ALBERTA'S UPSTREAM OIL AND GAS ASSETS INVENTORY STUDY

Opportunities to Reduce Greenhouse Gas Emissions at Existing Distributed Facilities

Prepared for Alberta Innovates – Energy and Environmental Solutions

Cap-Op Energy

September 30, 2013

Acknowledgements

This report was prepared by Cap-Op Energy Inc. for PTAC Petroleum Technology Alliance Canada with support from Alberta Innovates – Energy and Environment Solutions. The principal authors were Liz Brennan, Peter MacLeod, Hannah Simmons and Adam Winter. The authors wish to express their appreciation for the invaluable assistance, insight and comments received during the course of this work from representatives of PTAC and the members of the project steering committee.

Disclaimer

PTAC Petroleum Technology Alliance Canada and Cap-Op Energy Inc. do not warrant or make any representations or claims as to the validity, accuracy, currency, timeliness, completeness or otherwise of the information contained in this report, nor shall they be liable or responsible for any claim or damage, direct, indirect, special, consequential or otherwise arising out of the interpretation, use or reliance upon, authorized or unauthorized, of such information.

Table of Contents

Executive Summary

Activities in Canada's upstream oil and gas sector result in significant emissions of both carbon dioxide (CO_2) from combustion and flaring, as well as methane (CH_4) from venting. However, little analysis into the potential impact of applying existing energy efficiency upgrades to the sector has been completed. These energy efficiency upgrades are, at present, not regulated or incentivized; yet, the potential completion of energy efficiency projects provides the opportunity to realize substantial greenhouse gas (GHG) emissions reductions.

At a national level, energy-related activities are the largest source of GHG emissions reported in the Canadian National Inventory Report. In 2011, 163 Mt carbon dioxide equivalent (CO_2e) was attributable to the upstream oil and gas sector. This accounts for 23% of emissions in the Canadian National Inventory Report.

Upstream oil and gas facilities include batteries, compressor stations, gas gathering stations, and gas plants. Further, these facilities include pneumatic controllers, pneumatic pumps and engines that bleed methane gas or produce combustion emissions as part of their normal operations. Emissions from these assets of the oil and gas industry are significant.

An opportunity exists to reduce the emissions associated with these facilities using new market-ready technologies. These technologies can reduce or eliminate the amount of CO_2 emitted and methane vented as part of normal operations, capture vented methane to be sold or re-used in an engine, or replace natural gas in pneumatic instruments with compressed air. The objective of this inventory study is to establish the link between upstream oil and gas facility assets and alternative, market-ready technologies that perform an equivalent function while emitting fewer or no greenhouse gases. Establishing this link allows for the determination of the existing assets that could benefit from energy efficiency upgrades. Then, the volume of greenhouse gas emissions per year that could be reduced from the upstream oil and gas sector in Alberta are estimated. The compilation of this dataset can inform public or private energy efficiency projects or programs in the province.

At PTAC's request, Cap-Op Energy conducted a desktop review of the distributed oil and gas facilities in Alberta, and related methane control and energy efficiency technologies. The review was comprised of three main components: an inventory of distributed oil and gas facilities in Alberta, a subsequent inventory of the typical assets at each facility and a review of the applicable methane control or energy efficiency technologies. The information gained from this three-phase review was used to inform estimations of the potential greenhouse gas reductions possible within the upstream sector in Alberta.

The eight GHG reducing technologies studied in this report include:

- Low/no-bleed pneumatic controllers
- Engine fuel management systems (air-fuel ratio systems)
- Vent gas capture (SlipStream™ Technology)
- Low/no-bleed pneumatic pumps
- Custom waste heat recovery systems for process heat
- Instrument gas to instrument air for pneumatic technologies
- Well-site vent gas capture
- Green completions

The conservative estimate of the stock of GHG emitting equipment that could be retrofitted with the GHG efficient technologies was multiplied by the average GHG emissions reductions offered by each technology. The resulting emissions reductions opportunity was the calculated as 35,300,000 tonnes of CO_2e per year. As such, the results presented within this report demonstrate that a large opportunity to reduce GHG emissions within the upstream oil and gas sector of Alberta exists.

Introduction

Context

Alberta is an important oil and gas producing region within Canada, and therefore has much higher greenhouse gas emissions than other Canadian provinces, due in large part to the production and processing of fossil fuel resources. The upstream oil and gas (UOG) sector activities generally include the exploration for, and the production of, hydrocarbon resources. Downstream processes include separating produced oil and gas mixtures, removing water from each of the product streams, removing acid gases from natural gas, processing the sulphur gases, refining oil into transportation fuels, as well as compressing and transporting the products to further processing or distribution. These activities result in emissions of both carbon dioxide (CO_2) from combustion and flaring, as well as methane (CH_4) from venting of raw gas or solution gas[1].

Upstream oil and gas activities associated with the production of conventional crude oil and natural gas are characterized by remote facility locations, which require robust and reliable equipment that can be powered without access to electrical grids, or regular deliveries of processed liquid fuels. In many cases, upstream oil and gas facilities are powered by raw natural gas, also called fuel gas. Upstream oil and gas facilities include batteries, compressor stations, gas gathering stations, and gas plants.

Methane is the primary component in natural gas, comprising 85.8% of natural gas (averaged across the province of Alberta) (Johnson & Coderre, 2012), and has a global warming potential of 21 times that of carbon dioxide (CO_2). Raw natural gas is emitted from natural gas production system processes such as well completions and work-overs, well clean-up activities, pneumatic controllers, tank venting, and fugitive venting. Similarly, methane is vented from liquid petroleum system processes such as pneumatic controllers, tank venting, fugitives, refining, and process upsets (Natural Resources Defense Council, 2012). Combustion emissions are generated from the use of engines in compression, as well as from flaring, when flaring is employed to dispose of excess raw gas.

Emissions from these aspects of the oil and gas industry are significant. At a national level, energy-related activities are the largest source of GHG emissions reported in the Canadian National Inventory Report. In 2011, 163 Mt CO_2e was attributable to the oil and gas sector in Canada, which represents 23% of the national greenhouse gas total emissions (of 702 Mt CO_2e) (Environment Canada, 2013). Within Alberta, oil and gas and mining together (but excluding oil sands) constitute 18% of the province's greenhouse gas emissions (AESRD, 2013). There is substantial uncertainty in the estimations of fugitive and vented methane emissions from the oil and gas industry. The American National Inventory has been described as underestimating methane emissions, particularly with respect to gas vented during well completions, gas vented for liquids unloading ("blowdown[2]" events), venting from well workovers[3], and flaring (Natural

[1] Solution gas, or associated gas, is produced in association with crude oil, and is separated from the produced oil in an "Oil Battery", which collects produced volumes from multiple wells, and includes separation and storage infrastructure.

[2] A gas blowdown is the term for venting or flaring accumulated gas that is hindering the production process. Gas may accumulate in low pressure wells or other production equipment or facilities. For example, a natural gas well may begin to accumulate fluids that prevent further gas flow. These fluids can be removed by depressuring the well and allowing the fluids to phase to gas and be vented (or flared) to the atmosphere.

[3] A well workover generally refers to work performed on a well to replace a completion. Well workovers may be performed on wells with completions in poor condition, or due to changing operating conditions.

Resources Defense Council, 2012). That report highlights that similar uncertainty issues with respect to methane emissions exist in Canada. Small emission sources that may result in cumulatively large emissions totals have not been included in emissions monitoring and reporting programs, and not all emissions sources are accounted for, particularly as new techniques are developed for unconventional gas production. The NRDC paper indicates "natural gas processing plants discovered methane emissions were roughly an order of magnitude higher than estimated" (Natural Resources Defense Council, 2012, pp.13). The inaccuracy within the EPA estimates for the United States National Inventory stem from a lack of quality field data, as well as the inability to apply one emissions factor that correctly describes the emissions sources from each field. Emissions factors and Activity factors used within the American National Inventory have continued to evolve, in an increasing fashion, as date becomes available from field operators, and from participants in such programs as the EPA's Natural Gas STAR.

