	144,000
	Total PRS		**296,700**	**428,977**	**(132,277)**

[29] The station name was updated by AltaGas to Station ID AT123.
[30] The 2014 PMS Station Refurbishment projects approved in Decision 2014-373 include HL005, LE077, LE327.
[31] The 2014 TBS Station Refurbishment project approved in Decision 2014-373 is LE0904.
[32] AltaGas combined 11 SP stations, which were approved in 2015 for $13,100 each. These stations were retired.

		A	B	C	D=B-C
Station type	**Project name**	**2014 approved**	**2015 approved**	**2015 actual**	**2015 approved vs. actual**
		($)			
	Trailing costs	-	-	6,248	(6,248)
	Total	**981,400**	**3,652,200**	**6,188,985**	**(2,536,785)**
	2014 approved	981,400	-	2,110,568	(2,110,568)
	2015 approved	-	3,652,200	4,072,168	(419,968)
	Trailing costs	-	-	(6,248)	6,248
	Grand total	**981,400**	**3,652,200**	**6,176,489**	**(2,524,289)**
	Type	**2014 approved**	**2015 approved**	**2015 actual**	**2015 approved vs. actual**
	PMS	3	6	8	(2)
	TBS	1	4	5	(1)
	PRS	-	17	5	12
	Total no. of stations	**4**	**27**	**18**	**9**

Source: Exhibit 21627-X0007, application, Table 3.3-1, paragraph 246.

5.3 Gas Supply program

29. The Gas Supply program is also a multi-year program that ensures safe, continuous gas supply to customers. The Gas Supply program was first approved in Decision 2012-091 for the 2010-2012 test period. The need for this program, as part of project assessment under capital tracker Criterion 1, was approved in Decision 2013-435 for 2013 as a capital tracker program in Decision 2013-435. It was also approved for 2014 and 2015 forecast capital tracker purposes in Decision 2014-373, and for 2016 and 2017 forecast capital tracker purposes in Decision 20522-D02-2016.

30. AltaGas provided approved forecast and actual costs, and cost variance information for the projects in this program:

Table 6. Gas Supply program – 2015 actual versus approved forecast, and variances by project

Gas Supply project	Approved	Actual	Approved vs. actual variance
	($)		
BWM*	531,000	0	(531,000)
Trailing costs	0	(2,090)	(2,090)
Total	**531,000**	**(2090)**	**533,090**

*Barrhead-Westlock-Morinville.

6 Grouping of projects for capital tracker purposes

31. In Decision 2013-435, the Commission determined that the accounting test and the first tier of the materiality test would be applied to the approved groupings (i.e., either at a project or at a program level). When necessary however, the Commission would 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

is applied at the level of all capital tracker projects, in the aggregate.[33] The Commission also determined that the reasonableness of the grouping of capital projects would be assessed on a case-by-case basis for each individual company.[34]

32. In this application, for its three programs, AltaGas used the same approach to grouping that had been approved by the Commission in previous capital tracker decisions. AltaGas also included, as directed in paragraph 50 and Appendix 3 of Decision 3558-D01-2015,[35] a description of its 2015 non-capital tracker projects and programs, showing the 2015 actual capital additions to provide a better understanding of its proposed groupings of the capital projects and programs for which it was seeking capital tracker treatment.[36]

33. Interveners did not object to any of the groupings for the projects proposed by AltaGas in this proceeding.

Commission findings

34. Consistent with the approach set out in previous capital tracker decisions,[37] given that the groupings in the application are the same as those approved in Decision 2014-373, the Commission did not re-evaluate those groupings in this decision.

35. 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 only partially complied with the direction at paragraph 50 and Appendix 3 of Decision 3558-D01-2015. AltaGas provided, in Excel format with linked and working formulas, the actual capital additions for all programs, including supporting calculations and a breakdown of the amount of depreciation, overheads and income tax allocated to each capital tracker program and non-capital tracker program reconciled to the total amount of depreciation, overheads and income tax for all projects and programs. AltaGas did not provide a description of all non-capital tracker projects or programs that adequately describes, for the purpose of understanding project or program groupings, the nature and purpose of the proposed program. In Appendix I to the application, AltaGas described this non-capital tracker project requirement as "not relevant to the 2015 capital tracker true-up application." Since AltaGas provided these program descriptions in its application for the 2015 forecast capital trackers,[38] for the purposes of this decision, the Commission is willing to dispense with the requirement but reminds AltaGas that, as per page 5 of Appendix 3 to Decision 3558-D01-2015, project descriptions are a minimum filing requirement that need to be included with each capital tracker application for better understanding of the proposed grouping of capital projects and programs for capital tracker treatment. Accordingly, AltaGas is directed to provide a description of all non-capital tracker projects or programs pursuant to the Commission's requirements as set out in Appendix 3 to Decision 3558-D01-2015, at the time of its next capital tracker true-up application.

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33 Decision 2013-435, paragraph 407.
34 Decision 2013-435, paragraph 406.
35 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.
36 Exhibit 21627-X0006 - Appendix I, schedules 10.0 and 10.1.
37 See for example, Decision 3558-D01-2015, paragraph 51.
38 Proceeding 20522, Exhibit 20522-X0010, Appendix III.

7 Materiality threshold

36. AltaGas submitted the following with respect to its proposed materiality thresholds:

> 36. With the exception of overhead rate variances and using Rule 005[39] as a guideline, AUI provides variance explanations for:
>
> - Dollar differences, where the total costs for an individual project are greater than+/-$125,000; or
>
> - Unit (volume) (i.e. km) differences, where the actual lengths for an individual project are greater than +/- 10% of the forecast amount.
>
> 37. In AUI's submission, the proposed thresholds are similar to those used by other utilities (e.g. ATCO Utilities) and ensure larger cost and volume variances (positive or negative) are appropriately explained. As details on differences in total project costs and/or volumes will take into consideration individual costs or circumstances leading to the variance, AUI submits the proposed thresholds provide for an appropriate level of review and should be approved, as filed.
>
> 38. Explanations for differences in overhead rates for individual projects are provided where variances on an individual project are greater than +/- 0.5% and +/- $10,000.[40]

37. In the preamble to AUI-AUC-2016JUN21-001, the Commission provided the following reporting variance explanation criteria, extracted from Rule 005:

> Section 4.4:
>
> | Utility rate base | Variance threshold |
> |---|---|
> | ≥$2 billion | $5 million, or 10 per cent and having a $ amount greater than $1 million |
> | ≥$1 billion, <$2 billion | $2 million, or 10 per cent and having a $ amount greater than $500,000 |
> | ≥$100 million, <$500 million | $500,000, or 10 per cent and having a $ amount greater than $125,000 |
> | ≥$25 million, <$100 million | $200,000, or 10 per cent and having a $ amount greater than $100,000 |
> | <$25 million | $100,000, or 10 per cent and having a $ amount greater than $50,000 |
>
> Section 4.5: For non-financial data, a utility must provide an explanation for a variance greater than or equal to 10 per cent for each line item **unless clearly immaterial**. [emphasis added]

38. In its response to AUI-AUC-2016JUN21-001, AltaGas explained why its proposed variance explanation threshold for cost uses only a dollar amount criterion (variances of +/-$125,000) and does not include a per cent amount criterion, such as the +/- 10 per cent

[39] Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.
[40] Exhibit 21627-X0007, application, paragraphs 36-38.

threshold directed by Section 4.5 of Rule 005. AltaGas maintained that it considered its proposal to be reasonable because it would provide explanations for any project with variances greater than $125,000, even if the variance was less than 10 per cent. However, if the Commission preferred, AltaGas submitted that it would have no objections to adding to its variance explanation threshold for costs the +/- 10 per cent threshold criterion, provided it is at a project level.

39. In its response, AltaGas also commented on the need for line level versus project level variance explanations:

> The proposal to adjust the thresholds from prior applications was to focus review on overall project variances, rather than line by line variances within each project. Where variances trigger one or both thresholds, explanations are provided regarding the primary volume and cost change drivers.

40. AltaGas made the following request at the end of its response:

> AUI notes, due to changes in volumes and costs, almost all projects triggered the proposed thresholds. Consequently, for completeness and as the new thresholds are subject to AUC approval, AUI provided variance explanations with regard to all 2015 CT project additions. In future filings, AUI requests the Commission's approval to limit explanations to those meeting the thresholds proposed in this proceeding.

Commission findings

41. Based on AltaGas' most recent Rule 005 filing, the Commission agrees that AltaGas fits within the ≥$100 million, <$500 million AUC Rule 005 rate base category shown in the table above.

42. Regarding AltaGas' proposal to only use a cost component in the variance explanation threshold, the Commission finds that using a cost component as well as per cent component is preferable because it results in a more robust variance explanation.

43. The Commission accepts AltaGas' variance explanations at the project level, rather than for each line item, because AltaGas has included sufficient information with respect to significant line items. If AltaGas chooses to provide variance explanations at the project level in the future, the Commission will expect AltaGas to include information with respect to significant line items.

44. The Commission finds AltaGas' variance explanation threshold proposal to be reasonable but has decided not to be prescriptive with respect to directing precise thresholds. The Commission considers it more effective for AltaGas, in particular situations, to determine what it considers necessary to make its prudency and reasonableness case for forecasts and actuals in its capital tracker applications. In future applications, if the Commission requires further information on specific variances, it will address that need through the IR process.

8 Assessment of individual projects within programs under Criterion 1 - previously approved capital tracker projects

45. As discussed in Section 4 of this decision, each of AltaGas' individual projects within its three capital tracker programs proposed for capital tracker treatment for 2015 have been evaluated on an actual basis against the second part of the project assessment requirements of Criterion 1. Under this component of Criterion 1, the Commission assesses whether the actual scope, level, timing and costs of the project are prudent.

46. The Commission also evaluated whether, with respect to each project or program, AltaGas provided business cases, engineering studies, cost related information, and related evidence and argument to demonstrate compliance with each of the project assessment minimum filing requirements. However, in this decision, the Commission commented only on those aspects of the minimum filing requirements that AltaGas either failed to comply with, or did not satisfactorily comply with, or that were otherwise raised as an issue in the proceeding.

47. The assessment is organized as follows:

- Section 8.1 addresses previously approved capital tracker projects for which no issues were identified.
- Section 8.2 addresses previously approved capital tracker projects for which issues were identified.
- Section 8.3 addresses capital tracker projects not previously approved.

8.1 Previously approved capital tracker projects for which no issues were identified

48. The application includes a number of previously approved capital tracker projects and related trailing costs for which no objections were raised by the parties and with respect to which the Commission has no concerns regarding the projects respective need, scope, level, timing or costs.

8.1.1 Pipeline Replacement program

49. AltaGas provided tables detailing 2015 Pipeline Replacement program trailing costs for each of Pre-1957 Steel, PVC, and Non-Certified PE Pipe, and associated variance explanations for the trailing costs. These are provided below.

Table 7. Pre-1957 Steel Pipe trailing costs

Pre-1957 Steel Pipe – trailing costs	Cost component ($)					
Project	Labour	Other contractor	Material	Tendered contractor	Overhead	Total
Town of Bonnyville (2014)	1,835	-	361	-	(166)	2,030
Town of Drumheller (2014)	(1,228)	-	-	-	(2,241)	(3,470)
Town of Athabasca (2014)	7,956	25,205	14,728	51,523	3,554	102,966
Total	**8,562**	**25,205**	**15,090**	**51,523**	**1,147**	**101,527**

Source: Exhibit 21627-X0007, application, Table 2.2.6-1, paragraph 134.

50. AltaGas explained that the $101,527 of prior year Pre-1957 Steel Pipe project trailing costs were primarily related to civil site work, final documentation of as-built designs and accounting adjustments. For the Town of Bonnyville project, AltaGas stated that the costs incurred were related to final drafting, inspection and project close-out activities (i.e, decommissioning of old risers, final drafting and integration of as-built designs).[41]

51. For the Town of Drumheller project, AltaGas explained that the credit amount reflected final accounting adjustments to reverse minor over-accruals from 2014. For the Town of Athabasca project, the trailing costs reflected final clean-up and site restoration (i.e., paving) which could not be carried out at the end of 2014 due to timing and weather.[42]

Table 8. PVC Pipe trailing costs

PVC Pipe – trailing costs	Cost component ($)						
Project	Labour	Other contractor	Land payments	Material	Tendered contractor	Overhead	Total
Barrhead Area 1,2,3 (2014)	1,328	(4,569)	1,800	234	45,811	2,813	47,417
Morinville (2014)	1,285	8,595	219	44	5,059	952	16,153
Morinville Rural Phase 1 (2013)	140	-	(1,480)	(200)	-	45	(1,495)
Morinville Rural Phase 3 (2013)	47	-	(497)	(67)	-	15	(502)
2012 Projects	883	-	(8,844)	-	-	347	(7,614)
2011 Projects	2,185	-	(25,709)	-	-	719	(22,806)
Total	**5,867**	**4,026**	**(34,511)**	**11**	**50,870**	**4,891**	**31,154**

Source: Exhibit 21627-X0007, application, Table 2.3.4-1, paragraph 172.

52. AltaGas stated that the $31,154 of prior year PVC Pipe project trailing costs were incurred for civil site work, land compensation payments, final project close-out costs, and costs associated with completing and updating final (as-built) designs. For the Barrhead Area 1, 2, 3 project, AltaGas explained that the costs were incurred for restoration work (i.e., paving, topsoil and seeding) that were not completed in 2014 due to weather issues, land compensation payments for lost crops and costs associated with final drafting (as-built) work.[43]

[41] Exhibit 21627-X0007, application, paragraph 135.
[42] Exhibit 21627-X0007, application, paragraph 135.
[43] Exhibit 21627-X0007, application, paragraph 173.

53. For the Morinville (2014) project, AltaGas stated that the costs were incurred for final inspection, land compensation, installation of additional meter set piping required for safety code compliance and the finalization of as-built designs. For the 2011-2013 projects, AltaGas explained that the costs were primarily related to outstanding landowner compensation claims and final accounting adjustments to reverse minor over-accruals.[44]

Table 9. Non-Certified PE Pipe trailing costs

Non-Certified PE Pipe – trailing costs	Cost component ($)					
Project	Labour	Other contractor	Land payments	Material	Overhead	Total
Pigeon Lake (2014)	5,072	1,424	-	331	459	7,286
Ma-Me-O Beach (2014)	(396)	340	-	-	308	252
Looma (2013)	75	-	(787)	(107)	24	(795)
Kavanagh (2013)	19	-	(197)	(27)	6	(199)
Manola (2012)[45]	47	-	(494)	(67)	15	(499)
Tiebeke (2013)	24	-	(250)	(34)	8	(252)
Blaine Hochstein (2013)[46]	6	-	200	-	11	217
Sturgeon Valley (2012)	219	-	(1,459)	(284)	106	(1,419)
Total	**5,064**	**1,764**	**(2,988)**	**(187)**	**938**	**4,590**

Source: Exhibit 21627-X0007, application, Table 2.4.4-1, paragraph 229.

54. AltaGas stated that the $4,590 of prior year Non-Certified PE Pipe project trailing costs were incurred for civil site work and costs associated with the closing of a project. For the Pigeon Lake project, AltaGas explained that the costs were related to final inspection, repair drafting, and minor material adjustments. For the Ma-Me-O Beach project, AltaGas stated that the costs were related to minor accounting allocation adjustments and final inspection. For the Looma, Kavanagh, Manola, Tiebeke, and Sturgeon Valley projects, AltaGas explained that the costs reflect finalization of land compensation claims and final accounting adjustments to reverse minor over-accruals.[47]

Commission findings

55. 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.

[44] Exhibit 21627-X0007, application, paragraph 173.
[45] The Manola project was identified by AltaGas in the application as a 2013 project but the project was a 2012 project approved in Decision 2012-091.
[46] The Blaine Hochstein project is identified in the application as a 2013 project but the Commission was unable to find a project by this name.
[47] Exhibit 21627-X0007, application, paragraph 230.

56. The 2015 trailing costs reflect:

- The 2014 projects that were previously approved on a forecast basis by the Commission in Decision 2014-373.
- The 2013 projects that were previously approved on a forecast basis by the Commission in Decision 2013-435.
- The 2011 and 2012 projects that were previously approved in Decision 2012-091.

57. For the 2014 projects, AltaGas provided trailing costs, the specific year to which those trailing costs relate, trailing cost explanations on a program level and explanations for projects on an individual level. 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 2014 projects in this program were prudently incurred. Accordingly, the Commission approves the inclusion of these trailing costs as part of project total costs for the purposes of the K factor calculation.

58. For the 2011-2013 projects, AltaGas provided trailing costs, the specific year to which those trailing costs relate, trailing cost explanations on a program level and explanations for projects on a program level, as opposed to an individual project level. With the exception of the Blaine Hochstein project, 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 2011-2013 projects in this program were prudently incurred.

59. With respect to the Blaine Hochstein project, the Commission was unable to find a previous application for a project by this name or an approval of a project by this name in Decision 2013-435 on a forecast basis, or in Decision 2014-373 on a true-up basis. It was also not approved on a true-up basis as a 2013 project in Decision 20522-D02-2016 or in Decision 2012-091. Further, AltaGas did not provide a variance explanation specifically for these trailing costs. Therefore, the Commission cannot, at this point, approve this project or the project's trailing costs on a final basis. AltaGas is directed to remove all costs associated with this project from its 2015 actual K factor at the time of its next Rate Rider F application or capital tracker true-up application, whichever occurs first.

8.1.2 Station Refurbishment program

60. AltaGas provided information for the four PMS Station Refurbishment projects discussed in this section, which have been summarized in Table 10 below. This table shows the 2015 actual capital additions on which the 2015 capital tracker true-up is based for the four 2015 PMS Station Refurbishment projects. AltaGas also provided a summary table of 2015 Station Refurbishment program trailing costs for 2014 Station Refurbishment projects, which is reproduced below in Table 11, and variance explanations for the projects and the trailing costs. These are discussed below.

61. As directed by the Commission at paragraph 280 of Decision 2014-373, AltaGas included with its variance explanations, tables for each of the four stations showing the build-up of project costs for each station and comparing it to the build-up of project costs in a standard station. In addition, in compliance with Commission direction at paragraph 284 of Decision

2014-373, AltaGas included a discussion on why each station was completely replaced or only partially refurbished.[48]

Table 10. PMS Stations 2015 true-up

		Capital additions		Variance	
Stations	Typical	Approved	Actual	Approved vs. actual	% of total approved
	($)				(%)
AT123[49]	272,900	458,300	435,927	22,372	4.9
LE346	272,900	272,800	24,943	247,857	90.9
ST014[50]	272,900	327,400	347,320	(19,920)	(6.1)
ST002	272,900	191,000	-	191,000	-

Source: Exhibit 21627-X0007, application, unnamed tables, pages 93, 95, 99 and 100.

62. AltaGas submitted that PMS Station AT123 required full replacement because it had obsolete equipment, run-splitting regulators and numerous gate valves in its piping configuration; making partial refurbishment impractical. The station also leaked small amounts of gas by design and had a wooden building in poor condition. AltaGas explained that the station was forecast to have higher costs than a standard station because it was determined that the station needed to be physically moved, the valve and piping work was more complex, the associated fabrication costs were higher, and there was a need to locate, extend and tie-in high-pressure lines feeding the station.

63. AltaGas explained that PMS Station AT123 was located within the fenced boundaries of a third-party gas plant and was required to be moved in order to improve AltaGas' emergency access to the station and to avoid hazards to AltaGas workers, who were unfamiliar with the third party facility. The station was originally planned to be moved from the third-party site to an adjacent property. However, the final design moved the station a shorter distance, outside the fenced boundaries of the gas plant, but still on the same third-party's property. Moving the station a shorter distance reduced the amount of high pressure and distribution pipe that would have otherwise been required and eliminated the need for three pipeline crossings.

