Intent to Develop Alberta Offset System Quantification Protocols: ***<u>Venting Reduction Projects at Conventional Upstream Oil and Gas Facilities</u>***

Please contact Climate Change Central with any questions or clarification of requirements at contact@climatechangecentral.com.

This Intent to Develop an Alberta Offset System Quantification Protocol document is intended to provide Alberta Environment with an overview of the proposed protocol idea to demonstrate how this protocol will meet the requirements of the Alberta Offset System. The protocol developer is required to present this information to Alberta Environment and **must** receive approval in concept for the protocol before the protocol idea will be considered for development in the Alberta Offset System.

Familiarity with and general knowledge of the Alberta Offset System is required prior to initiating a protocol. Information on the Alberta Offset System is available on the Carbon Offset Solution website (http://carbonoffsetsolutions.climatechangecentral.com) and on the Alberta Environment website (http://environment.alberta.ca/02275.html).

Alberta Environment will review the submitted information in order to assess and provide feedback on the following elements:

- How the proposed protocol meets the eligibility criteria in section 7 of the *Specified Gas Emitters Regulation;*
- Applicability of the proposed protocol against purpose and intent of the Alberta Offset System;
- Baseline adoption levels and credit potential for Alberta;
- Baseline, project condition, and key assumptions for the proposed protocol;
- Key stakeholders and technical experts in the field; and
- Relevant science and technical information

General Description of the Proposed Protocol[1]

Conoco Phillips Canada has been awarding funding from the Climate Change and Emissions Management Corporation (CCEMC) Fund to implement a variety of innovative emission reduction technologies which reduce fuel gas use and associated greenhouse gas (GHG) emissions in natural gas processing and production.[2] Conoco plans to implement these technologies at over 400 well sites.

The proposed Protocol will include those funded technologies which reduce venting of fuel gas in upstream oil and gas processing: dehydrator pump electrification, low-bleed pneumatic controllers, solar chemical injection pumps, and vent gas capture. Due to the likelihood that the technologies will be

[1] **Some important notes to consider:**

- *Protocols should be based on best available science.*
- *Follow the ISO 14064:2 standard processes – specifically addressing principles of conservativeness, completeness, relevant, consistent with others, accuracy and be completely transparent in development and descriptive processes.*
- *Be very clear with respect to the Measurement, Monitoring and Verification requirements to allow little interpretation.*

[2] http://ccemc.ca/_uploads/EE-Approved-Projects.pdf

used in conjunction, one "Intent to Develop Protocol" was authored with the intention of developing four closely related protocols. These protocols will be collectively referred to as *Quantification Protocols for Venting Reduction Projects at Conventional Upstream Oil and Gas Facilities.*

Approximately 37 million tonnes CO_2e of vented and fugitive emissions were emitted by the oil and gas sector in Alberta in 2007.[3] The proposed *Quantification Protocols for Venting Reduction Projects at Conventional Upstream Oil and Gas Facilities* would promote a reduction in the emissions intensity of oil and gas production to help reduce greenhouse gas (GHG) emissions in Alberta. Direct, irreversible GHG emission reductions can be achieved by reducing the amount of natural gas vented to the atmosphere.

A brief description of each technology/process is given below.

Dehydrator Pumps

Natural gas producers commonly remove water from natural gas using glycol gas dehydrators. High-pressure glycol and wet gas are circulated through a contactor where the glycol absorbs water and some methane from the natural gas. Dry natural gas is introduced to the sales pipeline. Glycol is regenerated by a reboiler, which heats the glycol to release water, methane, and other contaminants to the atmosphere. A dehydrator pump is used to circulate glycol through the dehydrator system.

Pneumatic Controllers

Pneumatic controllers are used in the oil and gas industry for process controls. They may regulate pressure, temperature, and liquid level, among other variables. Most pneumatic instruments and controllers are powered by natural gas, and these controllers are designed to discharge natural gas to the atmosphere as a part of normal operations. Pneumatic controllers can be designed at both high and low-bleed rates. In addition, controllers may be self-contained and release gas into the downstream pipeline instead of venting to the atmosphere.

Chemical Injection Pumps

Chemical injection pumps are used in the oil and gas industry to inject small amounts of chemicals into process streams. Common chemicals injected include oxygen scavengers, surfactant, and corrosion inhibitor. Methanol is perhaps the most common chemical used in Canada, because is used to prevent line freezing.

