Lessons learned in a greenhouse gas emissions reduction program for a pipeline system in Alberta

CCTC 2013 Paper Number 1569657401

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Abstract

In 2007, Alberta was the first jurisdiction in North America to require greenhouse gas emission reductions for industrial emitters. Under Alberta's reduction program, large industrial emitters are required to report and reduce greenhouse gas emissions intensity by 12% from an average of 2003 to 2005 levels. As a large industrial emitter, the natural gas transmission system owned and operated by ATCO Pipelines is covered under the requirements of the SGRP. This paper discusses the challenges and successes of compliance with the SGRP as experienced from an industrial emitter perspective.

Keywords: emissions reporting; emissions reductions; greenhouse gases; climate change; pipelines; industry

Resumé

En 2007, le gouvernement de l'Alberta a été le premier en Amérique du Nord à imposer une réduction des émissions de gaz à effet de serre aux pollueurs industriels. En vertu du Specified Gas Reduction Program (SGRP), les gros émetteurs industriels sont tenus de déclarer l'intensité de leurs émissions et de la réduire de 12 % par rapport à la moyenne des niveaux de 2003 à 2005. En tant que gros émetteur industriel, le réseau de transport de gaz naturel que possède et exploite ATCO Pipelines relève des exigences du SGRP. Cette communication présente le point de vue d'un émetteur industriel sur les défis de la conformité au règlement et les progrès accomplis.

Mots-clés: déclaration des émissions; réduction des émissions; gaz à effet de serre; changements climatiques; pipelines; industrie

1. Introduction

Several Canadian provinces have developed or are in the process of developing regulations aimed at quantifying and/or reducing industrial greenhouse gas (GHG) emissions. Specific examples of introduced programs aimed at reducing emissions include the carbon tax in British Columbia, the Specified Gas Reduction Program (SGRP) to reduce GHG emissions intensity in Alberta, and the closing of coal-fired power plants in Ontario. A major aspect of any GHG reduction program that needs to be considered is the administrative burden imposed on industrial facilities in regards to GHG reporting (and reductions, if applicable) [1]. This paper illustrates one example of a pipeline company and the internal process changes required to comply with a specific emissions reduction system.

2. Background

In 2007, the Government of Alberta introduced the SGRP to reduce industrial GHG emissions in Alberta to meet GHG emissions reduction targets outlined in the Climate Change Strategy (Government of Alberta, 2008) [2]. Industrial facilities that emit more than 100,000 tonnes of carbon-dioxide equivalent (CO_2e) are required to reduce GHG emissions intensity by approximately 12% from an average of 2003 to 2005 levels on an ongoing basis (Government of Alberta, 2007) [3]. Facilities that are unable to meet the reduction level have the option to purchase emissions offsets from a third party or emissions credits at a cost of $15 per tonne from the Government of Alberta [3]. The SGRP established the first market for GHG emissions in Canada.

ATCO Pipelines (AP) is a natural gas transportation company with approximately 8,500 kilometers of transmission pipelines in Alberta. As opposed to many gas transmission systems which operate a series of pipelines in a single right-of-way (bullet-lines), the AP pipeline network consists of a significant portion of interconnected mainline and lateral pipelines. Included in the pipeline network are approximately 20 compressor stations fuelled by natural gas to increase the internal natural gas pressure allowing for transportation across longer distances.

