Introduction

The oil and gas industry in Canada has been a global leader in the safe, efficient, and environmentally-sound exploration, extraction, production, transport, and processing of fossil fuel resources. Innovation is at the heart of Canada's energy industry, and Canadian technology companies have demonstrated a value-oriented approach to environmental leadership and eco-efficiency by developing best practices and technologies, and putting them into practice. However, without a centralized compendium of available options operators are not always aware of the strategies and technologies they might implement to improve the eco-efficiency of their assets. The Canadian Upstream Oil and Gas Eco-Efficiency and Operations Handbook was developed to meet this need. The handbook showcases a collection of commercially-demonstrated products and practices available for the Canadian oil and gas industry.

Acknowledgements

The Handbook was prepared by a team under the leadership and editing of Marc Godin and PTAC Petroleum Technology Alliance Canada with oversight from oil and gas operators who sit on PTAC's Technology for Emissions Reduction and Eco-Efficiency (TEREE) Committee. The project was sponsored by Natural Resources Canada and The Alberta Upstream Petroleum Research Fund (AUPRF). Handbook sections were authored by Cap-Op Energy, New Paradigm Engineering, and Independent Contractor Jamie Callendar, with assistance from the technology providers included in the Handbook, and editorial contributions from Sarah-Jane Downing, Kristie Martin, and Marc Godin.

Disclaimer

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Purpose and Scope

The purpose of the Handbook is to help operators, asset managers, and project managers make efficient and cost-effective equipment selections, and to provide them with informative operations optimization strategies for their facilities. The Handbook serves as a rationale for facilities engineers and asset managers to advance sustainability objectives by using components that result in improved performance; many of these may otherwise been overlooked because the benefits are not perceived to compensate for the additional costs in the short term. This document details field-deployable technologies and serves as an informative checklist to create better standards and consistent practices that industry can refer to when installing new builds or completing upgrades and expansions on well sites. The Handbook also includes information on operational procedures and optimization strategies to assist operators in maximizing energy efficiency and emissions reduction benefits.

The Handbook might also act as a point of reference against which competing technologies may be compared or assessed, helping inform all phases of decision-making prior to installation and through to commercially relevant demonstration scale. That said, the Handbook is solely an informational tool providing a range of indicative values as supplied by the technology providers themselves. The vendors, technologies, and products listed are not affiliated with PTAC and do not have formal endorsement from PTAC. Datasheet information was provided by technology suppliers and, while it is believed to be representatively accurate at the time of publishing, no warranties or assertions about product performance or about product qualifications for regulatory or credit qualifications can be provided.

This handbook is a high-level summary of available equipment, products, and recommended best practices currently available for implementation. It is intended to increase awareness of available sustainable technologies for use during project planning stages. The relatively detailed, easily accessible, and concise information sheets can be supplemented and confirmed through direct follow up with suppliers. Thus, the Handbook aims to include and encourage consideration for benefits such as energy efficiency, improved safety, better environmental performance, social license, and ultimately promote adoption of better practices at the field level throughout Canada's oil and gas industry.

The products listed in the Eco-Efficiency Handbook are current as of July 2017. Recognizing that equipment, technology, regulatory certificates, pricing, and availability change over time, it is up to the user to confirm details about the products listed here and to seek out specific information unique to their requirements. Users should note that the suppliers included in this Handbook are not comprehensive and do not include all potential service companies and/or equipment vendors.

Contact Information

New submissions (please fill out the template forms provided at the bottom of this web page), inquiries, and comments regarding the Handbook can be sent to Info@PTAC.org

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Section 1.1. Burners, Heaters and Boilers – Facilities Design and Equipment

1.1.1. Utherm High Efficiency Process Heater	July 31, 2017

Description

Utherm was founded to provide the process industry with efficient, robust, and environmentally-friendly fired-heating packages.

Utherm process heaters contain a high-efficiency firecage heat exchanger designed to achieve 80% to 95% lower heating value (LHV) efficiency, depending on process temperature. An ultra-low emissions burner reduces NO_x and CO_2 emissions. The compact footprint of the design significantly reduces the required lease or building space.

Typical process applications for Utherm heaters include, but are not limited to: indirect gas heater, fuel oil heater, amine reboiler, hot oil heater, condensate stabilizer reboiler, heat medium heater, heater treater, steam generator, remote tank heater and glycol reboiler.

Technology Group

Burners, Heaters, and Boilers – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service

Emissions Reduction and Energy Efficiency

Advanced Combustion for Low Emissions

- Safe
- Low Emissions
- Quiet
- 30% to 40% reduced emissions
- 10% to 30% increase in thermal efficiency over conventional indirect bath heaters

Emissions:
Utherm heaters utilize radiant metal fiber matrix burner technology that reduces the environmental impact of burner operations, producing some of the lowest emissions available in the industry. Field-proven to be safe and reliable, the Utherm burner is simple to operate. Where higher gas pressures are available, the burner can operate without power due to available high-performance air entraining venturi injectors. Where only low gas pressures are provided, an industrial cast-aluminum blower provides the dynamic force for the efficient mixing of the fuel and air to the burner. Utherm burner technology's lower NOx emissions help the process industry better meet regulatory standards.

Efficiency:
Utherm heaters are designed for an efficiency of 85-95% LHV and utilize a state of the art heating technology to reduce heat loss to the environment through stack and jacket losses. Replacement of aged conventional heating equipment will result in reduced fuel consumption and increased heat

transfer to the process fluid. Comparing these units to aged convectional bath heaters, the return on investment, given fuel consumption alone, is predicted at two to three years.

Economic Analysis

Capital Cost:	$50,000-$300,000
Installation Cost:	$25,000
Operating Cost:	Fuel consumption and power. Reduced fuel consumption due to improved combustion efficiency. Low power design.
Maintenance Cost:	Semi-annual maintenance is recommended.
Return on Investment:	Two to three years depending on the equipment being replaced and cost of fuel.
Carbon Offset Credits:	No applicable carbon offset protocol currently exists.

Reliability

Expected Lifetime:	The equipment is expected to last more than 25 years.
Maintenance:	A pipefitter, a combustion tech., or an engineering and installation (E&I) tech is required for maintenance work.

Safety

American safety standards including CSA, UL, ASME, and NFPA.

Regulatory

- Hazard rated for CSA, Class1 Div. 2
- CSA B149.3 code compliant fuel train and control system
- Coil registration depending on process fluid (ASME B31.3 / ASME Sect. I / ASME Sect. VIII / non-registered coils are available)
- No AER Directive applicable

Vendor Information

Company Name:	Combustion Solutions Inc. / Utherm
Company Website:	www.combustionsolutions.ca
Product Website:	www.utherm.ca
Contact Person:	Ben Miller
Contact Phone#:	(403) 619-8100
Contact Email:	ben@combustionsolutions.ca

1.1.2. Black Gold Rush Industries Ltd. - All in One Rush Burner

April 26, 2019

Description




Black Gold Rush Industries' pre-built, all-in-one Rush Burners have been designed to significantly reduce install time and costs. The Rush Burners effectively combust volatile organic compounds (VOCs) and benzene, toluene, ethylbenzene, and xylene (BTEXs) produced from oil and gas equipment, such as storage tanks, casing gas, dehys, pneumatic devices, pumps, or any other low-pressure venting equipment while providing heat to line heaters, tank burners, dehys, free-water knockouts, reboilers, and heater treaters.

Rush Burners provide an alternative to venting gas or sending vent gas to expensive and sometimes unreliable VRUs and incinerators.

The ability to use the Rush Burners on new and existing process equipment with a minimal installation time makes it an economical solution for vent gas issues.

The Rush Burner's patented burner system achieves 99.99% total hydrocarbon destruction, and combustion efficiencies of 80% at pressures as low as two ounces. The Rush Burners can either use onsite power or the available solar package option. Incorporating safe and reliable ignition/flame sensing in the design creates a unique flame profile that increases heat transfer, inhibits flame lift off, and eliminates fire tube impingement. All Rush Burners come complete with:

- Hinged and latched flame arrestor (flange pattern pre-drilled)
- High-efficiency burner assembly (pre-assembled)
- B149.3-compliant valve train (pre-built and tested)
- CSA-approved ACL burner management system (pre-wired)
- Thermocouple and thermowell (pre-wired)
- Fire tube gasket (pre-cut)

Technology Group

Burners, Heaters, and Boilers – Facilites Design and Equipment

Site Applicability

Black Gold Rush Burners are a versatile technology that is easy to install. They can be used in almost any facet of the oil and gas industry, including upstream oil and gas facilities and midstream pipeline facilities. They are able to handle a wide range of gas types including H_2S.

Emissions Reduction and Energy Efficiency

- Rush 500 - 500,000 BTU/hr

- Rush 1000 - 1,000,000 BTU/hr
- Rush 2500 - 2,500,000 BTU/hr
- Rush 5000 - 5,000,000 BTU/hr

Economic Analysis

Capital Cost:	\$6,500.00 - \$20,000.00 depending on model and amount of BTU required.
Installation Cost:	Installation costs would reflect individual client operations. Typically, multiple Rush Burners can be installed in a single day. Interested parties should contact Black Gold Rush Industries to discuss specifics.
Operating Cost:	Operating costs of the Rush Burner are extremely low. The high-fire low-fire of the Rush 500 and Rush 1000 eliminates the need for a continuous pilot, thereby avoiding carbon taxation. The Rush 2500 and 5000 use an ACL 1500 pilot, which consumes less than 50 scf/d (1.5m3/d) of propane, fuel gas, or waste gas.
Maintenance Cost:	The only maintenance cost associated with the Rush Burner is regular inspection of the unit by company personnel. Preventative maintenance is typically performed on most burner applications.
Carbon Offset Credits:	Carbon offset credits from installation of the Rush Burner depend directly upon the amount of carbon offsets generated by using waste gas and avoiding venting.
Payback, Return on Investment and Marginal Abatement Cost:	Return on investment (ROI) results from reduced fuel gas usage and the corresponding reduction in carbon tax plus the carbon offsets generated by using waste gas and avoiding methane venting.

Reliability

Expected Lifetime:	When operated within the recommended specifications, the Rush Burner will most likely provide effective service for the life of the facility.
Maintenance:	There is no special training or certifications required. Each system is easy to install and simple to use. Black Gold Rush has 24-hour support for all clients.

Safety

Shutdown and start up procedures, along with flashback-tested flame arrestors, are provided.

Regulatory

CSA approved for Class 1 Div 2 locations, CSA B149.3-15 compliant, meets NFPA standards and comes with a B149.3 compliant valve train. It also meets NFPA standards and meets AER regulatory requirements.

- CSA approved Burner Management System (Pre-wired and tested)
- B149.3 compliant valve train (Pre-tubed, tested, and wired)

Vendor Information

Company Name: Black Gold Rush Industries Ltd.
Company Website: www.bgrindustries.com
Product Website: http://www.bgrindustries.com/products/rush-burner/
Contact Person: Dale Aldrich
Contact Phone#: 403-638-8561
Contact Email: dale@bgrindustries.com

Section 1.2. Burners, Heaters and Boilers – Recommended Practices

1.2.1. Recycle Hot Produced Water from the Treaters to the Free Water Knock-Out (FWKO) for Waste Heat Capture	**July 31, 2017**

Description

In oilfield production using Free Water Knock Out (FWKO)[1] technology, the oil is processed to pipeline specifications of <0.5% basic sediment and water (BS&W)[2]. The discharged fluids are further heated in several fired treaters[3]. While heat exchangers are used to recover heat from the sales oil, hot water from the treaters typically flows directly to the battery's water tank to be re-injected into the waterflood. Recycling this water from the treaters results in BTU savings that reduce the amount of fuel gas needed, thereby reducing emissions. It is recommended practice to recycle the hot water from treaters back to the FWKO so that emissions from fuel gas can be minimized and cost savings realized.

Baseline: Heat exchangers are in service to recover heat from the sales oil, but hot water from treaters flows directly to the battery's water tank to be re-injected to the waterflood. Hot water is not routinely recycled.

Technology Group

Burners, Heaters and Boilers - Recommended Practices

Site Applicability

Oilfield FWKO production facilities using gas-powered burners

Emissions Reduction and Energy Efficiency

Fuel gas consumption is reduced by recycling the hot water from treaters back to the FWKO, thereby reducing emissions.

Using right-sized vessels, or adding sufficient water volume in the case of oversized vessels, ensures the fluid entering the heated FWKO receives sufficient firetube contact and results in more effective heating and water separation. Variable recycled water volumes impact the fuel gas savings.

Recycling water from the treaters results in two different outcomes:

- The heated FWKO burner demand decreases to maintain the existing temperature and the vessel drops the original volume of water plus the recycled water. The BTU savings are recovered in the heated FWKO vessel.

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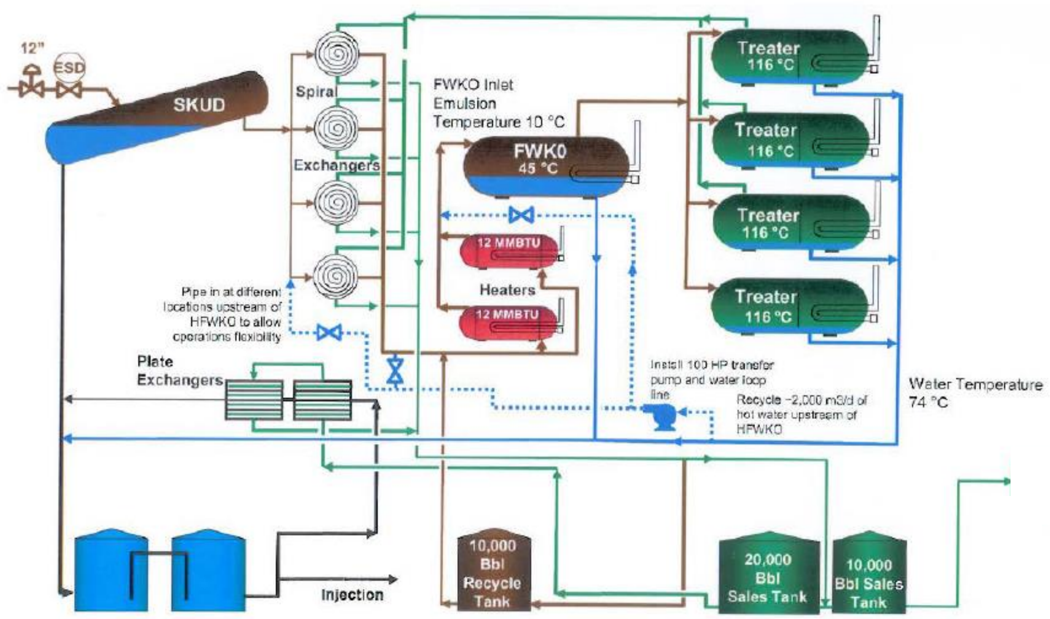
[1] FWKO (Free-Water Knock Out) is a vertical or horizontal separator used to remove any free water that could cause problems such as corrosion, the formation of hydrates, or the formation of tight emulsions. A three-phase separator can separate gas, oil, and free water. Liquids discharged from the free-water knockout are further treated in vessels called treaters

[2] Commonly-used abbreviation for basic sediment and water, as measured by sampling from the production stream

[3] A treater is a vessel used to treat oil-water emulsions to a specified level of BS&W so the oil can be accepted by a pipeline for transport.

- The heated FWKO burner demand remains constant, increasing the vessel temperature and improving water separation, thereby reducing the water cut to the treaters. The oil shipped to the treaters require less fuel to heat to the treating temperature and less water is heated. The BTU savings are recovered at the treaters, although the volume of water available for recycle is reduced.

By piping in more than one entrance point for the recycled water upstream of the heated FWKO (see facility schematic below), operations can obtain maximum benefit from the recycled water depending upon the process requirements. This flexibility could also improve the process performance in other areas of the battery, by reducing the viscosity of the emulsion flowing through the spiral exchangers for example.



Facility Schematic

Economic Analysis

Just as sites vary one to the other, costs will vary by site based upon specific circumstances. In the oil facility sample case, \$1.3MM was spent to recycle 2,000 m^3/d of hot water (about 74°C) from four treaters back to the heated FWKO (at about 45°C). The recycled water added 9.5 MMBTU/hr to the vessel, reducing gas consumption by 228.5 mcfd. The savings achieved were the gas consumption reduction multiplied by the gas cost.

Capital Cost:	In the sample case, the amount of \$1.3MM in capital costs was spent to recycle 2,000 m^3/d of hot water (about 74°C) from the four treaters back to the heated FWKO (at about 45°C). This number is dependent on the engineering design and equipment configuration for the project.
Operating Cost:	No operating cost differences

Payback Period: Simple Payout (years) = Capital cost of the project (installation, materials, design) ($) / Total Annual Savings ($)

Marginal Abatement Cost: GHG Cost Abatement ($/t$CO_2$e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital cost of the project (installation, materials, design) ($)

Reliability

Expected Lifetime: The expected lifetime is about eight years or depends on the facility. It is not long, due to unexpected technical changes.

Maintenance: Maintenance should be the same as before, other than the additional equipment

Parts and Skills Required: Equipment and process configuration is required, Downstream parameters and operations conditions

Safety

Recycling the hot water from treaters back to the FWKO does not create any additional safety concerns that are not covered by existing site safety practices.

Regulatory

Oilfield operators must obtain and demonstrate compliance with relevant oilfield facilities codes and regulations.

Service Provider/More Information on This Practice

Free-water knockouts (FWKO) and heaters are available from various vendors in an assortment of sizes and specifications to meet specific needs.

References:

Schlumberger. (2017). *The Oilfield Glossary: Where the Oil Field Meets the Dictionary*. Retrieved July 10, 2017, from http://www.glossary.oilfield.slb.com/

1.2.2. Treater Burner Management System and Firetube Upgrade

July 31, 2017

Description

At oil battery sites, heater treaters are used to process primary oil for transport and storage. Some legacy heater treaters use older burners that run at only 20%-40% of full capacity per treater, resulting in energy inefficient operation. While replacing old burners with new re-sized units may be an option, upgrading the burners can be a more cost-effective way to increase energy efficiency. Upgrading the Burner Management System (BMS) and firetubes generally involves two elements:

- Installing turbulators[4] and flue gas recycle lines.
- Replacing the existing stacks with those with optimal height and diameter to improve draw.