An opportunity exists to reduce emissions with new market-ready[4] technologies, which reduce or eliminate the amount of methane vented as part of normal operations, capture vented methane to be sold or re-used in an engine, or replace natural gas in pneumatic instruments with compressed air. These technologies are available today and able to provide functionally-equivalent retrofit options, yet understanding the magnitude of the opportunity to reduce greenhouse gas emissions in this sector is important in order to stimulate public and private efforts towards methane emissions reductions.

Objective

The objective of this inventory study is to establish the link between oil and gas facility assets and alternative, market-ready technologies that perform an equivalent function while emitting fewer or no greenhouse gases, in order to understand the gross opportunity for greenhouse gas emissions reductions in the Province of Alberta. The establishment of the link between facility assets and retrofit technologies will allow for the determination of the quantity of existing assets that could benefit from energy efficiency upgrades. Then, a gross volume of greenhouse gas emissions per year that could be reduced from the upstream oil and gas sector in Alberta can be estimated.

The compilation of this dataset can inform public or private energy efficiency projects or programs in the province. The task is complicated by the need for proprietary data sets and inventories in order to definitively address this problem, many of which are incomplete or non-existent. Therefore, a "top-down" approach will be employed to conservatively estimate the numbers of assets per facilities based on the Alberta Energy Regulator (AER) data.

Study Technologies

This study focuses on a limited number of the possible methane control and/or energy efficiency retrofit technologies that are applicable to upstream oil and gas equipment. Technologies included in this study were chosen from a longer list of possible technologies, all of which are presented in studies or publications highlighting methane control or energy efficiency technologies and their results to date. Such sources include the Canadian Association of Petroleum Producers (CAPP) Best Management Practices, the Environmental Protection Agency (EPA) Gas STAR program, and the Natural Defense Council's 2012 report entitled "Leaking Profits: The U.S. Oil Industry can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste". Technologies included in this study are also market-ready, have

[4] For the purposes of this paper, market-ready technologies are those that have moved beyond the demonstration phase of development, have been field-tested, and are commercially available.

the potential to be economic (i.e. the technologies show payback in 1 to 15 years, if carbon credit revenue and fuel gas savings considered), and in some cases, already have an approved carbon offset credit protocol in Alberta.

1. ***Engine Fuel Management***: An engine management system that controls the engine's air-to-fuel ratio is implemented to improve fuel use efficiency.

2. ***Facility Vent Gas Capture:*** An engine management system that captures and uses vented hydrocarbons, and then monitors and controls the addition of these hydrocarbons into the engine fuel source. The SlipStream™ by REM Technology is the primary example of this technology.

3. ***Low Bleed Pneumatics***: High bleed pneumatic controllers (both snap-acting and throttle acting) that are operated with natural gas can be retrofitted with low-bleed or self-contained pneumatic controllers. High bleed controllers are defined as having a bleed rate greater than 0.17m^3 per hour (6 ft^3 per hour), while low bleed controllers have a bleed rate less than 6 ft^3 per hour, and may include non-bleed controllers.

4. ***Waste Heat Recovery***: Recovering waste heat from various processes reduces the requirement for heat generation from fossil fuel combustion. A waste heat recovery system captures and makes use of heat that would have otherwise been wasted to the atmosphere, such as exhaust gases.

5. ***Chemical Pump Electrification***: Chemical injection pumps, used to inject methanol and other chemicals into wells and flow lines, are often powered by pressurized natural gas, and bleed methane as part of their normal operations. Such natural-gas powered pumps can be replaced with solar-charged direct current electric pumps, or standard alternating current electric pumps.

6. ***Instrument Gas to Instrument Air***: Pneumatic controllers that use (and bleed) pressurized natural gas as part of their normal operations can be retrofitted to run on compressed air. Atmospheric air is compressed, stored in a volume tank, filtered, and dried for instrument use. Air used for small pneumatic pumps, gas compressor motor starters, and pneumatic tools, does not need to be dried. Such a system is ideally suited to a facility with multiple pneumatic devices that can all be operated from one suite of air compressor equipment.

7. ***Well Site Vent Gas Capture***: Vented natural gas from pneumatic instruments located at a well site is captured. The fuel gas is routed to power a small flameless, gas-fired appliance that converts natural gas or propane into usable infrared energy displacing the need to burn other fuels for heat. The Cata-Dyne™ heater by CCI Thermal Technologies is an example of this technology.

8. ***Green Completions (Reduced Emissions Completions)***: Temporary processing equipment is brought to a wellbore cleanup in order to capture well cleanup fluids and gases, and to separate fluids, gases, and debris. Processing equipment may include gas-liquid-sand separator traps, portable separators, portable gas dehydration units, additional tanks, and small compressors. Such processing equipment can be owned by the producer, or rented from a service company for the duration of a well cleanup. Minimal permanent infrastructure is needed to link the processing

equipment with the well. This technology offers GHG reductions at new gas wells, and has not been extensively deployed in Alberta.

Methods Overview

Cap-Op Energy conducted a desktop review of the upstream oil and gas facilities in Alberta, and methane control and energy efficiency technologies. The review was comprised of three main components: an inventory of upstream oil and gas facilities in Alberta, a subsequent correlation of the number of relevant assets typically found at each facility type, and a review of the potential for methane control or energy efficiency technologies to reduce GHG emissions from these assets. The information gained from this three-phase review was used to inform estimations of the potential greenhouse gas reductions possible within the upstream sector in Alberta.

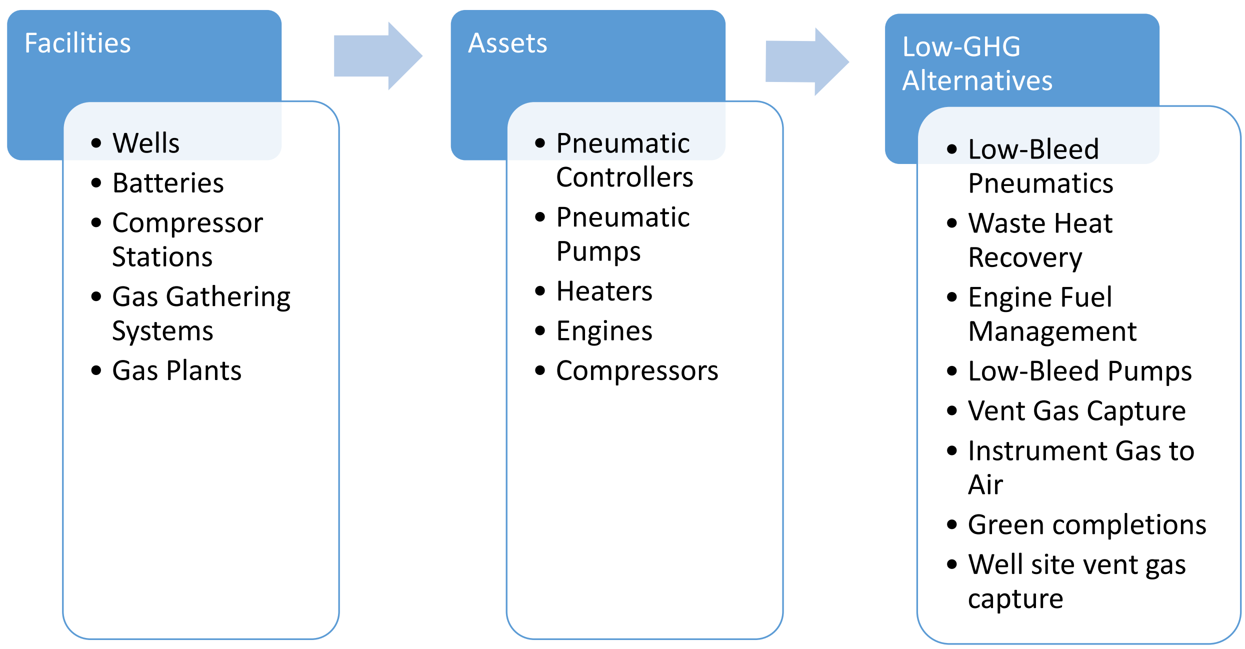

Figure 1: Top-Down Inventory Approach Flow Diagram

Alberta Facilities

The inventory of oil and gas facilities in Alberta was derived using data from Alberta Energy Regulator (AER; formerly the Energy Resources Conservation Board). Statistical Report (ST) 102 provides the list of active facilities, and was used in order to definitively quantify the number of each type of active facility. The ST102 report is generated on a daily basis; the report from June 5, 2013 was used for this inventory project. Facility types that are relevant to upstream oil and gas operations were summarized from the dataset; specifically, batteries, compressor stations, gas gathering systems, and gas processing plants were included. The AER Directive 007 Online Supplement provided definitions of facility types and facility sub-types, and provided some information as to the asset types that may be present at each facility. Multiple facility sub-types exist under each facility type.