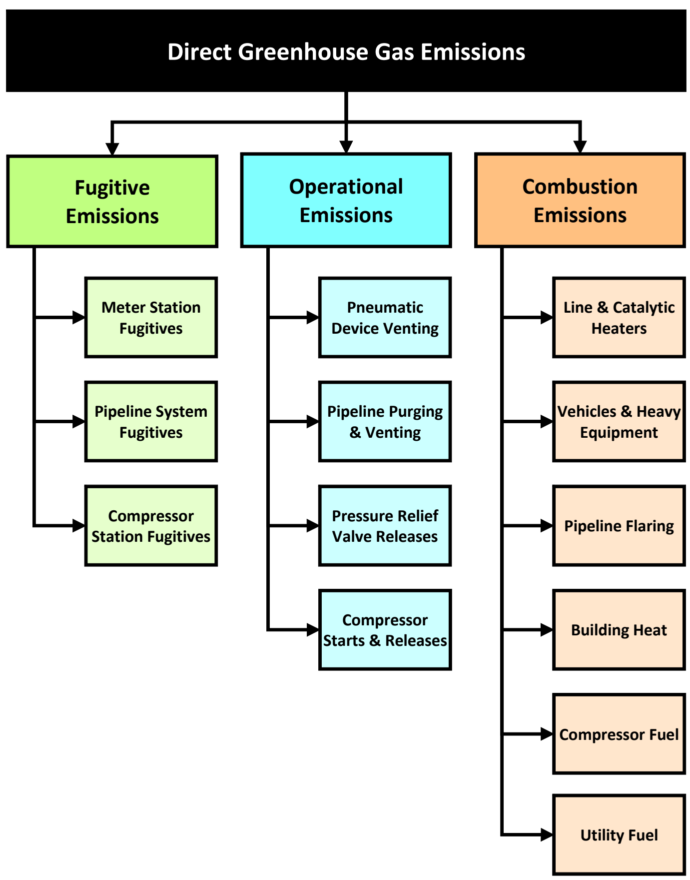

Figure 1. Diagram indicating GHG emissions by source

2.1 GHG Emissions Profile

The main GHG emission sources from the pipeline system include fuel combustion required for gas compression, fugitive emissions from leaking components on the natural gas system, and equipment venting required as a result of compressor operations and the pneumatic control of pipeline equipment. Combustion of gas for heating applications and pipeline flaring are other sources of emissions. A diagram differentiating the GHG emissions by source is included in Figure 1 and the percentage of emissions attributable to each source in 2011 is illustrated in Figure 2.

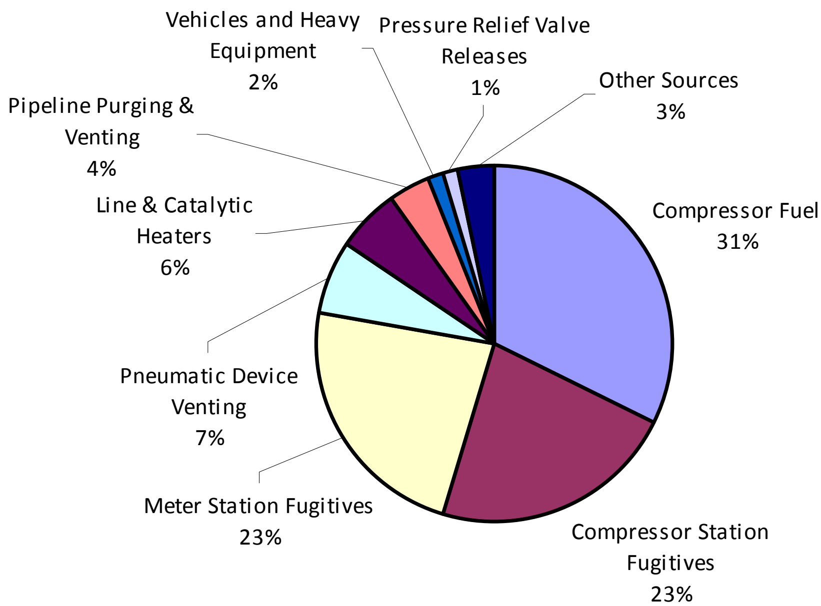

Figure 2. Percentage of overall GHG emissions by source

The main GHG emitted by the pipeline network is methane, as it is the most significant component of natural gas and is the main compound released when natural gas is released to the atmosphere. Carbon dioxide, methane, and nitrous oxide are also produced as a result of the combustion of natural gas in compressor stations and for station and pipeline heating applications. A process flow diagram indicating the type of GHG emission by source is included in Figure 3.

3. Lessons Learned Regarding Quantification and Reporting

The AP pipeline network has been required to report GHG emissions to the Government of Alberta and the Government of Canada since 2005. However, the implementation of requirements for emission reductions by the Government of Alberta required a re-evaluation of the overall emissions inventory. AP wanted to ensure cost-effective compliance with the requirements for emissions reporting without significantly changing emissions management procedures. Since the emissions reduction program was introduced in 2007, four areas were identified as particular areas of focus for review: the speciation of emissions, coverage of key emissions sources, data management storage and processes, and estimation of costs of compliance.