Well Site Vent Gas

The operation of well sites involves the use of equipment which vents natural gas (or other hydrocarbon-rich gas) to the atmosphere. Vented and fugitive emissions can be sourced from pneumatic instrumentation, compressor packings, storage tanks, and leaks.

Intent

The implementation of low-bleed pneumatic controllers, solar pumps, electric dehydrators, and vent gas capture at well sites would reduce the amount of natural gas vented to the atmosphere and thereby directly reduce vented methane emissions in the oil and gas industry. The successful implementation of these technologies and the dissemination of important lessons learned will serve to accelerate the deployment of these technologies across the entire upstream oil and gas sector. The use of this protocol will promote incremental GHG reductions by encouraging a reduction in natural gas venting.

[3] National Inventory Report. Table A11-19: 2007 GHG Emission Summary for Alberta. Environment Canada

Baseline

Dehydrator Pump Electrification

"The most common circulation pump used in dehydrator systems is the gas-assisted glycol pump... These mechanical pumps are specially designed to use [glycol] and natural gas at high pressure for power."[4] Gas assisted glycol pumps utilize energy from high-pressure, rich glycol[5] exiting the contactor to circulate low-pressure, lean[6] glycol exiting the reboiler. Additional energy from pressurized fuel gas is utilized by the pump to overcome friction losses within the pump and connecting piping. After the pressurized natural gas and rich glycol has been used to provide the motive force for operating the pump, the fuel gas and some of the natural gas from the rich glycol is vented to the atmosphere. These pumps are equipped with dedicated vents to safely release methane to atmosphere. The venting of natural gas from pumps used in dehydration processes is common practice across the industry.

The baseline for the project is the common practice of using gas-assisted glycol circulation pumps which vent natural gas to the atmosphere as a part of normal operations. This baseline is applicable for pump replacements and new build facilities.

A projection-based approach was selected to quantify the baseline condition. In this quantification approach, the time spent operating electric glycol pumps in the project condition represents an equivalent amount of time operating gas-assisted glycol pumps in the baseline condition. This type of projection-based baseline relies on the measurement of operating hours of the electric glycol pump. The direct measurement of the hours spent operating electric glycol pumps ensures that the project and baseline scenarios are compared in functionally equivalent terms.

The offset potential for dehydrator pump electrification is conservatively estimated at 599 kilotonnes of carbon credits per year, based on the best available data. Note that the number of glycol dehydrators in Alberta is based on 2006 data and is likely underestimated. Projected offset potential should be considered minimum rough estimate. Assumptions and calculations follow below.

Offset Potential Calculations

The CAPP Fuel Gas Management Best Practice Document for Glycol Dehydrators notes that average gas venting for glycol pumps is 0.015 – 0.033 m^3 gas per litre of glycol, and that gas savings of 15,000 m^3/year to over 200,000 m^3/year[7] can be achieved at facilities by replacing gas-assisted pumps with electric pumps.

It has conservatively been assumed that an average savings of 15,000 m^3/year can be achieved per pump and that natural gas contains on average 80% methane.

$$15{,}000\ m^3\ \text{gas/pump} \times 0.80\ m^3\ CH_4/m^3\ \text{gas} \times 0.678\ kg\ CH_4/m^3 \times 21\ kg\ CO_2e/kg\ CH_4$$
$$= 171\ t\ CO_2e/\text{pump}$$

[4] Lessons Learned from EPA Natural Gas Star Partners: Replacing Gas-Assisted Glycol Pumps with Electric Pumps. EPA. October 2006. http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf

[5] Glycol saturated with natural gas and water is referred to as rich.

[6] Lean glycol has not been saturated with natural gas and water.

[7] http://www.capp.ca/GetDoc.aspx?DocId=137317

In 2006, CAPP estimated that there were approximately 3,500 dehydrators in Alberta.[8] Assuming each dehydrating unit had at least one pump, the following estimate for emission reduction potential in Alberta was formed.

$$171 \text{ t } CO_2e/\text{pump} \times 3{,}500 \text{ pumps} = 599 \text{ kt } CO_2e$$

Note that for simplicity, emissions associated with operating the electric pumps were omitted for this preliminary assessment as they are relatively small.