64. AltaGas' explanation included additional cost savings realized in the replacement of PMS Station AT123 after further inspection of the existing odorant system revealed it could be re-used on the new station. These cost savings were partially offset by soil testing required to ensure the new location was not contaminated and by the requirement for a larger line heater system than originally estimated to meet the gas demand at the station.[51]

65. PMS Station LE346's originally approved replacement, included forecast costs for a new line heater, changes to the meter run assembly and a revised odorant system. On further review of the hydraulic flow characteristics of the Leduc district gas system, AltaGas determined that

[48] Exhibit 21627-X0007, application, paragraphs 240 and 242-243.
[49] Subsequently renamed AT123.
[50] A change in the scope of ST002, allowed the costs of the conversion to be charged to ST014, which took over the regulating function of ST002.
[51] Exhibit 21627-X0007, application, Table 3.4.1 and paragraphs 250-253.

only the meter run assembly change was required in order to accommodate the gas flows at this station, resulting in substantially reduced actual costs, as compared to forecast.[52]

66. PMS Station ST014 was scheduled for replacement because this high volume facility performed a large pressure cut, increasing the likelihood and consequence of potential failure. It also had run-splitting regulators, leaked small amounts of gas by design and had a wooden building in poor condition. Although a new odorant system was not required, valving and piping complexities and the need for greater use of external contractor resources increased the estimated cost of this project by $55,000 over an average station of its size. Actual costs were $20,000 higher than forecast due to additional AltaGas labour required to expose third-party owned piping within the station site to ensure it would not interfere with the planned construction.[53]

67. Initially, PMS Station ST002 was to be replaced because it had run-splitting regulators, gate valves, leaked small amounts of gas by design and had a wooden building in poor condition. AltaGas' refurbishment of PMS Station ST014 and reconfiguration of the associated gas flow to the town of Stettler reduced the need for ST002 and allowed it to be downgraded to a block valve assembly to control the high pressure pipeline at that location. As a result of the scope change, the costs of this conversion were charged to ST014, which took over the regulating function of ST002.[54]

Table 11. 2014 Station Refurbishment project trailing costs

		Cost component ($)					
Line	Project	Labour	Engineering	Other contractor	Material	Overhead	Total
1	DR017	188	141	(1,341)	8,656	406	8,051
2	MN008	45	-	1,072	547	95	1,759
3	LE214	668	-	605	189	87	1,549
4	SP316	(12)	-	(1,255)	1,740	30	503
5	LE081	384	-	(1,396)	(265)	(69)	(1,345)
6	SP014	(98)	-		(3,040)	(162)	(3,300)
7	ST004	(903)	-	(2,615)		(1,959)	(5,477)
8	SP252	2,908	-	(43)	(4,368)	(83)	(1,586)
9	MN020	(1)	-	(20)		(1)	(22)
10	LE310	2,006	-	(8,495)	462	(159)	(6,186)
11	LE060	27	-	(789)	540	27	(195)
12		**5,213**	**141**	**(14,277)**	**4,462**	**(1,788)**	**(6,248)**

Source: Exhibit 21627-X0007, application, Table 3.7-1.

68. In 2015, AltaGas incurred net credit charges of $6,248 for trailing costs associated with the 2014 Station Refurbishment projects listed in the above table. The trailing costs for Station DR017 included a rotary meter which was not accrued at 2014 year-end, credits received from other contractors and final (as-built) drafting costs. The trailing costs for stations MN008 and LE214 were for site restoration work, including cost of final grading, gravel and topsoil. The

[52] Exhibit 21627-X0007, application, unnamed table on page 95 and paragraph 254.
[53] Exhibit 21627-X0007, application, unnamed table on page 100 and paragraph 259.
[54] Exhibit 21627-X0007, application, unnamed table on page 99 and paragraph 258.

trailing costs for stations SP316, LE081, SP014, ST004, SP252, MN020, LE310 and LE060 mostly reflect final accounting adjustments to reverse minor over-accruals from 2014.[55]

Commission findings

69. In Decision 2014-373, the Commission approved the need for PMS Station Refurbishment projects AT123, LE346, ST002 and ST014 on a forecast basis, for the purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

70. With respect to the true-up of 2015 actual costs for these two projects, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that the PMS stations AT123, LE346, ST002 and ST014 projects were not required in 2015.

71. With respect to the scope, level and timing of the work associated with PMS Station Refurbishment project AT123 carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $435,927 for the replacement of the station and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for PMS Station Refurbishment AT123 project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the approved forecast and actual costs, and finds these costs to be prudent.

72. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that PMS Station Refurbishment AT123 project satisfies the project assessment requirement of Criterion 1 for 2015.

73. With respect to the scope, level and timing of the work associated with PMS Station Refurbishment LE346 project, carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $24,943 and finds that, after factoring in the identified reduction in the amount of work required, they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the costs of the 2015 actual capital additions for PMS Station Refurbishment LE346 project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the 2015 approved forecast and actual costs, and finds the actual costs to be prudent.

74. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the PMS Station Refurbishment LE346 project were prudent. Accordingly, the Commission finds that the PMS Station LE346 project satisfies the project assessment requirement of Criterion 1 for 2015.

[55] Exhibit 21627-X0007, application, paragraph 299.

75. With respect to the scope, level and timing of the work associated with PMS Station Refurbishment projects ST014 and ST002 carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $347,320 for the work done on the two stations combined and finds that, after factoring in the refurbishment of PMS Station ST014, the reconfiguration of the associated gas flow to the town of Stettler and the resultant reduced need for ST002, they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for PMS Station Refurbishment projects ST014 and ST002 in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the 2015 approved forecast and actual costs, and finds the actual costs to be prudent.

76. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the PMS stations ST014 and ST002 projects were prudent. Accordingly, the Commission finds that the PMS stations ST014 and ST002 projects satisfy the project assessment requirement of Criterion 1 for 2015.

77. The 2015 trailing costs for Station Refurbishment projects relate to 2014 projects that were previously approved on a forecast basis by the Commission in Decision 2014-373. Pursuant to the Commission's direction at paragraph 113 of Decision 2014-373, quoted above, in addition to providing the trailing costs, AltaGas also provided the specific year to which those trailing costs relate, trailing cost explanations on a program level and explanations for projects on an individual level. 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 these trailing costs as part of project total costs for the purposes of the K factor calculation.

8.1.3 Gas Supply program

78. AltaGas provided a table detailing 2015 Gas Supply trailing costs:

Table 12. Gas Supply trailing costs

				Cost			
Line	Project	Labour	Other contractor	Land payments	Payments material	Overhead	Total
		($)					
1	Suncor Athabasca (2013)	69	-	(726)	(98)	22	(733)
2	Westlock (2013)	(31)	5,256	-	(7,735)	(157)	(2,668)
3	St. Paul Cork Hall (2013)	3,515	1,212	1,000	(4,497)	82	1,311
4	Total	**3,552**	**6,468**	**274**	**(12,331)**	**(53)**	**(2,090)**

Source: Exhibit 21627-X0007, application, paragraph 315.

79. AltaGas stated that in 2015 it incurred net credit charges of $2,090 for prior period (2013) Gas Supply projects. AltaGas explained that the trailing costs for Suncor Athabasca were for finalization of land compensation payments to landowners for amounts lower than previously accrued. The Westlock trailing costs reflect the reversal of duplicate materials charges, partially offset by other contractor costs for fence installation. The St. Paul Cork Hall trailing costs were

for final site restoration, compensation to landowners and a credit for over-accrued material costs.[56]

Commission findings

80. At paragraph 113 of Decision 2014-373, the Commission directed AltaGas to identify the specific prior-year projects to which the trailing costs relate, identify the activities that give rise to the trailing costs, and fully support the prudence of the requested trailing cost amounts.

81. The 2015 trailing costs reflect 2013 projects that were previously approved on a forecast basis by the Commission in Decision 2013-435.

82. AltaGas provided trailing costs, the specific year to which those trailing costs relate, trailing cost explanations on a program level and explanations for projects on an individual level. The Commission considers that AltaGas has complied with the Commission's direction at paragraph 113 of Decision 2014-373 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 these trailing costs as part of project total costs for the purposes of the K factor calculation.

8.2 Previously approved capital tracker projects for which issues were identified

8.2.1 Pipeline Replacement program

83. As shown in Table 2, above, AltaGas identified a number of Pipeline Replacement projects that were previously approved for capital tracker treatment in Decision 2014-373 for 2015, and were either fully completed in 2015, or were partially completed in 2015 and deferred to a future year. AltaGas also identified projects that were previously approved for capital tracker treatment for 2014 in Decision 2014-373, and were partially completed in 2014 with the remainder deferred to 2015.

84. In the application, AltaGas discussed its forecasting accuracy for the Pipeline Replacement program. Parties asked IRs about AltaGas' forecasting accuracy but did not have any objections. Forecasting accuracy is addressed, where relevant, in the following sections regarding the need, scope, level, timing or costs of these projects.

85. AltaGas explained that its 2015 project cost estimates were based on average 2013 historical costs for similar projects, adjusted for inflation and that forecast deficiencies (both in terms of cost and total pipe length) arose, in part, because of the timing of the 2014-2015 capital tracker forecast application. Specifically, due to the timing of the 2014-2015 capital tracker forecast application, the 2015 forecast estimates did not have the benefit of on-site reconnaissance or the detailed pre-tender estimation process used for 2014 forecasts. In determining the 2015 forecast, the 2015 project estimates were based on desktop reconnaissance that had been completed at the time. AltaGas acknowledged that its desktop reconnaissance process was not as robust in 2015, as it was in 2014. For example, AltaGas only relied on basic map information from its Environmental Systems Research Institute, Inc. (ESRI) system to

[56] Exhibit 21627-X0007, application, paragraph 316.

prepare its forecasts. In several cases, not all ESRI information was used (such as the number of service connections) or other available information.[57]

86. In response to a Commission IR, AltaGas submitted that that the ability to complete on-site reconnaissance and detailed pre-tender contract estimates depends on the timing of the related application.[58] The optimal timing for on-site reconnaissance, including landowner negotiations, is during the 12- to 18-month window prior to the start of construction. If on-site reconnaissance is done too far in advance, changes can occur that materially affect the nature and cost of the project. The 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.[59]

87. AltaGas also explained that on-site reconnaissance is not cost-effective if completed more than 18 months in advance. This is because circumstances may change for a project prior to construction, thereby negating the benefit of this investment. Additional internal or external engineering resources may also be required, depending on the timing of the application relative to the construction activities that may be occurring in the same period.[60]

88. AltaGas explained that the 2014-2015 capital tracker forecast application was submitted on March 31, 2014, which was approximately 14 months prior to the start of the 2015 construction season. Due to the timing of the submission of this application, AltaGas' engineering and construction teams were engaged in planning and designing the 2014 construction projects, developing preliminary risk models for high-pressure steel pipe, redesigning project cost templates and leading improvements in the project management processes.[61]

89. AltaGas advised that it is reviewing forecasting deficiencies to identify opportunities for improved project estimation.[62] In response to a Commission IR, AltaGas explained that it will improve its desktop reconnaissance process to improve the accuracy of its forecast by fully incorporating all information that is readily available at this stage. These improvements will include enhancing its regression analysis to derive more accurate project forecasts at the preliminary desk reconnaissance stage. For example, AltaGas will identify all relevant factors that significantly impact the cost of a project, including the length of mains and services, service density, number of bell holes, drilling versus trenching, restoration and utility crossings.[63]

90. Other examples of improvements AltaGas is making to its desktop reconnaissance include:

- Use of the geographic information system software that AltaGas uses (ESRI) to provide service line density, which drives pipe installation and service connection costs for Pre-1957 Steel Pipe projects, including costs of drilling and utility and main crossings.

[57] Exhibit 21627-X0007, application, paragraph 59.
[58] Exhibit 21627-X0015, AUI-AUC-2016JUN21-002(b) and Exhibit 21627-X0035,AUI-UCA-2016JUN21-006.
[59] Decision 20522-D02-2016, paragraph 145.
[60] Exhibit 21627-X0015, AUI-AUC-2016JUN21-002(a) and (b).
[61] Exhibit 21627-X0007, application, paragraphs 60-61.
[62] Exhibit 21627-X0007, application, paragraph 60.
[63] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(g).

- Use of ESRI to provide the number of main connections (right angles or T-connections), which determines the number of bell-holes required, which are a major cost driver for Pre-1957 Steel Pipe projects.
- Determination from commercially available imagery of the general extent of ground cover and congestion, which impacts drilling and site restoration costs.
- Use of aerial survey information to identify elevation changes and crossings required for drilling on PVC and Non-Certified PE projects.[64]

91. AltaGas further stated that preliminary on-site visits during the initial desktop reconnaissance would likely increase the accuracy of a project forecast. However, preliminary on-site visits are not always feasible or cost-effective because project forecasts are submitted to the Commission up to two years in advance of the actual construction work, and the data obtained in a site visit may be irrelevant by the time a project is started. Therefore, enhancements to desktop reconnaissance should allow AltaGas to avoid the time and cost of travelling to each project site, while providing the same essential information. In AltaGas' view, the most cost-effective approach to on-site reconnaissance is to complete a review of the project area and determine the exact pipe alignment at the same time, consistent with AltaGas' final project planning timelines in the year of construction, rather than through a preliminary and final stage assessment.[65]

8.2.1.1 Pre-1957 Steel Pipe Replacement program

92. In Decision 2014-373, the Commission approved eight Pre-1957 Steel Pipe Replacement projects for 2015. These include the replacement of seven downtown projects (Drumheller, Hanna, Stettler, Barrhead, Westlock, Morinville, and St. Paul) and one town project (Drumheller).[66] In 2015, AltaGas completed the replacement of the seven downtown projects and deferred the town project to 2016.

93. The Commission has divided the Pre-1957 Steel Pipe Replacement program into the following two categories:

- Projects approved for 2015 and completed in 2015.
- Projects approved for 2014 and partially completed in 2014 with the remainder completed in 2015; projects approved for 2015 and partially completed in 2015 with the remainder deferred.

8.2.1.1.1 Projects approved for 2015 and completed in 2015

94. For the Pre-1957 Steel Pipe Replacement program, reconnaissance and land negotiations began in February 2014 and were expected to be complete by mid-2014. AltaGas based its 2015 cost estimates on historical costs for comparable downtown and town pipe replacement projects in 2013, adjusted for inflation, as well as insights gained by AltaGas from initial site reconnaissance.[67]

[64] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(b).
[65] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(f).
[66] Decision 2014-373, paragraphs 210 and 231.
[67] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(a).

95. AltaGas provided approved forecast and actual costs and pipeline lengths, as well as a variance analysis for each Pre-1957 Steel Pipe Replacement project completed in 2015:

Table 13. Pre-1957 Steel Pipe projects – 2015 capital additions and pipe length

	Capital additions				Pipe length			
Pre-1957 Steel	Approved	Actual	Approved vs. actual variance)	% of total approved	approved	Actual	Approved vs. actual variance	% of total approved
	($)			(%)	(km)			(%)
Drumheller (downtown)	1,163,000	1,962,526	(799,526)	-68.7	3.8	5.2	(1.4)	-37.0
Hanna (downtown)	909,300	1,193,286	(283,986)	-31.2	3.0	3.9	(0.9)	-30.2
Stettler (downtown)	472,900	1,147,856	(674,956)	-142.7	1.6	2.6	(1.0)	-66.3
Barrhead (downtown)	861,100	1,421,965	(560,865)	-65.1	2.8	3.9	(1.1)	-37.4
Westlock (downtown)	1,197,400	1,684,248	(486,848)	-40.7	3.9	5.5	(1.6)	-39.5
Morinville (downtown)	889,600	1,304,818	(415,218)	-46.7	3.0	4.2	(1.2)	-40.0
St. Paul (downtown)	591,200	1,013,042	(421,842)	-71.4	1.9	2.8	(0.9)	-44.7

Source: Exhibit 21627-X0007, application, paragraphs 82, 85, 88, 91, 93, 95 and 97.

96. For Pre-1957 Steel Pipe projects completed in 2015, AltaGas explained that it did not identify certain work elements and related costs until the detailed planning stage when the contractor bidding process for tendered contractors was completed and actual construction commenced. AltaGas stated that the higher than forecast actual costs were due to higher labour and materials costs for additional work on project redesign and as-builts, increased third-party contractor costs for contract inspectors, increased pipe installation costs for the installment of incremental pipe, additional service connection costs and additional site restoration costs for asphalt work not identified in the forecast.[68]

97. For the Drumheller, Stettler, Barrhead and St. Paul (downtown) projects, actual costs were higher than forecast due to the need for horizontal directional drilling, increases in the number of identified utility crossings and meter-sets, identification of more extensive above and underground infrastructures, and the inadvertent exclusion of incidental post-1957 steel pipe from the original project estimates. These factors all contributed to higher costs related to identifying and exposing pipe, crossing over other utility infrastructure, installing additional pipe and meter set protection in highly congested areas, and site restoration.[69]

98. For the Westlock (downtown) project, AltaGas explained that the higher than forecast actual cost of the project was primarily due to the need for horizontal directional drilling and the impact of higher contractor rates for all connections and tie-ins.[70] For the Hanna (downtown) project, AltaGas explained that the actual cost of the project was higher than forecast due to the additional work required to navigate a higher than expected density of third-party pipe and utility

[68] Exhibit 21627-X0007, application, paragraph 80.
[69] Exhibit 21627-X0007, application, paragraph 76.
[70] Exhibit 21627-X0007, application, paragraph 94.

crossings, and the impact of higher contractor rates relating to additional work for hydrovac and bell holes.[71] For the Morinville (downtown) project, AltaGas explained that the actual cost of the project was higher than forecast due to required pipe alignment changes caused by the discovery of existing third party utility infrastructure, an increase in the number of service line connections and the impact of higher contractor rates.[72]

99. For every Pre-1957 Steel Pipe project, AltaGas explained that the increases in pipeline length were caused by the inadvertent exclusion of incidental post-1957 steel services and mains from the original forecast provided by AltaGas and approved in Decision 2014-373.[73]

Commission findings

100. In Decision 2014-373, the Commission approved the need on a forecast basis, for each of the Pre-1957 Steel Pipe Replacement projects listed in Table 13 above, for purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

101. With respect to the true-up of 2015 actual costs, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that any of the Pre-1957 Steel Pipe Replacement projects listed in Table 13 were not required in 2015.

102. With respect to the scope, level and timing of each of the Pre-1957 Steel Pipe Replacement projects listed in Table 13 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the Pre-1957 Steel Pipe Replacement projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for each of the Pre-1957 Steel Pipe Replacement projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there are significant cost and pipeline length variances between the approved forecast and the actual cost for all of the Pre-1957 Steel Pipe replacement projects.

103. As discussed in Section 8.2.1 of this decision, the Commission notes that these significant cost and pipeline length variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.1 above, AltaGas provided an extensive description of the improvements to desktop reconnaissance that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost and pipeline length variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the

[71] Exhibit 21627-X0007, application, paragraph 86.
[72] Exhibit 21627-X0007, application, paragraph 96 and Exhibit 21627-X0022, AUI-AUC-2016JUN21-006(d).
[73] Exhibit 21627-X0007, application, paragraph 77.

use of forecasting methods that are not well suited to the timing of the related application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, such as the improvements currently being undertaken to its desktop reconnaissance. The Commission notes that improvements in forecasting accuracy were first proposed by AltaGas in its 2016 to 2017 forecast capital tracker application, and were approved by the Commission in Decision 20522-D02-2016. Specifically, the Commission approved changes that had been made by AltaGas to its cost estimating methodology, which included the introduction of initial (regression) analysis, desktop reconnaissance and field reconnaissance.

104. Despite the significant cost and pipeline length variances associated with each of the Pre-1957 Steel Pipe Replacement projects, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the Pre-1957 Steel Pipe Replacement program and each of the associated projects, as identified in Table 13, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.1.1.2 Projects approved for 2014 and partially completed in 2014 with remainder completed in 2015; projects approved for 2015 and partially completed in 2015 with remainder deferred

2015 Drumheller (town) project

105. In Decision 2014-373, the Commission approved the 2015 Drumheller (town) project.[74] AltaGas did not complete this project in 2015 and deferred the remainder to 2016. AltaGas provided the approved forecast and actual costs and pipeline lengths, and a variance analysis as set out in Table 14, below:

Table 14. Pre-1957 Steel Pipe project – 2015 capital additions and pipe length for Drumheller (town)

	Capital additions ($)				Pipe length (km)			
Pre-1957 Steel	Approved	Actual	Approved vs. actual	% of total approved	Approved	Actual	Approved vs. actual variance	% of total approved
Drumheller (town)	1,606,600	240,705	1,365,895	85%	6.9	0.4	6.5	94.9%

Source: Exhibit 21627-X0007, application, paragraph 107.

106. In Decision 2014-373, the Commission approved 15.6 km to be replaced for the Drumheller (town) project, of which 6.9 km was to be replaced in 2015 and 8.7 km in 2016. In the 2016-2017 capital tracker forecast application, AltaGas provided an update to the project forecast costs, to include the costs associate with the replacement of additional post-1957 steel pipe, which were mistakenly missing in the original costs estimate. In the update, AltaGas maintained that it planned to replace a total of 20.7 km of pipe for a total cost of $6.7 million, as shown in the table below:

[74] Decision 2014-373, paragraphs 210 and 231.