These upgrades increase burner efficiency, improve combustion, and reduce emissions. Additional benefits include better oil and water separation, which may allow for an increase in produced oil. Upgraded firetube systems operate at higher combustion efficiency, and the BMS can be programmed for automated sequencing to further decrease fuel gas consumption. Upgraded treaters may consume as much as 14% less fuel gas, with a corresponding reduction in emissions and increase in cost savings.

Technology Group

Burners, Heaters and Boilers – Recommended Practices

Site Applicability

Oil battery sites where fluids from the wellsite are processed using heater treaters

Emissions Reduction and Energy Efficiency

A case study of the installation of treater upgrades at a major operator in Western Canada resulted in a 14% reduction in fuel usage, with corresponding reductions in greenhouse gases, particulates, incompletely-combusted natural gas, CO emissions, and NOx emissions. Additionally, the new equipment operates at a reduced noise level. Before and after metrics are shown in the graph below.

Replacing the burners with an upgraded design featuring optimized burner controls minimizes downtime and allows for continuous firing, saving fuel and reducing heat loss. Replacing current stacks with optimal-diameter stacks improves efficiency and may reduce the number of treaters required. Installing return-side firetube turbulators increases heat transfer to the oil bath and optimizes heat disbursement in the firetube. Installing flue-gas recycle lines reduces emissions by enhancing burner operations. The increased burner efficiency of upgraded treaters improves combustion and reduces greenhouse gas emissions. Upgraded treaters can also be programmed for automated sequencing, which further decreases fuel gas usage.

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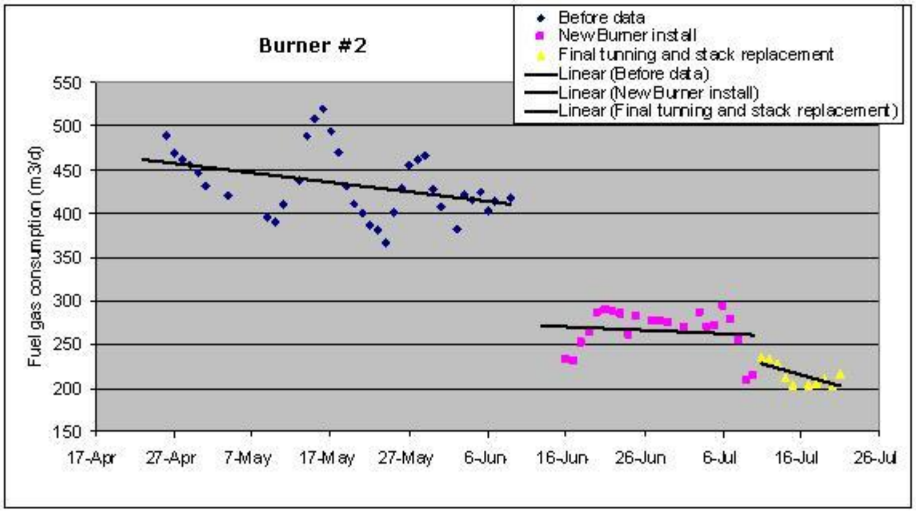
[4] A turbulator is a device that turns a laminar flow into a turbulent flow. In this case turbulence increases contact with firetubes and improves heat transfer to the emulsion.



Air Emissions Before and After the Treater Upgrade

Economic Analysis

The economic analysis of capital, installation, operating, and maintenance costs and carbon offset credits will be site-specific. The following metrics should be calculated to understand the economic benefits of the project.

Operating Cost:	(\$/yr) (differences) Annual fuel cost before upgrading (\$/yr) = Fuel gas usage per day (mcfd) x Value of Fuel Gas (\$/mcf) x # of operational days (days/year) Annual fuel cost after upgrading (\$/yr) = Fuel gas usage per day (mcfd) x Value of Fuel Gas (\$/mcf) x # of operational days (days/year)
Payback Period:	Payout period (yr) = Capital Costs of Upgrading the Treaters/Burners (\$) / Total Annual Savings (\$/yr)
Marginal Abatement Cost:	Annual GHG Reduction (tCO2e/yr) = Reduction of fuel gas used (mcfd) x Emission Factor of fuel gas combustion (tCO2e/mcf) x operational days/year
GHG Cost Abatement:	GHG Cost Abatement (\$/tCO2e) = Annual GHG Reduction (tCO2e/yr) x Project Life (year) / Capital Costs of Upgrading the Treaters/Burners (\$)

Additional Considerations:
Fuel measurement during pre- and post-data collection can be sensitive to the ambient temperature. It has been observed that there is a greater impact on fuel measurements for smaller burner/treaters. Burner efficiencies should be assessed before purchasing and installing new burners and turbulators. Before modifying burners, it is economical to tune for burner efficiency improvement, which may negate the need for burner upgrades:

Reliability

Expected Lifetime: Upgrading legacy burners is expected to extend their useful life.

Maintenance: No additional maintenance requirements or skill sets are expected.

Safety

Existing safety procedures for combustion equipment will continue to be required.

Installation of a CSA B149.3-compliant BMS increases safety to operations, especially during start-up and shut-down. A BMS prevents the costly and dangerous possibility of a flow of fuel with an extinguished pilot light.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.

Upgraded Treater Burner Management Systems and Firetubes must comply with CSA B149.3 –Field Approval of Fuel Related Components on Appliances & Equipment.

Vendor Information

Burner Management Systems are available from various vendors in an assortment of specifications to meet individual needs.

References:

Schlumberger. (2017). *The Oilfield Glossary: Where the Oil Field Meets the Dictionary*. Retrieved July 10, 2017, from http://www.glossary.oilfield.slb.com/

1.2.3. Optimization of Natural Gas Fired Burners for Energy Efficiency	July 31, 2017

Description

Natural-gas fired heaters are used throughout the oil and gas industry for process heating, tank heating and line heating applications. Burner optimization helps ensure efficient use of fuel gas. Typically, the first step in burner optimization is a pre-inspection or pre-audit of the existing burner configuration. This inspection usually involves the completion of a combustion efficiency test and an emissions/exhaust analysis by a qualified service company. The condition of the equipment and the combustion efficiency test should be used to inform the extent of the modifications that can be made to improve energy efficiency, safety and regulatory compliance.

One of the most common sources of reduced efficiency is excess air in the combustion process. Therefore, reducing excess air is a key strategy to improve fuel use efficiency. However, doing so may impact nitrogen oxide (NOx) emissions on a volumetric basis since dilution air is reduced. To achieve optimum efficiency levels, the heat transfer area should be properly designed based on the fire tube size, fire tube materials, process fluid, stack diameter and length. It is also important to stabilize the firing rate using the appropriate process controls. A new electronic burner management system (BMS) will help to control air-fuel ratios and manage process control set points.

For complete burner upgrades, the existing fuel train and BMS can be removed, decommissioned, and replaced with a new CSA-B149.3 code-compliant[5] fuel gas valve train. The new valve train would be installed with a new burner assembly (which may include an optimizer nozzle), a control panel, and pressure and temperature switches. The new BMS and fuel train must be tested to ensure the system and all components are working correctly before assembling and installing new burner internals. The burner can then be tuned for stability, efficiency, and optimal emission levels. A final combustion efficiency and emission analysis should be completed and all shut downs and controls should be function tested. Proper tuning is one of the most cost-effective ways to improve burner efficiency. Due to production declines, burners are often oversized for the application, so right-sizing burners may achieve additional savings and improved process control.

A good target efficiency benchmark for common burner types in upstream oil and gas applications ranges from 72%-83% (CETAC-West, May 2008)[6].

Baseline:

The baseline is the combustion of natural gas (fuel gas) in a fired heater operating at the heater's original configuration prior to any modifications made to improve burner efficiency. Direct greenhouse gas (GHG) emissions result from the combustion of fuel gas or propane to operate the burner. Fuel gas usage will vary based on the heating load requirements and ambient temperatures. Therefore, the baseline emissions are burner- and process-specific and depend on the operating characteristics and performance requirements of the underlying process utilizing the heat output from the burner.

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[5] CSA-B149.3-10 provides requirements for fuel-related components and accessories and their assembly on appliances & equipment utilizing gas.

[6] http://www.capp.ca/publications-and-statistics/publications/137312

Technology Group

Burners, Heaters, and Boilers – Recommended Practices

Site Applicability

The best approach for identifying candidate burners for energy efficiency improvements is to complete annual combustion efficiency tests, burner inspections, and tuning. An older burner can still be tuned to achieve target efficiency.

Emissions Reduction and Energy Efficiency

Estimating Gas Savings:

Most burner retrofit projects have achieved an average 5-20% improvement in fuel efficiency. In the case of one large producer, burner upgrade projects typically delivered between 10-20% improvement in fuel efficiency. Fuel gas savings from the company's 110 retrofit projects averaged 2.2mcfd, but significant variability occurred from burner to burner. The average burner size was approximately 400,000 BTU/hour for these projects. Fuel gas savings vary depending on burner size, so the best method to estimate fuel gas savings is to have a qualified combustion specialist perform pre- and post-audit inspections on the burner, including pre- and post-combustion efficiency tests.

Measurement:

In Alberta, a site fuel gas meter is required whenever fuel gas usage is >500 m^3/day. However, the fuel gas used by burners is usually just one component of overall fuel gas usage, and larger equipment, such as engines, usually burns significantly more fuel gas. In the conventional upstream oil and gas industry fuel gas usage is rarely measured at the individual unit operation/process or burner level. Therefore, it is necessary to complete short duration field measurements or use engineering estimates, or a combination of these approaches, to determine the specific fuel gas savings from a burner optimization project.

Net GHG Emission Reductions:

The net GHG reductions from a burner upgrade project are determined by comparing the pre- and post-retrofit gas savings. The estimated savings will depend on operating hours, firing rate, and other factors, so it is best to have a qualified combustion expert complete the analysis.

A Simplified Formula to Estimate GHG-Emission Reductions:

Net GHG Emission Reductions = (Estimated Gas Savings in m^3/year) * (Fuel Combustion Emission Factor in kg CO_2e/m^3 natural gas)*(0.001 t/kg)

As there is no dedicated Alberta Offset System Quantification Protocol for burner upgrade projects, it is unlikely this type of project will generate offsets. However, carbon tax savings may be achieved by reducing fuel gas usage (e.g. in BC presently, in Alberta in 2023, or where applicable in other provinces in the future).

Estimated GHG Emission Reductions:

GHG reductions from 110 burner retrofit projects completed in Alberta by a major producer averaged approximately 43 tCO_2e/burner/year based on average gas savings of 2.2mcfd per retrofit. GHG reductions are site-specific and depend on the type of baseline burner system, the process heat requirements, operating hours, excess air usage, and other factors.

Economic Analysis

Capital Cost: Capital costs are site specific, but costs from burner upgrade projects completed in Alberta at 110 facilities run by a major natural gas producer averaged $19,500 with a range from $3,000 to $35,000. These retrofits included many dehydrator re-boiler burners, line heaters, and other process heaters. A major integrated oil company optimized 12 400,000 to 800,000 BTU/hour burners averaged $17,900.

Operating Cost: Operating Costs are typically lower for high-efficiency burners relative to the previous configuration, and uptime may also be improved. Quantitative savings should be estimated on a site-specific basis.

Payback Period: Although project economics are very site specific, it is possible to achieve paybacks of 5 to 10 years from fuel gas savings. However, the best projects will achieve further cost savings and/or compliance benefits by incorporating regulatory upgrades (e,g. to comply with CSA B149.3 regulations) and including upgrades to outdated equipment. Without these additional maintenance and regulatory benefits, most projects would be uneconomic on fuel savings alone at a $2.50/mcf gas price.

Gas Savings: Gas savings are the primary benefit from burner optimization projects and these savings are site-specific. Gas savings from 110 burner optimization projects completed by a major natural gas producer in Alberta and BC averaged approximately 2.2 mcfd. At a flat $2.50/mcf AECO gas price, these gas savings would be worth about $2,000/year. The results from the oil company ranged from 1 mcfd to 7 mcfd of gas savings.

Carbon Offset Credits: There is unlikely to be any opportunity for carbon offsets from burner optimization projects in Alberta, but future carbon tax savings could be ~$1,300/year based 2.2 mcfd savings per burner and a $30/t$CO_2$ carbon tax. At present, these carbon tax savings would only be applicable to burner optimization projects completed in BC since BC has a $30/t$CO_2$ carbon tax in place. The carbon tax in Alberta is not anticipated to apply to on-site fuel gas combustion in burners at oil and gas production facilities until Jan 1, 2023.

Barriers:

- Financial barriers - low value of fuel gas makes many projects uneconomic without carbon offsets or other regulatory benefits.
- Capital costs can be high when retrofitting older facilities.
- Limited reserves life in conventional reservoirs makes it hard to justify capital expense of retrofits.
- Unwillingness to modify proven, reliable facility designs.

Reliability

High-efficiency burners typically provide high reliability and have been deployed at commercial scales by several large oil and gas producers. Reliability can be further improved through proper tuning and maintenance and the replacement of outdated burner management systems. Adding burner management systems that are tied into supervisory control and data acquisition (SCADA) to include remote start capabilities will also reduce operating costs for unmanned sites.

Safety

The completion of a comprehensive burner optimization program is an excellent time to assess the safety of existing combustion systems. The most common safety upgrades include upgrades to meet CSA B149.3 code requirements, removal of manual lighting of burners, and upgrades to the flame arrestors. This may include inspection of flame arrestor housings and performing a propane flashback test on the flame arrestor.

Regulatory

Future Regulatory Considerations:

Both the Alberta Government and the Federal Government have announced their intentions to tax CO_2 emissions from fuel combustion. In Alberta, a carbon levy came into force effective January 1, 2017, but an exemption applies to "natural gas produced and consumed on-site by conventional oil and gas producers (until Jan 1, 2023)."[7] (Government of Alberta, 2017) This exemption is very significant for oil and gas producers since the conventional (non-oil sands) upstream oil and gas industry consumes approximately 7% of the natural gas produced in the province to power its operations. Fired heaters are one of the largest sources of fuel usage, after engines.

From 2021 to 2026, the Federal Canadian Multi-Sector Air Pollutants Regulations (MSAPR) (Government of Canada, 2017) will be phased in to set limits for NOx emissions intensity for new and pre-existing boilers and burners that have a rated capacity of >10.5GJ/hour. These regulations are applicable to oil and gas operations; however, a large number of burners that have rated capacities of <10.5 GJ/hour will not be subject to this regulatory threshold.

By reducing fuel gas consumption from fired heaters**,** burner efficiency upgrade projects can be an excellent way to improve energy efficiency. Once on-site fuel gas usage in the conventional oil and gas sector does become subject to the Alberta carbon levy in 2023 (or if it becomes subject to a federal carbon tax), there will be an even greater incentive for producers to improve burner fuel efficiency.

Service Provider/More Information on This Practice

References:

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Section 2.1. Flares, Combustors and Incinerators – Facilities Design and Equipment

2.1.1. Black Gold Rush Industries Ltd. - Enclosed Vapour Combustor	April 26, 2019

Description

Black Gold Rush Industries enclosed vapour combustors (EVCs) effectively combust all volatile organic compounds (VOCs), benzene, toluene, ethylbenzene, and xylenes (BTEXs) produced from oil and gas equipment, such as storage tanks, casing gas, dehys, pneumatic devices, pumps or any other low-pressure venting equipment.

Black Gold Rush's EVC is the most effective and economical option to reduce the methane emissions from oil and gas sites. The combustors can be placed within 10m of wells, tanks or existing process equipment and do not require expensive valve train or piping. The patented burner system achieves 99.99% total hydrocarbon destruction with as low as 2oz of pressure. No additional fuel gas, air assist, or power is required.

The combustors can be solar-power-operated using a CSA B149.3 compliant burner management system.

A small continuous pilot that uses less than 100 scf/d of fuel gas allows for stable combustion of intermittent flows as soon as the vapours enter the combustion chamber.

All Black Gold Rush EVCs have been third-party tested and meet or exceed the U.S EPA, AER D-60, and Saskatchewan S-10 / S-20 regulations.

Technology Group

Combustors, Flares and Incinerators – Facilities Design and Equipment

Site Applicability

Versatile and easy to install, Black Gold Rush EVCs can be used in almost any area of the oil and gas industry including upstream oil and gas facilities, midstream pipeline facilities, or loading/unloading facilities, and are able to handle a wide range of gas types including H_2S.

Emissions Reduction and Energy Efficiency

- BGR 18- Up to 20,000 scf/d (566m^3/d)
- BGR 24- Up to 50,000 scf/d (1415m^3/d)
- BGR 36- Up to 100,000 scf/d (2831m^3/d)

Economic Analysis

Capital Cost:	$20,000.00-$50,000.00 depending on model and volume of vent gas required to be combusted.
Installation Cost:	Installation costs are reflective of individual client operations and the level of automation required. Other factors, such as quality of insulating, heat tracing, and piping configuration also impact installation costs.
Operating Cost:	Operating costs of the Black Gold Rush EVCs are extremely low. Continuous pilot fuel gas is the only operating cost. The ACL 1500 pilot uses less than 100 scf/d (2.8m3/d) of propane or fuel gas.
Maintenance Cost:	The only associated maintenance cost is company personnel to inspect the unit. In some rare circumstances, replacement of a battery on the solar package would be an additional cost.
Carbon Offset Credits:	Black Gold Rush EVCs qualify for carbon offset credits when combusting volumes below the allowable vented rates set out by the Alberta Energy Regulator (500m^3/d). Above this rate operators are required to capture or combust the vent gas.
Payback, Return on Investment and Marginal Abatement Cost:	Return on Investment (ROI) is directly correlated to the carbon offset credits received or the amount of carbon tax avoided.