High-Bleed to Low-Bleed Controller Conversion

Before 1990, all pneumatic controllers were designed with generally high-bleed rates. It has now become standard practice to use low-bleed pneumatic controllers in new construction in the oil and gas industry. Despite the existence of low-bleed technology as well as retrofit solutions, conversions of existing high-bleed controllers are uncommon.[9] Typically, high-bleed pneumatic controllers will be operated until the end of their useful life. Thereafter, high-bleed controllers will be replaced with low-bleed controllers in most situations. (There are still a limited number of applications which require the use of high-bleed controllers for their fast-acting response.)

The baseline for this project type is the continued use of high-bleed controllers until the end of their useful life. It is assumed that at the end of their useful life, high-bleed controllers will be replaced with low-bleed controllers. Therefore, credits may only be generated during the useful life of replaced/retrofitted high-bleed controller.

A projection-based approach was selected to quantify the baseline condition. In this quantification approach, the time spent operating low-bleed controllers in the project condition represents an equivalent amount of time operating high-bleed controllers in the baseline condition. This type of projection-based baseline relies on the measurement of operating hours of the low-bleed controllers. The measurement of the hours spent operating low-bleed controllers ensures that the project and baseline scenarios are compared in functionally equivalent terms.

The offset potential for high-bleed controller conversion is estimated at 2,038 kilotonnes of carbon credits per year, based on the best available data. Note that the number of pneumatic controllers in Alberta has been approximated due to lack of firm data; therefore, projected offset potential should be considered a rough estimate. Assumptions and calculations follow below.

Offset Potential Calculations

On average, the retrofit of a high-bleed controller will result in 1,400 to 5,660 m^3 of gas savings per year.[10] The replacement of a high-bleed controller with a low-bleed controller results in an average of 6,510 m^3 of gas savings per year.[11] As a conservative estimate, it has been assumed that the average

[8] Benzene Emissions from Glycol Dehydrators 2006 Operating Year Data. CAPP. September 2008. http://www.capp.ca/getdoc.aspx?DocId=141350&DT=PDF

[9] Emission Reduction Measurement and Monitoring Methodology for the Conversion of High-Bleed Pneumatic Controllers in Oil and Natural Gas Systems. Verdeo Group and Devon Energy Corporation. March 2010.

[10] EPA Gas Star Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. EPA October 2006

[11] Ibid

volume of natural gas savings is 3,500 m^3/year and that natural gas contains on average 80% methane. A conservative estimate of the average carbon offsets created per high-bleed controller conversion is shown below.

$$3{,}500\ m^3\ \text{gas/controller} \times 0.80\ m^3\ CH_4/m^3\ \text{gas} \times 0.678\ \text{kg}\ CH_4/m^3 \times 21\ \text{kg}\ CO_2e/\text{kg}\ CH_4 = 39.8\ \text{t}\ CO_2e/\text{controller}$$

Available data suggests that an acceptable activity factor for number of pneumatic devices per well in the production industry may be 0.517 controllers/well.[12] There are an approximately 105,700 natural gas wells operating in Alberta.[13] Assuming that 80% of high-bleed controllers can be replaced or converted,[14] a rough estimate of the offset potential was formed.

$$42.2\ \text{t}\ CO_2e \times 105{,}700\ \text{well sites} \times 0.517\ \text{controllers/well site} \times 80\%\ \text{conversion} = 2{,}038\ \text{kt}\ CO_2e$$

Solar Chemical Injection Pump Conversion

Pressurized natural gas is an ideal energy source for chemical injection pumps due to its consistent availability and the remote location of many well sites. According to CAPP, the majority of chemical injection pumps in industry are driven by compressed fuel gas.[15] After natural gas is utilized to drive pneumatic equipment, it is vented to the atmosphere by design.

The baseline for this project type is the common practice of operating pneumatic chemical injection pumps and venting natural gas to the atmosphere. This baseline is applicable for pump replacements and new installations at well sites with access to sweet gas or fuel gas. (Chemical injection pumps at sour wells typically use pressurized propane as a motive force. The Alberta Offset System does not recognize propane as a GHG and therefore pneumatic pumps used at sour wells do not form an accepted baseline.)

A projection-based approach was selected to quantify the baseline condition. In this quantification approach, the time spent operating solar chemical pumps in the project condition represents an equivalent amount of time operating pneumatic pumps in the baseline condition. This type of projection-based baseline relies on the measurement of operating hours of the low-bleed controllers. The direct measurement of the hours spent operating low-bleed controllers ensures that the project and baseline scenarios are compared in functionally equivalent terms.