Table 15. Update to Drumheller (town) project

	Project phase	Pipe length	Cost ($ million)
2015 Forecast Update 1	Drumheller – Phase 1	1.1 km	0.4
2016 Approved 2	Drumheller – Phases 2, 3, 4	9.7 km	3.5
2016 Approved 2	Drumheller – Phase 5	9.9 km	2.8
	Total	**20.7 km**	**6.7**

Source: Exhibit 21627-X0007, application, Table 2.2.4-1, paragraph 109.

107. AltaGas explained that it was unable to complete the entire 1.1 km of the Drumheller Phase 1 portion of the project as planned due to limited capacity driven by the focus in 2015 on replacing all pre-1957 steel pipe in downtown areas. Of the 1.1 km planned for replacement in Phase 1, AltaGas only replaced 0.4 km of pipe in response to a request of the town of Drumheller to coordinate with the town's paving program. AltaGas stated that the remaining pipe for this project would be replaced by the end of 2016. With the replacement of 0.4 km of pipe in 2015 at a cost of $0.2 million, AltaGas revised the 2016 forecast to replace 20.3 km at a cost of $6.5 million, resulting in no change to the original estimate of 20.7 km at a cost of $6.7 million.[75]

108. In the absence of an approved 2015 forecast, AltaGas provided the amounts approved in its authorization for expenditures (AFE)[76] for the purpose of assessing the prudence of the cost for the 0.4 km of pipe replaced in 2015. The AFE forecast cost was $238,387, the forecast pipeline length was 0.36 km and the forecast unit cost was $654,900/km. AltaGas completed a portion of the Phase 1 project in 2015, replacing 0.35 km of pipe at an actual cost of $240,705, for a total unit cost of $685,575/km. The cost variance was $2,319 (1.0 per cent) above forecast, the pipeline length variance was 0.01 km (3.5 per cent) below forecast and the unit cost variance was $30,675/km (4.7 per cent) above forecast.[77]

109. AltaGas explained that the overall project costs were within one per cent of the AFE resulting from the need for more labour from third-party contractors to offset the limited availability of tendered contractors.[78]

2014 Athabasca (downtown) project

110. In Decision 2014-373, the Commission approved the need for the 2014 Athabasca (downtown) project, scheduled to be completed in 2014. The approved project included replacement of 12.2 km of pipe. At the end of 2014, 0.2 km remained outstanding because AltaGas was awaiting a road crossing permit from the Alberta Ministry of Transportation for cutting open the highway to confirm a fibre line location prior to directional drilling. As a result, the replacement of the 0.2 km of pipe was carried over to 2015. AltaGas completed the project after the road crossing permit was received in 2015.[79]

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75 Exhibit 21627-X0007, application, paragraphs 111-113.

76 In paragraph 95 of Decision 20522-D02-2016, the Commission provided AltaGas' explanation that the 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 2015 AFE estimate details the costs for labour, materials, contractors and overhead.

77 Exhibit 21627-X0007, application, paragraph 115.

78 Exhibit 21627-X0007, application, paragraph 116.

79 Exhibit 21627-X0007, application, paragraph 99.

111. In support of its variance explanation of costs for the remaining 0.2 km section of pipe completed in 2015, AltaGas provided its AFE to serve as a baseline for assessing the prudence of the actual costs incurred. The AFE forecast cost for the 0.2 km was $64,901, for a forecast unit cost of $424,200/km. The actual costs for replacing the 0.2 km of pipe was $55,980, for a unit cost of $237,305/km. The cost variance was $8,920 (13.7 per cent) below forecast, the pipeline length variance was 0.1 km (54.2 per cent) above forecast and the unit cost variance was $186,895/km (44.1 per cent) below forecast.[80]

112. AltaGas explained that this project came in at a lower cost per km than originally forecast because pipeline installation costs were lower than forecast for two reasons. First, a local mains and services contractor was utilized at a lower rate, which decreased mobilization and demobilization costs. Second, drier than expected site conditions enabled AltaGas to change the pipe installation method from open trenching to lower-cost plowing.[81]

Commission findings

113. In Decision 2014-373, the Commission approved the need for the Drumheller (town) and Athabasca (downtown) projects on a forecast basis, for the purposes of capital tracker treatment in 2015 and 2014, respectively. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

114. With respect to the true-up of 2015 actual costs for these two projects, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that the Drumheller (town) and the Athabasca (downtown) projects were not required in 2015.

115. With respect to the scope, level and timing of the work associated with the Drumheller (town) project carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $240,705 for the replacement of 0.4 km of pipe and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for the Drumheller (town) project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between 2015 AFE estimate and actual costs, and finds these costs to be prudent.

116. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the Drumheller (town) project were prudent. Accordingly, the Commission finds that the Drumheller (town) project satisfies the project assessment requirement of Criterion 1 for 2015. Given that outstanding work is still required, the Commission expects AltaGas to provide actual cost, actual pipeline length and associated variance explanations in a future capital tracker true-up application.

117. With respect to the scope, level and timing of the Athabasca (downtown) project carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $55,980 for

[80] Exhibit 21627-X0007, application, paragraph 104.
[81] Exhibit 21627-X0007, application, paragraph 105.

the replacement of the remaining 0.2 km of pipe and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for the Athabasca (downtown) project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the 2015 AFE estimate and actual costs, and finds the actual costs to be prudent.

118. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the Athabasca (downtown) project were prudent. Accordingly, the Commission finds that the Athabasca (downtown) project satisfies the project assessment requirement of Criterion 1 for 2015.

8.2.1.2 PVC Steel Pipe Replacement program

119. In Decision 2014-373, the Commission approved one 2014 rural PVC Steel Pipe Replacement project (Leduc Area 4) and five 2015 rural PVC Steel Pipe Replacement projects (Leduc Areas 1, 3, 5, 8 and Ashmont).[82] In 2015, AltaGas completed the portion of the Leduc Area 4 project that was not fully completed in 2014 and all five 2015 rural PVC Steel Pipe Replacement projects.

120. The Commission has divided the PVC Steel Pipe Replacement program into the following two categories:

- Projects approved for 2015 and completed in 2015.
- Projects approved for 2014 and completed in 2015, with a new portion of project deferred.

8.2.1.2.1 Projects approved for 2015 and completed in 2015

121. As discussed in Section 8.2.1 of this decision, AltaGas identified certain concerns with its 2015 pre-1957 steel pipe cost and pipe length forecasts. For the PVC Steel Pipe Replacement program, reconnaissance and land negotiations began in February 2014 and were expected to be complete by mid-2014. AltaGas based its 2015 cost estimates on historical costs for comparable rural pipe replacement projects in 2013 and the 2014 project in Leduc Area 4, adjusted for inflation, as well as insights gained by AltaGas from initial site reconnaissance and land negotiations that occurred in the early stages of 2014.[83]

122. AltaGas provided approved forecast and actual costs and pipeline lengths, and a variance analysis for each PVC Steel Pipe Replacement project completed in 2015, as set out in Table 16, below:

[82] Decision 2014-373, paragraphs 198 and 231.
[83] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(a).

Table 16. PVC Pipe projects – 2015 capital additions and pipe lengths

	Capital additions				Pipe length			
PVC	Approved	Actual	Approved vs. actual variance	% of total approved	Approved	Actual	Approved vs. actual variance	% of total approved
	($)			(%)	(km)			(%)
Leduc Area 1 (Rural)	770,300	897,021	(126,721)	-16.5	11.0	10.1	0.9	7.8
Leduc Area 3 (Rural)	742,800	1,041,385	(298,585)	-40.2	10.6	11.5	(0.9)	-8.3
Leduc Area 5 (Rural)	476,200	524,467	(48,267)	-10.1	6.8	7.3	(0.5)	-7.9
Leduc Area 8 (Rural)	1,548,300	1,723,102	(174,802)	-11.3	22.1	26.5	(4.5)	-20.3
Ashmont (Rural)	41,100	60,592	(19,492)	-47.4	0.6	0.7	(0.1)	-12.8

Source: Exhibit 21627-X0007, application, paragraphs 142, 146, 150, 154, and 158.

123. For each of the Leduc Area 1, 3, 5 and 8 (rural) projects, AltaGas explained that higher than forecast actual costs were primarily due to landowner concerns with respect to potential transmission of the clubroot virus[84] resulting from the movement of pipeline equipment from field to field. AltaGas explained that, in general, project estimates for work in rural areas incorporate normal industry practices in the cleaning and disinfection of equipment. However, prior to the start of the project, landowners raised concerns regarding an increase in the number of clubroot-infested fields in the area. To address landowner concerns, AltaGas was required to do additional cleaning and disinfecting of equipment and tools used in the pipeline installation process. AltaGas did not include these costs in the 2015 forecast because the issue had not been identified during initial discussions with landowners regarding access for construction.[85]

124. For the Leduc Area 1 (rural) project, higher than forecast actual costs were also due to the need for horizontal directional drilling, as opposed to the cheaper trenchless plow method.[86] For the Leduc Area 3 (rural) project, higher than forecast actual costs were also due to additional required brushing, tree removal, and hydrovacing.[87]

125. For the Ashmont (rural) project, actual costs were higher than the approved forecast due to higher third-party contractor costs related to delays associated with land approval issues.[88]

[84] Exhibit 21627-X0007. At paragraph 139 of the application, AltaGas provided background information on the clubroot virus: "Clubroot is a serious soil-borne crop disease caused by a parasitic pathogen that spreads by way of spores. Historically affecting eastern Canada and BC, the number of infested fields in central Alberta is increasing sharply each year. Alberta Agriculture and Forestry has confirmed the county of Leduc is among the areas most significantly affected…. The disease causes root galls on infected plants (hence its name), which reduce the crop's water and nutrient uptake and cause stunting, wilting, and finally heavy yield losses. Clubroot spores have adapted to overwinter easily and can survive in the soil for up to 20 years. There is currently no known way to remove the disease from a field once it is infected—the only effective method of reducing spread is thorough equipment sanitation (power washing and bleach) and strict crop rotation using resistant crop varieties."

[85] Exhibit 21627-X0007, application, paragraph 144.

[86] Exhibit 21627-X0007, application, paragraph 144.

[87] Exhibit 21627-X0007, application, paragraph 148.

[88] Exhibit 21627-X0007, application, paragraphs 144 and 148.

126. AltaGas explained that for all of its PVC Pipe Replacement projects, refinements to pipeline lengths and routing were identified during the on-site and field reconnaissance process to address landowner access concerns in 2015 and small refinements in pipe length and routing identified in the final design stage.[89]

Commission findings

127. In Decision 2014-373, the Commission approved the need, on a forecast basis, for each of the PVC Steel Pipe Replacement projects listed in Table 16 above, for purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

128. With respect to the true-up of 2015 actual costs, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that any of the PVC Steel Pipe Replacement projects listed in Table 16 were not required in 2015.

129. With respect to the scope, level and timing of the PVC Steel Pipe Replacement projects listed in Table 16 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the PVC Steel Pipe Replacement projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for the PVC Steel Pipe Replacement projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the approved forecast and actual costs, and finds that there are some significant cost and pipeline length variances between the approved forecast and actual costs for some of the PVC Steel Pipe Replacement projects.

130. As discussed in Section 8.2.1 of this decision, the Commission notes that these significant cost and pipeline length variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.1 above, AltaGas provided an extensive description of the improvements to desktop reconnaissance that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, such as the improvements currently being undertaken to its desktop reconnaissance. The Commission notes that improvements in forecasting accuracy have already been introduced by AltaGas in its 2016 to 2017 forecast capital tracker application, and were recognized in Decision 20522-D02-2016. Specifically, improvements were made to AltaGas' cost estimation process and the Commission approved an

[89] Exhibit 21627-X0007, application, paragraphs 55, 143, 146, 151, 155 and 159.

updated cost estimating methodology to include initial (regression) analysis, desktop reconnaissance and field reconnaissance.

131. Despite the significant cost and pipeline length variances associated with each of the PVC Steel Pipe Replacement projects identified in Table 16, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the PVC Steel Pipe Replacement program, and each of the associated projects, as identified in Table 16, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.1.2.2 Projects approved for 2014 and completed in 2015, with a new portion of project deferred

132. In Decision 2014-373, the Commission approved the Leduc Area 4 (rural) project for completion in 2014. AltaGas explained that it was only able to complete 5.0 km of the 8.2 km planned for replacement in 2014 due to wetter than normal weather conditions in the early summer, work that was required to confirm the extent of additional PVC pipe, and delays to the original start date caused by contractor delay on another project. Ultimately, the decision to suspend the work in 2014 was based on safety issues related to working near brittle PVC pipe in deep frost conditions.

133. AltaGas partially completed the remainder of this project in 2015 but, due to further delays, the final portion of the project was deferred to 2016. AltaGas explained that extensive field investigations were required during 2015 to correct historical data with respect to the location and the nature of the pipe on the as-built drawings. Specifically, the pipe was incorrectly recorded as PE pipe instead of PVC pipe and an incremental section of pipe was identified in 2015 that also required replacement. Accordingly, the 2015 AFE forecast was revised to 3.6 km, and 3.2 km was completed in 2015. Higher than forecast contractor inspection time was also required for field investigations to identify the existing pipe location and to complete permanent and final tie-ins, resulting in higher than forecast hydrovac and site restoration costs. Material costs were also higher than forecast due to required additional fittings and miscellaneous materials that were not included in the original forecast. The remaining 400 metres of the project is to be integrated with the adjoining Patterson Estate Rural Subdivision project, approved for completion in 2016.

134. In the absence of an approved 2015 forecast, for the portion deferred to 2015 AltaGas provided the amounts approved in its AFE for purposes of assessing the prudence of the costs. The AFE cost was $327,500, the forecast pipeline length was 3.6 km and the forecast unit cost was $91,000/km. In 2015, AltaGas actually replaced 3.2 km of pipe at a cost of $469,156, for a total unit cost of $146,437/km. The cost variance was $141,656 (43.3 per cent) above forecast, the pipeline length variance was 0.4 km (11.0 per cent) below forecast and the unit cost variance was $55,437/km (60.9 per cent) above forecast.[90]

[90] Exhibit 21627-X0007, application, paragraphs 162-164, 166 and 170; Exhibit 21627-X0022, AUI-AUC-2016JUN21-014.

Commission findings

135. In Decision 2014-373, the Commission approved the need for the Leduc Area 4 (rural) project on a forecast basis, for the purposes of capital tracker treatment in 2014. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

136. With respect to the true-up of 2015 actual costs for this project, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that the Leduc Area 4 (rural) project was not required in 2015.

137. With respect to the scope, level and timing of the Leduc Area 4 (rural) project carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions of $469,156, for the replacement of 3.2 km of pipe, and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for the Leduc Area 4 (rural) project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the 2015 AFE estimate and actual costs, and finds these costs to be prudent.

138. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 was prudent. Accordingly, the Commission finds that the Leduc Area 4 (rural) project satisfies the project assessment requirement of Criterion 1 for 2015. Given that outstanding work is still required to complete the remaining 400 m of pipe now included with the Patterson Estate Rural Subdivision project in 2016, the Commission expects AltaGas to provide detailed variance explanations for this remaining pipe replacement in a future capital tracker true-up application.

8.2.1.3 Non-Certified PE Pipe Replacement program

139. In Decision 2014-373, the Commission approved 15 Non-Certified PE Pipe Replacement projects. The projects were for the replacement of 10 hamlet projects (Alcomdale, Ashmont, Colinton, Duvernay, Fort Assiniboine, Hairy Hill, Meanook, Pincher Station, Rosedale, and Seven Pearsons), four rural subdivision projects (Allarco, Looma Estates NE, Gateway and Patterson Estates (previously referred to as Looma Estates SW)) and one village project (Munson).[91] In 2015, AltaGas completed 12 Non-Certified PE Pipe Replacement projects, with the exception of three rural subdivisions (Looma Estates NE, Gateway, Patterson Estates (previously referred to as Looma Estates SW)) that were deferred by AltaGas to 2016.

[91] Decision 2014-373, paragraphs 203 and 231.

140. The Commission has divided the Non-Certified PE Pipe Replacement program into the following two categories:

- Projects approved for 2015 and completed in 2015.
- Projects approved for 2015 and deferred.

8.2.1.3.1 Projects approved for 2015 and completed in 2015

141. As discussed in Sections 8.2.1 of this decision, AltaGas identified certain concerns associated with its forecasting methodology to determine the cost and pipe length forecasts for 2015. For the Non-Certified PE Pipe Replacement program, reconnaissance and land negotiations began in February 2014 and were expected to be complete by mid-2014. AltaGas based its 2015 cost estimates on historical costs for comparable village, hamlet and rural area pipe replacement projects in 2013, adjusted for inflation, and insights gained by AltaGas from initial site reconnaissance.[92]

142. AltaGas provided approved forecast and actual costs and pipeline lengths, and variance analysis for each Non-Certified PE Pipe Replacement project completed in 2015 as set out in Table 17, below:

Table 17. Non-Certified PE projects – 2015 capital additions and pipe lengths

	Capital additions				Pipe length			
Non-Certified PE	Approved	Actual	Approved vs. actual variance	% of total approved	Approved	Actual	Approved vs. actual variance	% of total approved
	($)			%	(km)			(%)
Alcomdale (Hamlet)	290,600	350,582	(59,982)	-20.6	1.5	1.7	-(0.2)	-13.5
Ashmont (Hamlet)	376,400	597,561	(221,161)	-58.8	2.1	2.5	(0.4)	-19.7
Colinton (Hamlet)	574,300	748,256	(173,956)	-30.3	3.4	3.8	(0.3)	-10.0
Duvernay (Hamlet)	110,500	150,106	(39,606)	-35.8	0.7	0.7	(0.0)	-0.6
Fort Assiniboine (Hamlet)	692,900	1,068,390	(375,491)	-54.2	3.0	3.9	(0.9)	-31.5
Hairy Hill (Hamlet)	652,000	509,492	142,508	21.9	3.3	3.1	0.2	6.6
Meanook (Hamlet)	102,300	128,160	(25,860)	-25.3	0.6	0.7	(0.1)	-20.8
Pincher Station (Hamlet)	280,100	243,573	36,527	13.0	1.7	1.5	0.2	9.6
Rosedale (Hamlet)	576,800	665,309	(88,509)	-15.3	3.4	2.8	0.5	16.3
Seven Persons (Hamlet)	128,700	189,335	(60,635)	-47.1	0.8	0.7	0.1	9.0
Allarco (Rural Sub.)	313,000	290,594	22,406	7.2	2.0	2.1	(0.1)	-4.0
Munson (Village)	612,400	731,550	(119,150)	-19.5	2.6	3.5	(0.9)	-36.9

Source: Exhibit 21627-X0007, application, paragraphs 179, 183, 187, 191, 195, 199, 203, 207, 211, 215, 219 and 222.

143. For the Alcomdale (hamlet) project, actual costs were higher than forecast due to higher than forecast amounts of pipe installed and the requirement for additional services identified during the final design phase.[93] For the Ashmont (hamlet) project, actuals costs were higher than forecast due to changes in pipe alignment completed during the final design phase, higher

[92] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(a).
[93] Exhibit 21627-X0007, application, paragraphs 180-181.

contractor unit rates, and additional required services identified after the initial design phase. Contractor unit rates for the Ashmont (hamlet) project were higher than forecast due to the remote location of the project, which caused an increase in contractor travel time and fewer productive hours in a day.[94]

144. For the Colington (hamlet) project, actual costs were higher than forecast, primarily due to higher than forecast amounts of pipe and services installed as a result of deficiencies in historical records, and higher mobilization/demobilization costs associated with working in a remote location.[95]

145. For the Duvemay (hamlet) project, actual costs were higher than forecast due to higher than forecast actual pipe installation costs and higher associated tendered contractor costs. Specifically, the pipe type required for services to be replaced was misidentified in the ESRI system.[96] For the Fort Assiniboine (hamlet) project, actual costs were higher than forecast as a result of more pipe than forecast being installed due to deficiencies in historical records, and the associated increased contractor unit rates for main and service connections. The increased costs for the Fort Assiniboine (hamlet) project were partially offset by a requirement for less horizontal directional drilling.[97]

146. For the Hairy Hill (hamlet) project, actual costs were lower than forecast because some services did not have to be replaced due to inactive risers. Based on a reduction in the amount of pipe installed, additional savings were realized due to lower contractor unit rates.[98] For the Meanook (hamlet) project, actual costs were higher than forecast due to a higher than forecast amount of pipe being installed as a result of deficiencies in historical records, and additional services required as a result of incorrectly recorded data in the ESRI system.[99] For the Pincher Station (hamlet) project, actual costs were lower than forecast due to a reduction in the amount of pipe installed. Specifically, some services were abandoned and not required to be replaced.[100]

147. For the Rosedale (hamlet) project, actual costs were higher than forecast due to higher contractor rates, attributed to increases in service connection unit rates, service disconnections/reconnections missed in the original estimate, additional main tie-ins not reflected in the forecast and the required addition of a bypass to protect against an outage while switching from the old main to the new main. These higher costs were partially offset by a reduction in the amount of pipe installed due to the abandonment or disconnection of services.[101] For the Seven Persons (hamlet) project, significant cost variances were attributed to 16 services being missed in the original estimate, thereby increasing service and main connection costs, and higher pipeline installation costs resulting from increased unit rates and a requirement for additional pipe not identified in the initial design. These higher costs were partially offset by a reduction in the amount of pipe installed due to the abandonment or disconnection of services.[102]

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94 Exhibit 21627-X0007, application, paragraphs 184-185.
95 Exhibit 21627-X0007, application, paragraphs 188-189.
96 Exhibit 21627-X0007, application, paragraphs 192-193.
97 Exhibit 21627-X0007, application, paragraphs 196-197.
98 Exhibit 21627-X0007, application, paragraphs 200-201.
99 Exhibit 21627-X0007, application, paragraphs 204-205.
100 Exhibit 21627-X0007, application, paragraphs 208-209.
101 Exhibit 21627-X0007, application, paragraphs 212-213.
102 Exhibit 21627-X0007, application, paragraphs 216-217.