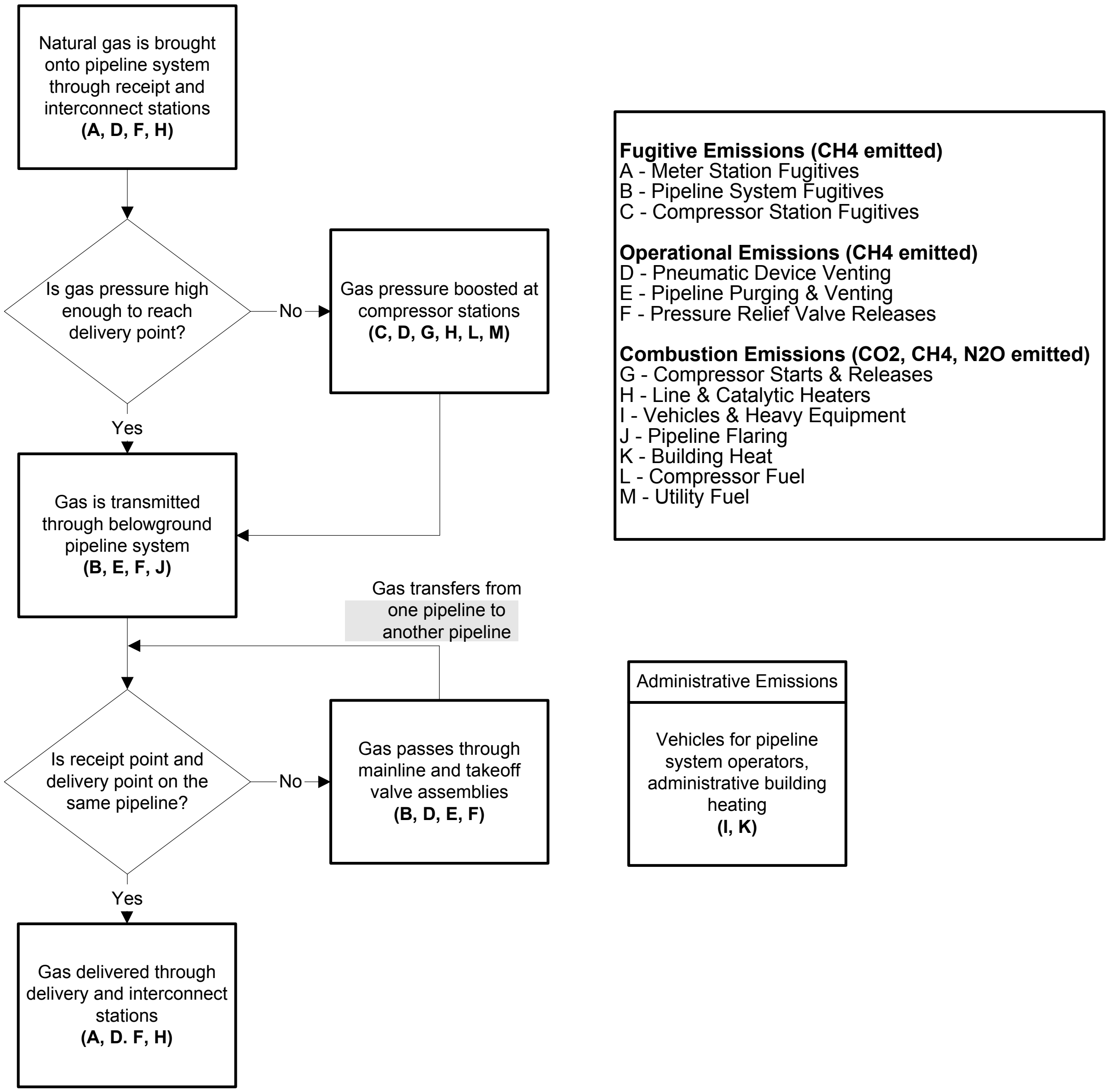

Figure 3. Process flow diagram for pipeline system

3.1 Speciation of Emissions

Certain definitions and requirements developed in the SGRP required AP to re-determine how to define and separate emissions and sources. For example, under the Alberta program, a reporting facility is defined as, "2 or more contiguous or adjacent sites that are operated and function in an integrated fashion" (Government of Alberta, 2013). The pipeline network consists of several hydraulically interconnected and isolated sections that may or may not operate in an integrated fashion. In addition, several pipelines are not physically connected to the main pipeline network. Prior to the introduction of the Alberta program, AP did not differentiate emissions on the pipeline network by physical location or hydraulic connectivity (in accordance with federal GHG emission reporting definitions). In order to comply with the SGRP, a system review was conducted to determine what would best fit the definition of a facility. GHG emissions were differentiated whether they occurred in the North or South of our system, and whether they occurred as part of the integrated system or as part of the isolated system. Emissions data from 2003 to 2007 had to be separated into regions under the new definition of the facility. However, for mandatory GHG emissions reporting to the Government of Canada, the entire system-wide GHG emissions inventory was maintained.