The offset potential for high-bleed controller conversion is estimated at 4,163 kilotonnes of carbon credits per year, based on the best available data. Note that the number of chemical injection pumps in Alberta has been approximated due to lack of firm data; therefore, projected offset potential should be considered a rough estimate. Assumptions and calculations follow below.

Offset Potential Calculations

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[12] Methane Emission from the Natural Gas Industry: Volume 5: Activity Factors. Table 5-8. EPA and the Gas Research Institute. EPA 95-263-081-14

[13] CAPP Statistical Handbook for Canada's Upstream Petroleum Industry: 2009. Table 3.18a. July 2010.

[14] EPA Gas Star Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. EPA October 2006

[15] Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Chemical Injection Pumps. CAPP. May 2008. http://www.capp.ca/GetDoc.aspx?DocId=137309

Based on a survey of chemical injection pumps in Alberta, CAPP suggests an emission factor of 0.3945 m^3 gas/hr/pump.[16] An estimate of the average carbon offsets created per chemical injection pump is shown below.

$$0.3945\ m^3\ gas/hr/pump \times 8760\ hr \times 0.80\ m^3\ CH_4/m^3\ gas \times 0.678\ kg\ CH_4/m^3 \times 21\ kg\ CO_2e/kg\ CH_4 = 39.4\ t\ CO_2e/pump$$

At year-end in 2009, there were 105,700 gas wells operated in Alberta.[17] Assuming at least one pump is required per well, and that approximately 30% of pneumatic chemical injection pumps are propane driven[18] and thus are not eligible for offsets, the following estimate was formed.

$$39.4\ t\ CO_2e/pump \times 105,700\ pumps = 4,163\ kt\ CO_2e/year$$

Well Site Vent Gas Capture

As described above, natural gas is commonly vented from pneumatic controllers, pneumatic pumps, and glycol pumps. In addition, compressor packing vents and storage tanks also vent hydrocarbons to the atmosphere. Approximately 1.3 million tonnes CH_4 of vented and fugitive emissions were emitted by the oil and gas sector in Alberta in 2007.[19]

Natural gas is the most common energy source used in the gathering, production, and processing of natural gas and conventional crude oil.[20] Based on the common practice of using natural gas to power equipment (which releases natural gas to the atmosphere through designed vents or fugitive emissions), and the common practice of venting storage tanks, the baseline condition is defined as the continued venting of gas to the atmosphere.

It is estimated that vent gas capture at well sites could result in a maximum of 6,356 kilotonnes of carbon credits per year, based on the best available data. Assumptions and calculations follow below. The offset potential for well site vent gas capture overlaps with estimates for other projects types covered by the protocol: sources of vent gas which could be captured by vent gas capture systems include pneumatic pumps and pneumatic controllers.

Offset Potential Calculations

According to a study by the Petroleum Technology Alliance Canada, approximately 558 million m^3/year of vented natural gas could be used as supplementary engine fuel. The sources of vent gas considered included storage tanks, reciprocating compressor packing vents and drains, instrument venting, and other venting.

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[16] Canadian Association of Petroleum Producers (CAPP), Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002.
Alberta, and was converted from a total gas basis to a CH4 basis using the CH4 content shown in the table.
[17] Statistics Handbook. Operated Gas Wells in Western Canada: 1956-2009. CAPP. 2009. http://membernet.capp.ca/SHB/Sheet.asp?SectionID=3&SheetID=176
[18] Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Chemical Injection Pumps. CAPP. May 2008. http://www.capp.ca/GetDoc.aspx?DocId=137309
[19] National Inventory Report. Table A11-19: 2007 GHG Emission Summary for Alberta. Environment Canada
[20] Alberta Fuel Gas Efficiency in the Upstream Gas and Conventional Oil Industry. ERCB. 2010. http://www.ercb.ca/docs/products/STs/ST110-2010.pdf

Project emissions from the possible combustion of conserved fuel gas to power engines, heaters, and/or other equipment is small and therefore has been excluded for this preliminary calculation.

$$558{,}000\ e^3m^3 \times 0.80\ m^3\ CH_4/m^3\ \text{gas} \times 0.678\ kg\ CH_4/m^3 \times 21\ kg\ CO_2e/kg\ CH_4$$
$$=6356\ kt\ CO_2e$$

Project Condition

All project technologies provide the same level of service (i.e. compression, process control, chemical injection, etc.) as their baseline counterparts. This ensures functional equivalence is maintained between the project and baseline condition.