148. For the Allarco (rural subdivision) project, actual costs were lower than forecast due a lower required amount of pipe than forecast. This did not cause any significant impact on costs and the overall project was completed for less than forecast.[103]

149. For the Munson (village) project, actual costs were higher than forecast due to the higher than forecast amount of pipe installed, and additional costs required for the use of horizontal directional drilling. This project also experienced additional service and main connection costs resulting from the need to meet current code/safety hazards and higher unit rates for service connection and main tie-ins. Additional main tie-ins were also identified in the final design phase.[104]

Commission findings

150. In Decision 2014-373, the Commission approved the need, on a forecast basis, for each of the Non-Certified PE Pipe Replacement projects listed in Table 17 above, for purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

151. With respect to the true-up of 2015 actual costs, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that any of the Non-Certified PE Pipe Replacement projects listed in Table 17 were not required in 2015.

152. With respect to the scope, level and timing of each of the Non-Certified PE Pipe Replacement projects listed in Table 17 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the Non-Certified PE Pipe Replacement projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for each of the Non-Certified PE Pipe Replacement projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there are some significant cost variances and pipeline length variances between the approved forecast and actual costs.

153. As discussed in Section 8.2.1 of this decision, the Commission notes that these significant cost and pipeline length variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.1 above, AltaGas provided an extensive description of the improvements to desktop reconnaissance that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost and pipeline length variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related application. The

[103] Exhibit 21627-X0007, application, paragraphs 220-221.
[104] Exhibit 21627-X0007, application, paragraphs 223-224.

Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission notes that improvements in forecasting accuracy have already been introduced by AltaGas in its 2016 to 2017 forecast capital tracker application, and were recognized in Decision 20522-D02-2016. Specifically, improvements were made to AltaGas' cost estimation process and the Commission approved an updated cost estimating methodology to include initial (regression) analysis, desktop reconnaissance and field reconnaissance.

154. Despite the significant cost and pipeline length variances associated with each of the Non-Certified PE Pipe Replacement projects identified in Table 17, based on the variance explanations that AltaGas provided the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the Non-Certified PE Pipe Replacement program, and each of the associated projects, as identified in Table 17, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.1.3.2 Projects approved for 2015 and deferred

155. In Decision 2014-373, the Commission approved, on a forecast basis, capital tracker treatment for the Looma Estates NE, Gateway and Patterson Estates[105] (rural subdivision) pipeline replacement projects for completion in 2015.[106] In the 2016-2017 capital tracker application, AltaGas proposed to defer these projects to 2016 to allow for the BWM project to proceed.[107] In Decision 20522-D02-2016, the Commission approved each of the three projects, on a forecast basis, as part of the 2016 capital tracker program.[108]

156. AltaGas advised that, since the projects were approved in Decision 2014-373, and no costs were incurred in 2015, a refund will be provided to customers through the 2015 K factor true-up adjustment and the true-up between the actual and approved forecast costs for these three projects will be part of the 2016 capital tracker true-up application.[109]

Commission findings

157. As no costs were incurred in 2015 for these three projects and the Commission approved the deferral of the projects to 2016, the Commission agrees with AltaGas that the 2015 K factor true-up should reflect a refund for the costs associated with these three projects that were approved in Decision 2014-373 and included in rates. The Commission notes that the refund has been included in the applied-for K factor.[110] The Commission accepts AltaGas' proposal to provide a true-up between the actual and approved forecast costs for these three projects as part of the 2016 capital tracker true-up application. The project assessment requirements of Criterion 1 will be assessed by the Commission at that time.

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105 This project was previously referred to as Looma Estates SW.
106 Decision 2014-373, paragraph 203.
107 Specifically, these projects included the deferral of 2.2 km at a cost of $337,000 for the Looma Estates NE project, 2.9 km at cost of $459,000 for the Gateway project and 4.1 km at a cost of $640,000 for the Looma Estates SW (renamed to Patterson Estates).
108 Decision 20522-D02-2016, paragraph 188.
109 Exhibit 21627-X0007, application, paragraph 228.
110 Exhibit 21627-X0002, supporting schedules to the application, schedules 4.0 and 5.0.

8.2.2 Station Refurbishment program

158. As shown in Table 5 above, AltaGas identified a number of Station Refurbishment projects completed in 2015 that were previously approved for capital tracker treatment in Decision 2014-373 for completion in 2014 and 2015. These projects were either deferred from 2014 and completed in 2015, completed in 2015 as planned, or deferred to a future year. Table 5 also includes projects that were not approved in Decision 2014-373 but completed in 2015.

159. As referred to in Section 8.1.2 above, AltaGas included with its variance explanations a table for each PMS, TBS or PRS station showing the buildup of project costs for each station and comparing it to the buildup of project costs in a standard PMS, TBS or PRS station. Also referenced in Section 8.1.2 above, AltaGas included a discussion on why each station was completely replaced or only partially refurbished.

160. As described in Section 8.2.1 above, AltaGas recognizes that its forecasting methodology is deficient and advised that it is reviewing its processes to identify opportunities for improved project costs estimation. As with the Pipe Replacement program, forecasting issues for the Station Refurbishment program relate to the timing of the forecasts and the use of desktop versus field reconnaissance. AltaGas explained that detailed designs for each station are ordinarily completed in the spring of each project year, so as to allow for sufficient time for installation and commissioning. Actual costs vary from estimates due to circumstances not identified in the preliminary field surveillance. For example, extra excavation and construction may be required due to frost movement of the risers, which can only be identified once work on the site commences and the facility is disconnected. For sites requiring component replacements only, extra welding may be required to align components due to strain on internal station piping as a result of shifting. Planned sites may also be deferred to a subsequent period or replaced by another station project identified during the year as a result of safety or operational priorities. Since the stations being refurbished or replaced are not standard in their design and configuration, some modification to the station footprint, configuration and underground piping may be required to accommodate the standardized design. Work on underground piping may also be required where pipe material and equipment are inconsistent with current codes and/or operational and safety procedures.[111]

161. In response to a Commission IR, AltaGas submitted that, going forward, to improve its forecast accuracy, line heater and odorant requirements will be cross-referenced to flow and pressure metrics from AltaGas' Synergy system. AltaGas has also revised its project template for stations; making it substantially more comprehensive with the inclusion of additional costs items such as: land costs, civil site work, field installation, in-service welding/bypassing/line stopping, pipeline installation, retirements, environmental, cathodic protection, project coordination and associated risk factors.[112]

162. In response to another Commission IR regarding high variances between forecast and actual external contractor costs for TBS stations LE085 and LE090, AltaGas outlined that it would attempt to improve its forecasts by using Powerplan capital asset records to verify the type, age and specifications of station components, including components such as regulators, valves and filters. AltaGas also indicated that it intended to use its photograph library to identify

[111] Exhibit 21627-X0007, application, paragraphs 236-239.
[112] Exhibit 21627-X0022, AUI-AUC-2016JUN21-002(b) and 2(g).

additional risers, fences and other site conditions affecting the project scope. AltaGas noted that even though some of these improvement processes are still being evaluated for implementation, it will formalize these processes into checklists and templates and include them as part of the senior management review and approval documentation.[113]

163. Another enhancement that AltaGas has made is specific to PRS stations. Based on experience to date, AltaGas stated that it has identified notable differences in the refurbishment/replacement requirements applicable to different sizes of PRS stations not previously taken into consideration in the project cost estimating process. By identifying and assigning targeted PRS stations to applicable categories, AltaGas anticipates that it will be able to more closely estimate applicable refurbishment/replacement costs which may assist in assessing the prudence of PRS projects and costs.[114]

164. AltaGas explained that the PRS station costs variances reflect limitations in its ability to accurately forecast costs. With respect to its 2014-2015 forecast capital tracker application, AltaGas was unable to complete all the steps it normally performs in capital project planning because its cost estimates failed to recognize the distinction between the five categories its engineering team uses to define these stations. AltaGas also noted that until 2015, its experience with PRS stations was limited to the most basic designs.[115]

165. Five categories of PRS station replacements were identified, based on the following features of PRS stations:

Table 18. Categories of PRS stations

Category	Design flowrate (m3/hr)	Standard inlet piping size (NPS)	Standard outlet piping size (NPS)	Standard relief valve size (NPS)
1	0 – 100	1	1	1 or 2
2	100 – 1000	1	2	1 or 2
3	1000 – 1500	2	2	2
4	1500 – 6000	2	4	3 or 4
5	> 6000	Custom	Custom	Custom

Source: Exhibit 21627-X0007, application, Table 3.6-2, paragraph 284.

166. AltaGas also provided explanations regarding additional differences amongst the five PRS categories. The explanations are as follows:

- Category 1 – A standard Category 1 PRS is the smallest station design, consisting of equipment for pressure regulation and relief in rural distribution areas. Since this equipment is designed to withstand the elements, these stations generally have no building. It has the capacity to serve approximately 35 customers.

- Category 2 – A standard Category 2 PRS is larger than a Category 1, but has the same configuration and does not require a building. A Category 2 PRS has the capacity to serve approximately 350 customers.

[113] Exhibit 21627-X0022, AUI-AUC-2016JUN21-023.
[114] Exhibit 21627-X0007, application, paragraphs 243-244.
[115] Exhibit 21627-X0007, application, Table 3.6-2, paragraph 281.

- Category 3 – A standard Category 3 PRS is larger than a Category 2, but with the same configuration. They usually do not have a building, but may have bollards or a fence. A Category 3 PRS has the capacity to serve approximately 550 customers.

- Category 4 – A standard Category 4 PRS is the largest standard PRS station. A Category 4 PRS has the capacity to serve approximately 2,200 customers (i.e., a large village or small town). It may have a building and be enclosed in a fence.

- Category 5 – A Category 5 PRS is customized to meet the service demands at a specific location. There is no standard Category 5 PRS or "typical" cost associated with this design and these stations are generally large stations flowing higher volumes than a Category 4 PRS.[116]

167. AltaGas also submitted the typical costs for each category of station in the following table:

Table 19. Typical cost of Category 1, 2, 3 and 4 PRS stations

Cost components	Category 1	Category 2	Category 3	Category 4
	($)			
Labour	17,100	20,040	23,703	26,483
Site work	2,600	3,300	3,500	3,940
Fabrication & assembly	5,500	6,300	7,170	11,380
Major components: valving, piping, fittings	6,000	6,500	9,000	13,500
Major components: regulators & pressure controls	1,700	1,700	3,100	14,200
Direct costs	32,900	37,840	46,473	69,503
Overhead (5.5%)	1,810	2,081	2,556	3,823

Source: Exhibit 21627-X0007, application, Table 3.6-3, paragraph 286.

8.2.2.1 PMS Stations

168. AltaGas provided information for the five PMS Station Refurbishment projects discussed in this section, which has been summarized in Tables 20 and 21 below. These tables identify the 2015 actual capital additions, which serve as the basis for the calculation of the 2015 capital tracker true-up.

169. The Commission has divided the PMS Station Refurbishment program into the following two categories:

- Projects approved for 2015 and completed in 2015.
- Projects approved for 2014 and completed in 2015.

8.2.2.1.1 Projects approved for 2015 and completed in 2015

170. AltaGas provided the costs of a typical PMS station, the approved forecast and actual capital additions for each of the PMS stations approved for 2015 and completed in 2015, and a variance analysis, as set out in Table 20, below.

[116] Exhibit 21627-X0007, application, paragraph 284.

Table 20. 2015 capital additions for PMS stations

	Capital additions			Variance	
PMS stations	Typical	Approved	Actual	Approved vs. actual	% of total approved
	($)				(%)
PC028	272,900	327,400	384,044	(56,644)	(17.3)
SP253	272,900	300,100	385,000	(84,900)	(28.3)

Source: Exhibit 21627-X0007, application, unnamed table above paragraphs 255 and 256.

171. AltaGas explained that both PMS stations PC028 and SP253 required full station replacements. The actual costs for these stations were higher than forecast because of the requirement for additional labour. Due to internal resource constraints, contract engineering resources which were not part of the original estimate were also utilized, thereby contributing to the higher actual labour costs.

172. PMS Station PC028 was an obsolete design and its replacement was more expensive than a typical PMS station due to its more complex configuration and requirement for a larger line heater. In addition to the higher labour costs, the costs to convert adjacent and connected PRS Station PC018 to a block valve assembly instead of a full replacement (see Section 8.2.2.3) were included in the replacement of the PMS Station PC028 project.

173. PMS Station SP253 had run-splitting regulators and was prone to significant frost balls and ground heaving because it did not have a line heater. The addition of a line heater contributed to the higher than forecast costs for this station.

Commission findings

174. In Decision 2014-373, the Commission approved the need, on a forecast basis, for the two PMS Station Refurbishment projects listed in Table 20 above, for the purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

175. With respect to the true-up of 2015 actual costs for these two projects, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that either of the PMS Station Refurbishment projects listed in Table 20 were not required in 2015.

176. With respect to the scope, level and timing of the work associated with the two PMS Station Refurbishment projects listed in Table 20 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with the PMS Station Refurbishment projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for these two PMS Station Refurbishment projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between the approved forecast and actual costs, and finds that there are significant cost variances between the approved forecast and the actual cost for the PMS Station Refurbishment projects.

177. As discussed in Section 8.2.2 of this decision, the Commission notes that these significant cost variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.2 above, AltaGas provided an extensive description of the improvements that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related application. The Commission accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, including the further use of templates and checklists.

178. Despite the significant cost variances associated with the PMS Station Refurbishment projects, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the PMS Station Refurbishment projects, as identified in Table 20, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.2.1.2 Projects approved for 2014 and completed in 2015

179. AltaGas provided the costs of a typical PMS station, the approved forecast and actual capital additions for three PMS stations approved for 2014 and completed in 2015, and a variance analysis, as set out in Table 21, below.

Table 21. 2015 capital additions for PMS stations

	Capital additions			Variance	
PMS stations	Typical	Approved	Actual	Approved vs. actual	% of total approved
	($)				(%)
HL005	272,900	424,400	849,633	(425,233)	(100.2)
LE077	272,900	201,600	300,506	(98,906)	(49.1)
LE327	272,900	169,800	308,199	(138,399)	(81.5)

Source: Exhibit 21627-X0007, application, unnamed tables above paragraphs 260, 263 and 265.

180. AltaGas identified PMS Station HL005 as one of the highest risk stations in its network because it controls very high volumes of gas and because it is the sole point of supply for downstream users in the High Level area. To continue operating under the current system configuration, the station required a higher capacity, a more advanced bundled (as opposed to multiple-sourced components) odorant system, a larger capacity line heater, and more elaborate internal configurations which, consequently, contributed to the increased costs for refurbishment of this station, compared to the costs for refurbishment of a typical PMS station.[117]

[117] Exhibit 21627-X0007, application, paragraph 260.

181. In addition, actual project costs were higher than forecast due to unexpected underground issues, the relative remoteness of the station location and the generally unfavourable ground and weather conditions. Further, additional labour was required to accommodate additional design and construction considerations driven by the small size of the site and to work around the structures of a gas co-op's facilities, which share the same property. As well, additional external contractors were required for welding and line-stopping thin-walled steel pipe found at the site. Construction of an access road, transport and disposal of hazardous waste, costs to install a power line and tie it into the local grid due to the unsuitability of solar power for this site, winter fencing, tree and brush clearing, and grading of the site were other unanticipated costs for PMS Station HL005.

182. The station refurbishment work for this station was delayed to late November 2014 due to additional design and fabrication requirements, and due to a delivery delay of the bundled odourizer. Additionally, early onset of freezing conditions resulted in the postponement of field installation and bypass work until warmer temperatures to ensure the security of supply to customers.

183. PMS Station LE077 required substantial internal refurbishment because it had run-splitting regulators and gate valves, and leaked small amounts of gas by design. A delay in the delivery of the required new large scale odorant system until December 2014 resulted in AltaGas not having sufficient time to complete and commission the refurbishment of Station LE077 until 2015.

184. AltaGas explained that actual costs for PMS Station LE077 were greater than forecast due to the need for more external contractors than forecast related to internal resource constraints during that time period, and due to higher costs associated with a bundled (as opposed to multiple sources of components) odourizer.[118]

185. PMS Station LE327 also required a substantial refurbishment to replace the existing odourizer in order to manage the loads experienced in the part the network that this station serves. AltaGas explained that delays in the delivery of equipment to early December 2014 led to a deferral of commissioning of the station until January 2015.

186. AltaGas explained that actual costs for PMS Station LE327 were greater than forecast due to the need for a more advanced injection odourizer, higher costs associated with a bundled (as opposed to multiple sources of components) odourizer, extra time required to install and commission the odourizer, and the inadvertent omission of necessary costs for modification of the station's internal piping and fittings to integrate the new odourizer.[119]

187. For PMS stations HL005, LE077 and LE327, the significant divergence in the actual cost of the odourizer from the forecast were driven by forecasts that were based on previous odourizer purchases for other projects. For these three stations, AltaGas chose to include all costs in one package because unbundling and sourcing the components from various contractors was difficult to coordinate with project delivery schedules. In response to a Commission IR asking about the impact to project schedules if AltaGas had chosen to source the components from various contractors instead of including them all in one package, AltaGas submitted:

[118] Exhibit 21627-X0007, application, unnamed table on page 105, paragraphs 263-264.
[119] Exhibit 21627-X0007, application, unnamed table on page 107, paragraph 265.

> Had AUI chosen to source components from various contractors, there would have been a negative impact of undetermined duration on the project schedules for HL005, LE077 and LE327. Within the scheduled construction windows for each project, these uncertainties presented greater risks projects would be delayed and result in higher costs than would be incurred by sole sourcing the respective odorant systems. On a go-forward basis, AUI will work to ensure longer lead times are used to procure its odorant systems, where possible.

188. In the same response, AltaGas explained its reasons for not arranging its purchases from different contractors earlier, in order to meet the project delivery schedules:

> AUI has historically used calendar year budgeting, so equipment of this magnitude would not normally be ordered in the year before it is to be installed. For station projects in 2017 and future years, longer lead-time equipment, such as the odourizers, will be ordered earlier in the project year, when possible, to avoid delays and minimize costs.[120]

Commission findings

189. In Decision 2014-373, the Commission approved the need, on a forecast basis, for the three PMS Station Refurbishment projects listed in Table 21 above, for the purposes of capital tracker treatment in 2015.

190. With respect to the true-up of 2015 actual costs, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that any of the PMS Station Refurbishment projects listed in Table 21 were not required in 2015.

191. With respect to the scope, level and timing of each of the PMS Station Refurbishment projects listed in Table 21 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the PMS Station Refurbishment projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for each of the PMS Station Refurbishment projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there are significant cost variances between the approved forecast and the actual cost for the PMS Station Refurbishment projects.

192. As discussed in Section 8.2.2 of this decision, the Commission notes that these significant cost variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.2 above, AltaGas provided an extensive description of the improvements that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related

[120] Exhibit 21627-X0022, AUI-AUC-2016JUN21-021.

application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, including the further use of templates and checklists.