Gas wells and conventional oil wells were of interest from this study. The AER ST59 report was used in order to determine the average rate of drilling gas wells over one year. Data from the Canadian Association of Petroleum Producers was used to determine the number of active oil and gas wells in Alberta.

Facilities and Assets Matrix

A Facilities and Assets matrix is presented below in Table 1. Average numbers of assets per facility type are shown, based on typical Piping and Instrumentation Diagrams (P&ID) and Process Flow diagrams, as well as averages from the inventory of a producer with operations in Alberta. Assets found at well sites include pumps, pneumatic instruments, and heaters. Assets found at compressor stations, batteries, gas gathering systems and gas plants include pneumatic pumps, pneumatic instruments, compressors, and reciprocating engines.

Deriving Asset Counts from Facility Counts

The information sources mentioned previously were also used to generate the inventory of assets at each facility sub-type in a "top-down" manner (i.e. starting from the general types of facilities and working down to the assets at each facility). This approach was determined to be appropriate compared to a "bottom-up" approach (such as summing all assets across all producers) because it allowed for the determination of the inventory across all producers in Alberta, and was best able to account for the variability in facilities by making use of facility sub-types as defined by the AER. This approach is explained in Figure 1 above, and the results are shown below in Table 1 and Table 2, which contains a summary of Alberta Facilities.

Assets of interest included pneumatic instruments (such as pressure, temperature, or level controllers), chemical injection pumps, compressors, and (reciprocating) engines. The AER definitions and other materials (such as AER directives and P&ID diagrams) formed the basis of the asset inventory. Several industry subject-matter experts were interviewed in order to more completely estimate the number of assets at each facility sub-type. Where possible, average numbers of assets per facility were used. Where a range of assets at each facility type was possible, the average presented is conservative.

Wells

Conventional oil and gas well sites are comprised of pneumatic control instruments, pneumatic pumps, and small heaters, amongst other assets. The well site asset counts used in Table 1 were derived from data on 54 well sites from a large producer in Alberta. A large range of pneumatic devices are possible at well sites; the minimum is one, although there can be many more, so a conservative estimate was chosen. The pneumatic pump and heater counts reflect standard well site configurations. A generic Piping and Instrument Diagram (P&ID) has been provided from a large producer with operations in Alberta, and is attached in Appendix A. This diagram shows that the averages presented in Table 1 for each of pneumatic controllers, pumps and heaters are conservative.

Compressor Stations

Compressor stations are comprised of pneumatic instruments, compressors, and reciprocating engines to power the compressors, amongst other assets. Compressor stations are another facility type that can exhibit a wide range of numbers of each asset type, based on location and volume of products handled. For example, there are larger compressor stations with at least 40 pneumatics devices, six pumps and up to eight compressors. The counts used in Table 2 are based on averages from 33 different compressor stations, using data provided from a large producer in Alberta.

Batteries

Batteries are facilities that are located downstream of a well, and they serve to collect produced materials, in some cases separate different products, and push these products to further processing. The size of batteries varies greatly in Alberta, based on the number of wells feeding into facility. The averages presented in Table 2 are generated from inventories from eleven facilities in Alberta, provided by a large producer in Alberta. Some battery sub-types list "zero" for certain assets, because minimal or no information was available on those sub-types.

Gas Gathering System

Gas gathering systems are another type of facility that works to move product to market, similar to a compressor station. For this reason, and based on the AER facility definitions, compressor counts are included in the compressor station counts. Averages of other pneumatic instruments are based on a sample of 58 gas gathering sites, provided by a large producer with operations in Alberta.

Gas Plant

Gas plants serve to collect, measure, and process raw gas. Although this processing is not necessarily considered to be part of upstream oil and gas operations, the facilities contain many of the same types of assets, and therefore the same types of opportunities to reduce greenhouse gas emissions. Again, the size of gas plants within Alberta varies greatly. For example, a gas plant may have up to twenty pneumatic devices, four pumps, ten engines, and ten compressors. The averages presented in Table 2 were derived from an inventory of 54 gas plants, provided by a large producer with operations in Alberta.

Table 1: Facilities and assets matrix: Well sites

Facility Type	Facility Sub-Type	Facility Count	Asset Type		
			Pneumatics	Pumps	Heaters
Wells	Conventional Oil Well	33,539	1.0	1.0	1.1
	Gas Well	99,539	1.0	1.0	1.0

Table 2. Facilities and assets matrix: Compressor stations, batteries, gas gathering systems and gas plants.

Facility Type	Facility Sub-Type	Facility Count	Asset Type			
			Pneumatics	Pumps	Compressors	Engines
Compressor Station	Compressor Station	5,422	26	0	1.7	1.8
Battery	Gas Multiwell Effluent Measurement	409	3	0	1.3	1.3
	Gas Multiwell Group Battery (summed)	3,360	11.5	1.9	1.2	1.2
	Gas Multiwell Proration (SE Alberta)[5]	1,573	0	0	0	0
	Gas Single-Well Battery	6,425	2.3	1.5	1	1
	Gas Test Battery	858	0	1.5	0	0
	Crude Oil Multiwell Group Battery	451	5.1	1.4	0	0
	Crude Oil Multiwell Proration Battery	1,860	1.7	1.3	1.0	1.0
	Crude Oil Single-Well Battery	8,112	3	1.2	1	1
Gas Gathering System	Gas Gathering System	3,027	1.5	1.7	In Compressor Stations, above	
Gas Plant	Gas Plant Acid Gas Flaring > 1 T/D Sulphur	35	5.5	1	1	1
	Gas Plant Acid Gas Flaring < 1 T/D Sulphur	70	5.5	1	1	1
	Gas Plant Acid Gas Injection	20	0	1	1	1
	Gas Plant Sulphur Recovery	53	5.5	1	1	1
	Gas Plant Sweet	437	5.5	2.3	2.3	2.3

[5] The asset count for gas batteries of the "Gas Multi-well Proration (SE Alberta)" sub-type is indicated as zero because no counts were provided from the sources interviewed, thus the count is conservative.

Table 3 below provides a summary of the data presented in Tables 1 and 2. The average asset counts of each asset type per facility sub-type were summed, and rounded down, in order to generate the totals presented below. The last line of the asset type presents the sum of the number sub-types of facilities (compressor stations and gas plants) with five or more pneumatic devices. This count is relevant to the instrument air retrofit explained below.

Table 3: Estimated total number of each type of assets in Alberta. The average asset count per facility in Tables 1and 2 was multiplied by the number of facilities and rounded down in order to generate this count.

Asset Type	Total Estimated Count
Pneumatic Controllers	340,000
Pneumatic Pumps (Chemical Injection Pumps)	161,000
Heaters	131,000
Compressors	29,000
Engines	29,000
Sum of facilities with >5 pneumatic controllers (compressor stations and gas plants)	14,000

Low Greenhouse Gas Alternative Technologies

Methods and Study Parameters

The inventory of assets was conceptually mapped to the methane control or energy efficiency technologies of interest (see Figure *2* below). A desktop review was conducted on these alternative technologies to determine: equipment costs, installation costs, and downtime costs (where relevant); fuel gas savings; greenhouse gas savings (in CO_2e per year); the stock of assets that would be able to accept the retrofit; and the stock of the technology in Alberta that has already been installed (where applicable). Numerous sources were used to generate the dataset used in this analysis. Interviews were conducted with several subject matter experts at several producers and vendors, including representatives of:

- Cenovus Energy Inc.
- ConcoPhillips Canada
- Devon Energy Inc.
- Encana Corporation
- Greenpath Energy
- Spartan Controls

Publicly available reports, such as "Leaking Profits" (NRDC, 2012), "EPA GasSTAR Lessons Learned" (EPA, 2013) and CAPP Best Management Practices documents were also utilized.