Dehydrator Pump Electrification

In the project condition, dehydrator glycol pumps are powered by electricity. These pumps do not recover energy from the rich glycol stream; they only move the lean glycol stream. Therefore, electric glycol pumps do not have vented or fugitive methane emissions. Emission reductions result from the conservation of fuel gas which would have otherwise been vented. (Natural gas vented from the rich glycol will be equivalent in the project and baseline condition.)

High-Bleed to Low-Bleed Controller Conversion

In the project condition, low-bleed controllers will replace high-bleed controllers. Low-bleed controllers will bleed less natural gas than their high-bleed counterparts. Emission reductions result from the conservation of fuel gas which would have otherwise been vented by the use of high-bleed controllers.

Solar Chemical Pump Conversion

In the project condition, chemical injection pumps are powered by solar-generated electricity, a zero-emissions power source. Emission reductions are generated by the avoidance of vented fuel gas emissions from the use of pneumatic pumps.

Well Site Vent Gas Capture

Vent gas from well sites is reduced or avoided by capturing gas which would normally be vented. Captured gas may be combusted, converting methane to carbon dioxide in the project condition. Combustion may occur in existing Cata-Dyne heaters, flares, or engines. Vent gas can partially or wholly replace conventional fuel gas required for engines and heaters. Alternatively, captured gas may be conserved. Emission reductions are realized through the conversion of methane to carbon dioxide, a less intensive GHG, and through conservation of fuel gas.

Applicability

The Protocol is written for oil and gas companies or organizations which normally vent natural gas to the atmosphere through the operation of gas assisted glycol dehydrator pumps, high-bleed pneumatic controllers, pneumatic chemical injection pumps, and equipment well sites, and wish to reduce this venting through the implementation of low-electric glycol pumps, low-bleed pneumatic controllers, solar chemical injection pumps, and well site vent gas capture.

Projects must serialize credits on a go-forward basis, as is consistent with the Alberta Offset System's Technical Guidance Document. Projects must also meet all Alberta Offset System requirements.

Regulatory Requirements

In Alberta, the *Specified Gas Emitters Regulation* applies to facilities with GHG emissions of greater than 100,000 tonnes CO2e per year, which are referred to as Large Final Emitters (LFEs). All facilities exceeding this threshold are required to reduce GHG emissions by 12% on an intensity basis beginning July 1, 2007. Because of these requirements, any facilities classified as LFEs are not eligible for offset generation as any emission reduction activity that occurs within the boundary of an LFE site will be subject to the SGER.

Emissions from gas assisted glycol pumps, high-bleed controllers, chemical injection pumps, and other pneumatic controls that are not operating within the boundaries of a regulated site are currently not subject to the SGER. Since the GHG emissions from individual instruments are small in magnitude it is very unlikely that these projects will become regulated under the current structure of the SGER.

Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting provides regulatory requirements and guidelines for flaring, incinerating, and venting in Alberta. It states that operators must burn all non-conserved volumes of gas if volumes and flow rates are sufficient to support stable combustion. This project type is not regulated under Directive 60 as the volumes and flows of vented natural gas from gas assisted glycol pumps, high-bleed controllers, chemical injection pumps, and other pneumatic controls are not high enough to support stable combustion.

No other relevant climate change regulations were identified that would impact the venting of natural gas from high-bleed controllers under the baseline scenario.

Additionality

Currently, fuel gas optimization by industry is not a regulatory or legislative requirement.[21] Emissions from pneumatic instrumentation are generally not regulated in Alberta under the Specified Gas Emitters Regulation as the majority of pneumatic instrumentation is situated at facilities not presently covered under the SGER (e.g. well sites, compressor stations, small gas plants etc.). Additionally, these sources of emissions are not normally covered under the Energy Resources and Conservation Board's (ERCB) Directive 60 as they not able to sustain stable combustion so gas conservation or flaring is not required. Any steps taken to reduce controller emissions would be surplus to regulation.

As previously discussed in the baseline selection section, it is not common practice to employ the vent gas reduction technologies outlined in this report. In addition, all technologies received funding from the CCEMC, whose express purpose is to fund new and innovative technologies which reduce GHG emissions. Therefore, the use of these technologies would result in real, incremental GHG reductions above and beyond business as usual practices.