Reliability

Expected Lifetime:	When operated within the recommended specifications, the Black Gold Rush EVC can provide effective service for the life of a facility.
Maintenance:	Black Gold Rush provides onsite startup and commissioning services to each client. No special training or certifications are required. Each system is easy to install and simple to use. Periodic operator checks should be conducted on the unit to inspect the burner.

Safety

Shutdown and start up procedures, along with a heat shield around the fire tube, provide for operator safety. Flame arrestors on the air intakes are a part of each unit, and it is recommended in-line flame arrestors be installed on the waste gas stream.

Regulatory

- The BMS system is a fully CSA approved and B149.3 compliant system
- Combustion efficiency meets and exceeds all AER regulatory requirements

Vendor Information

Company Name: Black Gold Rush Industries Ltd.
Company Website: www.bgrindustries.com

Contact Person:	Dallas Rosevear
Contact Phone#:	403-507-0485
Email:	dallas@bgrindustries.com

2.1.2. Total Combustion Inc. - Waste gas incinerators | February 13, 2018

Description

Total Combustion Inc. (TCI) is an incineration company that rents and sells patented waste gas combustion equipment. TCI's waste gas incineration products are an environmentally friendly alternative to flaring. Combustion efficiency is 99.8% resulting in no smoke, no odor and no visible flame during normal operations. This is a preferred method when operating in sensitive areas such as near residents. TCI's waste gas incineration products are highly reliable, simple to set up, operate and maintain. They are capable of efficiently combusting high and low pressure flows in an incinerator on a reduced ground footprint or on a crowded site. TCI products are also robust and require very little maintenance.

Total Combustion Inc. incinerators are used to effectively combust waste gases containing volatile organic compounds (VOCs), benzene, toluene, ethylbenzene, and xylenes (BTEXs) from oil and gas equipment, such as storage tanks, casing gas, dehydrators, pneumatic devices, well testing, tanker loading activity, and pipeline blowdowns.

Total Combustion Inc. incinerators use venturi aspirated burners for good premixing of waste gas and air, and do not require combustion air blowers. Power to operate the B149.3 compliant burner management system can be supplied by a small solar power system. These incinerators have been third party tested to comply with AER D-60, and Saskatchewan S-10 / S-20 regulations.

Technology Group

Flares, Combustors and Incinerators – Facilities Design and Equipment

Site Applicability

Total Combustion Inc. incinerators are versatile and can be used in an array of oil and gas industry applications including tank vapors, gas storage, dehydrator vapor, separator gas, casing gas, well completions, BTEX vapors, pipeline pigging stations, and tanker loading stations.

Emissions Reduction and Energy Efficiency

Total Combustion Inc. can supply models capable of handling waste gas flow rates from as low as 4.0 MSCFD (0.113 e3m3/d) to 6700 MSCFD (190 e3m3/d)

Economic Analysis

Capital Cost:	Capital cost of Total Combustion Inc. incinerators depends on the type and quantity of gas being incinerated, but a generally range from $15,000-$500,000
Installation Cost:	Installation cost of Total Combustion Inc. incinerators depends on the type and site conditions.
Operating Cost:	Operating costs of Total Combustion Inc. incinerators are very low. Typically, only a small amount of fuel gas is needed to operate the continuous pilot burner.
Maintenance Cost:	Maintenance costs of Total Combustion Inc. incinerators are very low, typically only requiring regular inspection by operating personal.
Carbon Offset Credits:	Total Combustion Inc. incinerators can qualify for carbon offset credits as per local regulations.
Payback, Return on Investment and Marginal Abatement Cost:	Return on Investment is a function of the carbon offset credits that can be achieved, the cost of carbon taxes avoided, or the cost of the next best alternative.

Reliability

Expected Lifetime:	If operated within the recommended parameters, Total Combustion Inc. incinerators provide effective service throughout the lifetime of most oil and gas industry facilities, approximately 15 years.
Maintenance:	Total Combustion Inc. incinerators require very little maintenance. If required, TCI can provide all required maintenance if operating personnel are not able or available.

Safety

Total Combustion Inc. has a 20-year track record of providing safe waste gas incinerators to the oil and gas industry in North America and around the world. TCI is COR certified and a member of ComplyWorks and ISNetworld in Canada and USA. All of TCI products are strictly manufactured to comply with current industry codes and standards.

Regulatory

All Total Combustion Inc. incinerators are configured to comply with provincial and state regulations regarding waste gas incinerators, this includes CSA B149.3 fuel train requirements. International regulation can be meet through customization.

Vendor Information

Company Name:	Total Combustion Inc.
Company Website:	www.tciburners.com
Product Website:	Product information is available on the company website

Contact Person:	Hans Kolb
Contact Phone#:	403-309-7731
Contact E-mail	h.kolb@tciburners.com

Section 2.2. Flares, Combustors and Incinerators – Recommended Practices

2.2.1. Flare Purge Gas Reduction Using Tip Reducers	July 31, 2017

Description

Flare stacks allow for the controlled burn of natural gas during routine oil and gas production. The diameter of the flare stack is determined based on the maximum combined load for the flare system – usually the inlet flow, compressor discharge, or depressurization volume control set at the facility. The diameter of the stack tip is selected to lower exit gas velocity to 0.4 Mach to prevent flame blowout and flame lift-off from stack. An ongoing flow of purge gas prevents air from entering the flare stack. This purge gas is critical because oxygen in the flare stack may lead to explosion when process gas is introduced, causing substantial damage to equipment or injury to personnel. Installing a tip reducer reduces the consumption of purge gas by as much as 92% while still eliminating air in the flare stack, substantially reducing emissions and realizing cost savings.

Technology Group

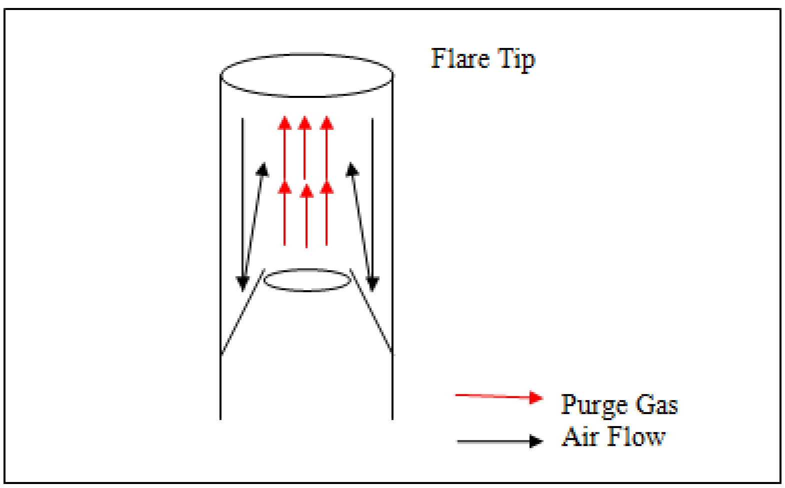
Flares, Combustors, and Incinerators – Recommended Practices

Site Applicability

Natural gas production sites

Emissions Reduction and Energy Efficiency

The tip reducer eliminates air travel down to the perimeter of the flare stack, redirecting it to the centre of the stack where the purge gas carries the air to the stack outlet (see diagram below). At the same time, the smaller diameter of the purge-gas outlet significantly reduces consumption of purge gas. The corresponding emissions are significantly reduced. Installation of tip reducers at the 10” diameter flare stack of the Wintering Hills Gas Plant allowed the purge gas rate to be reduced by about 92%.



Flare Tip Reducers from Flare Suppliers

Baseline:

In most current facilities, the purge gas flow rate is determined based on the flare stack diameters. The flare stack diameter is sized on the maximum combined load for the flare system – usually the inlet flow, compressor discharge, or depressurization volume control set at the facility.

Economic Analysis

Capital Cost:	\$50,000-\$100,000; costs will vary depending on the market conditions and flare accessibility.
Operating Cost:	Operation costs do not change as these are exclusively component changes, not process changes
Payback Period:	Simple Payout (years) = Capital cost of the project (installation, materials, design) (\$)/Total Annual Savings (\$)
Marginal Abatement Cost:	Annual GHG Reduction (tCO2e/yr) = Reduction of purge gas used (mcfd) x 1000 scf/mcf x 1 m3/35.315 scf x 0.6784 $tCO_2e/1000\ m^3$ x mole fraction of CH_4 in natural gas x 21 GWP CH_4 x operational days/year GHG Cost Abatement (\$/tCO_2e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital cost of the project (installation, materials, design) (\$)

Additional Considerations:
The installation of the tip reducer in the flare stack will add some back pressure to the flare system, which can impact the operation of relief valves and the blowdown system. An engineering review should be performed to confirm if any changes are required to manage this increased back pressure prior to the installation of the device. However, this will cause the project capital cost increase.

Reliability

Expected Lifetime:	The installation of the tip reducer in the flare stack will add some back pressure to the flare system, which can impact the operation of relief valves and the blowdown system.
Maintenance:	The tip reducer may require additional cleaning and checkup.
Parts and Skills Required:	Installation and use of the tip reducer requires no special training or certifications.

Safety

The tip reducers not only reduce purge gas consumption, but also significantly reduce the risk of flare explosion inside the flare stack. However, the correct rate of purge gas flow must be maintained at all times.

Regulatory

- Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.
- AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting

Service Provider/More Information on This Practice

Tip reducers/velocity purge reducers are available from various vendors in an assortment of sizes and specifications.

2.2.2. Process Re-Route – Flaring and Venting Prevention	July 31, 2017

Description

In oil and gas production, flaring allows for the controlled burn of sour solution gas. Instead, sour solution gas can be re-routed to supplement purchased fuel gas. This is accomplished by installing an amine contactor/regenerator and a glycol dehydrator, along with the required piping. Using sour solution gas to supplement fuel gas significantly reduces flare volumes and the corresponding emissions released to the atmosphere.

Technology Group

Flares, Combustors, and Incinerators - Recommended Practices

Site Applicability

Facilities venting sour solution gas

Emissions Reduction and Energy Efficiency

Re-routing sour solution gas and using it as supplemental fuel gas reduces flare volume significantly. The pilot of this technology in a large operator's processing facility resulted in flare volumes decreasing by 700 mcfd.

Annual GHG Reduction (tCO_2e/yr) = Overall reduction of energy used x Emission Factor of energy x operational days/year

Baseline:
Sour solution gas is routinely flared

Economic Analysis

Re-routing the sour solution gas likely involves redesign of existing facilities, and must be evaluated by engineering and operations teams to verify that the equipment and process work comply with all relevant industrial specifications and standards. It is also important to perform due-diligence investigating the opportunities as the economics can change significantly due to the capital costs.

Annual Savings ($/yr) = Overall Reduction in Operational and Maintenance Costs

Production Efficiency (PE) = Capital cost of the project (installation, materials, design) ($) / Total fuel savings

Capital Cost:	Re-routing sour gas involves significant capital costs. A new amine/dehy skid is likely necessary, as well as an additional compressor capable of increasing the gas pressure from 15psig to 350psig. The new skid will likely require additional electrical equipment. Civil, mechanical and electrical installation costs are also possible. Capital Cost = Installation + Materials + Design

Operating Cost:	Although the pilot project did not measure operating costs following the retrofit, the sour gas re-route should not have a significant impact on operating costs.
Payback Period:	Simple Payout (years) = Capital cost of the project (installation, materials, design) ($) / Total Annual Savings ($)
Marginal Abatement Cost:	GHG Cost Abatement ($/tCO2e) = Annual GHG Reduction (tCO2e/yr) x Project Life (year) / Capital cost of the project (installation, materials, design) ($)

Additional Considerations:

- The skids are complex and increased engineering costs should be anticipated if the skids are drafted into existing plants.
- Additional civil, mechanical and electrical installation costs are also possible due to unforeseen limitations on existing pipe racks, utility systems (including heat medium/tracing) and the potential need for additional skids. A vapour condensing tank, a water make-up tank, associated piping changes and the addition of a filter separator vessel at the upstream of the amine contactor are all required to meet the process design requirements at the later stage of the project.

Reliability

Expected Lifetime:	The expected lifetime of the equipment is about eight years.
Maintenance:	Sour gas re-routing requires no additional maintenance beyond the scope of existing equipment.
Parts and Skills Required:	Maintenance can be completed with the operation companies and designs can be completed with contracted or in-house Engineering, Procurement, and Construction groups.

Safety

The re-routing of sour solution gas must be completed in compliance with all existing safety regulations.

Regulatory

Operators must ensure they comply with all applicable regulations. All equipment must be evaluated by engineering and operations teams to verify that the equipment and process work comply with all relevant industrial specifications and standards.

Service Provider/More Information on This Practice

The re-routing process involves multiple pieces of equipment, each of which is available from multiple suppliers.

## 2.2.3. AERtools Application Software – ABflare	July 31, 2017

Description

AERtools is a collection of spreadsheet and application programs created to help air quality professionals calculate source parameters and ground level concentrations. The tools were created based on state-of-the-art engineering considerations of thermodynamics, energy balance, mass balance and practical application of these principles for use with current air dispersion models and methods. One of these tools, the ABflare, was created for evaluating non-routine flaring for sour gas facilities for use with the CALPUFF models. A similar tool, AERflare, was created to specifically address rapid screening level air quality dispersion model calculations up to refined modelling using the AERMOD (U.S. EPA) model only.

The term “ABflare” is used in reference to the entire modelling suite. The term ABflareUI is used in reference to the ABflareUI.xlsm spreadsheet user interface that is specifically designed to assist with the configuration of the CALPUFF model, running the CALPUFF model and post-processing the outputs from CALPUFF model. The air quality dispersion modelling for a flare can frequently require non-routine modelling techniques to incorporate blowdowns or hourly variations therefore requiring non-routine techniques for handling model inputs and post-processing the output files. The ABflare modelling suite includes a Windows executable ABflare.exe program that is used to perform the complex thermodynamics and combustion calculations for the flare source terms and the creation of CALPUFF ready source input files.

The ABflare tool was created to adapt flare-type source parameters for use with standard air quality dispersion models that are based upon chimney-type sources parameters. The basic premise of ABflare is to determine the momentum and buoyancy flux for the flare event; then, using the momentum and buoyancy flux relationship used by standard dispersion models that use chimney-type source parameters, reverse calculate the necessary inputs (equivalent chimney-type source parameters) that would result in the correct momentum and buoyancy flux.

The ABflare and AERflare models were created so that a minimal amount of technical background is required to run the models. As opposed to other flare source algorithms that make thermodynamic simplifications, the AERtools suite does not make these simplifications. This can be important when inputs go beyond the original applicability of algorithm assumptions, such as the extrapolation of plume rise formulations to hot non-chimney emissions. While the complexity of the methodology is increased by including more complex calculations, the calculations are readily performed by desktop computing. The tool requires only readily available data as inputs (thus not being onerous to the modeler) and standardizes the more complex calculations within the tool, preventing common calculation errors. The tool is therefore beneficial to the modeler (ease of use) and regulator (confidence in the calculations) without extensive technical experience.

Technology Group

Flares, Combustors and Incinerators – Recommended Practices

Site Applicability

The tool was conceived to address modelling of flaring issues that arise in Alberta (high hydrogen sulphide, acid gas, blowdowns, upsets and emergencies in complex terrain). However, the calculations within the tool are applicable to all flaring anywhere. The tool is designed to use datasets (available from the internet) for sites within Canada and for meteorology datasets for Alberta. However, the tool is readily transferable to sites world-wide should the appropriate datasets be available.

The ABflareUI spreadsheet tool is a flowchart-organized set of steps that walks a user through the development of the input datasets for the CALPUFF dispersion model, such as terrain, receptors, meteorology, source parameters (using the ABflare.exe tool) and the creation of CALPUFF model input files. The tool is current configured to use digital elevation model (DEM) terrain data and land use classification codes (LCC) data for Canada. The tool accepts the insertion of externally created datasets to the tool for use in other parts of the world or created by other means by the user.

The ABflareUI also assists the user in the post-processing of the CALPUFF output files. Flare modelling of blowdowns may require the re-assembly of many output files into a single output file. Utility (Windows executable) programs are provided for the calculation of maximums (merging files to create a single file with only the maximum concentrations, CALMAX), various time averages (CALAVE), and the percentiles typically required by various agencies (n'th highest, percentile or daily maximum percentiles).

The heart of the ABflare suite is the calculation of the flare source parameters which is performed by the ABflare.exe Windows executable program. The ABflare.exe is a standalone program that uses a text input control file (that can be created using any text editor or the ABflareUI) and input files. Thus, the program can be used world-wide. The ABflare.exe program uses the same calculations as the AERflare program and will calculate the same outputs based upon the same inputs. However, in general, the AERflare calculations are designed for AERMOD and therefore require simplifications suitable for AERMOD (plume model). Whereas, the ABflare calculations are designed for CALPUFF and do not require simplifications because of the advanced features (puff model) basis of the CALPUFF model.

ABflare performs both screening level calculations (uses only a few user inputs to create a realistic and conservative estimate of flare emissions and concentrations) and also refined level calculations (second-by-second, hour-by-hour or user time varying).

Although relatively few inputs are required through the interface, it is a complex tool. ABflare requires inputs that may require sound engineering judgement or other technical expertise. It uses site-specific thermodynamics, fluid dynamics, and air dispersion modelling. There remains some technical knowledge required to supply suitable inputs and the ability to understand whether the output is appropriate for the inputs and meets the needs of stakeholders. The user must recognize that the models are technical in nature and the correct interpretation of the result may require technical expertise that proceeds from consequences of the inputs.

Emissions Reduction and Energy Efficiency

The model has been created with a professional commitment to environmental protection and safeguarding the well-being of the public. It is the responsibility of the software user to accept and continue this commitment in their application of the software.

The software provides the most accurate emission parameters. Using other models may result in stack height or fuel gas over-estimates because of incorrect parameters and also, in some cases, under-estimates.