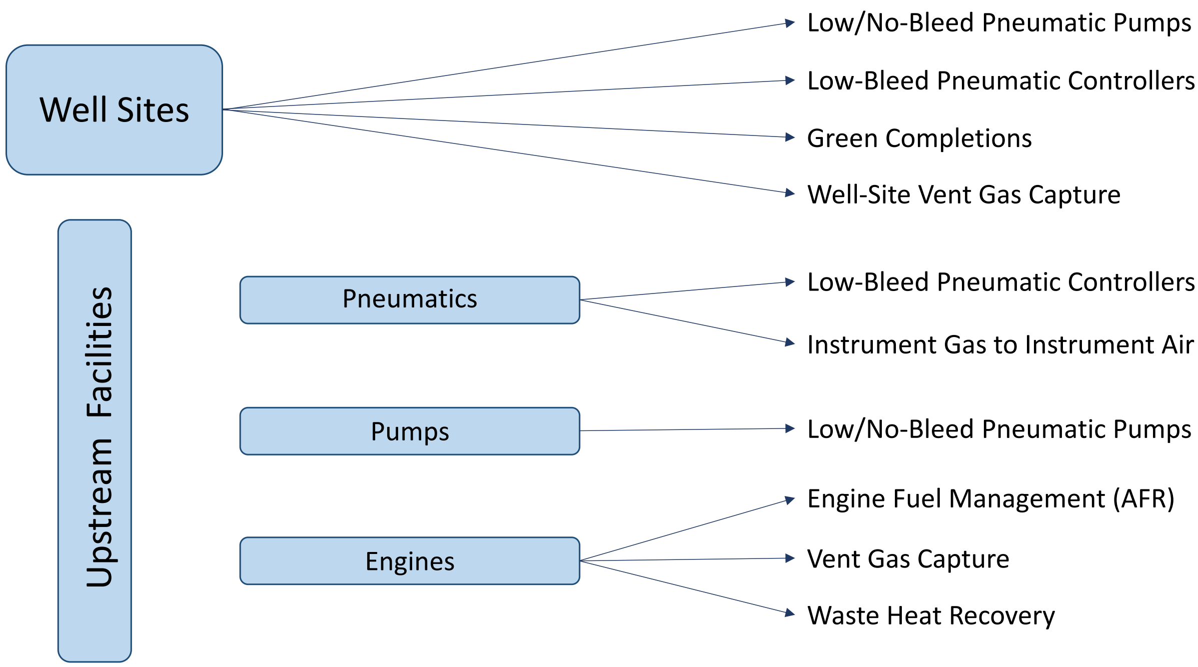

Figure 2: Flow chart of GHG emitting equipment and applicable GHG efficient alternative technologies

Summary of Findings

Table 4, below, presents a summary of the results of the greenhouse gas reduction potential of the selected alternative technologies discussed within this report. The table shows the pairing of assets to retrofit technologies, presents a conservative estimation of the asset stock eligible for retrofit, and presents a conservative estimation of the greenhouse gas emissions reductions per installation. Additional information on each technology is provided below.

The GHG emissions reduction per year was calculated by multiplying the annual GHG savings of each energy efficient technology type by the respective eligible stock of GHG emitting equipment. The sum of the GHG reductions from each technology type represents the potential annual GHG reductions offered by the market-ready technologies included in this study. These emissions calculated are an indicator of the opportunity for reductions, not an indicator or the exact quantification of emission from distributed assets.

Table 4: Stock of GHG emitting equipment eligible for retrofit by GHG efficient alternatives with conservative, and the resulting GHG reduction potential

GHG Emitting Equipment	Estimated Alberta Equipment Count	Estimated Eligible Alberta Equipment Count	GHG Efficient Alternatives	Average GHG Emissions Reduction	Estimated Total GHG Reduction Potential per year
High-bleed Instruments	340,000	100,000	Low-bleed instruments	40 tCO_2e/yr	4,000,000 tCO_2e
Pneumatic Pumps	161,000	145,000	Low/No-bleed pumps	75 tCO_2e/yr	10,875,000 tCO_2e
Gas wells	70,000 Well Sites	35,000	Well Site Vent Gas Capture	44 tCO_2e/yr	1,540,000 tCO_2e
Engines	29,000	1,000	Waste heat recovery	2,000 tCO_2e/yr	2,000,000 tCO_2e
Vented Gas from Pneumatic Instruments	28,000	10,000	Vent gas capture for engine fuel	1,000 tCO_2e/yr	10,000,000 tCO_2e
Natural Gas Combustion Engines	29,000	6,000	Air-fuel ratio controllers	600 tCO_2e/yr	3,600,000 tCO_2e
Facility-wide Fugitive Emissions from Pneumatic Instruments	1,000	200	Instrument gas to instrument air conversion	2,000 tCO_2e/yr	400,000 tCO_2e
New Well Completions	837 gas wells drilled/year*	837	Green (reduced Emissions) Completions	3,500 tCO_2e/well	2,929,500 tCO_2e/yr**
Annual Total					35.3 million tCO_2e

*These values are not rounded because they come directly from CAPP statistical production reports

**Green Completions do not collect offsets over a 10 year period like the other technologies because the reduction in CO_2/CH_4 emissions only occurs once during the well lifecycle and does not continue to reduce CO_2 emissions each year.

Asset and Technology Linkages

For those technologies that have already been installed to some extent within the province of Alberta, more precise data is available on the applicability of these technologies. Therefore, more precise estimations of the number of units that can be installed can be generated for these technologies. The eligible equipment reduces the total equipment count for each asset type to a more conservative estimation of the stock that could be retrofitted, and therefore creates a more conservative estimation of the magnitude of emissions reductions that can be achieved with specific technologies over the coming decade.

The difference between the total equipment count and the eligible equipment count arises from certain conditions that make some assets ineligible to be upgraded. These conditions, or eligibility criteria, include the age of the asset (some assets may be too new), distance from an electricity grid (they may be too close or too far from an electricity grid), and other technology-specific factors are discussed in the following sections. The eligibility criteria also takes into account that multiple technologies may be applicable to an asset at a particular facility type, therefore only one type of retrofit technology is applied to each asset, and carbon emissions reductions are not accounted for twice. For example, a facility with more than five venting sources and a compressor engine are most suitable vent gas capture system (SlipStream™) as opposed to replacing multiple pneumatics. The criteria used in the creation of the eligible count contribute to the conservativeness of the final estimation.

This paper aims to identify the gross opportunity to reduce emissions. The objective of this paper is to show the opportunity for energy efficiency projects and carbon emissions reductions, rather than to explicitly quantify the emissions from oil and gas facilities. The eligible count aims to examine all facilities that could be retrofitted or changed without economic constraint.

High Bleed to Low Bleed Pneumatic Instruments

Asset Linkages

Across all facility types, high bleed pneumatic controllers (such as level controllers, pressure controllers, or temperature controllers) can be retrofitted with low-bleed controllers. Pneumatic controllers bleed dynamically (while they perform a function), and statically (while they wait to perform a function). Low bleed controllers have a reduced static bleed volume, and can result in up to 40 tonnes of CO_2e per year saved per installation. Low bleed controllers have been installed as part of normal practice since 2008, although many high bleed controllers still exist at the numerous older active wells within the province of Alberta.

Eligible Count

The eligible equipment count for high bleed controllers excludes an estimation of those well sites that are new since 2008, as well as locations with an average of more than five pneumatic instruments, as other retrofit technologies may be able to better address those sites. At larger facilities, replacing pneumatic controllers may be redundant because these facilities may be more suited for an instrument air conversion, a vent gas capture system or connection to electric grid. Therefore, low-bleed controllers would be an effective alternative technology for locations with few pneumatic controllers on site, such as well sites and batteries. Thus, there are approximately 100,000 eligible pneumatic controllers.