Emission reductions are quantified using a projection-based approach. It is assumed that the time the project equipment (i.e. electric glycol pump, low-bleed controller, solar chemical injection pump, vent gas capture system) is operated is equal to the time the baseline equipment is operated (i.e. gas-assisted glycol pump, high-bleed controller, pneumatic chemical injection pump, vented gas). Using the vent rates of the baseline equipment and energy consumption of project equipment, emission reductions can be accurately quantified. Based on the documentation required by the protocol, such as

[21] http://www.capp.ca/GetDoc.aspx?DocId=137298

hours of operation and bleed rates of various controllers, an audit level or review level of assurance can be met by verifiers.

Barriers

A wide variety of barriers currently impede the implementation vent gas reduction projects in the oil and gas sector today. These barriers, inter alia, are listed below.

- **Economic Barriers:**
    - The current low price of natural gas (and the continued expectation that North American gas supplies will be exceed demand due to shale gas production) continues to negatively impact the expected rates of return on many gas conservation and efficiency projects, including vent gas reduction and fuel gas efficiency projects, as these projects may not compare favorably to other alternatives (e.g. exploration, drilling and production).
    - Many energy efficiency projects that have favourable rates of return may be hindered by limited budgets allocated to conventional natural gas exploration, production, and operations/maintenance. This is exacerbated by current low gas prices, which further constrain budgets and spending in general. Current prices have slowed drilling of new wells dramatically and have forced some companies, to shut in less profitable gas production, which in turn limits funding for energy efficiency projects. Conventional natural gas production in Alberta is also hampered by declining reserves, low plant utilization rates, and increased fuel gas consumption per unit of gas production due to declining reservoir pressures[22].
    - The value of fuel gas (natural gas used by oil and gas companies during extraction, processing and transmission) is often assigned a lower priority relative to operational reliability, and is reported as 'shrinkage', rather than a direct operating cost. No royalties are paid on fuel gas that is combusted or vented, but if this gas is conserved through energy efficiency projects, then royalties must be paid on those gas savings creating a disincentive to implement gas conservation projects. For many midstream operators, the cost of fuel gas shrinkage (lost production) is passed on to the producers, with little incentive for the operator to make energy efficiency investments.
    - Implementing new retrofit technologies at older facilities is subject to greater risks cost escalation. [23]

- **Operational Barriers:**
    - Operators are often unfamiliar with technologies that reduce vent gas or fuel gas and have little motivation to move from reliable technologies (e.g. engineered vents, pneumatic pumps, rich-burn engines) that in some cases contain no moving parts and require no monitoring or maintenance. The installation of new technologies usually increases operational complexity and adds measurement and data management burdens without tangible benefits to the operator. This is often true for GHG emission monitoring and

[22] ERCB. April 2010. Alberta Fuel Gas Efficiency in the Upstream Oil and Gas Industry
[23] Ibid.

validation/verification processes, which generally add to operator workload without obvious benefits to operating budgets.

  - The implementation of vent gas reduction and fuel gas efficiency technologies often requires some detailed engineering for each installation as many site specific considerations must be taken into account (e.g. for waste heat recovery, pressure drop for power generation). This limits the ability to rapidly roll out the technology and increases actual installation costs significantly above the unit purchase price.
  - Operators are generally motivated to avoid downtime at all costs and are incentivized through bonuses that are tied to production. The installation of simpler technologies normally requires a small amount of downtime (e.g. minutes or hours for well site retrofits, pump conversions, SlipStream) or one or more days for REMVue, waste heat recovery, Pressure Drop to Power etc. All of the new technologies present some additional perceived risk of downtime due to the newness of the technologies and this can be very difficult to overcome until each technology becomes widely accepted by the industry.

- **Organizational Inertia:**
  - Most oil and gas companies have small budgets and limited staffing resources for energy efficiency projects which have to compete for resources against conventional exploration and production activities.
  - The implementation of multiple small and medium scale energy efficiency projects requires significant coordination across multiple operating divisions of large corporations. In many cases, these operating divisions are autonomous within their own dedicated operating budgets and there is limited corporate drive to coordinate and implement energy efficiency activities across the corporation.
  - Oil and gas operations often have complicated ownership structures and any costs or benefits related to energy efficiency projects must be split out among the different working interests, which can greatly reduce the incentive for companies to implement small projects given the hassle of getting buy-in from multiple parties. Indeed, this barrier was the fourth most commonly cited challenge for the 15 largest oil and gas producers implementing energy efficiency projects, as per the 2010 ERCB survey on fuel gas efficiency.[24]

- **Unknown Value of GHG Reductions:**
  - The value of carbon can have a significant positive impact on the economics of vent gas reduction and fuel gas efficiency projects, but there is still considerable uncertainty about the value of GHG reduction credits and the costs of data collection, data management, documentation and validation/verification, especially for small projects. This uncertainty is largely due to the fact that there has been little experience with offset creation in the oil and gas sector to date in Alberta, as only 5 projects have created offsets and all have been large scale acid gas or CO_2-enhanced oil recovery projects. As such, there is considerable

[24] ERCB. April 2010. Alberta Fuel Gas Efficiency in the Upstream Oil and Gas Industry

skepticism among many companies about whether the GHG reductions will result in a tangible revenue stream for these projects.