Under the previous emissions reports provided, little criteria for data materiality existed and engineering estimates were used for a significant portion of emissions calculations. The introduction of the Alberta program required more stringent calculation methodologies. More accurate sources of data were desired in order to provide data validity and to prevent large swings in emissions occurring as a result of the uncertainty inherent in estimation. Where possible, metering data was introduced for emissions sources, and cross-referenced with operational data to confirm accuracy. For example, compressor and boiler room fuel are metered at most facilities. These metered values are cross-referenced with compressor run hours and historic operational output to determine whether the metered values are expected or atypical. If atypical values were identified, they could be further verified through interviews with site operators or through site visits. Emissions data from 2003 to 2007 were recalculated using improved methodologies where possible.

3.2 Coverage of Emissions Sources

One of the challenges encountered when the Alberta program was introduced included the coverage of emissions and the treatment of emission reductions. The SGRP resulted in direct economic incentives to complete a project that would result in emission reductions. However, not all emission reduction projects can be realized by AP under the Alberta program. As previously stated, emissions are split into operating regions Not all of the AP operating regions are covered by the reduction program (due to having GHG emissions less than the 100,000 tonne CO_2e threshold of the SGRP). Operating regions not covered do not have the same direct incentive to reduce emissions.

Fugitive emission reductions are also difficult to realize under the reporting program. A fugitive emission is an unintentional release of natural gas through equipment fittings at above-ground stations. Due to the inconsistent nature of equipment leaks, fugitive emissions are difficult to quantify. As of 2011, fugitive equipment leaks were attributable to 46% of the system-wide GHG emissions.

According to the emissions quantification methodology used by AP, the number of components in a station is multiplied by a component-specific emissions factor to determine the overall fugitive emissions for a station. In reality, repairing a leaking component will then repair the source of the fugitive emission, reducing actual GHG emissions emitted from the facility. However, the problem with the utilized methodology is that repairing a leaking component will not result in reduction of emissions in the calculated emissions at the end of the year. Different systems exist to quantify fugitive emissions although most require direct measurement of leaks at facilities by personnel. Given that there are hundreds of stations on the AP pipeline system, it is not practical to directly measure fugitive emissions.

Identification of previously omitted emission sources is also inflexible under the SGRP. Emissions sources that were originally missed or deemed negligible in the emissions baseline are required to be included as incremental emissions if identified in future compliance periods. An example of this occurred in 2010 when AP determined an error in the original assumption that emissions from catalytic heaters at stations, which are used for space and process heating, were a negligible emissions source (less than 1,000 tonnes CO_2e). An estimate in 2010 determined emissions from catalytic heaters are approximately 2,500 tonnes. Since the emissions were determined to be non-negligible, they needed to be included as an incremental emission. Even though the number of catalytic heaters had not changed significantly from the baseline to 2010, since the heaters were not identified in the baseline, they were treated as if the entire inventory of catalytic heaters were introduced in 2010. Assuming $15 per tonne emissions credits are purchased for the incremental catalytic heater emissions, the cost of the omission is estimated at thousands of dollars per year. The omission can be rectified through a baseline resubmission process; however, the 2003 to 2005 baseline would need to be recalculated, verified by an independent third party, and approved by the Climate Change Secretariat.

3.3 Data Management Storage and Processes

Prior to the Alberta program, few individuals were involved and engaged in the data collection and storage processes. When incorporating improvements to methodologies, more individuals become responsible for gathering and processing data. A new data storage system, flexible enough to separate emissions by operating region and to track emissions compared to a baseline was developed. In addition, to ensure the appropriate level of accuracy required under the Alberta program, data sources had to be internally proofed. The advantage of this process is that it engaged multiple individuals from various disciplines within AP. The engagement resulted in the determination of improved sources of data and increased awareness of the SGRP (and GHG emissions) within the company.

Prior to the introduction of the Alberta program, annual GHG emissions were not related to the previous year. Improved methodologies could be applied without recalculating previous emissions inventories. With the introduction of the reduction program, emissions inventories are always relative to the 2003 to 2005 baseline. Improved methodologies could not be applied to current inventories if they were not utilized in the baseline period. To incorporate improved methodologies, the baseline needs to be recalculated, verified by a third party and approved by the government. For example, a methodology document referenced extensively for emission factors in the 2004 to 2006 baseline was the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems* [4]. The emission factors in this document were updated in the methodology document *Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System* [5]. The revised emission factors cannot be applied without recalculating the baseline emissions.