193. Despite the significant cost variances associated with these PMS Station Refurbishment projects, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the PMS Station Refurbishment projects, as identified in Table 21, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.2.2 TBS Stations

194. AltaGas provided information on the four TBS Station Refurbishment projects subject to this application, which have been summarized in Tables 22 and 23 below. These tables identify the 2015 actual capital additions, which serve as the basis for the calculation of the 2015 capital tracker true-up.

195. The Commission has divided the TBS Station Refurbishment program into the following two categories:

- Projects approved for 2015 and completed in 2015.
- Projects approved for 2014 and completed in 2015, and approved for 2015 and deferred.

8.2.2.2.1 Projects approved for 2015 and completed in 2015

196. AltaGas provided the costs of a typical TBS station, the approved forecast and actual capital additions for each of the TBS stations completed in 2015, and a variance analysis, as set out in Table 22, below:

Table 22. 2015 capital additions for TBS stations

	Capital additions			Variance	
TBS Stations	Typical	Approved	Actual	Approved vs. actual	% of total approved
	($)				(%)
HA004	191,000	191,000	323,649	(132,649)	69.4
LE085	191,000	523,700	615,186	(91,486)	17.4

Source: Exhibit 21627-X0007, application, unnamed tables above paragraphs and 266 and 277.

197. TBS Station HA004 required complete replacement because it had an obsolete design with run-splitting regulators, numerous gate valves and a wooden building in poor condition. AltaGas attributed the high variance between actual and forecast costs to errors in forecasting. The labour costs were calculated using 10 man-days for a four-man crew, whereas a typical TBS station requires approximately double the man-days. Further, detailed assessment of the specifications needed at this location revealed the requirement for a non-standard design, which increased the labour cost required for final design and field installation above what it should have been for a standard TBS design. Additionally, external contractor costs were also higher

than forecast because the estimate was based on using internal labour resources, but due to timing and resource constraints, external resources were also required.[121]

198. AltaGas identified TBS Station LE085 as one of the highest risk stations in its network, because it is one of the largest TBS stations with very high volumes of gas flow. This was a complete replacement because the station had run-splitting regulators, numerous gate valves, a wooden building in poor condition and leaked small amounts of gas by design. AltaGas attributed the variance between actual and forecast costs to errors in forecasting. Its non-standard design required more engineering services than forecast and the necessary assistance from district operations personnel was under-estimated. The cost for external contractors exceeded budget due to an under-estimation of the complexity of the installation and the requirement for a larger than forecast line heater.[122]

Commission findings

199. In Decision 2014-373, the Commission approved the need, on a forecast basis, for the two TBS Station Refurbishment projects listed in Table 22 above, for the purposes of capital tracker treatment in 2015. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

200. With respect to the true-up of 2015 actual costs for these two stations, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that either of the TBS Station Refurbishment projects listed in Table 22 were not required in 2015.

201. With respect to the scope, level and timing of the two TBS Station Refurbishment projects listed in Table 22 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the TBS Station Refurbishment projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for both of the TBS Station Refurbishment projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there are significant cost variances between the approved forecast and the actual cost for the two TBS Station Refurbishment projects.

202. As discussed in Section 8.2.2 of this decision, the Commission notes that these significant cost variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.2 above, AltaGas provided an extensive description of the improvements that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process,

[121] Exhibit 21627-X0007, application, unnamed table on page 108 and paragraph 266.
[122] Exhibit 21627-X0007, application, unnamed table on page 110 and paragraph 267.

specifically the use of forecasting methods that are not well suited to the timing of the related application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, including the further use of templates and checklists.

203. Despite the significant cost variances associated with the TBS Station Refurbishment projects, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the TBS Station Refurbishment projects, as identified in Table 22, satisfy the project assessment requirement of Criterion 1 for 2015.

8.2.2.2.2 Projects approved for 2014 and completed in 2015, and approved for 2015 and deferred

204. AltaGas provided the costs of a typical TBS station, the approved forecast and actual capital additions for TBS Station LE090, which was approved for 2014 and completed in 2015, and for TBS Station BA041, which was approved for 2015 and deferred to a future year, and a variance analysis; all of which is set out in Table 23, below:

Table 23. 2015 capital additions for TBS Stations

		Capital additions		Variance	
TBS Stations	Typical	Approved	Actual	Approved vs. actual	% of total approved
	($)				(%)
LE090	191,000	185,600	652,229	(466,629)	251.4
BA041	191,000	327,400	-	327,400	-

Source: Exhibit 21627-X0007, application, unnamed table above paragraphs 272 and 279.

205. The costs originally forecast for replacement of TBS Station LE090 were consistent with costs for replacement of a typical station. However, AltaGas ultimately decided to undertake a full replacement of this station, which significantly increased costs because the station regulates high volumes of gas, had run-splitting regulators and gate valves in its piping configuration, was subject to flooding, suffered frost balls and ground heaving, and had a wooden building in poor condition.

206. Following further on-site investigation and engineering, it was determined there was a need for more land and improvements to the site. AltaGas also found that some of the existing underground steel piping did not meet specifications for normal welding to install line-stoppers. Costs were also incurred to retain line-stopping consultants to develop technical welding and installation procedures. Further, additional land was acquired for the new site and the elevation of the site was raised to prevent flooding, which required a new drainage culvert. A line heater was also added to mitigate the risk of regulators freezing and disrupting service.

207. These additional requirements delayed design, fabrication and ordering of materials. Extreme cold weather in November made station bypass too risky and installation was not completed in 2014. AltaGas decided to delay installation until spring 2015 when warmer

temperatures and reduced loads would reduce the risk of a station bypass and reduce the potential impact of an outage.[123]

208. TBS Station BA041 was approved for completion in 2015 but deferred to 2016 due to operational priorities that required TBS Station LE092 to be replaced ahead of TBS Station BA041.[124]

Commission findings

209. In Decision 2014-373, the Commission approved the need, on a forecast basis, for the two TBS Station Refurbishment projects listed in Table 23 above, for the purposes of capital tracker treatment in 2014 and 2015, respectively. The Commission also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

210. Given that the station refurbishment work on TBS Station BA041 was deferred to 2016, the Commission expects AltaGas to provide actual costs and associated variance explanations in a future capital tracker true-up application. The Commission notes that a refund for this deferred project has been included in the 2015 applied-for K factor.[125]

211. With respect to the true-up of 2015 actual costs for TBS Station LE090, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that the TBS Station LE090 refurbishment project was not required in 2015.

212. With respect to the scope, level and timing of the work associated with TBS Station LE090 Refurbishment project carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital addition of $652,229 associated with the project and finds that it is generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for the TBS Station LE090 Refurbishment project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there is a significant cost variance between the approved forecast and the actual cost.

213. As discussed in Section 8.2.2 of this decision, the Commission notes that these significant cost variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.2 above, AltaGas provided an extensive description of the improvements that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related

[123] Exhibit 21627-X0007, application, paragraphs 272-274.
[124] Exhibit 21627-X0007, application, unnamed table on page 124, paragraph 279.
[125] Exhibit 21627-X0002, supporting schedules to the application, schedules 4.0 and 5.0.

application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, including the further use of templates and checklists.

214. Despite the significant cost variance associated with the TBS Station LE090 Refurbishment project, based on the variance explanation that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the TBS Station LE092 Refurbishment project satisfies the project assessment requirement of Criterion 1 for 2015.

8.2.2.3 PRS Stations

215. In Decision 2014-373, the Commission approved 17 PRS stations on a forecast basis for 2015. Subsequently, AltaGas decommissioned and removed 11 of those 17 PRS stations from the Station Refurbishment program – SP026, SP050, SP076, SP104, SP106, SP116, SP128, SP156, SP160, SP251 and SP259.[126] AltaGas undertook the replacement of the remaining six PRS stations – LE251, LE302, PC018, SP094, SP124 and ST006.

216. AltaGas provided the costs of typical PRS stations, the approved forecast and actual capital additions for the six PRS stations completed in 2015, and a variance analysis, as set out in Table 24 below:

Table 24. 2015 capital additions for PRS stations

	Capital additions				Variance	
Stations	Typical	Category	Approved	Actual	Approved vs. actual	% of total approved
	($)		($)			(%)
LE251	40,239	2	21,800	67,624	(45,824)	210.2
LE302	73,910	4	21,800	167,015	(145,215)	666.1
PC018	34,986	1	10,900	-	10,900	-
SP094	49,419	3	54,600	120,249	(65,649)	120.2
SP124	40,239	2	21,800	71,296	(49,496)	227.1
ST006	34,986	1	21,800	2,793	19,007	87.2

Source: Exhibit 21627-X0007, application, unnamed tables before paragraphs 288, 290, 292, 293, 294 and 297.

217. PRS Station LE251 was a complete station replacement because it had obsolete equipment throughout its configuration, crooked inlet and outlet risers (with the resulting stress creating safety and reliability risks) and required new support footings and clamps to minimize station shifting in the future. AltaGas incorrectly estimated the costs for this Category 2 PRS station using the average cost for a typical Category 1 PRS station replacement. The actual costs for this station were $17,000 higher than a typical Category 2 replacement due to the requirement for external contractors as a result of internal labour constraints, unexpected site work to meet landowner requirements, fabrication and x-ray inspection of risers and critical welds, specialized

[126] Decision 2014-373, Table 25.

equipment rentals, additional time to replace the high-pressure transmission line tie-in, and additional hydrovac costs to locate the transition point of the main, because as-built information was not fully accurate.[127]

218. PRS Station LE302 was a complete replacement because the station had an obsolete design and the site needed to be elevated for continued operation. AltaGas incorrectly forecast the station's replacement cost using the average cost for a typical Category 1 PRS station replacement. Actual costs were higher than forecast because this station was more complex than a standard Category 4 station. Additional labour was required for on-site supervision to ensure continued operation of the network while completing the station bypass and riser installations, and moving the new station into place. External contractors were required to address unanticipated circumstances such as the discovery of an unknown underground branch which required further hydrovac and line-stopping. Land compensation payments were higher than forecast and a larger than typical regulator was required due to the gas flows at this station.[128]

219. PRS Station PC018 was a Category 1 PRS station located on the same site and directly connected to the outlet side of PMS Station PC028 (see Section 8.2.2.1.1). PRS Station PC018 had an obsolete design with numerous screw-type fittings, was corroded and was susceptible to leaking small amounts of gas. To replace PMS Station PC028, which AltaGas redesigned to more safely and reliably serve customers in the Pincher Creek district, PRS Station PC018 needed to be removed and was converted to a block valve assembly. The actual costs of the PRS Station PC018 conversion were included with the PMS Station PC028 Replacement project.[129]

220. PRS Station SP094 was a complete replacement due to its obsolete design, extensive gate valves and corroded screw-type fittings. This station is a more complex station than a typical Category 3 station because it performs a double pressure cut. AltaGas attributed the differences in actual costs, as compared to the approved forecast, primarily to the scope change needed for additional stopping/bypassing/lower operating pressure from the main station. Higher labour costs were due to the use of external contractors, and the additional requirement of contractor services for the installation of a new fence and a field hydro test also contributed to the cost variance.[130]

221. PRS Station SP124 was a complete station replacement because it had obsolete regulators and old piping and valves that were becoming ineffective for fully controlling gas flow. AltaGas incorrectly forecast the costs for this Category 2 PRS station using the average cost for a typical Category 1 PRS station replacement. The actual costs for this station were also higher than those of a typical Category 2 PRS station due to higher labour costs because AltaGas was required to use external contractors resulting from the unavailability of AltaGas internal labour. In addition, contractors were also required for services such as set-up and removal of a temporary station required to maintain gas flow during transition to the new station, field riser fabrication, x-ray testing of welds, and fabrication and installation of protective bollards not anticipated in the forecast.[131]

[127] Exhibit 21627-X0007, application, unnamed table on page 129 and paragraphs 288-289.
[128] Exhibit 21627-X0007, application, unnamed table on page 129 and paragraphs 290-291.
[129] Exhibit 21627-X0007, application, unnamed table on page 133 and paragraph 292.
[130] Exhibit 21627-X0007, application, unnamed table on page 134 and paragraphs 293-294.
[131] Exhibit 21627-X0007, application, unnamed table on page 135 and paragraphs 295-296.

222. PRS Station ST006 was originally intended to be a complete replacement. However, AltaGas' on-site review of the stability of the existing risers found that it was more prudent to reduce the project to a refurbishment by exchanging the obsolete regulators for ones with a current design. As a result, actual costs were $19,000 below the approved budget.[132]

223. Forecast costs for each of the 11 decommissioned stations were $13,100 per station, for a total cost of $144,000. The actual costs for the 11 stations that were decommissioned were shown by AltaGas as not applicable, but no further explanation was provided.[133] AltaGas also stated elsewhere, in apparent conflict, that 12 PRS stations, approved for a total of $155,000, were subsequently decommissioned and removed from the program.[134]

Commission findings

224. In Decision 2014-373, the Commission approved the need, on a forecast basis, for the 17 PRS Station Refurbishment projects discussed in this section, for the purposes of capital tracker treatment in 2015.

225. With respect to the true-up of 2015 actual costs for these projects, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2015, then AltaGas is not required to demonstrate that a project was needed in order to provide utility service at adequate levels in 2015. The Commission finds no evidence on the record of this proceeding to indicate that any of the six PRS Station Refurbishment projects listed in Table 24 above were not required in 2015.

226. With respect to the scope, level and timing of the work associated with each of the PRS Station Refurbishment projects listed in Table 24 and carried out in 2015, the Commission has reviewed AltaGas' 2015 actual capital additions associated with each of the PRS Station Refurbishment projects and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 2014-373. The Commission has also reviewed the 2015 actual capital additions for each of the PRS Station Refurbishment projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there are significant cost variances between the approved forecast and the actual cost for all of the PRS Station Refurbishment projects listed in Table 24.

227. As discussed in Section 8.2.2 of this decision, the Commission notes that these significant cost variances are in large part a result of the deficiencies identified by AltaGas in its cost estimation process. As explained by AltaGas, these deficiencies are related to the use of forecasting methods that are not well suited to the timing of the related application. As described in Section 8.2.2 above, AltaGas provided an extensive description of the improvements that are currently being undertaken to address the deficiencies and improve the accuracy of its forecasts. The Commission accepts AltaGas' explanation that these significant cost variances are in large part a result of the deficiencies identified by AltaGas with respect to its cost estimation process, specifically the use of forecasting methods that are not well suited to the timing of the related

[132] Exhibit 21627-X0007, application, unnamed table on page 137 and paragraphs 297-298.
[133] Exhibit 21627-X0007, application, Table 3.3-1.
[134] Exhibit 21627-X0007, application, paragraph 247.

application. The Commission also accepts that a certain amount of the costs cannot be accurately predicted in advance of the commencement of the actual work. The Commission is satisfied with AltaGas' proposed efforts to address these deficiencies, such as the further use of templates and checklists and, specific to PRS stations, incorporation into its cost estimation process of the five different categories of stations that AltaGas has identified in order to recognize differences in the refurbishment requirements applicable to different sizes of PRS stations.

228. Despite the significant cost variances associated with the PRS Station Refurbishment projects, based on the variance explanations that AltaGas provided, the Commission finds that the costs were prudently incurred. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that the PRS Station Refurbishment projects, as identified in Table 24, satisfy the project assessment requirement of Criterion 1 for 2015.

229. With respect to costs claimed for the decommissioning of the PRS stations, for the purposes of this decision and for regulatory efficiency, the Commission is prepared to approve these costs on an interim basis, on the assumption that: (a) the actual number of decommissioned PRS stations was 11; (b) the actual decommissioning costs did not vary significantly from the forecast costs of $13,100 per station, for a total cost of $144,000; and (c) the decommissioning costs were absorbed into the other PRS station costs. Accordingly, AltaGas is directed to confirm, in its next capital tracker true-up application, the number of PRS stations decommissioned, the actual decommissioning costs per station, and whether these costs were in fact absorbed into the other PRS station costs.

8.2.3 Gas Supply program

230. In Decision 2014-373, the Commission approved a $531,000 (including overhead) placeholder for 2015 for gas supply costs, based on the averaging of previous Gas Supply project costs. In Decision 20522-D02-2016, for 2016 Gas Supply projects, the Commission approved a $661,250 (including overhead) placeholder for 2016, again based on the average of previous gas supply costs. The Commission's approval of placeholders for gas supply costs, based on an average historical costs methodology, is to account for the fact that at least one Gas Supply project is likely to arise in any given year and that the particulars related to gas supply projects may not be known sufficiently in advance for AltaGas to provide detailed costing information or a business case. Only one Gas Supply project, BWM, has been identified for 2016.[135] The BWM Gas Supply project was expected to commence in 2015 and to continue into 2016.

231. In the application, AltaGas explained that the BWM Gas Supply project[136] was driven by a December 2014 notice from ATCO Energy Solutions (AES) informing AltaGas that it would be selling or decommissioning the Carbondale system. The Carbondale system supplies gas to AltaGas at seven PMS facilities, which serve about 6,200 farm, residential and commercial customers in and around the Town of Morinville. AES offered to sell the system to AltaGas and indicated that it had no other interested parties, and if AltaGas did not purchase the system, AES would shut-in and abandon the system in place. Based on a consideration of the system's remaining asset life, a confidential engineering assessment by a third-party engineering firm, and

[135] Proceeding 20522, AltaGas' 2014 capital tracker true-up and 2016-2017 capital tracker forecast application.
[136] Exhibit 21627-X0007, application, unnamed table on page 129 and paragraphs 301-311 and 314.

consideration of potential environmental concerns, AltaGas determined that acquisition of the Carbondale system was not a prudent utility acquisition. Therefore, AltaGas decided to consider alternatives for gas supply at the seven PMS facilities rather than purchase the AES system.

232. While evaluation of these alternatives was underway, AltaGas' engineers found that most of the alternatives involved replacing sections of non-certified PE and PVC pipe already identified for replacement through AltaGas' Pipeline Replacement program. Because time was of the essence with the imminent shut-down of the Carbondale system, AUI advanced the installation of 30 km of this pipe to the fall of 2015. The costs of this construction were for engineering, design and land work to advance the overall BWM gas supply strategy and incremental pipe replacements to complete a full gas supply solution on a critical path basis. The costs were accounted for as work-in-progress as at December 31, 2015, with tie-ins and completion scheduled for 2016.

233. On January 7, 2016, AES informed AltaGas that it had sold the system to Tidewater Midstream and Infrastructure Ltd. (Tidewater) and that Tidewater's intentions were to continue operating the system as a natural gas transmission line for the time being, but with a view to increasing its use as a natural gas liquids gathering system to move liquid-rich gas to its processing facilities in Fort Saskatchewan. Shortly thereafter, AltaGas signed an agreement with Tidewater to continue purchasing natural gas from the Carbondale system on the same terms it had previously with AES.

234. AltaGas stated:

> 312. The acquisition and extension of the gas supply agreement by Tidewater has staved off the need for high-priority, immediate action by AUI. However, it has not eliminated the requirement to bypass this system. Based on Tidewater's clearly stated intention to begin moving increasing volumes of NGLs [natural gas liquids] through the Carbondale system, AUI's engineers and senior management have concluded the best and most reasonable approach is phased construction of a bypass, in conjunction with completion of planned capital tracker replacements of NCPE [non certified PE], PVC and pre-1957 high-pressure steel over the next 2-3 years. This will allow AUI reasonable time to prudently allocate its construction forces across all its capital projects and provide control of its gas supply to the BWM area when Tidewater's transport of NGLs on this system jeopardizes AUI's system safety and reliability.[137]

235. As part of the initial work related to the BWM Gas Supply project, AltaGas incurred costs of $536,000 in 2015.[138] For 2016, AltaGas provided the following 2016 expenditures update:

> During the period January 1-June 30, 2016, AUI invested approximately $300,000 in advancement of the BWM gas supply project. AUI is forecasting approximately $350,000 in additional funds to be spent on the BWM project during the remainder of 2016, for work related to upsizing of pipe, route design, acquiring right of ways, land access agreements, topographic surveys, permit applications and site reconnaissance.[139]

[137] Exhibit 21627-X0007, application, paragraph 312.
[138] Exhibit 21627-X0043, AltaGas argument, paragraph 36.
[139] Exhibit 21627-X0022, AUI-AUC-2016JUN21-027(b).