- The process to generate emission reduction credits is always costly and almost always requires additional expenditures related to measurement, monitoring and data management. Investing in continuous metering equipment with the appropriate data logging capabilities (e.g. tie into SCADA) significantly increases project data collection and management costs, especially in the case of small projects that involve the installation of multiple technologies at hundreds of sites. Further costs related to GHG quantification protocol development, project documentation, third party validation/ verification and registration collectively cost in the tens of thousands of dollars.

The development of a complex vent gas reduction program in the upstream oil and gas sector is impeded by a large number of barriers. Some of the barriers are systemic across all project types, as discussed above, while others are technology specific. The table below provides a list of the top barrier(s) that are likely to impede the implementation of each technology.

Technology	Primary Barriers
Well Site High-Bleed to Low-Bleed Instrument Conversions	Organizational
Solar Powered Well Site Conversions	Organizational
Well Site Vent Gas Capture	Technological and Organizational
Dehydrator Pump Electrification	Financial and Organizational

In conclusion, each of the above technologies faces a unique set of barriers to implementation. However, the common barrier across all project types is the organizational inertia that prevents wide scale deployment of energy efficiency technologies in the upstream oil and gas sector. Most energy efficiency programs are limited in terms of staffing and/or budgetary resources so it is rare for a company to complete a comprehensive review of retrofit opportunities. The difficulty in coordinating retrofits across a large number of sites that individually generate small fuel gas or emission savings is a major impediment for companies that would like to implement larger scale energy efficiency initiatives. As such, most companies in the sector focus on implementing only a few of the most economic technologies or focus on demonstrating a mix of technologies at smaller scales.

Permanence

Emission reductions are the result of a reduction in natural gas venting, and are therefore permanent and irreversible.

Leakage

GHG emissions from Affected SSRs or Related SSRs outside the project boundary are commonly referred to as leakage. Sources of leakage have been conservatively excluded from the Protocol. For example, the conservation of fossil fuel reduces GHG emissions from fuel delivery, as less fuel is consumed in the project condition. Therefore, excluding fuel delivery is conservative. In addition, projects types under this protocol are expected to conserve relatively small amounts of fuel and would therefore have negligible market influence on natural gas and electricity prices, eliminating any “rebound effect” from a decrease in prices.

Emissions from the construction, testing, and delivery of project technology are “one-time” emission sources. These negligible sources of leakage have been excluded as they are not expected to be material considering the long life of the project.

Conservativeness

According to ISO 14064, accuracy should reduce bias and uncertainty as far as possible. If accurate estimates or monitored data are not available, bias and uncertainty can be managed by making conservative estimates of the parameter.

For example, manufacturer’s bleed rates of controllers typically have a high level of uncertainty. To make a conservative estimate of bleed rates, a sample population from each make/model of controller must be monitored. Using a statistical analysis, bleed rates are established with a 95% confidence level. In the baseline condition, the lower bound of the confidence interval is used; this means that 95% of all baseline controllers will experience a bleed rate higher than the estimate. Conversely, in the project condition, the higher bound of the confidence interval is used, ensuring 95% of project controllers will experience a bleed rate lower than the estimate. By underestimating baseline bleed rates and overestimating project bleed rates, a conservative estimate of emissions reductions is formed.

It is the intent of the Protocol to use statistically relevant sampling and confidence intervals to conservatively estimate emission reductions for all project types.

Aggregation

Aggregation projects are expected, as the carbon offsets generated by the operation of individual installations of project technology will not subsidize the cost of project verification. As with any aggregation project, proponents may face an organizational challenge to provide the proper documentation for verification. However, the Protocol manages this risk by providing clear guidelines on data management procedures.