Economic Analysis

Capital Cost:	The software is provided free of charge
Operating Cost:	Other than source inputs, terrain and land use input data files are available free of charge for Canada, meteorological datafiles are available free of charge for Alberta.
Payback Period:	The ABflare tool provides a rapid and cost-effective method(s) for setup of CALPUFF dispersion modelling and for modelling of flares in particular, significantly reducing the configuration and modelling times.
Marginal Abatement Cost:	The ABflare provides the state of the art calculations for flare source dispersion modelling providing the most representative model of the flaring source parameters and thus the most accurate model predictions for stack design and protection of the environment. Where applicable, ABFlare can be used to generate the emissions volumes required to calculate abatement costs

Reliability

Expected Lifetime:	This tool is regularly updated in accordance with the changing government regulations. Thus, the lifetime of the tool is subject to change with respect to new regulations.
Maintenance:	The user should regularly check the status of the tool for any available and downloadable updates.
Parts and Skills Required:	The tool is designed for a Windows platform and Microsoft Excel. Suitable technical or engineering background is recommended with an understanding of oil and gas operations, and air quality dispersion modelling.

Safety

There are no unusual safety requirements associated with the use of the ABflare tool.

Regulatory

ABflare is freely distributed to assist in AER D060 temporary flaring permitting, non-routine and routine flaring air dispersion modelling within Alberta. The software is supplied as a tool to assist the user to comply with applicable statutes, regulations and bylaws. Neither the software nor application of the software is intended to replace statutes, regulations or bylaws.

Service Provider/More Information on This Practice

- The full users guide for this tool can be found at http://www.zeltpsi.com/aertools.html
- For the latest regulatory updates, visit the AER website (see Directive 060): http://www.aer.ca/rules-and-regulations/directives/
- The CALPUFF air dispersion model: The CALPUFF source code, documentation and executable files are available at the U.S. EPA Technology Transfer Network website: http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#calpuff
- Required User Knowledge: While the full technical background is not a requirement to execute the models, the user of the software is required to have a general engineering and environmental

science background; a general knowledge of the emission sources: wells, pipelines, and pipeline networks; and a working knowledge of the most current version of:

- AER Directive 060 can be found at https://www.aer.ca/rules-and-regulations/directives/directive-060
- Alberta ESRD Air Quality Model Guideline can be found at https://extranet.gov.ab.ca/env/infocentre/info/library/8908.pdf
- Non-Routine Flaring Management: Model Guidance can be found at https://open.alberta.ca/publications/9781460108123
- CALPUFF/CALMET user guides

Section 3.1. Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

3.1.1. Fisher™ C1 Pressure Controller | July 31, 2017

Description

The Fisher™ C1 is an improved design pressure controller, based upon the original Fisher™ 4150. The Fisher™ C1 retains the same instrument case dimensions as the Fisher™ 4150. Process and pneumatic connections are also in the same location, which makes it easy to retrofit and achieve improved pneumatic efficiency. It can be used for pressure reduction or back-pressure control and is available with proportional-only, proportional-plus-reset, and differential-gap control modes. The Fisher™ C1 is also sour-service compatible and available with national association of corrosion engineers (NACE) MR0175/ISO 15156 and NACE MR0103 construction materials. Its mechanical-proportional band assembly makes it a true low-bleed controller that maintains good dynamic control and consumes less than six scfh of air or fuel gas at steady state.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and gas, but can be used in all industries for pressure control.

Emissions Reduction and Energy Efficiency

Fuel gas reductions up to 36scfh (1.0m^3/hr) have been achieved. Additional details are available in the field studies, manufacturer published specs[8], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices[9].

Economic Analysis

Capital Cost:	New low bleed instruments are available for from $1,000 to $3,000 each.
Installation Cost:	Typical installation costs are between $150 and $300 per controller. This cost variance is impacted by proximity and site access.
Operating Cost:	The cost of the pneumatic supply consumed can be determined based on the

[8] Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html

[9] http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/PneumaticDevices-Jan25-2017.pdf

	bleed rate of the controller and the value of instrument air or fuel gas ($/GJ) pneumatic supply.
Maintenance Cost:	Although available, repair kits to maintain operation of this controller are rarely required. The instrument performance will be extended when used with a clean dry pneumatic supply.
Carbon Offset Credits:	A Fisher™ C1 pressure controller is eligible for offsets in Brownfields in Alberta. Using low bleed controllers is considered business-as-usual and is not eligible for offsets in Greenfield applications.
Payback Considerations:	Installing this instrument in the field can pay for itself in less than a year when a carbon offset protocol is available. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices. The payback is specific to the value of fuel gas and the carbon offset.

Reliability

Expected Lifetime:	Field experience has shown that instrument longevity is impacted by the quality of the pneumatic supply and how dynamic the control loop is. If the Fisher™ C1 pressure controller is maintained and used within its design limits, it will continue working for the life of the project.
Maintenance:	No scheduled maintenance program, nor are any special tools required beyond those used by qualified instrumentation technicians. Please refer to the Fisher™ C1 pressure controller manual[10].

Safety

The bourdon tube within the controller senses the process. Therefore, it is necessary to ensure all process connections and pneumatic supply tubing and fittings are properly tightened and effectively contain applicable pressure.

Regulatory

As is being reviewed by the Alberta Energy Regulator (AER), a Fisher™ C1 pressure controller is a form of low-bleed compliance when operated with fuel gas pneumatics, and is a form of no-bleed compliance when operated with instrument air or fuel gas collected for use downstream.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.emerson.com/catalog/en-us/fisher-c1
Contact Person:	Brian Van Vliet
Contact Phone #:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

[10] https://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d103292x012.pdf

3.1.2. Fisher™ C1 Pressure Controller — April 26, 2019

Description

The Fisher™ C1 is an improved design pressure controller, based upon the original Fisher™ 4150. The Fisher™ C1 retains the same instrument case dimensions as the Fisher™ 4150. Process and pneumatic connections are also in the same location, which makes it easy to retrofit and achieve improved pneumatic efficiency. It can be used for pressure reduction or back-pressure control and is available with proportional-only, proportional-plus-reset, and differential-gap control modes. The Fisher™ C1 is also sour-service compatible and available with national association of corrosion engineers (NACE) MR0175/ISO 15156 and NACE MR0103 construction materials.

Its mechanical-proportional band assembly makes it a true low-bleed controller that maintains good dynamic control and consumes less than six scfh of air or fuel gas at steady state.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and gas, but can be used in all industries for pressure control.

Emissions Reduction and Energy Efficiency

Fuel gas reductions up to 48scfh (1.0m^3/hr) have been achieved. Additional details are available in the field studies, manufacturer published specs[11], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices[12].

Economic Analysis

Capital Cost:	New low bleed instruments are available for from $1,000 to $3,000 each.
Installation Cost:	Typical installation costs are between $150 and $300 per controller. This cost variance is impacted by proximity and site access.
Operating Cost:	The cost of the pneumatic supply consumed can be determined based on the bleed rate of the controller and the value of instrument air or fuel gas ($/GJ) pneumatic supply.

[11] Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html

[12] https://open.alberta.ca/publications/9781460131633

Maintenance Cost:	Although available, repair kits to maintain operation of this controller are rarely required. The instrument performance will be extended when used with a clean dry pneumatic supply.
Carbon Offset Credits:	A Fisher™ C1 pressure controller is eligible for offsets in Brownfields in Alberta. Using low bleed controllers is considered business-as-usual and is not eligible for offsets in Greenfield applications.
Payback Considerations:	Installing this instrument in the field can pay for itself in less than a year when a carbon offset protocol is available. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices. The payback is specific to the value of fuel gas and the carbon offset.

Reliability

Expected Lifetime:	Field experience has shown that instrument longevity is impacted by the quality of the pneumatic supply and how dynamic the control loop is. If the Fisher™ C1 pressure controller is maintained and used within its design limits, it will continue working for the life of the project.
Maintenance:	No scheduled maintenance program, nor are any special tools required beyond those used by qualified instrumentation technicians. Please refer to the Fisher™ C1 pressure controller manual[13].

Safety

The bourdon tube within the controller senses the process. Therefore, it is necessary to ensure all process connections and pneumatic supply tubing and fittings are properly tightened and effectively contain applicable pressure.

Regulatory

A Fisher™ C1 pressure controller is a form of low-bleed compliance when operated with fuel gas pneumatics, and is a form of no-bleed compliance when operated with instrument air or fuel gas collected for use downstream.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.emerson.com/catalog/en-us/fisher-c1
Contact Person:	Brian Van Vliet
Contact Phone #:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

[13] https://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d103292x012.pdf

3.1.2. Norriseal Level Controllers (1001, 1001A and 10001XL)	July 31, 2017

Description

Norriseal has been a leader in providing quality level-measurement devices to the petroleum market for more than five decades. Various models of Norriseal no-bleed pneumatic liquid level-controllers reduce fuel gas requirements, waste, and fugitive emissions in pneumatic control loops:

- The economical Series 1001 Level Controller uses a non-weatherproof case/cover.
- The Series 1001A Level Controller uses a weather resistant sealed case and a manifold-style pilot assembly.
- The Series 1001XL Level Controller offers the features of a Series 1001A, but with a back-mount connection.

All three models feature:

- No-bleed Pilots. The pneumatic controller is equipped with one of three types of no-bleed pilots: a snap pilot, throttling pilot, or patented Envirosave pilot[14].
- Built-In Filter. A built-in 40-micron stainless steel filter in the gas supply connection reduces required maintenance of the controller's pilot.
- Electric Controller. This option utilizes a standard electric switch; SPDT or DPDT.
- Split Displacer. For liquid dump spans greater than the standard displacers can provide, a split displacer can give dump spans up to 70 feet in length.

Technology Group

- Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The expected reduction in methane emissions is dependent on system design and operating conditions.

Economic Analysis

Capital Cost:	Capital cost varies depending on materials and operating conditions.
Installation Cost:	Installation cost depends on specific requirements. However, cost is comparable installation cost for similar products.

[14] See Product Website (listed below) for more information.

Operating Cost:	Minimal to no additional operating costs are expected as operational adjustments can be incorporated into existing operator rounds.
Maintenance Cost:	Maintenance costs vary depending on materials and operating conditions. However, they will be similar to, or less than, the maintenance costs of other controllers.
Carbon Offset Credits:	Norriseal level controllers (1001, 1001A, 1001XL) are eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	The payback considerations for the unit are the conservation of process gas and the associated eligibility for pneumatic protocol offset credits.

Reliability

Expected Lifetime:	The longevity of the device depends upon process fluid and operating conditions. However, life expectancy of the Norriseal liquid level-controllers is in line with typical pressure controllers.
Maintenance:	No special tools or training are required for maintenance or installation. Yearly maintenance and inspection required.

Safety

No unusual safety requirements apply.

Regulatory

- Dual Seal Certification. CSA certified Dual Seal to ANSI/ISA 12.27.01 standard meets CEC and NEC secondary seal requirement.
- NACE. All controllers can be configured to meet NACE MR0175-2002 specifications.
- UL & CSA Listed Class I, Div.1, Groups C&D Class II, Div.1, Groups E, F, &G.
- No AER Directive applicable

Vendor Information

Company Name:	CVS Controls
Company Website:	http://www.cvs-controls.com/contact.html
Product Website:	http://norrisealwellmark.com/wp-content/uploads/2016/10/NOR_Bulletin_No.120802_081414.pdf http://norrisealwellmark.com/support/literature/
Contact Person:	Garett Reimond
Contact Phone:	403-250-1416
Contact Email:	garett@cvs-controls.com

3.1.4. Fisher™ L2e Electric Level Controller

April 26, 2019

Description

Optimizing existing control loops for environmental compliance using no-bleed instruments reduces operating costs and provides positive return on investment (ROI). Modeled on the successful Fisher™ L2 pneumatic controller, the Fisher™ L2e Electric level-controller uses a displacer-type sensor to detect liquid level or the interface of two liquids of different specific gravities, but provides an electric on-off level output instead of a pneumatic output.

In its normal position, the weight of the displacer is balanced against the spring force within the controller, the pneumatic supply pressure available, and the buoyant force acting on the displacer. When sufficient buoyant force is present, the imbalance in force is converted to an electric output that runs to a control/dump valve, which changes position and helps bring the forces back into equilibrium. This controller is ideal for controlling level in oil and gas separators, treaters, and scrubbers. The reliability of the L2e force-balanced sensor design makes it well-suited for applications in the oil and natural gas production, compression, and processing industries.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and gas production, compression, and processing

Emissions Reduction and Energy Efficiency

Reductions up to 30scfh (0.8m^3/hr) of fuel gas have been achieved when retrofitting Fisher™ 2900 series level controllers. Additional details are available in the field studies, manufacturer published specs[15], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices[16].

Economic Analysis

Capital Cost: New no-bleed instruments are available for $1,000 to $3,000 per unit. Pricing

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[15]Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html

[16]https://open.alberta.ca/publications/9781460131633

is specific to model capability and materials of construction.

Installation Cost:	Typical installation costs are between $150 and $300 per controller. This cost variance is impacted by proximity and access to site.
Operating Cost:	Operating costs are low. The instrument doesn't consume power; it just provides the signal to the dump valve when required based on the level of fluid in the vessel. The quality design and components help eliminate current leakage.
Maintenance Cost:	Maintenance costs are minimal given the controller contains no repairable or replaceable parts, and can easily be replaced in the field.
Carbon Offset Credits:	A Fisher™ L2e controller is eligible for offsets in Brownfields in Alberta. Using no-bleed electric controllers is not considered business-as-usual and is eligible for offsets in Greenfield applications as well.
Payback, Return on Investment and Marginal Abatement Cost:	The payback is specific to the value of fuel gas and the carbon offset. However, installing this instrument in the field can pay for itself in less than a year when a carbon offset protocol is available. Note that vent rate reductions are larger when dynamic consumption is included in the pre and post retrofit vent rate measurements or emission factors. The period of payback is dependent on both the type of level controller replaced and the dump frequency. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime:	Field experience demonstrates that instrument longevity is impacted by how dynamic the control loop is. The Fisher™ L2e sensor is based on the Fisher™ L2 design. Insufficient field data is currently available to accurately determine an expected lifetime.
Maintenance:	Replacing a conventional pneumatic level loop with fully electric level control eliminates controller- and dump-valve venting and requires less maintenance. Please refer to the Fisher™ L2e level controller manual[17].

Safety

The Fisher™ L2e utilizes the same displacer sensor and pressure containing components as the Fisher™ L2 pneumatic controller. The Fisher™ L2 Canadian registration number (CRN) also applies to the Fisher™ L2e. The Fisher™ L2e level controller is a pressure-containing component of the vessel when threaded into the 2" NPT process connection or bolted to the flange on the vessel. The controller case of an older Fisher™ L2 can be separated from the displacer, while the latter is left in place. This allows for field retrofit by replacing the Fisher™ L2 level controller case with a Fisher™ L2e level controller case, without needing to depressurize the process vessel. Note that it is best practice to ensure the process flow into the vessel is isolated while performing the retrofit unless manual dump operations can be performed while doing so.

[17] http://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d103531x012.pdf

Regulatory

A Fisher™ L2e level controller is a form of no-bleed compliance.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	https://www.documentation.emersonprocess.com/groups/public/documents/bulletins/d103532x012.pdf
Contact Person:	Brian Van Vliet
Contact Phone #:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

3.1.5. Fisher™ L2sj Low Emission Liquid Level Controller	April 26, 2019

Description

Optimizing existing control loops for environmental compliance using low-bleed instruments reduces operating costs and provides positive return on investment (ROI). The Fisher™ L2sj[18] low emission liquid level controller uses a displacer-type sensor to detect liquid level, and delivers a pneumatic output signal to a control/dump valve when sufficient buoyant force acts on the displacer.

The controller features a rugged, metal-seated relay with proportional and integral action.

In its normal position, the weight of the displacer is balanced against the spring force within the controller, the pneumatic supply pressure available, and the buoyant force acting on the displacer. When sufficient buoyant force is present, the imbalance in force is converted to a pressure output to a control/dump valve, which changes position and helps bring the forces back into equilibrium. This controller is ideal for controlling the level in oil and gas separators, treaters, and scrubbers. The reliability of the L2sj force-balanced sensor design makes it well-suited for applications in the oil and natural gas production, compression, and processing industries.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and Gas production, compression, and processing

Emissions Reduction and Energy Efficiency

Reductions up to 29scfh (0.8m^3/hr) of fuel gas have been achieved when retrofitting Fisher™ 2900 series level controllers. Additional details are available in the field studies, manufacturer published specs[19], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices[20]:

[18] Design of the Fisher™ L2sj improves upon its predecessor, the Fisher™ L2.
[19] Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html
[20] https://open.alberta.ca/publications/9781460131633

Economic Analysis

Capital Cost:	New low-bleed instruments are available for $1,000 to $3,000 per unit. Pricing is specific to model capability and construction materials.
Installation Cost:	Typical installation costs are between $150 and $300 per controller. This cost variance is impacted by proximity and access to site.
Operating Cost:	The cost of the pneumatic supply consumed can be determined based on the bleed rate of the controller and the value of instrument air or fuel gas ($/GJ) pneumatic supply.
Maintenance Cost:	Maintenance costs are low. Although available, repair kits to maintain operation of this controller are rarely needed. The instrument performance will be extended when used with a clean dry pneumatic supply.
Carbon Offset Credits:	A Fisher™ L2sj controller is eligible for offsets in Brownfields in Alberta. Using low-bleed controllers is considered business as usual and is not eligible for offsets in Greenfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	The payback is specific to the value of fuel gas and the carbon offset. However, installing this instrument in the field can pay for itself in less than a year when a carbon offset protocol is available. Note that vent rate reductions are larger when dynamic consumption is included in the pre and post retrofit vent rate measurements or emission factors. The period of payback is dependent on both the type of level controller replaced and the dump frequency. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime:	Field experience has shown that instrument longevity is impacted by the quality of the pneumatic supply and how dynamic the control loop is. If the Fisher™ L2sj level controller is maintained and used within its design limits, it will continue working.
Maintenance:	The instrument has no scheduled maintenance program. No special tools are required beyond those used by qualified instrumentation technicians. Please refer to the Fisher™ L2sj level controller manual: (https://www.emerson.com/documents/automation/instruction-manual-fisher-l2sj-low-emission-liquid-level-controller-en-135070.pdf)

Safety

All process connections and pneumatic supply tubing and fittings must be properly tightened and are pressure-containing. The Fisher™ L2sj level controller is a pressure-containing component of the vessel when threaded into the 2” NPT process connection or bolted to the flange on the vessel. The controller case of an older Fisher™ L2 can be separated from the displacer, while the latter is left in place. This allows for field retrofit by replacing the Fisher™ L2 level controller case with a Fisher™ L2sj level controller case without needing to depressurize the process vessel. Note that it is best practice to ensure the process flow into the vessel is isolated while performing the retrofit, unless manual dump operations can be performed while doing so.