3.4 Estimation of compliance costs

One of the largest challenges specific to an intensity-based reduction system is accurate predictions of the cost of compliance associated with emissions reduction programs. AP management is required to set aside proper budget dollars to ensure compliance with the Alberta program. Since the regulation requires a reduction in emissions intensity, the cost of compliance is dependant on two factors: emissions and the unit of production.

With an intensity-based system, pipeline companies need to determine a unit of production. As a natural gas transmission company, AP transports natural gas from upstream facilities (wells, natural gas processing plants, and other natural gas transmission companies) to downstream customers (industrial facilities and local distribution companies). The unit of production is natural gas throughput, or the amount of natural gas transported as measured through receipt points on the AP pipeline system.

For pipelines, the measure of throughput is particularly difficult as the amount of natural gas transported is highly variable and fluctuates with changes in commodity costs, weather, and the development of associated upstream and downstream infrastructure. The emissions themselves also are variable and are highly dependant on local operational conditions. For example, the decision to use a compressor is dependant on local gas pressures provided by producers, the distance to demand points, and the capacity of the pipeline system. The link between throughput and emissions is not always direct. As such, developing estimates for costs of compliance has proven difficult. For the 2010 compliance year onward, forecasts for cost of compliance have been developed by computing emissions intensity at the mid-point of the compliance year and assuming emissions intensity would remain similar. The estimated compliance cost at mid-year versus the actual compliance at year-end for 2010 through 2012 shown in Table 1 below.

Year	Percentage Difference, Estimated Compliance Cost to Actual Compliance Cost
2010	+496%
2011	-329%
2012*	25%
** - Percentage difference estimated as final compliance submission not yet completed*	

Table 1. Difference between estimated and actual compliance costs

Compliance cost estimates have varied from actual compliance costs significantly. Based on preliminary internal analysis, a model to accurately estimate emissions would be complex and dependant on several variables which are difficult to predict (commodity prices, weather, etc.). Since the variables can greatly change from the first half of the year to the second half, estimating full-year compliance payments entirely based on emissions intensity at the mid-year point is ineffective.

4. Successes

Despite the challenges presented as a result of the implementation of the Alberta program, several innovations regarding GHG emissions quantification were realized in order to remain in regulatory compliance. The introduction of an improved data management system resulted in more accurate and auditable emission calculations. In addition, the system is flexible enough for impact analysis, allowing for easier implementation of improved methodologies and dissection of data. Improved data management principles and quantification methodologies have minimized quantitative errors in the emissions inventory. In addition, some external benefits were realized by AP while complying with emission reduction requirements. These benefits include:

- Enhanced communication between AP, consultants, and regulators regarding acceptable quantification criteria, coverage of emissions sources, and policy guidance, and,

- Improved internal communication within AP in regards to emissions sources and methodology,

- Increased employee awareness of GHGs emitted as a result of operations,

- The introduction of a quantitative financial incentive for proceeding with emission reduction projects

Partially as a result of the system, AP implemented numerous projects that have resulted in direct GHG emission reductions. These projects include:

- Replacing high-bleed pneumatic instrumentation with low- and zero-bleed pneumatic instrumentation, or replacing natural gas with compressed air as the pneumatic fluid;

- Installing enhanced engine controllers at compressor stations to improve compressor efficiency, and,

- The increased use of higher-diameter of looped pipelines to transport gas, reducing the amount of gas compression required.

5 Conclusions

Although the introduction of a GHG emission required the implementation of several changes to emissions management processes, AP has been able to successfully comply with the reduction requirements. This paper presented the particular challenges of complying with a regulated emissions reduction system for one industrial company. To ensure an effective system is introduced that obtains buy-in from industry, regulators should consider the administrative burdens imposed under an emissions reduction systems and be flexible enough to allow industrial facilities time to implement any required changes to emissions management system.

6. References

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7. Acknowledgements

I would like to thank ATCO Pipelines for allowing the use of GHG methodologies and data to be used extensively throughout this paper. I would also like to thank my colleagues and supervisor at ATCO Pipelines for valuable and constructive suggestions in regards to the topic of industrial emissions management.

8. Biography

Curtis Clark is a project leader with the Environment, Standards and Quality Assurance Department at ATCO Pipelines. He has been responsible for the greenhouse gas and air emissions inventories for the previous four years. Curtis has a Bachelor of Science in Civil Engineering from the University of Alberta and is a registered professional engineer with the Association of Professional Engineers and Geoscientists of Alberta.