GHG reductions

The GHG reductions of 40 tonnes per year comes from the Cap-Op Energy inventory of high to low bleed pneumatic conversions and real quantifications from producers who have installed this type of retrofit. The figure of 40 tonnes of CO_2e per year is conservative compared to the 70 tonnes of CO_2e per year as estimated by the United States EPA. If the estimated eligible 100,000 high bleed controllers were changed for low-bleed controllers, retrofits could result in GHG emissions reductions of up to 4,000,000 tonnes CO_2e per year.

Pneumatic (Chemical Injection) Pumps to Low/No Bleed Pneumatic Pumps

Asset Linkages

Pneumatic pumps, which function as chemical injection pumps, can be retrofitted with low-bleed alternatives, or electric pumps (which may be able to run on solar electric power). As with pneumatic controllers, the amount of methane released as a part of normal operations is substantially reduced on a low-bleed pump.

Eligible Count

Subject matter expert interviews indicated that relatively few (<1%) of pumps in Alberta have been retrofitted with a low-bleed alternative, and a large opportunity still exists. The eligible count of pumps to be retrofitted excludes those pumps that are found at facilities with greater than five pneumatic instruments, because these facilities may be more suited to vent gas capture or instrument air conversions.

This criteria removes gas plants and compressor stations from the facilities to target for pump conversions. The eligible count was a conservative estimate of 145,000 pumps based on extrapolations from our facilities to assets linkages. The CAPP BMP for Chemical Injection Pumps (2008) estimates that there may be over a 1,000,000 pneumatic powered chemical injection pumps in the oil and gas industry.

GHG Reductions

The GHG reductions of 75 tonnes of CO_2e per year comes from the Cap-Op Energy inventory and producer's quantification of the reductions associated with this type of retrofit. Therefore, the installation of low/no-bleed pumps in the place of the 145,000 high bleed pumps currently in service could result in reductions of up to 10,875,000 tonnes CO_2e per year.

Instrument Gas to Instrument Air

Asset Linkages

For facilities with numerous pneumatic components on site, such as compressor stations and gas plants, all of the pneumatic controllers can be retrofitted to run on compressed air instead of natural gas. Retrofitting the instruments to run on air instead of gas necessitates access to electricity to power air compressors. For this type of retrofit, operational and economic factors also come into play; an instrument gas to instrument air retrofit is best suited to sites with many pneumatic devices.

Eligible Count

It is not possible to estimate the eligible equipment count with publicly available data given the criteria presented here. Therefore, the estimations that comprise the eligible equipment count are comprised of province-wide extrapolations, based on the number of scheduled conversions planned by interviewed producers, and their share of production in Alberta. The eligible count is intended to include facilities that are easily accessible but not in such close proximity to the electrical grid that pumps and controllers will be converted from pneumatic air to electricity. This eligible count of 200 facilities may be extremely conservative but is intended to be the most accurate number based on data available.

GHG Reductions

Although these retrofits result in variable greenhouse gas savings, an average of 2,000 tonnes CO_2e pear year was used, informed by initial results from instrument gas to instrument air installations in the province by large oil and gas producers. Using the estimation of 200 eligible sites in Alberta, Instrument Air systems could result in GHG emissions reductions up to 400,000 tonnes CO_2e per year.

Engines Coupled with Waste Heat Recovery

GHG Reductions

Engines are used for compression and other upstream processes that move products to market, and in the process create a significant amount of heat. Gas plants are an example of a facility that would be able to make use of low quality waste heat that can be captured at these facilities using waste heat recovery units, and diverted to one or more other processes.

Eligible Count

ERCB statistical reports indicate that there are more than 31,000 engines at gas facilities in the province. Due to the large installation cost (waste heat projects require larger amounts of downtime to retrofit facilities with the equipment to capture waste heat) and variability of GHG savings from waste heat projects, a conservative estimate was made on the number of facilities where waste heat could be applicable, and so a large discrepancy between the total number of facilities and the eligible facility estimation of 1000 sites. This eligible count only includes largest gas facilities and larger compressor stations because large amounts of waste heat are required to make the type of waste heat recovery possible. Other facilities may be suitable for smaller waste heat recovery systems but will not be able to capture the 2,000 tCO_2e estimated, below.

GHG Reductions

Waste heat recovery systems could result in GHG emissions reductions of up to 2,000 tonnes CO_2e per year. This estimate comes from producer experience and projects for scheduled projects. These are larger energy efficiency projects and can result in greater CO2e savings. Across the 1000 eligible sites, 2,000,000 tonnes CO_2e per year could be saved by employing waste heat recovery systems.

Engines Coupled with Vent Gas Capture

Asset Linkages

A Vent Gas Capture (VGC) system is another alternative for facilities with multiple pneumatic devices, or other equipment venting or bleeding small amounts of low-pressure methane. The diffuse sources of methane are captured and fed into an engine using a computer-controlled system. An example of this is SlipStream™ Technology, from Spartan Controls.

Eligible Count

The application of a VGC system may be an operationally-appropriate solution for gas plants and other large facilities, depending on site-specific conditions. VGC systems are not reliant upon electricity grids, as instrument gas to instrument air systems are. They allow for the collection of fuel gas from many sources, and thus the estimation of eligible vent gas capture sites is larger than the instrument gas to instrument air sites. VGC systems can be paired with rich burn or lean burn engines that have a digital air fuel ratio control system installed (see below).

The eligible count targeted sites that had an average of five or pneumatic instruments. Sites that were targeted for instrument air conversions, or sites that produce sour gas, were not considered in this count. The engines at facilities eligible for vent gas capture may already have an AFR, be eligible for an AFR, or have a lean burning engine if they are a newer facility. There are approximately 10,000 sites eligible. The eligible count in the PEMA Inventory Report is slightly less than the population count of facilities (10,083) in the 2009 Accurata report.

GHG Reductions

The GHG reductions of 1,000 tonnes per year are conservative estimates from different producer quantification and the 2009 Accurata Report. The emissions reductions indicated in the Accurata report range from 912.5 tonnes CO_2e per year to 8687 tonnes CO_2e per year. Implemented across the 10,000 eligible sites, this results in greenhouse gas emissions reductions of up to 10,000,000 tonnes CO_2e per year. The emissions reductions estimated in the 2009 Accurata report were 9,400,000 tCO_2e. The eligible count of facilities is very similar to the 2009 Accurata report on SlipStream™ technology, but because our initial population used different criteria to determine the eligible count our overall reductions differ slightly.

Engines Coupled with Air Fuel Ratio Controllers

Asset Linkages

Many engines that are operating in oil and gas facilities are "rich burn" engines, meaning that more fuel gas is used than is stoichiometrically necessary. These engines can be retrofitted with a device that controls and optimizes the ratio of air to fuel. Air-Fuel Ratio (AFR) controllers are generally only suited to older, rich burn engines, instead of newer, lean burn engines. Furthermore, a VGC system can be paired with an AFR system.

Eligible Count

The count of eligible engines is reduced from the total engine count in Alberta as newer engines are, in most cases, already lean burn systems. Other factors that further limit the use of AFR systems include engine tuning and other process-specific challenges, and in some cases, other energy efficiency projects may be more appropriate compared to AFR controls.

The eligible count was produced from extensive surveys of subject matter experts. Vendors, producers and the Accurata Report on REM AFR systems informed the eligible count of engines that could be retrofitted with an AFR system in Alberta. The eligible count removed new engines that are lean burning or have already have an AFR installed. Feedback (including planned installs by producers) was used to extrapolate the eligible count over the Alberta. A single producer estimated that a very small percentage of their 1000 rich burn engines had already been retrofitted with an AFR. The eligible count was determined to be 6,000 engines. The eligible count was compared to the Accurata Report on REM AFR Systems (2006).The Accurata Report on REM AFR Systems (2006) estimates that 3,913,000 tCO2e can be reduced by AFR systems. This reductions estimated in the report would require approximately 6,500 AFRs installed in Alberta to achieve these reductions. Therefore, the eligible count presented here is somewhat more conservative than the Accurata Report.