Regulatory

A Fisher™ L2sj level controller is a form of low-bleed compliance when operated with fuel gas pneumatics, and is a form of no-bleed compliance when operated with instrument air or fuel gas that is collected for use downstream.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.documentation.emersonprocess.com/groups/public/documents/bulletins/D103229X012.pdf
Contact Person:	Brian Van Vliet
Contact Phone #:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

3.1.6. Fisher™ D3e Control Valve with Gen 2 Easy-Drive™ Electric Actuator	April 26, 2019

Description

Optimizing existing control loops for environmental compliance using no-bleed instruments reduces operating costs and provides positive return on investment (ROI). The Fisher™ easy-Drive™ uses the same globe valve body as the Fisher™ D3 pneumatically-actuated valve. This valve is ideal for use as a dump valve on gas separators and scrubbers. It is also well-suited for other high-pressure applications in natural gas production, compression, and processing. National Petroleum Service (NPS) 1 and 2 D3 control valves are available with CL900 National Pipe Thread (NPT) end connections. The NPS 2 D3 is also available with CL600 raised-face flanged end-connections.

The Fisher™ easy-Drive™ electric actuator operates from nine to 30VDC and less than 0.1 watt hours per operation, using Modbus, 4-20 mA, or dry contact control signals. The actuator is specifically designed for upstream, low-power applications and operates with 12 or 24VDC in on/off configuration. The on/off configuration has either opened or closed states, which are ideal for dump or snap acting applications.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The reduction in pneumatic consumption is equal to the volume of gas used by a pneumatic actuator in the same service. Every time a pneumatic actuator strokes open and closed, it is loaded pneumatically and unloaded in the reverse direction. That consumption in a control loop forms a portion of the dynamic consumption that, depending on the stroke frequency, can be significant.

Economic Analysis

Capital Cost:	New Gen 2 easy-Drive™ Electric Actuators are available from $2,500 each. Pricing is specific to model capability and construction materials.
Installation Cost:	Typical installation costs are between $150 and $300 per unit. This cost variance is impacted by site proximity and access.

Operating Cost: The Fisher™ easy-Drive™ electric actuator operates on less than 0.1 watt hours per operation. It consumes less than 3.5A while moving, and less than 1W while resting.

Maintenance Cost: Specific maintenance costs have not yet been realized. However, the electrically-operated valve assembly is not subject to maintenance concerns posed by dirty or wet pneumatic supplies. Field experience has shown that the Fisher™ easy-Drive™ electric actuator operates in ambient temperatures as low as -20°C without use of a heater.

Carbon Offset Credits: The actuator is eligible for the Pneumatics Protocol Offset credits in Alberta. A Fisher™ D3 Control Valve with Gen 2 easy-Drive™ Electric Actuator is eligible for offsets in Brownfields in Alberta. Because using no-bleed electric actuation is not considered business-as-usual, it is also eligible for offsets in Greenfield applications.

Payback, Return on Investment and Marginal Abatement Cost: Payback is specifically linked to the value of fuel gas and the carbon offset Installing this instrument as part of a Greenfield install can pay for itself in less than two years when a carbon offset protocol is available. Note that measurements will be needed to determine the amount of dynamic consumption avoided. The period of payback is dependent on stroke frequency. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime: Currently, an expected lifetime cannot be determined due to insufficient field data. However, field experience has shown that longevity of the Fisher™ easy-Drive™ electric actuator is impacted by how dynamic the control loop is.

Maintenance: Replacing a conventional pneumatic level loop with a fully electric level control eliminates venting of the controller and dump valve, and requires less maintenance. Please refer to the Fisher™ D3 Control Valve with Gen 2 easy-Drive™ Electric Actuator manual[21].

Safety

The Fisher™ D3 Control Valve with Gen 2 easy-Drive™ Electric Actuator uses the same valve body as its pneumatic equivalent, but does not have an equivalent means of achieving an equivalent fail-safe on loss of motive force to the pneumatic actuator. It does provide fail-safe on loss of input signal, which means one needs to either ensure adequate power is available or determine what the consequence would be to have the valve remain in the last position upon loss of power.

[21] http://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d104161x012.pdf

Regulatory

The actuator is CSA (C/US): Explosion Proof Class I, Division 1, Groups C and D, T6, Ex d IIA T6, Class I, Zone 1, AEx d IIA T6. As is being reviewed by the AER, the Fisher™ D3 Control Valve with Gen 2 easy-Drive™ Electric is a form of no-bleed compliance.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	https://www.documentation.emersonprocess.com/groups/public/documents/bulletins/d103269x012.pdf
Contact Person:	Brian Van Vliet
Contact Phone #:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

3.1.7. Fisher™ D4e Electric Actuated Valve	April 26, 2019

Description

The Fisher™ easy-Drive™ electric actuated valve assembly uses the same globe valve body as the Fisher™ D4 pneumatically actuated valve. This valve is especially useful for throttling control of liquids or gases that are gritty, sticky, or that tend to build up on internal valve parts. It is also well suited for other high-pressure applications, such as high-pressure separators, scrubbers, and other processing equipment.

The Fisher™ easy-Drive™ electric actuator operates from 9VDC to 30VDC and less than 0.1 Watt hours per operation using Modbus, 4-20 mA, or dry contact control signals. The actuator is specifically designed for upstream, low-power applications, and operates with 12 or 24VDC in on/off or throttling configuration. D4 control valves for Nominal Pipe Size 1 and 2 are available with national pipe thread (NPT) end connections, CL150/300/600900/1500 raised face flanged and CL600/900/1500 ring-type joint end connections.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The reduction in pneumatic consumption is equal to the volume of gas used by a pneumatic actuator in the same service. Every time a pneumatic actuator strokes open and closed, it is loaded pneumatically and unloaded in the reverse direction. That consumption in a control loop forms a portion of the dynamic consumption that, depending on the stroke frequency, can be significant.

Economic Analysis

Capital Cost:	New Gen 2 easy-Drive™ Electric Actuators are available from $2,500 each. Pricing is specific to model capability and construction materials.
Installation Cost:	Typical installation costs are between $150 and $300 per unit. This cost variance is impacted by site proximity and access.
Operating Cost:	The Fisher™ easy-Drive™ electric actuator operates on less than 0.1 Watt hours per operation. It consumes less than 3.5A, while moving and less than 1W resting.

Maintenance Cost:	Specific maintenance costs have not yet been realized. However, the electrically-operated valve assembly is not subject to maintenance concerns posed by dirty or wet pneumatic supplies. Field experience has shown that the Fisher™ easy-Drive™ electric actuator operates in ambient temperatures as low as -20°C without use of a heater.
Carbon Offset Credits:	The Fisher™ D4 Control Valve Assembly is eligible for the Pneumatics Protocol Offset credits in Brownfields in Alberta. Because using no-bleed electric actuation is not considered business-as-usual, it is also eligible for offsets in Greenfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	Payback is specifically linked to the value of fuel gas and the carbon offset. Installing this instrument as part of a Greenfield install can pay for itself in less than three years when a carbon offset protocol is available. Note that vent rate reductions are larger when dynamic consumption is included in the pre and post retrofit vent rate measurements or emission factors. The period of payback is dependent on stroke frequency. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime:	Currently, an expected lifetime cannot be determined due to insufficient field data. However, field experience has shown that longevity of the Fisher™ easy-Drive™ electric actuator is impacted by how dynamic the control loop is.
Maintenance:	Replacing a conventional pneumatic level loop with a fully electric level control eliminates venting of the controller and dump valve, and requires less maintenance. Please refer to the Fisher™ D4 Control Assembly manual.[22]

Safety

The Fisher™ D4 Control Valve Assembly uses the same valve body as its pneumatic equivalent, but does not have an equivalent means of achieving fail safe on loss of motive force that the pneumatic actuator provides. It provides fail safe on loss of input signal, which means one needs to either ensure adequate power is available or determine what the consequence would be to have the valve remain in last position upon loss of power.

Regulatory

The actuator is CSA (C/US): Explosion Proof Class I, Division 1, Groups C and D, T6, Ex d IIA T6, Class I, Zone 1, AEx d IIA T6. The Fisher™ D4 Control Valve with Gen 2 easy-Drive™ Electric is a form of no-bleed compliance.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/

[22] http://www.emerson.com/resource/blob/135076/a2a641226057dce4fa98f2a891d0a648/d103042x012-data.pdf

Product Website:	https://www.documentation.emersonprocess.com/groups/public/documents/bulletins/d103039x012.pdf
Contact Person:	Brian Van Vliet
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## 3.1.8. Spartan Controls Ltd. BETTIS™ RTS Fail-Safe Electric Actuators	April 26, 2019

Description

The BETTIS™ RTS Fail-Safe electric actuators provide the means to actuate a valve with a 20-30VDC power supply while maintaining fail-safe capability upon loss of power. They can also operate with a Single Phase 115V-230V +/-10% power supply.

The BETTIS™ RTS Fail-Safe electric actuators provide the dynamic control needed in a throttling service, comparable to the performance of a pneumatic actuator. They are rated for a 40% duty cycle in modulating service. The linear FL-05, FL-15, FL-25, and FL-40 can deliver up to 3kN (674lbs), 8kN (1,798lbs), 12kN (2,697lbs) and 15kN (3,372lbs) respectively with up to 30KN (6,745lbs) spring-return available to achieve a failsafe position on loss of power. The quarter turn FQ-03, FQ-06, FQ-10, FQ-20, FQ-30 and FQ-50 can deliver up to 300Nm (221ft-lbs), 600Nm (442ft-lbs), 1,000Nm (737ft-lbs), 2,000Nm (1,475ft-lbs), 3,000Nm (2,212ft-lbs.) and 5,000Nm (3,687ft-lbs) with a spring that provides a maximum fail-safe torque of 2,500Nm (1,844ft-lbs). An integral PID positioner for two analog input signals 4-20mA (set point, external actual value) is available as an optional function. This actuator is rated for use in ambient temperatures from -40°C to 60°C, which makes it well-suited for use at upstream oil and gas sites.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and Gas, sweet and sour. Any application requiring fail safe on/off or modulating control.

Emissions Reduction and Energy Efficiency

The reduction in pneumatic consumption is equal to the volume of gas used by a pneumatic actuator in the same service. Every time a pneumatic actuator strokes open and closed, it is loaded pneumatically und unloaded in the reverse direction. That consumption in a control loop forms a portion of the dynamic consumption that, depending on the stroke frequency, can be significant.

Economic Analysis

Capital Cost:	Cost varies based on model and application for the BETTIS™ RTS Fail-Safe, with units starting at $7,000. Equipment can be tailored for specific needs.
Installation Cost:	Typical installation costs are ~$500 per unit. This cost is impacted by the type of valve to which the actuator is coupled.
Operating Cost:	BETTIS ™ RTS Fail-Safe electric actuators use about 5mA with a 24VDC power supply resting, and consumes ~2.5A while moving.
Maintenance Cost:	Specific maintenance costs have not yet been realized. However, the electrically-operated valve assembly is not subject to maintenance concerns posed by dirty or wet pneumatic supplies. Field experience has shown that the EIM™ RTS Fail-Safe electric actuators operate in ambient temperatures as low

as -40°C without use of a heater.

Carbon Offset Credits: An BETTIS ™ RTS Fail-Safe electric actuator is eligible for offsets in Brownfields in Alberta. Because using no-bleed electric actuation is not considered business-as-usual, it is also eligible for offsets in Greenfield applications.

Payback, Return on Investment and Marginal Abatement Cost: Payback is specifically linked to the value of fuel gas and the carbon offset. Installing this instrument as part of a Greenfield install can pay for itself in less than three years when a carbon offset protocol is available. The period of payback is dependent on stroke frequency. Note that measurements must be taken to determine the amount of dynamic consumption avoided. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime: Currently, an expected lifetime cannot be determined due to insufficient field data. However, field experience has shown that longevity of the BETTIS ™ RTS Fail-Safe electric actuator is impacted by how dynamic the control loop is.

Maintenance: Replacing a conventional pneumatic level loop with a fully electric level control eliminates venting of the controller and dump valve, and requires less maintenance. Please refer to the FQ and FL BETTIS ™ RTS Fail-Safe electric actuator product data sheets. Service interval is estimated at 10,000-20,000 hours of operation depending on application.

The product data sheet for the BETTIS RTS FL Fail-Safe Linear Actuator can be found at: http://www.emerson.com/resource/blob/183920/ec3f208be39a64bdcca5b2f85e044a4d/eim-rts-fl-fail-safe-linear-data-sheet-data.pdf

The product data sheet for the BETTIS RTS FQ Fail-Safe Quarter-Turn Actuator can be found at: http://www.emerson.com/resource/blob/183922/cbb5b6d5581c144e75f0a0cca150a855/eim-rts-fq-fail-safe-quarter-turn-data-sheet-data.pdf

Safety

The BETTIS ™ RTS Fail-Safe electric actuators are available in weather-proof and explosion-proof construction with adjustable positioning speeds. The FL can stroke between 0.16-5.8mm/sec (FL) and 1-10sec to fail safe on loss of power. The FQ can position between 14-850sec full stroke and 1-10sec to fail safe on loss of power.

Regulatory

The BETTIS RTS failsafe electric actuators meet CSA CL 1 Div 2 and are marked cLCUS. Using electric actuation is a form of no-bleed compliance as will be required for AER Greenfield upstream oil and gas sites.

Vendor Information

Company Name: Spartan Controls Ltd.

Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.emerson.com/resource/blob/178862/01945c28b75bb03fc371b75f354a410e/bettis-rts-compact-fail-safe-actuators-brochure-data.pdf
Contact Person:	Charlie Crisby
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3.1.9. Fisher™ i2P-100 Electro-Pneumatic Transducer Retrofit Kit	April 26, 2019

Description

The Fisher™ i2P-100 receives a 4-20 mA DC input signal and transmits a proportional pneumatic output pressure.

The pneumatic output ranges are typically 20 to 100kPag (3 to 15 psig), 40 to 200kPag (6 to 30 psi), and 14 to 23 kPag (2 to 33 psig). This instrument is used in electro-pneumatic control loops where the final control element is a pneumatically-operated control valve assembly. Two types of retrofit kits allow first generation i2P-100s to achieve the pneumatic efficiency of a second generation i2P-100. Replacing the primary restrictor/filter lowers natural gas steady-state consumption for the i2P-100 transducer to below the 6scfh (0.16 m3/hr) definition for low-bleed pneumatic instruments.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and gas, sweet, can be used in all industries as transducer.

Emissions Reduction and Energy Efficiency

Reductions of up to 9scfh (0.25m^3/hr) of fuel gas have been achieved. Additional details are available in the field studies, manufacturer published specs[23], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.[24]

Economic Analysis

Capital Cost:	New low-bleed retrofit kits are available for from $100 each to $500 each. Pricing is specific to model capability and construction materials.
Installation Cost:	Typical installation costs are ~$150 - $300 per transducer retrofit kit. This cost is impacted by proximity and site access.
Operating Cost:	The cost of the consumed pneumatic supply can be determined based on the bleed rate of the transducer and the value of instrument air or fuel gas ($/GJ) pneumatic supply.
Maintenance Cost:	Maintenance costs are low. Repair kits to maintain operation of this transducer are available, although they are rarely needed. The instrument performance will be extended when used with a clean dry pneumatic supply.

[23]Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html

[24]http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/PneumaticDevices-Jan25-2017.pdf

Carbon Offset Credits:	A Fisher™ i2P-100 transducer is eligible for offsets in Brownfields in Alberta. Using low-bleed transducers is considered business-as-usual, so is not eligible for offsets in Greenfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	The payback is specific to the value of fuel gas and the carbon offset. Installing this instrument in the field can pay for itself in less than six months when a carbon offset protocol is available. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime:	Field experience has shown that instrument longevity is impacted by the quality of the pneumatic supply and how dynamic the control loop is. If the Fisher™ i2P-100 transducer is maintained and used within its design limits, it will continue working.
Maintenance:	No scheduled maintenance program or special tools are required beyond those used by qualified instrumentation technicians. Please refer to the Fisher™ i2P-100 transducer manual[25].

Safety

All process connections and pneumatic supply tubing and fittings must be properly tightened and are pressure-containing. The Fisher™ i2P-100 transducer is a single sealed device per ANSI/ISA 12.27.01. Note that most transducers in the field are operating with 40 to 200kPag (6 to 30psig) output pressure; if the transducer needs to provide 14 to 23kPag (2 to 33psig) output, the printed wiring board must also be updated.

Regulatory

The transducer is: CSA Class I, II, III Division 1 GP A, B, C, D, E, F, G per drawing GE07471.[26] The Fisher™ i2P-100 Electro-Pneumatic Transducer is a form of low-bleed compliance when operated with fuel gas pneumatics, and is a form of no-bleed compliance when operated with instrument air or fuel gas collected for use downstream.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.emerson.com/catalog/en-us/fisher-i2p-100
Contact Person:	Brian Van Vliet
Contact Phone#:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

[25] https://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d103198x012.pdf

[26] see figure 1 at http://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d104192x012.pdf

3.1.10. Fisher™ i2P-100 Electro-Pneumatic Transducer

April 26, 2019

Description

Optimizing existing control loops using low-bleed instruments reduces operating costs, reduces emissions, and provides positive returns on investment. The Fisher™ i2P-100 Electro-Pneumatic Transducer is a replacement for the Fisher™ 546 shown here that receives a 4-20 mA DC input signal and transmits a proportional pneumatic output pressure.