236. In response to a CCA IR, AltaGas provided the following description of work performed so far on the BWM project:

- Internal engineering, engineering field visits, drafting and Graphic Information System (GIS) labour for preliminary design options including study of data provided by AES, risk assessment modelling, field reconnaissance and project management;
- Field work and compilation of field reconnaissance investigation data by a 3rd party contractor, Engineering and Project Management for various cost estimate options;
- Engaging outside consulting firm to complete integrity assessment on existing AES (now Tidewater) line;
- Conducting a topographic aerial survey including an infrared scan of ground surface of existing AES line and Right of Way (ROW);
- Completed work on pipe reconfiguration based on Engineering and field assessments to protect/improve flow characteristics on Barrhead-Westlock transmission connection;
- Land work for accessing fields during survey work, initial ROW land work, estimating land damages and acquisition of land for ROW, initial routing and land title searches for proposed ROW; and
- Initial land agreement consultations with landowners.[140]

237. AltaGas submitted that it will file further BWM Gas Supply details, including a full business case, as part of its 2016 capital tracker true-up application due in May 2017. At that time, AltaGas will also request approval of capital additions completed and placed into service in 2016. Because the project is expected to extend into 2018 and, possibly 2019, AltaGas stated it will also include applicable forecast amounts in its 2018-2019 capital tracker application, to be filed as part of AltaGas' rebasing application.[141] AltaGas further submitted that since there were no additions related to the BWM project in 2015, the scope and costs related to the project are outside the scope of this proceeding.[142]

238. AltaGas has not recognized any capital additions in its gas supply program in 2015 and, as a result, requested approval to refund the 2015 approved placeholder amount of $531,000 to customers as part of the 2015 K factor true-up adjustment. AltaGas stated that it will reapply for these costs as part of its 2016 capital tracker true-up application once the additions are placed into service.[143]

239. The UCA submitted that it is concerned about potential prejudice regarding a future capital tracker ruling on this project that may arise as a result of AltaGas continuing to provide detail and information that is short of that required for approval of the project costs on a capital tracker basis but may imprint an approval of these costs in the minds of parties. The UCA requested that the Commission provide direction to the effect that the BWM project is not approved as a capital tracker, that the information provided by AltaGas to date is considered to be on a "without prejudice" basis and that it will not fetter the discretion of the Commission in a future proceeding to whether capital tracker treatment is to be approved for this project. Once AltaGas has actually filed a proper business case and is applying for approval of the costs, the

[140] Exhibit 21627-X0027, AUI-CCA-21JUN2016-006(a).
[141] Exhibit 21627-X0007, application, paragraph 314; Exhibit 21627-X0022, AUI-AUC-2016JUN21-027(b); Exhibit 21627-X0043, AltaGas argument, paragraph 35.
[142] Exhibit 21627-X0043, AltaGas argument, paragraph 34.
[143] Exhibit 21627-X0043, AltaGas argument, paragraph 36.

UCA intends to thoroughly test it and expects to do so without any preconception that these costs have been previously approved.[144]

240. AltaGas responded that it has never been its intention to imply that the BWM project has been approved. AltaGas has submitted evidence to the Commission indicating that the BWM project is required to maintain reliable gas supply but has not yet filed a business case. AltaGas stated that it appreciates the patience and understanding it has received to date from the Commission and intervenors, and that it remains AltaGas' intention to provide full and timely disclosure of its plan for this project, while ensuring such information is sufficiently accurate so that all parties can be assured that AltaGas is fully committed to its completion within the timeframes and the costs proposed. Accordingly, AUI submitted that the UCA's request that the Commission provide direction to the effect the BWM project is not approved as a capital tracker and the information provided by AltaGas to date will not fetter the Commission's discretion, is not necessary or appropriate.[145]

Commission findings

241. The Commission accepts the explanation of AltaGas as to the sequence of events regarding the availability of gas supply to its Morinville-area customers, and AltaGas' approach for the development of an optimal solution.

242. Because there were no capital additions in AltaGas' Gas Supply program in 2015, the Commission is not required to determine whether the project scope, level and timing, and the resulting 2015 costs were prudently incurred. The Commission approves AltaGas' request to refund the 2015 approved placeholder amount of $531,000 to customers as part of the 2015 K factor true-up adjustment. The Commission notes that the refund has been included in the applied-for K factor.[146]

243. Regarding the UCA's request for a direction in the decision to the effect that the BWM project is not approved as a capital tracker and, consequently, will not fetter the Commission's discretion in a future proceeding to determine whether capital tracker treatment is warranted for this project, the Commission does not find such a direction necessary. At paragraphs 298 and 299 in Decision 20522-D02-2016, the Commission accepted that the BWM Gas Supply project will be required, based on the evidence that had been filed by AltaGas to that point in time, and recognizing the confidential nature of the negotiations with a third-party supplier and that the projected 2015 costs for the project would result in some level of financial hardship on AltaGas in the absence of placeholder funding. Because the need for the Gas Supply program has been previously established and because the Commission has previously determined that 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, at this time. However, given that a full business case for the BWM Gas Supply project remains outstanding, evidence that the ongoing or recurring project or program is no longer required may arise when AltaGas files it business case for the BWM project. In addition, in the absence of a business case, AltaGas

[144] Exhibit 21627-X0042, UCA argument.
[145] Exhibit 21627-X0051, AltaGas reply argument.
[146] Exhibit 21627-X0002, supporting schedules to the application, schedules 4.0 and 5.0.

has not satisfied the second component of capital tracker Criterion 1 and, accordingly, the Commission confirms that no determination has been made as to whether the BWM Gas Supply project qualifies for capital tracker treatment. Parties will be afforded an opportunity to test the business case for this project once it is filed, currently expected as part of AltaGas' 2016 capital tracker true-up application, as indicated by AltaGas.

8.3 Capital tracker projects not previously approved in Decision 2014-373

8.3.1 Pipeline Replacement program

244. In the application, AltaGas applied for capital tracker treatment for the St. Paul (town) and the Morinville (town) projects. Since these projects were undertaken in 2015 but were not approved as capital tracker forecast projects in Decision 2014-373, the Commission will assess these projects, using the capital tracker criteria, to determine whether they qualify for capital tracker treatment. In doing so, the Commission will consider whether the actual scope, level, timing and costs of each project was prudent. Cost and pipe length information provided by AltaGas is shown in the table below:

Table 25. Pre-1957 Steel Pipe – St. Paul (town) and Morinville (town)

	Capital additions			Pipe length			Unit cost		
Pre-1957 Steel	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance	Approved	Actual	Approved vs. actual variance
	($)			(km)			($/km)		
St. Paul (town)	-	563,901	(563,901)	-	1.7	(1.7)	-	329,555	(329,555)
Morinville (town)	-	256,827	(256,827)	-	0.6	(0.6)	-	402,488	(402,488)

Source: Exhibit 21627-X0007, application, Table 2.2-1, paragraph 74.

8.3.1.1 Pre-1957 Steel Pipe Replacement program

St. Paul (town)

245. In 2015, AltaGas completed 1.7 km of pipeline replacement for the St. Paul (town) project. AltaGas stated that although the St. Paul (town) project was originally planned for replacement in 2018,[147] this project was advanced to 2015 for logistical reasons and because there was a relatively high risk associated with the existing facilities. AltaGas explained that it was prudent to replace this relatively short section of pipe in advance of schedule in order to complete the replacement of all pre-1957 steel pipe in the district, so as to coincide with other replacement projects in the town, therefore causing less disruption to customers.

246. In response to a Commission IR, AltaGas provided the following table showing the risk assessment score for this project.[148] AltaGas explained that the St. Paul (town) facilities were considered to be relatively high risk. As shown in the table, the risk score of 18 places the project above all PVC and non-certified PE projects completed in 2015, and on a level similar to AltaGas' remaining Pre-1957 Steel projects.[149]

[147] Exhibit 21627-X0022, AUI-AUC-2016JUN21-09(b).
[148] Exhibit 21627-X0022, AUI-AUC-2016JUN21-010(f).
[149] Exhibit 21627-X0022, AUI-AUC-2016JUN21-09(a).

Table 26. Risk score for the St. Paul (town) project

Pipe type	Name of zone	Geotype	Pipe material	Population density	Ground cover	Leak rate	Locatable	Logistics	Score
Pre-57 Steel	Drumheller Main (1)	Downtown	4	4	4	4	0	1	**28**
Pre-57 Steel	Hanna Steel Main (2)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Stettler Steel Main (3)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Downtown Barrhead Main (4)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Downtown Morinville Steel Main (6)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Town of Drumheller Main (1)	Town	4	2	3	4	0	1	**22**
Pre-57 Steel	Downtown St Paul Steel Main (7)	Downtown	4	4	4	0	0	0	**20**
Pre-57 Steel	Downtown Westlock Steel Main (5)	Downtown	4	3	4	0	0	0	**18**
Pre-57 Steel	Town of Morinville 2015	Town	4	3	3	0	0	1	18
Pre-57 Steel	**Town of St Paul (2015 and Remainder)**	**Town**	**4**	**3**	**3**	**0**	**0**	**1**	**18**

247. In the absence of an approved 2015 forecast, AltaGas provided the amounts approved in its AFE for purposes of assessing the prudence of the costs. The AFE forecast cost was $654,369, the forecast pipeline length was 2.0 km and the forecast unit cost was $333,200/km.

248. In 2015, AltaGas replaced 1.7 km of pipe at an actual cost of $563,901 for a total unit cost of $329,555/km. The actual costs were $90,498 (13.8 per cent) below forecast, the pipeline length was 0.3 km (12.9 per cent) below forecast and the unit cost was $3,645 (1.1 per cent) below forecast.[150] AltaGas explained that it only needed to install 1.7 km of the 2.0 km of pipe identified in the AFE estimate because of minor changes in the pipe alignment and routing identified during final field work.[151]

249. AltaGas explained that the lower actual costs compared to the AFE forecast costs were primarily a result of fewer tie-ins due to the reduction in the number of services required for replacement, thereby lowering service/main connection costs. Site restoration costs were also lower than the AFE forecast due to less asphalt being required for the final design and alignment of the project, and less gravel being required for roadway subgrade. Third-party contractor costs were also lower than the AFE forecast due to lower inspection costs resulting from a shorter project construction schedule. These lower costs were partially offset by higher miscellaneous costs due to incomplete ESRI data, additional hydrovac costs, and the movement of services to meet current safety code requirements not anticipated in the original estimate.[152]

Morinville (town)

250. In 2015, AltaGas completed 0.6 km of pipe replacement for the Morinville (town) project. AltaGas stated that, although the Morinville (town) project was originally planned for replacement in 2019, work was undertaken on this project in 2015 at the request of the municipality to co-ordinate with roadworks and paving in the area. AltaGas explained that, logistically, it was reasonable and practical to advance the replacement of this project in the town, given the municipality's request. AltaGas also submitted that the risk scores, relative to other pipe projects in the downtown areas, were higher and completing both a downtown and

[150] Exhibit 21627-X0007, application, paragraph 120.
[151] Exhibit 21627-X0022, AUI-AUC-2016JUN21-09(f).
[152] Exhibit 21627-X0007, application, paragraphs 121-122.

town project at the same time would be less disruptive to customers and likely result in mobilization and demobilization cost savings.[153]

251. In response to a Commission IR, AltaGas provided the following risk assessment score for this project.[154]

Table 27. Risk score for the Morinville (town) project

Pipe type	Name of zone	Geotype	Pipe material	Population density	Ground cover	Leak rate	Locatable	Logistics	Score
Pre-57 Steel	Drumheller Main (1)	Downtown	4	4	4	4	0	1	**28**
Pre-57 Steel	Hanna Steel Main (2)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Stettler Steel Main (3)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Downtown Barrhead Main (4)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Downtown Morinville Steel Main (6)	Downtown	4	4	4	4	0	0	**26**
Pre-57 Steel	Town of Drumheller Main (1)	Town	4	2	3	4	0	1	**22**
Pre-57 Steel	Downtown St Paul Steel Main (7)	Downtown	4	4	4	0	0	0	**20**
Pre-57 Steel	Downtown Westlock Steel Main (5)	Downtown	4	3	4	0	0	0	**18**
Pre-57 Steel	**Town of Morinville 2015**	**Town**	**4**	**3**	**3**	**0**	**0**	**1**	**18**
Pre-57 Steel	Town of St Paul (2015 and Remainder)	Town	4	3	3	0	0	1	**18**

252. In the absence of an approved 2015 forecast, AltaGas provided the amounts approved in its AFE for purposes of assessing the prudence of the costs. The 2015 AFE forecast cost was $223,850, the forecast pipeline length was 0.75 km and the forecast unit cost was $298,466/km.

253. In 2015, AltaGas replaced 0.64 km of pipe at an actual cost of $256,828, for a total unit cost of $402,551/km. The costs were $32,978 (14.7 per cent) above forecast, the pipeline length was 0.11 km (14.9 per cent) below forecast and the unit cost was $104,085 (34.9 per cent) above forecast.[155] AltaGas explained that it only installed 0.64 km of the 0.75 km of pipe identified in the AFE estimate because of final field condition adjustments.[156]

254. AltaGas stated that the cost variance was primarily the result of higher third-party contractor costs compared to the AFE forecast, due to additional inspection costs that were required for steel pipe tie-ins. Additional engineering was also required to address the scope of the project and on-site reconnaissance, thereby increasing labour costs. Site restoration costs were also higher due to the increased number of bell hole restorations required. These increased costs were offset by lower pipe installation costs due to a reduction in the size of the pipe installed, and slightly more favourable contractor rates than in the original AFE estimate.[157]

Commission findings

255. In Decision 2012-237 and in Decision 2013-435, the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker

[153] Exhibit 21627-X0007, application, paragraphs 125 and 127.
[154] Exhibit 21627-X0022, AUI-AUC-2016JUN21-010(f).
[155] Exhibit 21627-X0007, application, paragraph 128.
[156] Exhibit 21627-X0022, AUI-AUC-2016JUN21-010(a).
[157] Exhibit 21627-X0007, application, paragraphs 130-131.

treatment. In other words, capital tracker treatment may be granted on the basis of actual capital expenditures, without prior approval of capital forecasts for a project.

256. With respect to the St. Paul (town) and the Morinville (town) pipeline replacement projects, the Commission is satisfied with AltaGas' explanation of the need for these projects and finds that it was prudent for AltaGas to undertake them.

257. With respect to the scope, level and timing of the work associated with these two projects, the Commission has reviewed the 2015 AFE estimates, the 2015 actual capital additions and the variance explanations. For the purposes of this decision, the Commission finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved for the Pre-1957 Steel Pipe Replacement program in Decision 2014-373. The Commission has also reviewed the 2015 AFE estimates and actual capital additions for these two projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between 2015 AFE estimates and the 2015 actual costs, and the variance explanations for both projects and, for the purposes of this decision, finds the costs to be prudent.

258. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that these two projects satisfy the project assessment requirement of Criterion 1 for 2015.

8.3.2 Station Refurbishment program

259. As shown in Table 5 above, AltaGas identified two TBS Station Refurbishment projects, TBS stations PC024 and LE092, which were not approved in Decision 2014-373 on a forecast basis for completion in 2014 or 2015, but were completed in 2015.

260. AltaGas provided information for the three TBS Station Refurbishment projects subject to this application, which have been summarized for two of the three projects in Table 28 below. The table identifies the 2015 actual capital additions, which serve as the basis for the calculation of the 2015 capital tracker true-up.

261. In the absence of an approved 2015 forecast for Station Refurbishment projects PC024 and LE092, AltaGas provided the amounts approved in its 2015 AFE for purposes of assessing the prudence of the costs. AltaGas also provided the costs of a typical TBS station and the actual capital additions for TBS stations PC024 and LE092, and a variance analysis, as set out in Table 28.

Table 28. 2015 capital additions of TBS stations

	Capital additions			Variance	
Stations	**Typical**	**AFE**	**Actual**	**AFE vs. actual**	**% of total AFE**
	($)				(%)
PC024[158]	191,000	581,347	684,312	(102,964)	17.7
LE092	191,000	463,457	442,807	20,650	4.4

Source: Exhibit 21627-X0007, application, unnamed table before paragraphs 275 and 277.

262. Since these projects were undertaken in 2015 but were not approved as capital tracker forecast projects in Decision 2014-373, the Commission will assess the projects, using its the capital tracker criteria, to determine whether they qualify for capital tracker treatment. In doing so, the Commission will consider whether the actual scope, level, timing and costs of each project was prudent.

263. The replacement for TBS Station PC024 was required to improve the reliability and safety of gas supply to the Town of Pincher Creek. The costs for this station were based on the replacement costs of TBS Station PC001, in the same vicinity, which had been approved in Decision 2014-373 for $436,400. However, after the approval of TBS Station PC001, AltaGas revised its plan to completely replace TBS Station PC024, and TBS Station PC001 was converted to a block valve assembly with a distribution line connecting the two facilities. The scope change reduced the overall infrastructure needed to serve the community and removed the potential risk of having a regulating station and higher-pressure pipeline within the town limits.

264. AltaGas attributed the difference between the AFE forecast costs and actual costs to the project's scope change which resulted in higher AltaGas labour costs, higher external contractor costs required due to internal resource constraints, additional site work, additional fabrication and assembly, a larger line heater system and more valves, piping, fittings, regulators and pressure controls.[159]

265. The timing for completion of TBS Station LE092 was moved forward because it was considered one of the highest risk stations in AltaGas' network. AltaGas undertook a complete replacement because the station flows large volumes of gas, is located in close proximity to residential customers, had run-splitting regulators and multiple gate valves in its piping configuration, and was subject to significant frost heaving and instability.

266. AltaGas explained that the replacement of the TBS Station LE092 was more complex than that of a typical TBS station and required additional AltaGas labour, a line heater, advanced valves, piping and fittings, and larger regulators and pressure controls. AltaGas also incurred higher costs related to site work because the city of Leduc rebuilt its new industrial subdivision and raised the entire area and roadway beside TBS Station LE092. In order to match the new elevation, AltaGas had to raise the entire station site 0.75 metres to make the site accessible and

[158] This project absorbed the costs of TBS Station Refurbishment Project PC001. Both PC024 and PC001 are included in the PC024 actual costs but not in the PC024 AFE estimate.

[159] Exhibit 21627-X0007, application, unnamed table on page 118 and paragraph 275.

to ensure it drains properly. AltaGas also incurred additional costs for external contractors for the installation of the station, field x-ray inspection of riser welds, and hydrovac work.[160]

Commission findings

267. In Decision 2012-237 and in Decision 2013-435, the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker treatment. In other words, capital tracker treatment may be granted on the basis of actual capital expenditures, without prior approval of capital forecasts for a project.

268. With respect to the two TBS Station Refurbishment projects discussed above, the Commission is satisfied with AltaGas' explanation of the need for these projects and finds that it was prudent for AltaGas to undertake them.

269. With respect to the scope, level and timing of the work associated with these two projects, the Commission has reviewed the 2015 AFE estimates, the 2015 actual capital additions and the variance explanations. For the purposes of this decision, the Commission finds that they are generally consistent with the scope, level and timing of the work outlined in the business case approved for the Station Refurbishment program in Decision 2014-373. The Commission has also reviewed the 2015 AFE estimates and actual capital additions for these two projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between 2015 AFE estimates and the 2015 actual costs, and the variance explanations for both projects and, for the purposes of this decision, finds the costs to be prudent.

270. Given the above, the Commission finds that the information provided by AltaGas supports a finding that the actual scope, level, timing and costs of the work undertaken in 2015 were prudent. Accordingly, the Commission finds that these two projects satisfy the project assessment requirement of Criterion 1 for 2015.

9 Accounting test under Criterion 1

9.1 Accounting test for the 2015 true-up

271. 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 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.[161]

272. The first component of the accounting test, the calculation of revenue provided under the I-X mechanism, and the second component, AltaGas' calculation of the accounting test model

[160] Exhibit 21627-X0007, application, unnamed table on page 121 and paragraphs 277-278.
[161] Decision 2013-435, paragraphs 149-150.

for the 2015 capital tracker true-up on an actual basis, was provided in the supporting schedules to the application.[162]

273. A comprehensive overview of the accounting test under PBR is set out in Appendix 4.

274. For the 2015 capital tracker true-up, AltaGas used the following assumptions in its accounting test:

Table 29. AltaGas' 2015 capital tracker true-up accounting test assumptions

2015 I-X index[163]	1.49%
2015 Q factor[164]	1.97%
Weighted average cost of capital (WACC) rate embedded in AltaGas' going-in rates used in the first component of the accounting test	6.708%
Actual 2015 WACC rate used in the second component of the accounting test[165]	6.215%

275. Specifically, the 2015 I-X index of 1.49 per cent was approved in Decision 2014-357. The 2015 Q factor was based on a billing determinants forecast approved in the same decision. AltaGas' actual 2015 WACC rate of 6.215 per cent is based on the actual cost of debt of 4.706 per cent, the approved equity thickness of 42 per cent and the approved return on equity (ROE) of 8.3 per cent, as determined in the 2013 generic cost of capital Decision 2191-D01-2015.[166] AltaGas' actual 2015 cost of debt of 4.706 per cent as reported in its 2015 Rule 005 filing, is a blend of its new $15 million long-term debt issued in 2015 with a coupon rate of 3.91 per cent, and rates for 5 prior debt issues dating back to 2009.[167]

276. No intervener raised issues with any of the above assumptions in AltaGas' accounting test.

Commission findings

277. The Commission has reviewed AltaGas' schedules that make up its accounting test analysis for the purposes of the 2015 capital tracker true-up and finds these schedules to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435. The Commission has verified AltaGas' WACC, I-X and Q factor assumptions used in the first component of the accounting test, and finds that AltaGas used the correct values.