GHG Reductions

The installation of an air-fuel ratio controller results, on average, of reductions of 600 tonnes CO_2e per year. This estimation comes from vendor information, producer projects and Cap-Op inventory. Multiplied over the approximately 6,000 eligible engines in Alberta, air-fuel ratio controllers could result in GHG emissions reductions of up to 3,600,000 tonnes CO_2e pear year. The eligible assets is a conservative estimate from SME at vendors. This takes into account economic constraints, engines that have been retrofitted, smaller engines where an AFR may not be viable and newer engines that may already be lean burning.

Well Site Vent Gas Capture

Asset Linkages

A well site vent gas capture system can make use of the gas emitted from pneumatic controllers at a well site and feed it to a small flameless, gas-fired appliance that converts natural gas or propane into usable infrared energy. An example of such a system is a Cata-Dyne™ heater.

Eligible Count

The eligible count was derived from the AER (ERCB) ST59 report for 2012. This report shows the number of new wells drilled each year. (The "development" category of this report was considered, while the "exploratory" and "observation" categories were excluded.) This information indicates that there are approximately 140,000 active wells in Alberta. With a range of 1-3 wells per conventional well site there may be approximately 70,000 well sites operating in Alberta (NEB, 2009). According to CAPP BMP for Pneumatic Instruments (2008), over 50% of well sites in Alberta use fuel gas while 30% use propane because they are sour wells. This number continues to grow with the continued development of resources. With half of Alberta well sites running on fuel gas, there are approximately 35,000 well sites that could have WSVGC systems. The eligible count is conservative, but as more multi wells and unconventional wells are drilled the ability to capture vent gas will continue and the emissions reduced per well site will increase.

GHG Reductions

The greenhouse gas savings per installation were informed by initial results from a producer's pilot project. Approximately 44 tonnes CO_2e per year can be saved per installation. If 100% of gas well sites were retrofitted with well-site vent gas capture systems, GHG emissions reductions of up to 1,540,000 tonnes CO_2e per year could result.

Green (Reduced Emissions) Completions at New Gas Well Sites

Asset Linkages

As a well is being drilled and completed, a green completion process can be implemented to capture gas, sands, and drilling fluids that are emitted or removed from the well as part of the normal completions process. Temporary processing equipment brought on site can be connected to the well with some minimal additional piping and infrastructure. This results in the capture of raw natural gas and its subsequent processing, such that it can be routed to a sales line, instead of being vented directly to atmosphere.

Eligible Count

This process can be applied to every new gas well being drilled, and the AER ST59 report for 2012 indicates a rate of drilling of 837 new gas wells per year. All green completions were included in the eligible count because this technology has not been readily adapted and the payback occurs over the lifetime of a green completion.

GHG Reductions

The green completions technique has been used successfully and profitably in other gas basins in North America, capturing a conservative average of 3,500 tonnes CO_2e per well. If 100% of new gas wells (837 wells per year) were completed with a green completions system, GHG emissions reductions of up to 2,929,500 tonnes CO_2e per year could result.

Discussion

Magnitude of GHG Emissions Reductions Possible

The results presented shows that the eight GHG-efficient technologies addressed in this report may yield up to 34 million tonnes of CO_2e per year if they could be implemented across eligible equipment in the province of Alberta. This magnitude of reductions from Alberta's upstream oil and gas sector is substantial, considering 163 Mt CO_2e per year is attributable to the upstream oil and gas sector across Canada in the National Inventory (Environment Canada, 2013).

The possible greenhouse gas emissions reductions presented within this report are also greater than other published numbers. For example, upstream venting and flaring emissions from 2008 are estimated at 8.03 million tonnes of CO_2e (Johnson & Coderre, An analysis of flaring and venting activity in the Alberta upstream oil and gas industry, 2011). However, it should be noted that the estimate presented in this report is based on a different methodology than in the National Inventory Report, thus, the two estimates are not directly comparable.

The Canadian National Inventory Report detailing national GHG emissions indicates that 163 Mt CO_2e per year is attributable to oil and natural gas activities. The estimate of GHG savings available in Alberta appear to be roughly 20 percent of all Natural Gas processing emissions across Canada, and thus may appear to be over-estimated. The Natural Resources Defense Council in the United States found that as emissions reductions projects were completed, the increased information about the GHG emissions reductions unveiled the true magnitude of vented and fugitive emissions in the upstream oil and gas sector. The US National Inventory was claimed to have under-estimated the fugitive and vented emissions in the upstream oil and gas sector by as much as an order of magnitude (Natural Resources Defense Council, 2012). This may also be the case within Canada and Alberta, and therefore the estimate of possible GHG emissions reductions presented in this study may not be a significant over-estimation.

The estimation of GHG reductions possible from these GHG efficient technologies was prepared using conservative assumptions. However, the potential for reductions may be inaccurate for the following reasons. First, calculations of GHG reductions possible from each technology are based on results from retrofits completed over the last decade in both Canada and the United States. The first retrofits completed are likely the highest yielding, in the sense that they would be the oldest facilities offering the greatest GHG reduction potential. Second, using these numbers is applicable to a certain (unknown) number of facilities, although new facilities constructed in the last decade may have already been designed with the most efficient technologies (such as low-bleed models of pneumatic controllers). Therefore, the GHG reductions possible per technology is accurate for the first many retrofits, but as the retrofits are performed on increasingly new equipment, the GHG resulting emissions reductions will decrease. Finally, the time, labor, and costs required to complete all of the retrofits may make achieving the full potential GHG emissions reductions unlikely in the immediate future.

Barriers to Reducing GHG Emissions from Upstream Oil and Gas Facilities

The opportunity exists to substantially reduce methane emissions in Alberta with the market-ready technologies presented in this report. Although these technologies are able to provide functionally-equivalent retrofit options, and save enough methane or fuel gas to pay for themselves within 1-15 years, many barriers prevent producing companies from prioritizing the installation of such technologies. Barriers are primarily operational or economic in nature.

Operational factors include site-specific challenges (such as unique operating conditions that are not suitable to a retrofit technology). Operational complexity and data management burdens may arise from the installation of new technologies without any obvious benefit to the operator. If detailed engineering is required for a complex technology retrofit at each site, then the rate of installations may be slowed, and installation costs will add significantly to the unit purchase price. Production downtime is discouraged in organizations where operator incentives are tied to production. Finally, if field operations have a complex ownership structure, buy-in must be achieved from each of the owners, and this can be a disincentive to proceed with small projects.

Financial barriers exist because GHG control technologies compete with core business projects based on internal rate of return, so it may be difficult for novel technologies to be awarded corporate funding (Natural Resources Defense Council, 2012). Economic barriers are also presented by the current low price of natural gas (which impacts the expected rate of return on energy efficiency projects), and may also arise in the cases of producers who keep low operations/maintenance budgets. Fuel gas is reported as "shrinkage" instead of an operating cost; no royalties must be paid on shrinkage, whereas royalties are paid on fuel gas savings. This distinction may serve to discourage energy efficiency projects. An additional financial barrier may be greater risks cost escalation when new retrofit technologies are implemented at older facilities.

Cost of Reducing GHG Emissions from Oil and Gas Facilities

Most of the technologies presented in this study have the potential to earn positive returns on investment (ROI) for the producer, as captured methane displaces the need for other fuel use, or in some cases can be directly sold to market. Unfortunately given the current low price of natural gas, the majority of these technologies yield unacceptably long payback periods when evaluated on fuel gas savings alone.

Carbon offsets in Alberta enable producers to see greater returns from many of these technology types when carbon offset verification is pursued under approved protocols. For the purpose of this cursory financial evaluation, carbon offsets are included in the payback period analysis for all technology types, even if they are not covered by a current Alberta protocol. At the time of writing, there is only protocol coverage for: instrument gas to instrument air, waste heat recovery, vent gas capture and air-fuel ratio controllers.