The pneumatic output ranges are typically 20 to 100kPag (3 to 15 psig), 40 to 200kPag (6 to 30 psig), and 14 to 23 kPag (2 to 33 psig). This instrument is used in electro-pneumatic control loops where the final control element is a pneumatically-operated control valve assembly.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Oil and Gas, sweet, can be used in all industries as transducer.

Emissions Reduction and Energy Efficiency

Fuel gas reductions up to 35scfh (1 m^3/hr) of have been achieved. Additional details are available in the field studies, manufacturer published specs[27], and Table C2 in Appendix C of the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices[28].

Economic Analysis

Capital Cost:	New low-bleed instruments are available for $1,000 to $3,000 per unit. Pricing is specific to model capability and construction materials.
Installation Cost:	Typical installation costs are ~$150 - $300 per transducer. This cost is impacted by proximity and site access.
Operating Cost:	The cost of the consumed pneumatic supply can be determined based upon the bleed rate of the transducer and the value of instrument air or fuel gas ($/GJ) pneumatic supply.

[27] Manufacturer specs found using Emerson Process Management's Energy Responsible Tool at http://www3.emersonprocess.com/fisher/energyresponsibletool/index.html

[28] https://open.alberta.ca/publications/9781460131633

Maintenance Cost:	Maintenance costs are low. Although available, repair kits to maintain operation of this controller are rarely needed. The instrument performance will be extended when used with a clean dry pneumatic supply.
Carbon Offset Credits:	A Fisher™ i2P-100 transducer is eligible for offsets in Brownfields in Alberta. Using low-bleed transducers is considered business-as-usual and is not eligible for offsets in Greenfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	The payback is specific to the value of fuel gas and the carbon offset. However, installing this instrument in the field can pay for itself in less than six months when a carbon offset protocol is available. In Alberta, please refer to Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Reliability

Expected Lifetime:	Field experience has shown that instrument longevity is impacted by the quality of the pneumatic supply and how dynamic the control loop is. If the Fisher™ i2P-100 transducer is maintained and used within its design limits, it will continue working.
Maintenance:	The instrument has no scheduled maintenance program. No special tools are required beyond those used by qualified instrumentation technicians. Please refer to the Fisher™ i2P-100 transducer manual[29].

Safety

All process connections and pneumatic supply tubing and fittings must be properly tightened and are pressure-containing. The Fisher™ i2P-100 transducer is a single sealed device per ANSI/ISA 12.27.01.

Regulatory

The transducer is: CSA Class I, II, III Division 1 GP A, B, C, D, E, F, G per drawing GE07471[30]. The Fisher™ i2P-100 Electro-Pneumatic Transducer is a form of low-bleed compliance when operated with fuel gas pneumatics and is a form of no-bleed compliance when operated with instrument air or fuel gas that is collected for use downstream.

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com/
Product Website:	http://www.emerson.com/catalog/en-us/fisher-i2p-100
Contact Person:	Brian Van Vliet
Contact Phone#:	403-207-0700
Contact Email:	vanvliet.brian@spartancontrols.com

[29] https://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d103198x012.pdf

[30] see Figure 1, http://www.documentation.emersonprocess.com/groups/public/documents/instruction_manuals/d104192x012.pdf

3.1.11. General Magnetic TRIDO Solar-Powered Instrument Air Compressor

April 26, 2019

Description

The TRIDO solar-powered instrument air compressor creates emissions-free wellsite instrument air. Its simple design combines cutting-edge motor technology with the TRIDO variable-frequency drive (VFD) controller to deliver successful solar-power for an entire wellsite in the harshest of conditions. Where the use of bottled gas is inefficient, the TRIDO compressor provides reliable instrument air. It can replace fuel-gas-driven, propane-driven, or bottle-gas-driven instruments.

The device:

- Delivers air efficiently with a simple compressor design.
- Features a low RPM.
- Utilizes the TRIDO proprietary low-wear and long-life, Class 1, Div 1 motor.
- Simplifies maintenance through effective design of TRIDO compressors.
- features an oil-less compressor design that provides air supply free of contaminate and oil
- Produces up to 400 scf per day at 30 psi, on a 60% duty cycle.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Converting pneumatic devices from fuel gas to instrument air eliminates methane emissions while freeing up additional fuel gas for sale.

Economic Analysis

Capital Cost:	Capital costs vary depending on the level of application for the technology, but are estimated at approximately $7,000.
Installation Cost:	Installation costs are very low. The technology is designed to be delivered and installed by field rep or operator.
Operating Cost:	Operating costs are very low and might be nil. The sale of natural gas no longer being vented provides further financial benefit.
Maintenance Cost:	Basic maintenance costs apply.
Carbon Offset Credits:	The TRIDO Solar Powered Instrument Air Compressor is eligible for use in the

	Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Retaining vented gas for sale and savings from offset credits varies depending upon application. However, costs associated with instrument-maintenance and instrument failure are reduced.

Reliability

Expected Lifetime:	It is anticipated that the air compressor will last 10 years
Maintenance:	Maintenance costs are estimated at $250/year.

Safety

No unusual safety requirements apply.

Regulatory

- Compressor: CSA Class 1, Div. 1. Controller Class 1 Div 2
- No AER Directive applicable

Vendor Information

Company Name:	TRIDO Industries Inc.
Company Website:	www.tridoind.com
Product Website:	Product information is available on the company website.
Contact Person:	Russell Graham
Contact Phone#:	1-855-368-7438
Contact Email:	sales@tridoind.com

3.1.12. CalScan Bear Solar Control System

July 31, 2017

Description

On average, onsite pneumatic devices vent from 100 to 650 tCO_2e per year, depending on how many devices and chemical pumps are being driven by fuel gas at a particular site. Calscan's Bear Solar Electric Control System is a complete no-bleed solution for wellhead separators. This low-power electric system run on solar panels can completely replace all pneumatically-powered devices on the wellsite that use electric controls, eliminating the need for fuel gas except for heating in cold climates. Greenhouse gas emissions generated from running the separator are eliminated.


Electric Actuator


Electric Chemical Pump


Bear Controller Retrofit

The equipment features include:
Chemical Pump:

- Electric-explosion-proof Injection/Chemical Pump
- Methanol and/or chemical injection with individually scalable rates.

Control Panel:

- Integrated PLC for control & ESD system
- PLC programming for turnkey solution and easy install
- PID control available
- Solar Power system is engineered for 10 days reserve at -40°C with an average of two hours per day of sunlight
- Electronics rated for -40°C
- RS-485 Modbus communication
- Level Control
- Pressure or Flow control
- Chemical pump control

Instrumentation:

- Two or Three phase separators
- Displacement or Float type level control
- Electric Explosion Proof dump valves
- Pressure Switches
- Pressure Transmitters
- Level Switches
- Hydraulic or Pneumatic ESD Fail Safe Actuator with low power solenoid
- PID controlled Explosion Proof electric actuators with choke valve

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Calscan's Bear Solar Electric Control System provides a 100% reduction in greenhouse gas emissions.

Economic Analysis

Capital Cost:	Capital costs vary depending on the level of application, especially in comparing a retrofit to a new installation. The Bear Solar Electric Control System must be purchased, as it is a permanent install.
Installation Cost:	Installation costs vary depending on the level of applications.
Operating Cost:	The equipment has very low operating costs, possibly nil. However, propane may be required for the catadyne heater.
Maintenance Cost:	Maintenance costs are very low, with typical maintenance required on the process valves. Batteries typically last from four to seven years. Solar Panels typically last 20 to 30 years.
Carbon Offset Credits:	The Bear Solar Electric Control System is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	The equipment offers immediate fuel gas savings, including both natural gas and propane. Savings from offset credits vary depending on the application, although it is eligible for Protocol offset credits for both Greenfield and Brownfield. However, the ROI on installing the equipment can vary from one to three years using the Protocol.

Reliability

Expected Lifetime:	The equipment is expected to last the life of the facility.
Maintenance:	Maintenance of the equipment requires no special tools, as it is suitable for standard instrumentation tech qualifications.

Safety

No unusual safety requirements apply.

Regulatory

The CalScan Bear Solar Control System meets all AER regulatory requirements.
Rated C1 D1/D2 and CSA approved.
Control Panel Class 1 Div 2 CSA Approved
Instrumentation CSA Approved Class 1 Div 1
Chemical Pump CSA Approved Class 1 Div 1

Vendor Information

Company Name:	CalScan Solutions
Company Website:	www.Calscan.net
Product Website:	http://www.calscan.net/solutions_ZeroGHGVenting.html
Contact Person:	Henri Tessier

Contact Phone#: (780) 944-1377
Contact Email: HTessier@CalScan.net

3.1.13. Blair Air System

July 31, 2017

Description

The Blair Air System is a zero-emissions motor that harnesses energy from a flowing gas stream to generate compressed air to power pneumatic devices. As a result, the Blair Air System prevents pneumatic devices from venting methane. The system is also capable of driving up to three mechanical liquid pumps, allowing operators to consolidate air compression and liquid handling into a single package. The unit does not require any electrical utilities, making it ideally suited for remote well pad sites.

The gas that drives the unit is routed back into the main flow line in a closed system. The unit can run on a wide range of gas compositions, including liquid rich sour gas, and requires as little as eight psi intermittent pressure differential. Free flow occurs on each piston stroke, resulting in a negligible effect on gas flow rate. The mechanical package is fully autonomous and can be run without the use of a control system.

Specifications:
Driver

- Maximum Continuous Speed: 25 strokes/min
- Minimum Differential Pressure: 8 psi (increases with load demand)
- Max Operating Pressure: 1500 psi
- Max Power Output: 650 W (mechanical)

Air Compressor

- Maximum Flow Rate – 6" air cylinder: 2.1 scf/m @ 25 strokes/min (current design)
- Maximum Flow Rate – 8" air cylinder: 3.7 scf/min @ 25 strokes/min (under development)
- Maximum Operating Pressure: 50 psi

Plunger Pumps (Configuration: Three ½", or Two ½" and One 1 ¼")

- Maximum Flow Rate ½" Plunger: 237 L/day @ 25 strokes/min
- Maximum Flow Rate 1 ¼" Plunger: 1608 L/day @ 25 strokes/min
- Maximum Operating Pressure: 1500 psi

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The expected reduction in methane emissions is dependent upon system design and operating conditions. Field experience provided by an oil and gas operator on a single well set up showed the following methane emission reductions:

- 940 Mscf/year for operation of methanol pumps (replacing three Texsteam style chemical pumps)
- 525 Mscf/year (1 scf/m average) replacing instrument gas with instrument air

This equals a total methane emission reduction of 1,465 Mscf/year, or 744 tonnes of CO_2 equivalent.

Economic Analysis

Capital Cost:	The capital costs range from $30,000 to $60,000 depending on configurations such as the number of pumps, building requirements, size of air receiver, need for fire and gas (F&G) detection.
Installation Cost:	Installation costs depend upon installation requirements (e.g. availability of tie-in points, green field vs. retrofit, piping specifications, need for F&G detections etc).
Operating Cost:	Minimal additional operating costs are expected, and possibly none. Operational adjustments can be completed as part of normal operator rounds. The unit does not require utility power and does not consume any gas.
Maintenance Cost:	The unit can be isolated from the process stream, enabling equipment maintenance without shutting in production. Once per year, gas driver seals should be replaced, and all other seals and wear parts should be inspected. Total expected maintenance costs are $1,000 to $3,000 annually.
Carbon Offset Credits:	The Blair Air System is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	The payback considerations for the unit are the conservation of process gas and the associated eligibility for pneumatic protocol offset credits. The unit also provides means to consolidate process equipment, and will extend the operational life of pneumatically-operated equipment.

Reliability

Expected Lifetime:	The expected equipment life is 20 years, contingent on regular maintenance intervals.
Maintenance:	No special tools or training are required for maintenance or installation. Yearly maintenance and inspection are required.

Safety

No unusual safety requirements apply. All routine safety considerations are applicable, such as moving parts / pinch points, hot surfaces, and pressures.

Regulatory

The design satisfies all NACE requirements for sour service operation, equipment meets all oil and gas regulatory requirements for operation in Canada. There are no electrical area classification restrictions for the Blair Air System, as this is a 100% mechanical device and does not require CSA approval. No AER Directives are applicable.

Vendor Information

Company Name:	Blair Air Systems Inc. supported by – Tundra Process Solutions
Company Website:	http://www.blairair.com/ - https://www.tundrasolutions.ca/
Product Website:	Product information available on company website
Contact Person:	Jim Blair -- Anno Roobol
Contact Phone#:	(403) 820-9715 - (403) 255-5222
Contact Email:	info@blairair.com - info@tundrasolutions.ca

3.1.14. AirWorks Aurora A60 Eco-System | July 31, 2017

Description

Airworks Compressors Corp.'s Aurora A60 Eco-System supplies well site pneumatic systems with instrumentation air sourced from the atmosphere, replacing the use of natural gas. Methane emissions are eliminated, enabling producers to avoid fines and other regulatory consequences that are becoming more stringent across North America. Furthermore, the conserved natural gas can be sold at market, increasing profits.

Aurora A60 Eco-System units include a proprietary rotary screw compressor (60 CFM; 150 psi) powered by an emissions-free solar and/or wind power generation system plus a battery pack for power storage, allowing 24/7 operation. Units are remotely monitored via satellite/cellular networks. The entire system is contained in one shipping container which can be installed in a single day without any special hook-ups/infrastructure because it uses existing onsite piping. No power grid connection is required. No permits are required. It is exceptionally well-suited to remote locations.

Smaller Aurora units can serve one to two wells each. Larger Aurora units can serve pads with three to fifteen wells.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Converting pneumatic devices from fuel gas to instrument air eliminates methane emissions.

Economic Analysis

Capital Cost:	Capital costs vary depending on level of application, but are approximately $12,000.
Installation Cost:	Installation costs are very low as this is a 'plug and play' device. The technology is designed to be delivered and installed by field rep or operator.
Operating Cost:	The operating costs of the system are very low and may be nil. Natural gas that is no longer being vented can be sold for additional cost savings.
Maintenance Cost:	Maintenance costs are approximately $500 per year. The equipment requires basic oil and filter changes every six months.
Carbon Offset Credits:	The Aurora A60 Eco-System is eligible for use in the Pneumatics Protocol Offset credits in Alberta.

Payback, Return on Investment and Marginal Abatement Cost:	Retaining vented gas for sale and savings from offset credits varies depending on application. Aurora Eco-Systems payback period is typically one to three years (not including any costs of avoided fines or other regulatory penalties). Methane & VOC emissions compliance is achieved, and monitoring/reporting requirements are reduced.

Reliability

Expected Lifetime:	It is anticipated that the Aurora60 will last 10 years.
Maintenance:	The equipment requires a basic oil and filter change twice a year.

Safety

No unusual safety requirements apply.

Regulatory

- Suitable for use in Alberta oil and gas facilities.
- No AER Directive applicable
- CSA rating not required

Vendor Information

Company Name:	Airworks Compressor Corp
Company Website:	www.airworkscompressors.com
Contact Person:	Sheila Stang
Contact Phone#:	780-454-2263 Ext: 222
Contact Email:	info@airworkscompressors.com

3.1.15. Simark Controls Ltd. EFOY Pro Hybrid Fuel Cell Solution	April 26, 2019

Description

EFOY Pro Hybrid solutions provide users with a fully autonomous, eco-friendly, reliable power source designed for extreme weather conditions.

EFOY Fuel Cells are smart energy producers that can be used to continuously and automatically recharge batteries. They are based on DMFC (Direct Methanol Fuel Cell Technology), which converts methanol into electricity through a single stage catalytic conversion process. Making the fuel cell one of the cleanest and most efficient ways to generate power for off-grid applications

When a solar array is unable to deliver enough power, the EFOY senses the battery voltage drop and automatically switches on to keep the battery bank charged before going back into standby mode. Large oversized solar arrays and battery banks can be reduced by up to 75% while at the same time significantly increasing the system reliability by providing years of fuel autonomy versus the traditional 4-7+ days of battery autonomy.

EFOY Pro Hybrid solutions are sized based on application specific load and location details. A typical design will provide 12-18 months of fuel autonomy.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls - Facilities Design and Equipment

Site Applicability

Off-grid upstream well sites, Midstream off-grid block valve stations, Off-grid communication sites.

Emissions Reduction and Energy Efficiency

The EFOY Hybrid system is a highly reliable, eco-friendly solution for off-grid upstream facilities that require consistent electrical power. This system is a suitable solution for two different project types regarding emission reductions from pneumatic devices:

1) Electrification of pneumatic devices (ex. chemical injection pumps): These devices require an alternative electrical source such as solar power. During operation these devices typically have a large inrush current which is supplied by batteries and often times results in battery capacity being reduced significantly in a short period of time. Pure solar is more often than not unable to supply

adequate amount of charge back to the batteries in a reasonable amount of time which results in power loss, and damaged batteries. The EFOY hybrid can be integrated to provide supplemental power to these batteries which eliminates any downtime at site, and increases the life expectancy of batteries by preventing deep discharge.

2) Instrument Air Systems: Switching pneumatic devices to operate via instrument air can be done with the use of an air compressor which requires an electrical power source. Air compressors generally have higher power requirements which can be challenging for pure solar systems and often times result in a large system footprint (PV array and battery bank). The EFOY hybrid can be integrated to compliment solar systems by providing consistent, reliable power, and significantly reduce the overall system footprint (usually up to 75% reduction in batteries and solar panels).