Verification

Pertinent documentation must be complied for project verification. Documentation should be obtained for the following parameters for each project type:

Dehydrator Pump Electrification

- Electronic or manual documentation of facility downtime will be used to determine the operation time of electric dehydrator pump
- Records of the monitored baseline natural gas vent rate
- Make/model of project and baseline pumps

High-Bleed to Low-Bleed Controller Conversion

- Electronic or manual documentation of facility downtimes will be used to determine the operation time of project controllers
- Records of the monitored of bleed rates from the sample population of each make/model of baseline and project controller
- A database of converted controllers

Solar Pump

- Electronic or manual documentation of solar pump operating hours
- Vent rates of baseline pneumatic pumps
- Make/model of project and baseline pumps

Well Site Vent Gas Capture

- Electronic or manual documentation of facility downtime will be used to determine the operation time of vent gas capture system
- The volume of vent gas captured will be monitored with a totalizer or similar device
- A list of equipment with make/model numbers, if applicable

Ownership

An oil and gas company or other company attempting to aggregate offsets may not have ownership or have split ownership of pneumatic controllers in their operation. Aggregation projects should take care to ensure that they have title to offsets. Ownership of offsets may be transferred to another party via a commercial contract. This could occur during the aggregation of offsets from multiple companies, which would serve to reduce the costs of offset creation through economies of scale.

Related Protocols and/or Methodologies

Dehydrator Pump Electrification

N/A

High-Bleed to Low-Bleed Controller Conversion

American Carbon Registry's (ACR) *Emission Reduction Measurement and Monitoring Methodology for the Conversion of High-Bleed Pneumatic Controllers in Oil and Natural Gas Systems* was used as the technical seed document for this Protocol. It quantifies the emissions reductions from the conversion of high-bleed pneumatic controllers to low-bleed alternatives.

In both the proposed protocol and the ACR protocol, the time spent operating low-bleed controllers in the project condition represents an equivalent amount of time that would have been spent operating high-bleed controllers in the baseline condition. The actuation time of snap-acting controllers is similarly quantified between protocols.

Although both protocols require monitoring of a sample population to estimate the bleed rates of controllers, slightly different methods are used to select the sample population. The ACR Protocol suggests a sample population of 30 controllers. This Protocol suggests a sample population of 10% of controllers, with a minimum sample size of 3. Additionally, the ACR Protocol does not quantify emissions from Fuel Processing and Extraction.

Solar Chemical Injection Pump Conversion

The draft Alberta Offset System Protocol for pump conversions has a broad scope, and can be applied to many types of pump conversions. The proposed protocol would only be applicable to conversions of pneumatic pumps to solar pumps.

The draft AOS protocol requires the monitoring of the volume of liquid injected by each pump to establish functional equivalence, and uses manufacturer's bleed rates to estimate vented emissions. However, experience has shown that the volume of liquid injected is difficult to accurately track in the oil and gas industry. In addition, manufacturer's bleed rates often have a high level of error associated with them. Therefore, the proposed protocol will monitor the bleed rate of a sample population of pneumatic pumps to determine pump vent rate. Similar to the high to low bleed conversion protocol, a statistically relevant sample will be taken, and confidence intervals will be used to ensure the estimate is conservative.

Well Site Vent Gas Capture

The approved Alberta Offset System Protocol for Engine Fuel Management and Vent Gas Capture Projects has a very specific scope. Vent gas capture technology is only considered for projects which use vent gas as a supplemental fuel source for engines. The proposed protocol would allow vent gas to be captured from a variety of sources. In addition, the end use of captured gas would not be limited to combustion in an engine; it could be flared, combusted in heaters or other equipment, or conserved.

The approved AOS protocol also mandates that the vent gas be metered with a mass flow meter. However, the proposed protocol would allow for a totalizer or similar meter to be used. This would have equal accuracy but may not rely on SCADA systems for data download.

Other Benefits

Even though natural gas conserved by individual projects is small, the combined effect of many conversions has the capability to significantly reduce vented emissions from the oil and gas industry. The implementation of gas-conservation measures will help provide additional economic benefits to the producer and to the province as more gas will be sold to end users. Reduced venting of natural gas at a facility also reduces the risk of fire hazards, odours, and increases worker safety. In addition, pollution from trace compounds found in natural gas, such as benzene, can be reduced.

Adverse Effects

There are no adverse effects from the implementation of projects of this type.

Proposed Timing for Submission into the Offset System Review Process

The proposed protocol is expected to be submitted to Alberta Environment on or before October 1, 2011 to meet timelines associated with stakeholder review.

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