The current price cap on carbon offset values in Alberta is indirectly set at $15/tCO_2e$ as this is the price producers can pay into the Alberta Environment and Sustainable Resource Development Climate Change and Emissions Management Fund in lieu of generating offsets. The price of $15/tCO_2e$ is considered the maximum gross value of an offset, but this must be netted down to account for risk, administrative and verification costs associated with producing offsets to get to a more representative value. For this study $10/tCO_2e$ is used as the net offset value (which is a best-case scenario, attainable only when offsets are pursued at large scale). As shown in Table 5, carbon-inclusive payback periods of one to 15 years are calculated for each technology.

Table 5: Installed costs and estimated payback period of GHG Efficient technologies with carbon offset at $10/tonne and fuel gas valued at $2.50/GJ.

GHG Efficient Technologies	Average Installed Cost	Estimated Payback Period (Years) with Carbon Offset Creation ($10/tCO$_2$e and $2.50/GJ of fuel gas)
Low-Bleed Instruments	$2,625	3.9
Low/No-Bleed Pumps	$8,085	6.0
Well Site Vent Gas Capture	$15,000	>15
Waste Heat Recovery	$400,000	11.6
Vent Gas Capture	$120,000	7.3
Air-fuel Ratio Controllers	$183,750	5.4
Instrument Gas to Instrument Air	$210,000	6.4
Green Completions	$30,000	<1*

*Green Completions are a one-time event at each new well.

The costs presented for each of these technologies are derived from the same sources as the GHG savings estimates as above. The payback time was calculated using the simple payback method, assuming a fuel gas cost of $2.50/GJ and a net carbon offset price of $10 tCO$_2$e . A higher cost of fuel gas would significantly decrease the payback time (previous published papers addressing these technologies have valued fuel gas between $6 and $8/GJ).

Given the long payback time of some of the technologies, achieving methane and CO_2 emission reductions on the order of magnitude possible will not be incentivized with fuel gas savings alone given the current low price of fuel gas and the complexity of offset creation. If actual large-scale reductions in the near term are to be expected, increased carbon value, more stringent venting regulations, incentives such as technology rebates, or some combination of the above are required.

As a greenhouse gas emissions reductions strategy, investments in fuel gas conservation and operational efficiency make sense. Potentially significant emissions reductions are possible, given the variability of different upstream oil and gas sites, potentially at a profit. Furthermore, "Investment in CO_2 equivalent reductions from upstream…venting is likely to be much more economically viable in the near term than other possible strategies for achieving similar reduction magnitudes" (Johnson & Coderre, 2012a, pp.130). Achieving the greenhouse gas emissions reductions presented within this study will not be without some operational or economic barriers, yet recent uptake of the technologies within Alberta and other jurisdictions indicate that the barriers are not insurmountable. Some amount of incentive or stimulation would likely be enough to see a drastic increase in the deployment of these technologies, and a corresponding reduction in greenhouse gas emissions from the upstream oil and gas sector of Alberta.

Conclusion

In sum, a large opportunity exists to reduce methane and combustion emissions from the upstream oil and gas sector in Alberta. The opportunity to reduce GHG emissions in the upstream oil and gas sector of Alberta offered by the eight GHG efficient alternative technologies studied in this report may amount to as much as 35,300,000 tonnes of CO_2e per year. This figure is an estimation; however, it demonstrates that the opportunity is significant, and investments in upstream oil and gas energy efficiency projects can result in meaningful GHG emissions reductions.

The eight market-ready technologies presented in this report each offer significant emissions reductions opportunities, when considering the extensive stock of GHG emitting equipment across the province. The deployment of these technologies can result in the reduction of fugitive and vented methane emissions and combustion emissions, as well as fuel gas savings, and the potential to earn carbon offset revenues.

Achieving methane and CO_2 emission reductions on the order of magnitude possible will not be incentivized with fuel gas savings alone given the current $2.50/GJ price of fuel gas. If actual reductions in the near term are to be expected, increased carbon value, more stringent venting regulations, incentives such as technology rebates, or some combination of the above are required.

References

Accurata Inc. (2006). *Emissions and Efficiency Enhancements with REM AFR Systems.* Calgary: PTAC.

Accurata Inc. (2009). *REM Technology Inc Slipstream System: Industry Impact Assessment with Field Quantification Tests.* Calgary: PTAC.

AER. (2011). *Directive 007: Volumetric and Infrastructure Requirements .* Calgary: Alberta Energy Regulators.

AER. (2012). *Statistical Series 60: Upstream Petroleum Industry Flaring and Venting Report.* Calgary: Alberta Energy Regulators.

AER. (2013). *Statistical Series 102: New/Active Reporting Facilities List.* Calgary: Alberta Energy Regulators.

AER. (2013). *Statistical Series 59: Alberta Drilling Activity Monthly Statistics.* Calgary: Alberta Energy Regulators.

AESRD. (2013, June 18). *Regulating Greenhouse Gas Emissions*. Retrieved from Alberta Environment and Sustainable Resource Development: http://www.environment.alberta.ca/0915.html

CAPP. (2008). *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments.* Calgary: CAPP.

CAPP. (2008). *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Chemical Injection Pumps.* Calgary: Canadian Association of Petroleum Producers.

CAPP. (2012). *Alberta Production: Operated Gas Wells.* Canadian Association of Petroleum Producers.

CAPP. (2012). *Alberta Production: Operating Oil Wells - Bitumen.* Canadian Association of Petroleum Producers.

CAPP. (2012). *Alberta Production: Operating Oil Wells - Conventional.* Canadian Association of Petroleum Producers.

Environment Canada. (2013). *National Inventory Report 1990 - 2010: Greenhouse Gas Sources and Sinks in Canada - Executive Summary.* Ottawa: Government of Canada.

EPA. (2006). *Lessons Learned from Natural Gas STAR Partners: Convert Gas Pneumatic Controls to Instrument Air.* Washington, DC: United States Environmental Protection Agency: Air and Radiation.

EPA. (2006). Lessons Learned from Natural Gas STAR Partners: Options For Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Washington, DC.

EPA. (2011). *Lessons Learned from Natural Gas STAR Partners: Convert Natural Gas-Driven Chemical Pumps.* Washington.

Gibb, B., Terrell, K., & Zahner, F. (2006). *Emissions and Efficiency Enhancements with REM AFR Systems.* Calgary: Petroleum Technology Alliance Canada.

Johnson, M. R., & Coderre, A. R. (2011). An analysis of flaring and venting activity in the Alberta upstream oil and gas industry. *Journal of the Air & Waste Management Association*, 190-200.

Johnson, M. R., & Coderre, A. R. (2012a). Opportunities for CO2 equivalent reductions via flare and vent mitigation: A case stduy for Alberta, Canada. *International Journal of Greenhouse Gas Control*, 121-131.

Johnson, M., & Coderre, A. (2012). Compositions and greenhouse gas emission factors of flared and vented gas in the Western Canadian Sedimentary Basin. *Journal of the Air & Waste Management Association*, 992-1002.

Kenilworth. (2012). BTEX Emissions Reduced By 99.9% in Pilot Project. Lloydminster, Alberta.

Ladlee, J., & Jacquet, J. (2011). *The Implications of Multi-Well Pads in the Marcellus Shale.* Cornell University.

Natural Resources Defense Council. (2012). *Leaking Profits: The U.S. OIl and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste.* www.nrdc.org/energy/leaking-profits.asp: Natural Resources Defense Council.

NEB. (2009). *A Primer for Understanding Canadian Shale Gas - Energy Briefing Note.* Canadian National Energy Board.

Appendix A: Facility Process Flow Diagrams

Below are diagrams for Piping and Instrumentation Diagram (P&ID) that provide examples for the two facility types resulting in the two most numerous asset counts presented in this report. These schematics provide examples of the types of materials that were used to inform the asset counts, and in both cases, demonstrate that the counts used herein are conservative, and significantly lower than the instrumentation present in these diagrams.

Wells are where the largest number of pneumatic devices are located, due to the large volume of active wells in Alberta. These sites are small, and therefore can easily be illustrated on a one page P&ID. A generic compressor station was used to illustrate all the assets associated with a single compressor. Compressors were the second most abundant facility type after wells. Batteries, Gas Gathering Facilities and Gas Plants were excluded from Appendix A because these P&ID's are much larger and simple schematic cannot illustrate all the assets at a facility. These facilities are also not as numerous as wells and compressor stations, therefore they contribute to a smaller percentage of assets that are generating GHG emissions.