Economic Analysis

Capital Cost:	Competitive capital cost, varies dependent upon power output and system design/complexity. Systems range from 45W to 500W Hybrid power solutions
Installation Cost:	Installation is simple and does not require any specific training. End users existing electrical contractors can install the package within 2 hours so costs are minimal, with labor estimated at approximately $300.
Operating Cost:	Operating costs will vary depending on the system size and site load requirements, however customers only need to budget to replace empty fuel cartridges once every 12 – 18 months. The cost to do so will range from $374 for 2x 28L cartridges up to $1,596 for 4x 60L cartridges. Detailed Hybrid power calculations including estimated yearly fuel costs are included with all system proposals.
Maintenance Cost:	Annual preventative maintenance is not required.
Carbon Offset Credits:	Existing sites where pneumatic devices are being electrified or modified for instrument air and incorporate an EFOY hybrid solution for off grid power would be eligible for carbon credits or applicable emissions reduction funding programs.
Payback, Return on Investment and Marginal Abatement Cost:	Payback considerations vary depending on electrical load, location and specific site details. Detailed economic analysis available upon request and in most scenarios the payback period vs. alternative technologies is one year or less.

Reliability

Expected Lifetime:	Contingent upon annual runtime hours. Properly balanced hybrid packages will incur minimal hours for an overall expected lifetime of 7+ years at which the fuel stack will need to be replaced.
Maintenance:	Annual preventative maintenance, specialized tools or in-depth specialized training is not required.

Safety

No unusual safety requirements apply.

Regulatory

EFOY Hybrid packages are rated for non-hazardous locations, no AER directive applicable. EFOY hybrid packages follow electrical code and can be installed 3m outside of the classified area. Certification: Nema 3R EFOY/Battery panel built to CSA 22.2 NO. 14 and carries a cETL/us (North American) certification.

Vendor Information

Company Name:	Simark Controls Ltd.
Company Website:	www.simark.com
Product Website:	https://www.efoy-pro.com/
Contact Person:	Chelsea O’Connor & Chris Wollin
Contact Phone#:	403-354-3537 / 587-437-6828
Contact Email:	chelsea.oconnor@simark.com / chris.wollin@simark.com

## 3.1.16. Calscan BA-15L Bear Solar Electric Linear Actuator	April 26, 2019

Description

Zero Emission, no-bleed, Linear Actuator for your Wellhead Separator. Calscan's Bear BA-15L Linear Actuator are designed for the 21st century zero-emission well site by replacing fuel gas driven pneumatic actuators with electrically powered ones. Advanced electronics and high efficiency brushless DC motor gives the BA-15L low active and standby energy consumption ideally suited for remote non-grid power sites, such as solar or thermoelectric generators.

Easily installed on standard control valves such as the Fisher ET and D-body valves. The BA-15L linear actuator can be used in processes for throttling or on-off control. The actuator is designed for harsh environmental conditions of the Canadian climate.

The Calscan Bear BA-15L Electric linear actuators operate from 20 to 30 vdc with standby current less than 50mA. Control with digital inputs or 4-20mA signals. Electronically adjustable thrust and speed. Single hand manual operations and hand wheel does not move during automatic operations. Electronic detection of blockage and soft seating. Installed on 1" to 4" Control valves of pressure ranges from 150 to 2500 ANSI. With 4 to 20mA input and feedback the BA-15L is ideal for inlet pressure control and flow /pressure control downstream of separator.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Calscan's BA-15L Solar Electric Linear Actuator provides a 100% reduction in greenhouse gas emissions.

Economic Analysis

Capital Cost: Capital costs vary depending on the level of application.

Installation Cost:	Installation costs can vary depending on the level of applications. Typical installation cost between $200 and $400 depending by site proximity. Typically controlled by existing RTU at field location.
Operating Cost:	The equipment has very low operating costs. It consumes less than 4.2 amps while moving and less then 50mA for standby current. Extra solar panels and batteries maybe required.
Maintenance Cost:	Maintenance costs are very low, with typical maintenance required on the process valves. Batteries typically last from four to seven years. Solar Panels typically last 20 to 30 years. No concerns by dirty or wet fuel gas used with pneumatic devices.
Carbon Offset Credits:	The Bear BA-15L Solar Electric Linear Actuator is eligible for Pneumatics Protocol Offset credits in Alberta. Eligible for Greenfield and Brownfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	The equipment offers immediate fuel gas savings, including both natural gas and propane. Savings from offset credits vary depending on the application, although it is eligible for Protocol offset credits for both Greenfield and Brownfield.

Reliability

Expected Lifetime:	The equipment is expected to last the life of the facility.
Maintenance:	Maintenance of the equipment requires no special tools, as it is suitable for standard instrumentation tech qualifications.

Safety

No unusual safety requirements apply. Provides fail-safe on loss of signal.

Regulatory

The CalScan Bear BA-15L Solar Electric Linear Actuator meets all AER regulatory requirements.
BA-15L / 24 vdc / 115 vac / 5 Amps Max. / EX de 11B T4 Gb / Rated C1 D1/D2 and CSA approved.

Vendor Information

Company Name:	CalScan Solutions
Company Website:	www.Calscan.net
Product Website:	http://www.calscan.net/solutions_ZeroGHGVenting.html
Contact Person:	Henri Tessier
Contact Phone#:	(780) 944-1377
Contact Email:	HTessier@CalScan.net

3.1.17. Calscan BA-Q Bear Solar Electric Actuators

April 26, 2019

Description

Zero Emission, no-bleed, Quarter Turn Actuators for your Wellhead Separator. Calscan's Bear BA-Q series Quarter Turn Electric Actuators are designed for the 21st century zero-emission well site by replacing fuel gas driven pneumatic actuators with electrically powered ones.

Easily installed on standard quarter turn ball valves. The BA-Q series actuators can be used in processes for throttling or on-off control. The actuator is designed for harsh environmental conditions of the Canadian climate. Ideally used for level control on spearators and controlled by RTU.

The Calscan Bear BA-Q Electric actuators operate from 10 to 30 vdc. Control with digital inputs for On/Off configuration or 4-20mA input signal. Torque ranges from 300 in-lbs to 3000 in-lbs. and cycle time from 5 to 14 seconds depending on models. Single hand manual operations and hand wheel does not move during automatic operations. Comes with Calscan Bear solid state relays installed in RTU cabinet for high current actuator operations and feedback.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Calscan's BA-Q Solar Electric Quarter Turn Actuator provides a 100% reduction in greenhouse gas emissions.

Economic Analysis

Capital Cost:	Capital costs vary depending on the level of application. Ranges from $1000.00 to $4000.00
Installation Cost:	Installation costs can vary depending on the level of applications. Typical installation cost between $200 and $400 depending by site proximity. Typically controlled by existing RTU at field location.
Operating Cost:	The equipment has very low operating costs. It consumes less than 5 amps

	while moving and ZERO standby current. Extra solar panels and batteries maybe required.
Maintenance Cost:	Maintenance costs are very low, with typical maintenance required on the process valves. Batteries typically last from four to seven years. Solar Panels typically last 20 to 30 years. No concerns by dirty or wet fuel gas used with pneumatic devices.
Carbon Offset Credits:	The Bear BA-Q Solar Electric Quarter Turn Actuator is eligible for Pneumatics Protocol Offset credits in Alberta. Eligible for Greenfield and Brownfield applications.
Payback, Return on Investment and Marginal Abatement Cost:	The equipment offers immediate fuel gas savings, including both natural gas and propane. Savings from offset credits vary depending on the application, although it is eligible for Protocol offset credits for both Greenfield and Brownfield.

Reliability

Expected Lifetime:	The equipment is expected to last the life of the facility.
Maintenance:	Maintenance of the equipment requires no special tools, as it is suitable for standard instrumentation tech qualifications.

Safety

No unusual safety requirements apply. Provides fail-safe on loss of signal.

Regulatory

The CalScan Bear BA-Q Solar Quarter Turn Actuators meets all AER regulatory requirements.
BA-Q / 12 VDC / 24 vdc / 115 VAC / 4 Amps Max. / EX de 11B T4 Gb / Rated C1 D1/D2 and CSA approved.

Vendor Information

Company Name:	CalScan Solutions
Company Website:	www.Calscan.net
Product Website:	http://www.calscan.net/solutions_ZeroGHGVenting.html
Contact Person:	Henri Tessier
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Section 3.2. Wellsite and Upstream Facilities Instrumentation and Controls – Recommended Practices

3.2.1. Wellsite Electrification	July 31, 2017

Description

An electric wellsite configuration typically includes a well control system, a power supply (grid or off-grid) and a variety of electrically-driven controllers, valve actuators, switches and pumps. The use of electrical pumps and electric controllers eliminates methane emissions associated with pneumatic equipment. Typically, a well electrification project includes electrification of almost all wellsite components, except for certain emergency shutdown valves that may continue to use a pneumatic supply or hydraulics for safety reasons, and building heaters that burn a small amount of natural gas or propane.

Few wellsites are connected to grid electricity. The high cost of connecting small wellsite electrical loads to the grid and the long lead times to connect to the grid often make it uneconomic or infeasible to electrify sites with grid power. Therefore, this document assumes an off-grid configuration. Where grid power is available for wellsites with larger electrical loads, wellsite electrification costs are reduced because a power supply is not required.

A fully electric (off-grid) well control system package typically features the following components:

- Control Panel – Canadian Standards Association (CSA) Class 1, Division 2 certified programmable logic control (PLC) system integrated for process control and emergency shutdown (ESD) functionality with optional Modbus communication protocol and all electronics rated for -40°C;
- Solar photovoltaic panels and batteries, engineered to meet 10 days of reserve at -40°C with an average of two hours of sunlight per day. Typical systems may include:
    - Two to four 140 Watt solar photovoltaic (PV) panels;
    - Four to eight 12 volt batteries, each 100 amp-hours;
- Emergency shutdown (ESD) system consisting of pressure switches, level switches and a hydraulic or pneumatic fail-safe actuator with low power solenoid;
- Level control system – electric explosion proof dump valve for two (gas-water) or three (oil-water-gas) phase separator with displacement or float style level control;
- Pressure or flow control system – proportional–integral–derivative (PID) controlled explosion proof electric actuator with choke valve; and,
- Electric explosion-proof pump(s) for injection of methanol, corrosion inhibitor, or other chemicals into the wellbore or into pipelines.
- Optional auxiliary power supply such as a 50-200 watt thermoelectric generator (TEG) or a similar-sized fuel cell. To reduce costs, solar photovoltaic (PV) and batteries are preferred, and auxiliary power systems are only used where necessary.

The entire system is direct current (DC), eliminating the need for inverters. The electrical loads (pumps, actuators etc.) draw current from the batteries, and the batteries are primarily charged by the solar panels during the day time. Some sites charge the batteries with TEGs to make up for any shortfall in solar output during periods of low sunlight. TEGs are most commonly used when the reliability, or perceived reliability, of solar is lower, such as in cloudy regions in north-central Alberta.

Baseline:

Pneumatic chemical injection pumps continue to be the standard in the oil and gas industry given the simplicity, reliability, and low capital cost of pneumatic controllers and pneumatic pumps, and the frequent lack of available electricity at wellsite locations. The baseline for a wellsite electrification project is the venting of natural gas or "instrument gas" (containing primarily methane) to the atmosphere from dedicated vent lines associated with the operation of the existing pneumatic controllers and pneumatic pumps. The exhaust tubing from the outlet of each pneumatic pump and controller is routed outside of the building to vent the gas to the atmosphere. For safety and operational reasons, instrument gas is not usually flared.

Throughout the oil and gas industry it is standard practice to use pressurized natural gas to operate pneumatic chemical injection pumps and pneumatic controllers. Pneumatic controllers and pumps take pressurized gas and use the energy of that gas to actuate a valve or to drive a pump. Gas that could have otherwise been directed to sales is vented to the atmosphere, resulting in both lost revenue and increased methane[31] emissions.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Recommended Practices

Site Applicability

The first step identifying potential electrification project opportunities is to collect an inventory of pneumatic equipment at candidate wellsites, including:

- Pneumatic controller makes, models and pneumatic supply pressures
- Manufacturer specs or published vent rates for each controller
- Pneumatic pump make, model and stroke length;
- Injection rate (Litres/day);
- Injection pressure;
- Estimated pump operating hours per year;
- Injection fluid type (methanol, corrosion inhibitor, de-waxing agents etc.)
- Other site-specific factors

The next step is to prioritize the baseline wellsites that have the highest vent rates and those sites that have the highest maintenance costs associated with instrument gas (e.g. wet fuel gas at site, freezing issues, and/or frequent replacement of instrumentation due to liquids carry-over and other issues). Sour gas sites that do not have a supply of sweet fuel gas may also be excellent candidates since sour gas must not be vented to the atmosphere. Any sites that use propane for instrumentation are also ideal candidates due to the high operating costs of purchasing propane and safety issues with venting propane. There may also be opportunities to optimize chemical usage by switching to electric pumps, and these cost savings should also be assessed, where applicable, to help improve paybacks.

Due to the upfront cost of electric well control systems, the best opportunities will be at greenfield deployments. The cost of the electric actuators, controllers, and electric pumps can be partly offset by not having to purchase the equivalent pneumatic end devices. In comparison, retrofit projects are disadvantaged in this regard because of the additional cost of decommissioning existing pneumatic equipment.

[31] Methane is a potent GHG, with global warming power of 25 times that of carbon dioxide. On January 23, 2014 Alberta Environment updated the GWP of methane to be 25 (from 21). For further details refer to this bulletin: http://esrd.alberta.ca/focus/alberta-and-climate-change/regulating-greenhouse-gas-emissions/alberta-based-offset-credit-system/offset-credit-system-protocols/documents/MemoOnGlobalWarmingPotentials-Feb2014.pdf

Site selection is critical as the solar system (panels and batteries) must be designed with enough autonomy or reserve capacity to reliably deliver power during the coldest (~-40°C) and cloudiest weeks of the year. Ideally, the solar panels should either be deployed far from trees/tree lines or should be on an elevated mast (masts with panels can blow over if not secured properly). While it is typically possible to design a solar system to meet almost any site configuration, the system cost will increase significantly as more panels and batteries are added for sites at higher latitudes and in cloudy regions with low levels of winter sunlight. However, over 300 solar-electric well control systems (including solar pumps and electric controllers/actuators) have been successfully deployed in Western Canada by Calscan Solutions of Edmonton, so latitude is not necessarily a limiting factor for solar. The technology has been very successfully deployed with wellsite separator packages in southern and eastern Alberta.

Emissions Reduction and Energy Efficiency

Estimating Gas Savings:

The potential gas savings and greenhouse gas (GHG) reductions from a well electrification project will vary depending on the equipment at the site, but most oil and gas facilities use common types of pneumatic equipment. Equipment configurations will vary from site to site and operator to operator, depending on design requirements and operator preferences. The chart below[32] shows that the gas savings from a well-electrification projects can be estimated by completing an inventory of pneumatic equipment at each site and estimating operating hours.

Equipment Type	Example Make/Model	Count	Vent Rate (m^3/hour)	Operating Hours/Year	Gas Vented (m^3/year)	GHG Emissions (tCO_2e/year)
Pressure Controller	Fisher C1	1	0.0649	8760	569	8.7
Level Controller	Fisher L2	2	0.2641	8760	2,314	35.4
High Level Shutdown Switch	Murphy L1200	1	0.2619	8760	2,294	35.1
High Pressure Shutdown Switch	Fisher 4600	1	0.0151	8760	132	2.0
Pneumatic Pump (Methanol)	Generic Diaphragm Pump	1	1.0542	4380	4,617	70.6
Pneumatic Pump (Other Chemical)	Generic Piston Pump	1	0.5917	8760	5,183	79.3
Total Gas Savings (m^3/year)					**15,109**	-
Total GHG Emission Reductions (tCO_2e/year						**231**

Estimated Gas Savings from Wellsite Electrification

It may be beneficial to use manufacturer specifications in place of published emission factors to improve accuracy, especially when estimating vent rates from pneumatic pumps. The most common method for determining gas savings is to reference the manufacturer specifications for the pump. Most manufacturers of pneumatic pumps provide a curve or plot of the gas consumption per unit volume of chemical injected (scf natural gas/gallon chemical) versus the injection pressure for specific models and stroke lengths. By knowing the model of pump, the injection pressure, the chemical injection rate and the annual operating hours, you can determine the amount of gas vented (or saved) per year.

To qualify for offset credits in Alberta additional data collection may be required. This may include monitoring and recording information from the new solar-electric wellsite equipment as well as the pre-existing pneumatic configuration. Refer to the monitoring and quantification sections of this document for further details.

[32]The example uses published vent rates from the 2013 Prasino Study to calculate the estimated savings from the replacement of conventional pneumatic equipment required to operate a typical oil or gas well separator package with a zero emissions solar-electric design.

Measurement:
To generate verifiable carbon offsets in Alberta from wellsite electrification projects it may be necessary to collect additional documentation that would not normally be recorded by operators. The Alberta Offset System (AOS) Quantification Protocol for Greenhouse Gas Emissions Reductions from Pneumatic Devices specifies for pumps that to estimate baseline emissions, either the count of pump strokes from the new electric pump or the volume of chemical injected by the new pump must be tracked. For pneumatic controller electrification, the make and model of the baseline pneumatic controller also needs to be tracked. Refer to the section below on estimating GHG reductions and refer to the AOS protocol for further data collection and documentation requirements.

Estimating GHG Reductions:
Under AOS Protocol for Pneumatic Devices the net GHG emission reductions are calculated based on the following:

- The type of pneumatic controllers in operation in the baseline (or type typically used in that region, if the project is a greenfield deployment), including make/model and pneumatic supply pressure
- Pneumatic controller operating hours
- The type of pneumatic pump that was operating baseline, including make, model, plunger size, operating pressures and other information needed to determine a pump emission factor from manufacturer specifications for the baseline pneumatic pump;
- The chemical injection rate (e.g. in Litres/day) may have to be estimated from other information, such as a count of the number of pump strokes per time increment, the volume of chemical injected per time increment, or other factors;
- Solar pump operating days (or hours) per year;
- The site fuel gas composition (% methane);
- The density of methane; and,
- The global warming potential of methane.