278. At paragraph 329 of Decision 20522-D02-2016, referenced in Appendix 4 of this decision, the Commission indicated that it will accept a company's embedded debt rate from the previous year's Rule 005 filing in the absence of any evidence that the actual cost of debt was not reasonable. The prudence of this actual debt will be assessed 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 (GRA). Therefore, the Commission finds AltaGas' 2015 actual WACC of 6.215 per cent used in the second component of its accounting test, based on

[162] Exhibit 21627-X0002.
[163] Exhibit 21627-X0002, Schedule 9.0.
[164] Exhibit 21627-X0002, Schedule 9.0.
[165] Exhibit 21627-X0002, Schedule 9.1.
[166] Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.
[167] AltaGas' 2015 Rule 005 filing, schedules 2 and 2.3.

the 2015 actual cost of debt of 4.706 per cent, as well as the approved equity thickness of 42 per cent and the approved ROE of 8.3 per cent from Decision 2191-D01-2015, to be reasonable.

279. For the reasons above, the Commission is satisfied that AltaGas' accounting test model sufficiently demonstrates that all of the 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 the accounting test component of Criterion 1. The Commission's determinations on whether AltaGas' programs or projects proposed for capital tracker treatment in 2015 on an actual basis satisfy both the accounting test and the project assessment components of Criterion 1 are set out below.

9.2 Commission's conclusions on Criterion 1

280. In Section 7 of this decision, based on the project assessment under Criterion 1, the Commission approved the need, scope, level, timing, and the prudence of actual capital additions for each project or program that AltaGas proposed for capital tracker treatment on an actual basis for 2015. In Section 9.1, the Commission determined that all of AltaGas' 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 the accounting test component of Criterion 1. Accordingly, subject to Commission directions to provide additional supporting information in future capital tracker applications for certain items, the Commission finds that AltaGas' programs or projects proposed for capital tracker treatment in 2015 on an actual basis satisfy the project assessment requirement of Criterion 1.

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

281. 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, 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.[168] Certain projects proposed 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.[169]

282. As set out in Section 4 of this decision, for the purposes of the true-up of the 2015 capital tracker programs or projects for which the Commission undertook and approved the assessment against the Criterion 2 requirements in Decision 2014-373, there is no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. In the application, AltaGas confirmed that there are no changes to the drivers of any of its previously approved capital tracker projects or programs.[170]

[168] Decision 2013-435, paragraph 309.
[169] Decision 2013-435, paragraph 314.
[170] Exhibit 21627-X0007, application, paragraph 17.

Table 30. Applied-for 2016-2017 capital tracker projects and programs and Criterion 2 requirements

Project name	Criterion 2 project type
Applied-for programs previously approved for capital tracker treatment	
Pipe Replacement	Replacement
Station Refurbishment	Replacement
Gas Supply	External party driven/replacement

283. 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

284. Consistent with the determinations in Section 4 of this decision, because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each project or program included in AltaGas' 2015 capital tracker true-up have not changed since the Commission undertook and approved proposed capital tracker projects and programs against the Criterion 2 requirements in Decision 2014-373, there is no need to undertake a reassessment of these programs or projects against the Criterion 2 requirements.

285. The Commission reminds AltaGas that the following direction from Decision 2014-373 continues to apply for subsequent capital tracker true-up applications:

> 345. In subsequent capital tracker true-up applications, the Commission directs AltaGas to address whether the driver for any of the previously approved forecast projects or programs has changed, so as to warrant a reassessment under Criterion 2. In the event that the driver of the project or program has changed since the forecast project or program was approved, AltaGas is directed to identify such projects and programs and to provide evidentiary support that the project or program continues to satisfy the requirements of Criterion 2.[171]

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

286. Section 9 of this decision addressed AltaGas' accounting test, which determines whether all of the 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 program or project proposed for capital tracker treatment.

287. In accordance with the Commission's determinations 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

[171] Decision 2014-373, paragraph 345.

point threshold," is applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.[172]

288. In Decision 2013-435, the Commission calculated the four basis point threshold and the 40 basis point threshold based on the 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 2012 amount by I-X.[173]

289. For the 2015 capital tracker true up, AltaGas used a 2015 four basis point threshold of $32,290 calculated by escalating the 2012 amount by the approved 2013, 2014 and 2015 I-X index values. Using the same methodology resulted in a 40 basis point threshold of $322,896 for 2015.[174] AltaGas then assessed each of the capital tracker projects included in the 2015 true-up against the four basis point threshold and the total K factor request against the 40 basis point threshold. AltaGas demonstrated that its proposed capital tracker projects or programs exceed these materiality thresholds for K factor treatment on an actual basis for 2015.[175]

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

Commission findings

291. For its 2015 true-up calculations, AltaGas used the first and second tier materiality thresholds calculated by escalating the 2012 amount by the approved 2013, 2014 and 2015 I-X index values. The Commission has reviewed AltaGas' calculations, and is satisfied that AltaGas has interpreted and applied the Criterion 3 two-tiered materiality test properly for the purposes of its 2015 capital tracker true-up, based on the projects and assumptions included in the application. The Commission finds that each of AltaGas' proposed capital tracker programs for 2015 exceed the materiality thresholds, and therefore satisfy Criterion 3.

12 Other matters

12.1 Z factor versus K factor for Pickardville line

292. As explained in more detail in Section 8.2.3, above, AltaGas was required to find an alternative to bypass the Carbondale system, which currently supplies gas to AltaGas at seven PMS facilities (BWM area). AltaGas concluded that the best and most reasonable approach is phased construction of a bypass, in conjunction with completion of planned replacements of NCPE, PVC and pre-1957 high-pressure steel over the next two to three years. Specifically, as detailed in the unnamed tables before paragraphs 308 and 310 of the application, AltaGas' proposed strategy is to:

[172] Decision 2013-435, paragraphs 382-385.
[173] Decision 2013-435, paragraphs 378 and 384.
[174] Exhibit 21627-X0002, Schedule 8.1.
[175] Exhibit 21627-X0007, application, paragraph 28; Exhibit 21627-X002, Schedule 8.0.

- Complete the approved 2016 NCPE and PVC Pipe projects.
- Defer replacement of the approved 2016 pre-1957 high-pressure steel 10.5 km Pickardville line and 1.5 km Westlock town portion of that same line to 2017 or 2018, depending on Tidewater's actions in the near term.[176]

293. Given that AltaGas is proposing to defer replacement of the approved 2016 pre-1957 high-pressure steel 10.5 km Pickardville line to either 2017 or 2018, the CCA asked AltaGas in IR AUI-CCA-21JUN2016-007 to explain why the Pickardville line should continue to qualify for capital tracker treatment, as opposed to Z factor treatment. AltaGas responded:

> AUI has approximately 100 km of pre-1957 HP steel pipe in its system. In the business case for the pre-1957 steel pipe replacement program submitted in its 2016-2017 Forecast Capital Tracker Application, the replacement of pre-1957 HP steel pipe is included. In AUI's view, the replacement of the 10.5 km high-pressure (HP) Pickardville line is being deferred from 2016 to 2017 or 2018 driven by timing, pending Tidewater's plans in the near future. At this time, there are no valid reasons or changes in circumstances to warrant the exclusion of the replacement of the HP steel Pickardville line from the pre-1957 steel pipe replacement program.
>
> In Decision 2012-237, the Z Factor mechanism is intended to address the impact of material exogenous events for which AUI has no other reasonable cost recovery mechanism within the PBR plan. Currently, the replacement of the Pickardville line is appropriately identified for recovery under the capital tracker (K Factor) mechanism.[177]

294. The CCA maintained that AltaGas has not effectively made its case for ongoing capital tracker treatment of the Pickardville Pipeline Replacement project as a capital tracker and requested that the application for deferral of this project be rejected. The CCA maintained that if the project indeed proves to be necessary, it might be better classified and dealt with as a singular project for Z factor treatment. In support of its request, the CCA submitted:

> 11. Essentially, AUI's treatment of the Pickardville pipeline replacement project is in direct response to the actions of an exogenous event outside of the control of management: the third party decision by Tidewater to shift the usage of the pipeline. While AUI characterizes this event as unforeseeable, the actual event itself was not. The trigger point of this project was the decision of Tidewater and its predecessor, an unforeseeable event. Furthermore, the CCA submits that the current timing of the pipe replacement, while a response that has some foresight, remains a response to an unforeseeable and exogenous event.
>
> 12. The PBR formula allows for applications in such circumstances as a Z Factor when an exogenous event is outside of management's control, is material, does not impact the wider Albertan or Canadian economy, the costs of which are prudent, and that the event was unforeseeable. The Z Factor component of the PBR formula also allows consumers to fully and purposefully test the application for recovery from rates for projects that management has not been able to address within the I-X formula.[178]

[176] Exhibit 21627-X0007, application, paragraphs 312-313.
[177] Exhibit 21627-X0027, AltaGas response to AUI-CCA-21JUN2016-007.
[178] Exhibit 21627-X0047, CCA argument, paragraphs 11-12.

295. Further, the CCA stated that the forecast for the Pickardville line, as laid out in Proceeding 20522, is no longer accurate in light of the reported intentions of Tidewater and that the request for deferral indicates that non-capital tracker treatment is required for the replacement of the Pickardville line.

296. In reply argument, AltaGas disagreed with the CCA that deferral of the Pickardville project is in direct response to Tidewater's actions in shifting the use of the pipeline. AltaGas maintained that:

> 4. … While the actions of Tidewater are being considered in AUI's timing of the 2016 Pickardville HP steel project, the project itself has been and continues to be part of AUI's Pipe Replacement program required to maintain safety and service quality.

297. AltaGas further submitted that the need for the Pickardville project has been appropriately identified and approved under the existing Pre-1957 Steel Pipe Replacement program and that there has been no change in the basis for the Pickardville project as originally approved in the Pre-1957 Steel Pipe Replacement business case. Accordingly, AltaGas requested that the CCA's position that the regulatory treatment of the Pickardville project be changed from its approved status as a capital tracker K factor, to a Z factor, be rejected.[179]

298. The CCA did not file reply argument.

Commission findings

299. The Commission acknowledges that AltaGas will likely need to construct a bypass in the BWM area and, therefore, deferral of the Pickardville Pipeline Replacement project to coincide with construction of the bypass may be the most cost-effective approach. However, the exact timing of construction of the bypass is currently unknown. Accordingly, the Commission finds that it is premature to approve AltaGas' request to defer the Pickardville Pipeline Replacement project or to rule on the issue of K factor versus Z factor treatment. AltaGas may reapply for the Pickardville Pipeline Replacement project once it has sufficient information about when the project will proceed.

300. With respect to previously-approved 2016 or 2017 K factor amounts that have changed as a result of the deferral of the Pickardville line, AltaGas is directed to reflect these changes in its capital tracker true-up applications.

13 K factor calculations for 2015 true-up

301. Table 31 below details the 2015 approved and actual K factors by program, and resulting variances applied for in this application as K factor adjustments. The resulting net adjustment to the K factor is a $148,796 refund to customers. This amount was included in AltaGas' 2017 annual PBR rate application.

[179] Exhibit 21627-X0051, AltaGas reply argument, paragraphs 5, 6 and 9.

Table 31. Applied-for 2015 K factor true-up adjustments

		2015 K factor adjustment		
Line	Program	2015 actual K factor	2015 approved forecast K factor[180]	2015 K factor adjustment
		A	B	C = A - B
		($)		
1	Pipe Replacement	2,584,174	2,617,747	(33,573)
2	Station Refurbishment	387,712	499,844	(112,131)
3	Gas Supply	329,063	332,154	(3,091)
4	Total	3,300,949	3,449,744	(148,796)

Source: Exhibit 21627-X0007, Table 1.2-1; Exhibit 21627-X0002, Schedule 1.0.

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

303. With the exception of the CCA's proposal to reclassify the Pickardville Pipeline Replacement project as a Z factor rather than a K factor (see Section 12.1), there were no objections by interveners to AltaGas' K factor proposals.

Commission findings

304. The Commission has reviewed AltaGas' calculations and finds that AltaGas' methodology to determine the 2015 K factor true-up amount meets the requirements set out in Decision 2012-237 and Decision 2013-435. The 2015 K factor true-up refund amount of $148,796 is approved, subject to the disallowances in this decision.

305. The difference between the 2015 true-up adjustment of ($148,796) that AltaGas has included in its 2017 interim rates[181] and the disallowances in this decision will need to be addressed. Accordingly, AltaGas is directed to refund that difference to customers in its next Rate Rider F application or AltaGas 2018 annual PBR rate adjustment filing, whichever occurs first.

14 Compliance with previous Commission directions

306. In Decision 2014-373, Decision 20590-D01-2015 and Decision 20522-D02-2016, the Commission provided a number of directions to AltaGas that were applicable to its future capital tracker applications or other PBR-related applications. In Decision 3434-D01-2015 and in Decision 3558-D01-2015, the Commission also provided clarifications on the capital tracker mechanism and issued a number of related directions to companies under PBR, including AltaGas.

[180] 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.

[181] Proceeding 21987, AltaGas 2017 annual PBR rate adjustment application.

307. AltaGas addressed the Commission's directions[182] and the associated compliance are set out in Appendix 5 to this decision. AltaGas also provided a summary table of concordance to demonstrate compliance with each of the minimum filing requirements prescribed in Decision 3558-D01-2015.[183]

308. Other than as specifically mentioned in the above sections, no party challenged AltaGas' compliance with these previous directions.

Commission findings

309. In previous sections of this decision, the Commission dealt with AltaGas' compliance with certain directions from Decision 2014-373.

310. The Commission has reviewed AltaGas' responses to the Commission's directions that were not specifically addressed in the previous sections of this decision and is generally satisfied that AltaGas has complied with these directions in the application, with one exception, item 1.c. from the revised minimum filing requirements set out in Appendix 3 to Decision 3558-D01-2015. Under item 1.c., the Commission requires evidence that the capital cost allowance amounts have been reconciled with the amounts filed by AltaGas with the CRA, AltaGas stated "AUI will submit evidence of reconciliation when 2015 amounts have been filed with the CRA (due June 30, 2016.)." However, similar to the finding and direction made by the Commission at paragraph 373 of Decision 20522-D02-2016, 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, for purposes of regulatory efficiency, AltaGas is directed to fulfill this requirement at the time of its next capital tracker true up application.

[182] Exhibit 21627-0005, application, Appendix 2.
[183] Exhibit 21627-0006, application, Appendix 1.

15 Order

311. It is hereby ordered that:

(1) AltaGas Utilities Inc. is directed to comply with the findings contained within this decision.

Dated on December 7, 2016.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

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

Alberta Utilities Commission Commission panel M. Kolesar, Vice-Chair B. Lyttle, Commission Member Commission staff L. Desaulniers (Commission counsel) P. Howard N. Mahbub P. Genderka

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 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 only partially complied with the direction at paragraph 50 and Appendix 3 of Decision 3558-D01-2015. AltaGas provided, in Excel format with linked and working formulas, the actual capital additions for all programs, including supporting calculations and a breakdown of the amount of depreciation, overheads and income tax allocated to each capital tracker program and non-capital tracker program reconciled to the total amount of depreciation, overheads and income tax for all projects and programs. AltaGas did not provide a description of all non-capital tracker projects or programs that adequately describes, for the purpose of understanding project or program groupings, the nature and purpose of the proposed program. In Appendix I to the application, AltaGas described this non-capital tracker project requirement as "not relevant to the 2015 capital tracker true-up application." Since AltaGas provided these program descriptions in its application for the 2015 forecast capital trackers, for the purposes of this decision, the Commission is willing to dispense with the requirement but reminds AltaGas that, as per page 5 of Appendix 3 to Decision 3558-D01-2015, project descriptions are a minimum filing requirement that need to be included with each capital tracker application for better understanding of the proposed grouping of capital projects and programs for capital tracker treatment. Accordingly, AltaGas is directed to provide a description of all non-capital tracker projects or programs pursuant to the Commission's requirements as set out in Appendix 3 to Decision 3558-D01-2015, at the time of its next capital tracker true-up application. ..... Paragraph 35

2. With respect to the Blaine Hochstein project, the Commission was unable to find a previous application for a project by this name or an approval of a project by this name in Decision 2013-435 on a forecast basis, or in Decision 2014-373 on a true-up basis. It was also not approved on a true-up basis as a 2013 project in Decision 20522-D02-2016 or in Decision 2012-091. Further, AltaGas did not provide a variance explanation specifically for these trailing costs. Therefore, the Commission cannot, at this point, approve this project or the project's trailing costs on a final basis. AltaGas is directed to remove all costs associated with this project from its 2015 actual K factor at the time of its next Rate Rider F application or capital tracker true-up application, whichever occurs first. ..... Paragraph 59

3. With respect to costs claimed for the decommissioning of the PRS stations, for the purposes of this decision and for regulatory efficiency, the Commission is prepared to approve these costs on an interim basis, on the assumption that: (a) the actual number of decommissioned PRS stations was 11; (b) the actual decommissioning costs did not vary significantly from the forecast costs of $13,100 per station, for a total cost of $144,000; and (c) the decommissioning costs were absorbed into the other PRS station costs. Accordingly, AltaGas is directed to confirm, in its next capital tracker true-up application, the number of PRS stations decommissioned, the actual decommissioning

costs per station, and whether these costs were in fact absorbed into the other PRS station costs. ..... Paragraph 229

4. With respect to previously-approved 2016 or 2017 K factor amounts that have changed as a result of the deferral of the Pickardville line, AltaGas is directed to reflect these changes in its capital tracker true-up applications. ..... Paragraph 300

5. The difference between the 2015 true-up adjustment of ($148,796) that AltaGas has included in its 2017 interim rates and the disallowances in this decision will need to be addressed. Accordingly, AltaGas is directed to refund that difference to customers in its next Rate Rider F application or AltaGas 2018 annual PBR rate adjustment filing, whichever occurs first. ..... Paragraph 305

6. The Commission has reviewed AltaGas' responses to the Commission's directions that were not specifically addressed in the previous sections of this decision and is generally satisfied that AltaGas has complied with these directions in the application, with one exception, item 1.c. from the revised minimum filing requirements set out in Appendix 3 to Decision 3558-D01-2015. Under item 1.c., the Commission requires evidence that the capital cost allowance amounts have been reconciled with the amounts filed by AltaGas with the CRA, AltaGas stated "AUI will submit evidence of reconciliation when 2015 amounts have been filed with the CRA (due June 30, 2016.)." However, similar to the finding and direction made by the Commission at paragraph 373 of Decision 20522-D02-2016, 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, for purposes of regulatory efficiency, AltaGas is directed to fulfill this requirement at the time of its next capital tracker true up application. ..... Paragraph 310

7. AltaGas Utilities Inc. is directed to comply with the findings contained within this decision. ..... Paragraph 311(1)

Appendix 3 – AltaGas' prior capital tracker-related proceedings

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1. Because the 2013 capital trackers proceeding leading to Decision 2013-435[1] was ongoing at the time, in Decision 2013-072,[2] 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.