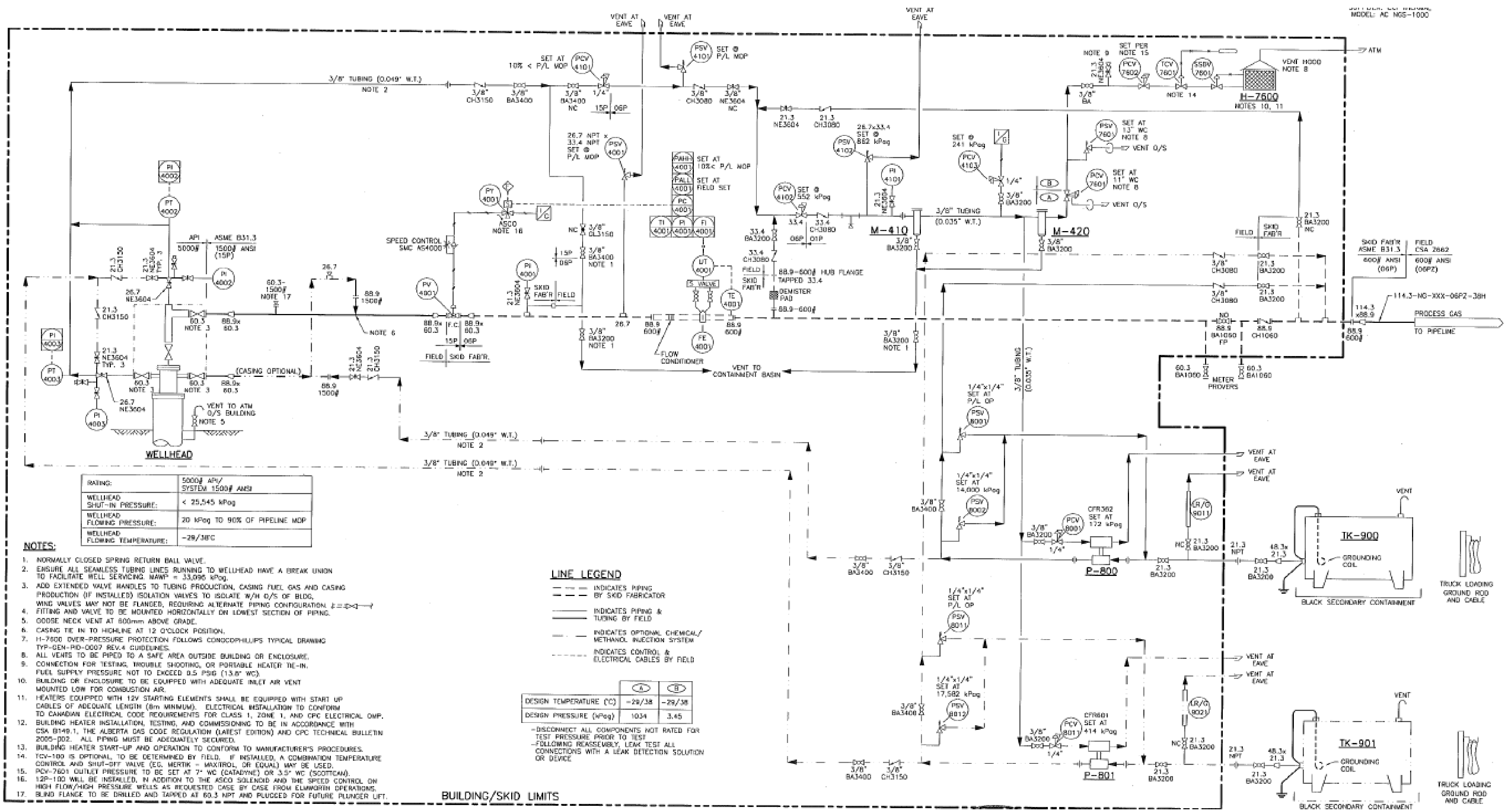

Figure 3. A P&ID for a generic well.

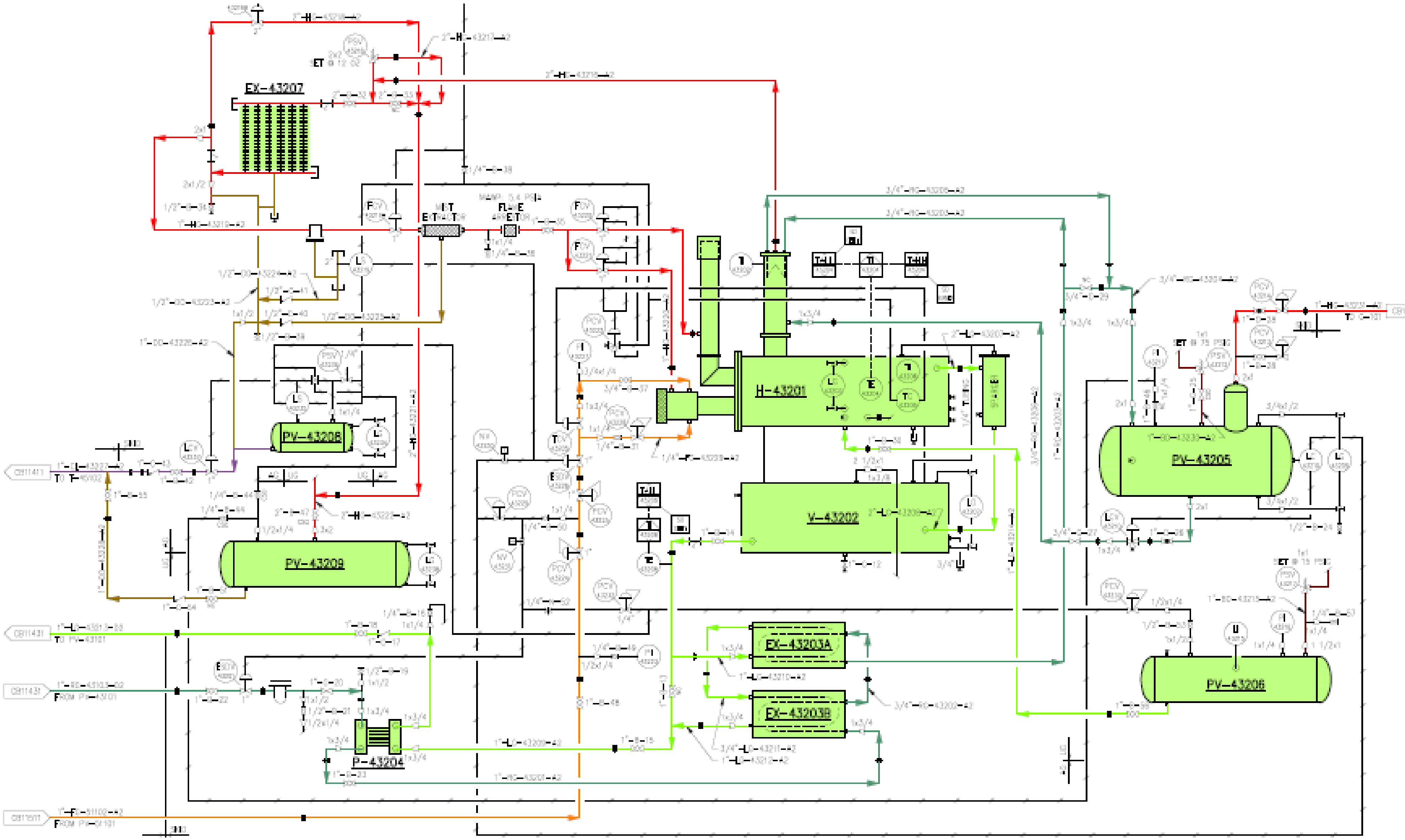

Figure 4. A P&ID for a generic compressor station containing 1 compressor. This does not illustrate a complete facility just the components required for one compressor.