2. Interim K factor placeholders were similarly approved by the Commission for each of 2014, 2015, 2016 and 2017. Specifically, in Decision 2013-465, the Commission approved, a 2014 K factor placeholder in the amount of $1.23 million to be included in AltaGas' 2014 PBR rates, based on 60 per cent of the proposed 2014 K factor.[3] In Decision 2014-357, the Commission approved a 2015 K factor placeholder in the amount of $3.14 million to be included in AltaGas' 2015 PBR rates, based on 90 per cent of the proposed 2015 K factor and 100 per cent of the proposed 2013 K factor true-up.[4] In Decision 20823-D01-2015,[5] the Commission approved a 2016 K factor placeholder in the amount of $4.86 million to be included in AltaGas' 2016 PBR rates, based on 90 per cent of the proposed 2016 K factor and 100 per cent of the proposed 2014 K factor true-up.[6] In its 2017 annual PBR rate adjustment application, AltaGas requested a 2017 K factor placeholder in the amount of $8.15 million to be included in its 2017 PBR rates, based on the $8.30 million 2017 forecast K factor approved in Decision 21380-D01-2016,[7] and the 2015 K factor true-up amount applied for in Proceeding 21627.

3. 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,[8] 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.[9]

4. Decision 2014-373[10] dealt with AltaGas' 2013 true-up and 2014-2015 forecast capital tracker applications. The 2013 K factor true-up amount and 2014-2015 K factor forecast amounts

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1 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

2 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.

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

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

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

6 Decision 20823-D01-2015, paragraph 65.

7 Decision 21380-D01-2016: AltaGas Utilities Inc. Compliance Filing to Decision 20522-D02-2016 (2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast), Proceeding 21380, May 19, 2016.

8 Paragraph 600.

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

10 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.

were approved in the compliance filing Decision 20176-D01-2015.[11] 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.

5. In Decision 20695-D01-2015,[12] the Commission approved AltaGas' application to collect a net deficiency of $0.91 million, consisting of a 2013 capital tracker K factor true-up adjustment surplus, a 2014 capital tracker K factor true-up adjustment deficiency and a 2015 capital tracker K factor true-up adjustment deficiency, as determined in Decision 20176-D01-2015.[13]

6. Decision 20522-D02-2016[14] dealt with AltaGas' 2014 true-up and 2016-2017 forecast capital tracker applications. The 2014 K factor true-up amount and 2016-2017 K factor forecast amounts were approved in the compliance filing Decision 21380-D01-2016. 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.

7. Finally, in Decision 21898-D01-2016,[15] the Commission approved AltaGas' application to collect a net deficiency of $0.77 million, consisting of a 2013 Y factor true-up deficiency, a 2014 K factor true-up deficiency, and a 2016 K factor adjustment net deficiency, as determined in Decision 21380-D01-2016.

[11] 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.

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

[13] 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.

[14] Decision 20522-D02-2016: AltaGas Utilities Inc. 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.

[15] Decision 21898-D01-2016: AltaGas Utilities Inc. 2016 Net Deficiency and Rate Rider F, Proceeding 21898, September 14, 2016.

Appendix 4 – Overview of the accounting test under PBR

(return to text)

1. In Decision 2013-435,[1] 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 expenditure escalated by I-X and including the effect on revenue of any changes in billing determinants.[2] The impact on revenue of any changes in billing determinants, which is calculated as the forecast percentage change in billing determinants in any given PBR year, was referred to as "Q"[3] or "Q factor."

2. 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. As explained in Decision 3434-D01-2015,[4] this component of the accounting test utilizes the WACC rate embedded in a company's approved going-in rates[5] and requires assumptions regarding the values for the I-X index and Q for each year.

3. In Decision 3100-D01-2015,[6] the Commission established that the accounting test for a capital tracker true-up application for a given year, should utilize the approved I-X index and the Q factor based on the final approved forecast of billing determinants for that year.[7]

4. 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, approved by the Commission as part of the project assessment review under Criterion 1. As set out in Decision 3434-D01-2015, for purposes of the revenue requirement calculations, this component of the accounting test requires assumptions regarding the current year's WACC rate; namely, cost of debt, approved ROE and capital structure, including preferred shares.[8]

5. In Decision 20522-D02-2016,[9] dealing with AltaGas' 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, the Commission made the following

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1 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.
2 Decision 2013-435, paragraphs 262-263.
3 Decision 2013-435, paragraph 499.
4 Decision 3434-D01-2015: 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.
5 Decision 3434-D01-2015, paragraph 37.
6 Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565 and 1610362, January 25, 2015.
7 Decision 3100-D01-2015, paragraphs 577-578.
8 Decision 3434-D01-2015, paragraph 40.
9 Decision 20522-D02-2016: AltaGas Utilities Inc., 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.

determination regarding the review process to establish the reasonableness of a company's actual debt costs included in the capital tracker true-up accounting test:

> 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 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,[10] 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.[11]

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

[11] Decision 20522-D02-2016, paragraph 329.

Appendix 5 – AltaGas' compliance with prior Commission directions

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	Decision reference	Direction	Application reference
1	Decision 2013-435,[1] paragraph 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 31of 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.	Exhibit 21627-X0007, application: 2015 Pipe Replacement program: • Section 2.2.6 - Pre-1957 Steel • Section 2.3.4 – PVC • Section 2.4.4 – Non-Certified PE 2015 Station Refurbishment program: • Section 3.7 – Stations 2015 Gas Supply program: • Section 4.2 – Gas Supply
2	Decision 2014-373,[2] paragraph 113	In order to demonstrate the prudence of the trailing costs, the Commission agreed 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 directed AltaGas to identify the specific prior-year projects 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.	Exhibit 21627-X0007, application: • Sections 2.2.6, 2.3.4, 2.4.4, 3.7 and 4.2

[1] Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

[2] Decision 2014-373: AltaGas Utilities Inc., 2014-2015 Capital Tracker Application and 2013 Capital Tracker True-up Application, Proceedings 3152 and 3244, Applications1610446-1 and 1610600-1, December 24, 2014.

	Decision reference	Direction	Application reference
3	Decision 2014-373, paragraph 115	The Commission accepted AltaGas' explanation for the gas supply trailing costs, and finds these trailing costs to have been prudently incurred. Given that the remaining costs are immaterial, the Commission was willing to approve the unexplained trailing costs for the purposes of this decision. However, in future applications, AltaGas was directed to provide the justifications for all trailing costs identified in the application.	Exhibit 21627-X0007, application: • Sections 2.2.6, 2.3.4, 2.4.4, 3.7 and 4.2
4	Decision 2014-373, paragraph 146	The Commission noted that the Morinville (five km) project was completed in 2013 below the forecast approved in Decision 2013-435. A variance explanation was not provided. Given that the project was completed under budget, the Commission approved this project, as filed. However, for the purposes of achieving symmetry in cost variance explanations, the Commission directed AltaGas, in future capital tracker true-up applications, to explain negative variances that exceed the company's variance threshold of $10,000 or 10 per cent.	Exhibit 21627-X0007, application: • Section 1.6.1
5	Decision 2014-373, paragraph 226	With respect to the 2015 forecast costs for hamlets and rural subdivisions, the Commission observed that the 2015 forecast costs were generally comparable to similar projects completed in 2013, when adjusted for inflation. However, for some of the projects, particularly the Village of Munson and Fort Assiniboine, the Commission noted that the unit costs were materially higher than the costs for similar projects completed in 2013, but are similar to the forecast for 2014. Therefore, the Commission directed AltaGas to provide a detailed6explanation of the actual costs for these projects in the 2015 capital tracker true-up application.	Exhibit 21627-X0007, application: • Section 2.4.2

	Decision reference	Direction	Application reference
6	Decision 2014-373, paragraph 247	With regards to stations PMS-BO002 & AT036, the Commission noted that the variances were primarily due to actual costs incurred in 2012 as work in progress, but not reflected as 2013 forecast capital additions. The Commission accepted that this was a forecasting oversight and approved the costs of the stations as filed in the application. However, for future applications, the Commission directed AltaGas to be mindful in accounting for all work in progress in forecast capital additions along with detailed information justifying the costs.	Exhibit 21627-X0007, application
7	Decision 2014-373, paragraph 280	The Commission was in agreement with the CCA that the explanations were lacking in detail, making it difficult to assess the reasonableness of the costs. 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 was 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 directed AltaGas to include information that explained the difference between the variance in costs from a standard station.	Exhibit 21627-X0007, application: • Sections 3.3 - 3.6
8	Decision 2014-373, paragraph 284	AltaGas' 2014 and 2015 forecast capital additions associated with this program were provided in tables 24 and 25. The Commission reviewed the information supporting AltaGas' forecasts and generally found the individual project and total annual cost forecast to be reasonable. However, since the scope of each station refurbishment or replacement varied, where in some cases regulators and valves were replaced, while in others, the entire above-ground facilities required replacement, the Commission found that the alternatives for replacement or refurbishment, including all costs, should be explored in the business case for each station so that the Commission was assured that each station was being refurbished or replaced prudently. For each of the 2014-2015 station refurbishments or replacements, AltaGas was directed to provide this type of information in the applications where the costs are trued-up to actual.	Exhibit 21627-X0007, application: • Section 3.3 - 3.5

	Decision reference	Direction	Application reference
9	Decision 2014-373, paragraph 308	AltaGas' 2014 forecast capital additions associated with the gas supply program were $3.64 million. AltaGas' 2015 forecast capital additions associated with this program were provided in Table 28. The Commission reviewed the information supporting AltaGas' forecasts and generally found the individual projects and total annual cost forecast were reasonable. However, the Commission considered that the cost of these gas supply projects were considerable and, therefore, the Commission required additional detail in the future. Although the projects tended to be unique in nature, for future applications the Commission directed AltaGas to provide information describing how the project costs compared to similar projects over at least the last five years, and to break down the forecast costs into unit costs for gas supply, similar to that addressed in the pipeline replacement and station refurbishment sections above, and for any other categories of work that AltaGas deemed to be relevant in explaining the project	Exhibit 21627-X0007, application: • Section 4
10	Decision 2014-373, paragraph 325	AltaGas filed its 2015 annual PBR rate adjustment application on September 11, 2014. The filing included AltaGas' 2015 I-X index and billing determinant forecast. In Decision 2014 357, released on December 18, 2014, the Commission stated that it had reviewed AltaGas' calculation of the 2015 I-X index and AltaGas' forecast 2015 billing determinants and the supporting calculations, and found that the forecasting methodology used was consistent with previous PBR-related applications, and that the resulting 2015 I-X index forecast billing determinants were reasonable. The 2015 I-X index and billing determinants were, therefore, approved as filed. The Commission directed AltaGas to use the 2015 I-X index and forecast billing determinants approved in Decision 2014-357 in its compliance filing to this decision, for AltaGas' 2015 capital tracker forecast application, and for AltaGas' 2015 capital tracker true-up application	Exhibit 21627-X0004, Appendix V • Schedules 2.0, 2.1, 2.2, 2.3 and 9.0

	Decision reference	Direction	Application reference
11	Decision 2014-373, paragraph 345	In subsequent capital tracker true-up applications, the Commission directed AltaGas to address whether the driver for any of the previously approved forecast projects or programs had changed, so as to warrant a reassessment under Criterion 2. In the event that the driver of the project or program had changed since the forecast project or program was approved, AltaGas was directed to identify such projects and programs and to provide evidentiary support that the project or program continued to satisfy the requirements of Criterion 2.	Exhibit 21627-X0007, application: • Section 1.3
12	Decision 2014-373, paragraph 363	The difference between the recalculated true-up adjustment and the $188,287 adjustment already included in AltaGas' 2015 annual PBR rate adjustment application would need to be corrected. Accordingly, AltaGas was directed to file an application for an adjustment to Rate Rider F to refund amounts that were approved in Decision 2014-357 related to the 2013 capital tracker true-up in excess of the 2013 capital tracker true-up amount that would need be approved in the compliance filing to this decision. This Rate Rider F application would be made after AltaGas' compliance filing to this decision is approved, and the amount would need to be refunded by December 31, 2015.	AltaGas filed an application for its 2015 Net Deficiency Rider F on August 1, 2015. This application was approved in Decision 20695-D01-2015[3] on September 24, 2015, and applied to customer bills from October 1 to November 30, 2015.

[3] Decision 20695-D01-2015, AltaGas Utilities Inc., 2015 Net Deficiency and Rider F, Proceeding 20695, September 24, 2015

	Decision reference	Direction	Application reference
13	Decision 2014-373, paragraph 365	The Commission found that AltaGas used the correct inputs in its 2014 and 2015 capital tracker calculations. The Commission also reviewed the K Factor calculations and was satisfied that the calculations were performed correctly and in accordance with previous Commission directions (see Section 9). The Commission noted that AltaGas applied for a 2014 K Factor of $2,184,474 and a 2015 K Factor of $3,712,184. The Commission directed AltaGas to update these forecasts in the compliance filing to this decision to give effect to: • The updated 2013 approved true-up amounts, adjusting for the projects that the Commission determined in this decision to not satisfy the project assessment component of the Criterion 1. • The use of the 2015 I-X index and the billing determinants approved in Decision 2014-357. • Any Commission directions in Proceeding No. 3434 (WACC assumptions used for the capital tracker accounting test).	Direction was addressed in AltaGas' 2013 capital tracker true-up and 2014-2015 capital tracker compliance filing, in Decision 20176-D01-2015.[4]
14	Decision 2014-373, paragraph 366	The Commission was aware that the company had used K Factor placeholder values in its 2014 and 2015 PBR rates that were different from the amounts approved in Decision 2014-357 and discussed two paragraphs above. AltaGas was directed to file an application for an adjustment to Rate Rider F to collect, on an interim basis, the 2014 and 2015 forecast amounts approved in this decision that were in excess of the K Factor placeholder amounts that had been included in AltaGas' 2014 and 2015 PBR rates. This Rider F application would be made after AltaGas' compliance filing to this decision was approved, and the amount was to be collected by December 31, 2015.	Direction was addressed in Decision 20695-D01-2015.

[4] 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.

	Decision reference	Direction	Application reference
15	Decision 2014-373, paragraph 391	In future capital tracker applications, to demonstrate the reasonableness and prudence of overhead costs, AltaGas was 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 was also directed to be prepared to explain any significant year-over-year changes in the items that made 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 had done with inter-affiliate costs, the Commission considered that to be a reasonable approach for capital tracker purposes. However, a company was not required to limit its increases to its overhead items to I-X if it could demonstrate that an increase in excess of this amount was prudent.	Exhibit 21627-X0007, application: • Section 1.6.2 Exhibit 21627-X0004, Appendix V • Schedule 9.3
16	Decision 2014-373, paragraph 407	PBR encouraged a company to seek out and realize process, operational and capital efficiencies continually with respect to those functions and activities funded under the I-X mechanism in order to enhance overall profitability. These activities would 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 required 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 considered that formal project management policies and procedures were 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 directed AltaGas to describe fully its formal project management policies and procedures in its next capital tracker application.	Exhibit 21627-X0004, Appendix III

	Decision reference	Direction	Application reference
17	Decision 3434-D01-2015,[5] paragraph 76	The Commission considered that using the forecast cost of embedded debt and preferred shares for the year in which the capital tracker is being applied for was a reasonable method of matching capital tracker revenues to costs. As such, the Commission directed the companies in their 2016 and 2017 capital tracker applications to use their forecast cost of embedded debt and preferred shares, if applicable, when calculating the revenue requirement associated with a proposed capital tracker. The companies were not required to update the debt rates used in their 2014 and 2015 forecast capital tracker applications because these would eventually be trued-up to actual, and a revised forecast was not required to ensure that the final rates would eventually reflect the correct debt rates.	Exhibit 21627-X0004, Appendix V • Schedules 3.0, 3.1, 3.2, and 3.3 • Schedules 2.0, 2.1, 2.2, and 2.3. • Schedule 9.1
18	Decision 3434-D01-2015, paragraph 89	In Section 3.2 of Decision 3434-D01-2015, the Commission directed the companies to use their forecast cost of embedded debt in calculating the forecast revenue requirement associated with a proposed capital tracker in the second component of the accounting test, to reflect the correct funding requirements associated with expenditures made on capital tracker projects. Similarly, the Commission found that the forecast cost of embedded debt should be trued-up to the actual cost of embedded debt incurred by the utility in the year for which the capital tracker was approved. The Commission agreed with Calgary 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 directed the company to provide an explanation of why it does not match, in its capital tracker true-up application.	Exhibit 21627-X0004, Appendix V • Schedule 9.1

[5] Decision 3434-D01-2015: 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.

	Decision reference	Direction	Application reference
19	Decision 3434-D01-2015, paragraph 92	The Commission directed that in capital tracker true-up applications, for the second component of the accounting test, a company's WACC would reflect the company's current embedded debt rate based on its actual debt issues, and would use the ROE and capital structure for the year, as approved in the most recent Commission decision establishing the deemed ROE and capital structure for the company.	Exhibit 21627-X0004, Appendix V • Schedules 2.0, 2.1 and 2.3
20	Decision 3558-D01-2015,[6] Appendix 3	**Appendix 3 – Minimum filing requirements** The Commission set out the following revised minimum filing requirements: **1. Schedules and related evidence** In addition to the materials required pursuant to paragraph 1091 of Decision 2013-435, a company must include in each capital tracker true-up application and in each capital tracker forecast application a set of Microsoft Excel® schedules setting out all the elements of the accounting test, materiality test and the resulting K factor calculation as directed in Decision 2013-435. a. The schedules provided must demonstrate that the revenue generated under the I-X mechanism for each capital tracker project or program are not covered by the actual or forecast revenue requirement associated with that capital project or program. b. The schedules provided must list each capital project and program, both capital tracker projects and programs and non-capital capital projects and programs with actual or forecast capital additions in the year. The schedules must also demonstrate, in Excel format with linked and working formulas, that the amounts of depreciation, overheads and income tax allocated to each capital tracker and non-capital tracker project or program, reconciled to the total amount for all projects or programs. c. Evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the CRA	Exhibit 21627-X0006, Appendix I

[6] 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.

	Decision reference	Direction	Application reference
		2. Capital tracker projects or programs a. The rationale for the project, including the nature, scope, location, timing and cost of the project. (To the extent the scope and nature of an approved on-going multi-year project remain significantly unchanged year-over-year, this information is not required.) b. A summary of the services provided by an affiliate, the amounts paid and identification of how those amounts were determined. c. Any context for the project, which may include related past, present and future plans (e.g., for multi-year capital expenditures). d. Evidence demonstrating that in the absence of the proposed capital expenditures, deterioration in service quality and safety would result. e. Qualitative and, to the extent possible, quantitative descriptions of the service quality and safety risks addressed by the project. f. Evidence that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program. g. A discussion of any reasonable alternatives, including the rationale for recommending the proposed solution. h. A detailed forecast of costs for the project or project components, in sufficient detail to allow an evaluation of the reasonableness of the forecast. i. A comparison of actual expenditures to forecast expenditures on similar projects over at least the previous five years, if available, including an explanation of any differences. j. With respect to proposed capital trackers, an explanation of any differences between the forecast costs of projects proposed for capital tracker treatment and the actual or updated forecast costs of similar projects undertaken in the prior year. This explanation should provide a breakdown of the project costs that includes both units and costs-per-unit on a forecast and actual or updated forecast basis. k. With respect to the true-up of capital tracker projects, an explanation of any differences	

	Decision reference	Direction	Application reference
		between the forecast costs of projects approved for capital tracker treatment and the actual cost of these projects undertaken in the prior year. This explanation should provide a breakdown of the project costs that includes both units and costs-per-unit on a forecast and actual basis. **3. Non-capital tracker projects or programs** a. Project descriptions of all non-capital tracker projects and programs with actual or forecast capital additions in the year, that adequately describe, for the purpose of understanding project or program groupings, the nature and purpose of the proposed project or program.	
21	Decision 20590-D01-2015,[7] paragraph 25	However, the onus still resides with AltaGas to demonstrate that the actual debt issuance was obtained prudently. Given the changing market conditions between November 2014 and August 2015, the Commission was concerned that mirroring the coupon rate of the AL $300 million 10-year MTN to the AltaGas 2015 Debenture would 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."[8] Consequently, AltaGas was 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 would be considered for rate-setting purposes, whether that be a performance-based regulation rebasing, a full general rate application (GRA) or some other application.	AltaGas will comply with the direction from Decision 20590-D01-2015 in its next cost of service/rebasing application

[7] Decision 20590-D01-2015, AltaGas Utilities Inc., 2015 Debenture and Common Shares Issue Applications, Proceeding 20590, August 25, 2015.

[8] Decision 2012-091, paragraph 204.

	Decision reference	Direction	Application reference
22	Decision 20522-D02-2016,[9] paragraph 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 would 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 would review the reasonableness of AltaGas' 2015 debt costs at the time of its 2015 capital tracker true-up application. Accordingly, AltaGas was 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. That information was to 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.	Exhibit 21627-X0004, Appendix V • Schedule 9.1

[9] Decision 20522-D02-2016: AltaGas Utilities Inc., 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.