The formula below is generalized, as different calculation methods may be required for pneumatic controllers versus pneumatic pumps. Refer to the AOS Protocol for the full calculation.

<u>A Simplified Formula to Estimate GHG-Emission Reductions:</u>

Net GHG Reductions = Baseline Emissions[33]

$$=\sum_{i}^{n}(\text{Baseline Pneumatic Vent Rate Device}_i \text{ in } m^3/h) * (\text{Op. Hours/year}) * (\%_{CH4} \text{ in Fuel Gas}) * (\text{Density}_{CH4} \text{ in kg/h}) * (0.001 \text{ t/kg}) * (\text{GWP}_{CH4})$$

Estimated GHG Emission Reductions:
GHG reductions will vary depending on the equipment at each site, but the sample project depicted in the Estimated Savings chart would reduce GHG emissions by ~230 tCO_2e /well/year and is expected to

[33] Global Warming Potential of Methane is 25 currently (but subject to change), per: http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/CarbonEmissionHandbook-Mar11-2015.pdf
Density of Methane gas at 15°C and 1 atmosphere is 0.6797 kg CH_4/m3, per https://encyclopedia.airliquide.com/methane

be representative of typical separator packages. GHG reductions will vary significantly depending on the baseline pneumatic controllers and pneumatic pumps, the required injection rate for the new solar pump, pump injection pressures, operating hours, percent methane in fuel gas, and other factors.

Economic Analysis

Capital Cost:	Capital costs are site specific, but the incremental cost to install a solar-electric well control system is estimated to range from $17,000 to $40,000, with greenfield projects and simpler well configurations at the lower end of the range and retrofits and more complex well designs at the higher end of the range (These estimates do not include a TEG, which could add $10,000 or more to the capital costs). The incremental cost to deploy a solar-electric well control system for new (greenfield) wellsites is much lower at $15,000 to $20,000 per separator package. The equipment costs (electric actuators, controllers, pumps, batteries, panels, control system) make up most of the capital costs for wellsite electrification projects, as installation can be done in 1-2 days.
Installation Cost:	Based on vendor information, the estimated incremental cost to install a solar-electric well control system ranges from $17,000 to $40,000.
Operating Cost:	Operating Costs are typically lower for electric wellsites than for pneumatic configurations. For solar-electric control systems the main incremental operating costs are battery replacements. Assuming four batteries per site and a 6-year battery life, with a replacement cost of $175/battery, this would result in an average operating cost of $116/well/year over a six-year period. These costs are still lower than the operating savings from reducing chemical usage and eliminating fuel gas usage as described below.
Maintenance Cost:	Maintenance cost savings and chemical savings are also significant, as electric control systems improve reliability by eliminating issues with wet instrument gas (or sour gas), and significantly reduce chemical costs by improving the precision of chemical injection. Installing an electric control system also allows for increased automation and cost savings, which can include ability to remotely adjust chemical injection rates and other operating parameters on equipment tied into SCADA. Pneumatic pumps are prone to chemical leaks around the pump seals (methanol destroys elastomers), a problem reduced by the secondary seal on electric pumps. Chemical savings can be significant on more expensive chemicals like corrosion inhibitors. Additionally, significant methanol savings can be achieved for lower-pressure gas wells because pneumatic pumps have poor turndown capabilities and are often set to over-inject chemical. In particular, diaphragm pumps often cannot be operated effectively below 10 litres/day. Electric pumps can easily operate down to rates as low as 0.5L/day. Replacement of 140 pneumatic pumps at a major producer’s shallow gas facilities in southern Alberta achieved methanol savings of approximately $500/year/pump, based on an average 5 litres per day reduction in methanol injection rates.

Carbon Offset Credits:	The value of carbon offsets can be very significant for wellsite electrification projects and could outweigh the value of the gas savings by a significant margin using an assumed carbon offset value of \$25/offset in Alberta. Based upon this offset value, the estimated 230 tCO_2e/year GHG reduction from Figure 1 would be worth \$5,800/year - more than four times the value of the gas savings!
Payback, Return on Investment and Marginal Abatement Cost:	Gas savings are one of the primary benefits of wellsite electrification projects. Gas savings depend on many factors, including types and numbers of pneumatic controllers and pumps being replaced, operating hours, chemical injection rates, pump makes/models, operating pressures and other factors. Gas savings from the sample project depicted in the Estimated Savings chart were estimated to be 15,100 m^3/year (530 mcf/year). At a flat \$2.50/mcf AECO gas price, these gas savings are worth at least \$1,330/year. Overall Cost-Benefit: Based on vendor information, the estimated incremental cost to install a solar-electric well control system ranges from \$17,000 to \$40,000. Without carbon offsets, the payback for these types of projects is typically >10 years, except at sites where clean, dry fuel gas is unavailable (sour gas) and/or where wet fuel gas causes high maintenance costs from replacements of instrumentation or freezing issues. If carbon offsets are generated, the payback can be reduced to ~2 to ~5 years, but additional data collection will be required for the project to be eligible for carbon offsets. Economics are far better for greenfield sites because the incremental cost of the electric equipment is partly offset by not having to purchase conventional pneumatic equipment.

Barriers:

- Financial barriers – solar-electric well control systems are considerably more expensive than pneumatic systems (estimated incremental cost of \$15,000 to \$20,000 for a greenfield deployment, assuming solar-only with no TEG) and the low value of fuel gas makes many projects uneconomic based on the gas savings alone, although chemical/maintenance savings and carbon offsets can improve economics. Minimal capital is often available for energy efficiency, optimization or emission reduction projects;
- Solar reliability may be lower in areas with reduced sunlight, such as valleys, heavily-treed areas, or regions with frequent cloud cover. In extreme cold weather and long periods without enough sunlight to charge batteries, this can lead to battery failure, incremental downtime, and increased operating costs from battery replacements.
- Some electric pumps may not be able to overcome the high injection pressures (e.g. >3000 psig) required for new high-pressure horizontal wells in the Montney, Duvernay, and Deep Basin regions. In these situations, it may make sense to install the solar pump after 6-12 months, when the well pressure has declined.
- Unwillingness to modify proven facility designs that are reliable.
- Remaining asset life is limited for many conventional gas facilities.

Reliability

Designed properly, solar-electric well control systems can provide equivalent or better functionality than the previous pneumatic design. However, solar systems may not be appropriate for all applications, or may require a supplemental power supply. The solar system (batteries, panels and charging system) must be designed to provide sufficient autonomy (reserves) for extended periods of minimal sunlight (<2 hours per day) during the coldest days of the year when batteries are most prone to failure.

In some regions of the province, it may be advisable to add a thermoelectric generator or other remote power generator to supplement solar/battery power systems, providing redundancy and ensuring sufficient power output is available at the site to power communication systems (SCADA, remote terminal units etc.), electric actuators/controllers, and electric chemical injection pumps. However, the addition of a TEG increases costs by $10,000 or more.

Safety

Switching from pneumatic equipment to non-emitting electric equipment reduces venting of flammable gas and improves worker safety. The electric well control system components should be designed to comply with Canadian Standards Association (CSA) certification requirements for hazardous locations (e.g. Class 1, Division 2).

Regulatory

Future Regulatory Considerations:
Both the Alberta Government[34] and the Federal Government[35] have announced their intentions to regulate methane emissions from pneumatic equipment. Draft regulations are expected in 2017 with compliance requirements by the 2020-2023 timeframe. It is expected that there will be specific limits on methane venting from pneumatic pumps and pneumatic controllers, including different standards for new (greenfield) facilities and potential requirements to retrofit existing high-bleed pneumatic controllers.

Electrification of wellsites is an effective way to eliminate methane emissions from all wellsite pneumatic equipment to meet regulatory compliance. The sample project depicted in the Estimated Savings chart would reduce GHG emissions by an estimated 230 tCO_2e/well/year at a low abatement cost of between \$3.70/tCO_2e and \$17.30/tCO_2e (assuming the incremental cost of the solar-electric package ranges from $17,000 to $40,000 and the equipment lifetime is between 10-20 years).

Service Provider/More Information on This Practice

References:

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3.2.2. High to Low Bleed Instrumentation Conversion Projects	July 31, 2017

Description

Across the upstream oil and gas industry, instrumentation is used to take measurements and control processes, typically by sending a signal to a valve to adjust its position based on changes in the process conditions. In pneumatic control systems, pressure (in the form of compressed gas) provides the energy source for process control. Common process-control devices include liquid level controllers, temperature controllers, pressure controllers, pressure regulators, switches and valve controllers (e.g. positioners or transducers).

In general, most pneumatic controllers are set to operate with supply pressures of either 20 pounds per square inch (psig) (for a 3-15 psig signal) or 35 psig (for a 6-30 psig signal), depending on the instrument design. Some larger emergency shut-down valves (ESDVs) may operate at 80 to 100 psig. Devices that operate at higher pressures will vent more gas.

In broad terms, there are three types of pneumatic devices:

- Continuous bleed devices are used to modulate flow, liquid level, or pressure, and will generally vent gas at a steady rate. These devices are used for throttling control and in situations where fast responses are required, such as flow- or pressure-control.
- Intermittent bleed or actuating bleed devices perform snap-acting or on/off-type control, and vent gas only when they stroke a valve open or closed or when they throttle gas flows. Examples of intermittent bleed controllers include certain liquid-level controllers or controllers used for ESDVs.
- No-bleed devices are non-emitting devices such as self-contained devices that vent into the downstream pipeline or other devices that are driven by compressed air. Non-pneumatic devices that rely on electricity or hydraulics may also be referred to as no-bleed devices.

It is common to define controllers as either “high-bleed” or “low-bleed”, where high-bleed controllers are those that vent more than six standard cubic feet per hour (scfh) and low-bleed devices vent less than that threshold. It is important to note that manufacturers usually only specify the steady-state bleed rate and not the dynamic bleed rate associated with valve actuations. Both continuous and intermittent devices can be high-bleed, depending on the device type and process conditions (e.g. frequency of valve actuations).

The conversion from a high-bleed controller to a low-bleed controller can be achieved either by replacing the existing controller or by installing a retrofit kit. Both types of projects will reduce venting of natural gas. A third alternative is to remove from service the high-bleed controllers that are no longer needed to safely operate the process; however, the feasibility of removing controllers is more site-specific.

Baseline:

The baseline for a high to low bleed project is the venting of natural gas or “instrument gas” (containing primarily methane) to the atmosphere from dedicated vent lines associated with the operation of pneumatic controllers. Flaring of instrument gas is not normally practiced for safety and operational reasons (E.g. to prevent backpressure on the instruments).

Throughout the oil and gas industry it is standard practice to use pressurized natural gas to operate pneumatic instruments in process control applications. Once the natural gas has run through the instrument or through the instrumentation loop, it is vented to the atmosphere, resulting in lost natural gas that could have otherwise been directed to sales, as well as greenhouse gas (GHG) emissions. Methane is a potent GHG, with a global warming potential (GWP)[36] of 25 times that of carbon dioxide. Due to the simplicity and reliability of pneumatic instrumentation as well as the lack of available electricity in many locations, pneumatic instrumentation continues to be the standard in the oil and gas industry.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Recommended Practices

Site Applicability

The first step in identifying potential retrofit opportunities is to collect an inventory of pneumatic controllers either across an operating region or for an entire producing field. Completing field-wide retrofit programs helps to achieve economies of scale, which are important in spreading out the transportation and logistics costs associated with retrofit programs.

The next step is to prioritize the sites with known high-bleed controllers such as Fisher 4150 pressure controllers, Fisher 546 transducers, and Fisher 2500 and 2900 level controllers, among others. Typical bleed rates for both high- and low-bleed devices are outlined in the references[37] section of this document.

When evaluating retrofit projects, it is important to confirm that the existing high-bleed controller is necessary. In some cases, it may be possible to completely remove existing high-bleed controllers from service. This is usually the most economical solution. In other cases, a throttling controller can be replaced with a snap-acting controller, such as when a flow controller is replaced with an on/off solenoid for older gas wells that build up pressure and flow intermittently (e.g using timers or plunger lifts).

If the existing controller is in poor condition, the best option is to install a new low-bleed controller rather than a retrofit kit (e.g. for a Fisher 4150 retrofit, a new low bleed C1 controller should be selected instead of a Mizer kit).

Emissions Reduction and Energy Efficiency

Estimated Gas Savings:

Determining the potential gas savings and GHG reductions from a high to low bleed conversion project is relatively straightforward since most oil and gas facilities use common types of pneumatic controllers. The most common method for determining gas savings is to reference the manufacturer specifications for the steady-state gas consumption for each device.

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[36] On January 23, 2014 Alberta Environment updated the GWP of methane to be 25 (from 21). For further details refer to this bulletin: http://esrd.alberta.ca/focus/alberta-and-climate-change/regulating-greenhouse-gas-emissions/alberta-based-offset-credit-system/offset-credit-system-protocols/documents/MemoOnGlobalWarmingPotentials-Feb2014.pdf

[37] The 2013 Prasino study includes field measurements of the most common pneumatic devices, while other sources such as the CAPP BMP document contain manufacturer specifications with steady-state bleed rates.

To qualify for offset credits in Alberta additional data collection is usually required and the best way to estimate potential fuel gas savings and GHG emissions is to take pre- and post-retrofit measurements of the gas vented from the controller. Often, this can be done at the same time as the retrofit is completed to avoid multiple trips to the site. To accurately account for intermittent bleed rates, it may be necessary to collect other information about the underlying process to determine how much venting can be expected from dynamic valve actuations.

Measurement:
To generate verifiable carbon offsets in Alberta from high to low bleed instrumentation conversion projects, it may be necessary to take vent gas measurements from a representative sample of controllers. The Alberta Offset System (AOS) Quantification Protocol for Greenhouse Gas Emissions Reductions from Pneumatic Devices specifies that at least 30 field sample measurements must be taken to generate an emission factor for a controller, if the direct measurement approach is used to quantify GHG reductions. An alternative approach in the protocol does allow for the use of manufacturer's specifications in place of measured values, provided that this approach is conservative (under-estimates GHG reductions). The AOS protocol provides detailed data collection and documentation requirements.

Estimating GHG Emissions:
Under the Alberta Offset System (AOS) Quantification Protocol for Greenhouse Gas Emissions Reductions from Pneumatic Devices the net GHG emission reductions are calculated based on the difference in measured or estimated vent rate between the baseline high-bleed device and the newly-installed low-bleed device, the equipment operating hours, the site gas composition (% methane), the density of methane, and the global warming potential of methane. The AOS protocol provides the full calculation.

A Simplified Formula to Estimate GHG Emission Reductions:
Net GHG Reductions = Baseline Emissions – Project Emissions = (Baseline High Bleed Vent Rate – Low Bleed Vent Rate, each in m^3/hour)*(Operating Hours per year)*(% Methane in gas)*(Density of Methane in kg/m^3)*(0.001 t/kg)*(GWP of Methane).[38]

Estimated GHG Emission Reductions**:**
GHG reductions from 1,062 high to low bleed conversion projects completed by a producer in Alberta averaged 13.2scfh per device (115 mcf/controller/year), equivalent to approximately 50 tCO_2e/controller/year. These retrofits included replacement of high-bleed Fisher 4150 pressure controllers with new low-bleed C1 controllers and replacement of high-bleed Fisher 546 transducers with lower-bleed Fisher I2P-100 transducers, among other retrofits. These projects reduced methane emissions by about 80-90%. Another producer's project installed 110 retrofit kits ("Mizer Kits") on Fisher 4150 pressure controllers, resulting in gas savings of 9.4 scfh per controller (82 mcf/controller/year and GHG reductions of ~36 tCO_2e/controller/year. This project achieved a >85% reduction in vented emissions.

[38] Global Warming Potential of Methane is 25 currently (but subject to change), per: http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/CarbonEmissionHandbook-Mar11-2015.pdf
Density of Methane gas at 15̊C and 1atmosphere is 0.6797 kg CH_4/m3, per https://encyclopedia.airliquide.com/methane

Economic Analysis

Capital Cost:	Capital costs are device- and site-specific, but costs from large retrofit programs completed in Alberta have ranged from \$1,100 to \$2,090 per controller. The equipment costs are only a fraction of the total costs as the drive time between sites and installation labour costs typically make up at least 50% of the total installed costs. Where a retrofit kit can be used (e.g. only a few components need to be swapped out from the old model to the new model, such as the relay), the capital costs may be <\$500/device for certain types of controllers.
Operating Cost:	Operating Costs are typically the same for high-bleed and low-bleed controllers. The replacement of high-bleed devices with new low-bleed controllers may improve reliability, if the existing high-bleed equipment is old, outdated, or in poor condition. This is especially true if replacement parts are hard to find for obsolete controllers.
Maintenance Cost:	Maintenance costs are expected to be similar for high-bleed and low-bleed controllers, but new low-bleed controllers may improve reliability compared to older, outdated, or obsolete high-bleed controllers.
Carbon Offset Credits:	The value of carbon offsets can be very significant for high to low bleed projects and would outweigh the value of the gas savings by a significant margin using an assumed carbon offset value of \$25/offset in Alberta. The ~1,170 projects mentioned above achieved GHG reductions of between 36 to 50 tCO_2e/ controller/ year, which could be worth \$900 to \$1,250/controller/year, assuming a carbon offset value of \$25/offset. The carbon offsets could be worth more than 4X the value of the gas savings!
Payback, Return on Investment and Marginal Abatement Cost:	Gas Savings are the primary benefit from a high to low bleed project and will be somewhat device-specific. Gas savings from over 1,170 projects completed in Alberta averaged between 82 to 115 mcf/controller/year. At a flat \$2.50/mcf AECO gas price, these gas savings would be worth from \$200 to \$300/year. The all-in installed capital costs for the above 1,170 retrofits ranged from \$1,100 to \$2,090 per retrofit. Without carbon offsets the payback for these types of projects is typically three to six years, although certain retrofit kits may have faster paybacks. If carbon offsets are generated, the payback can be reduced to <2 years or even under one year, but additional data collection will be required for the project to be eligible for carbon offsets. The highly-successful retrofit program mentioned above achieved GHG reductions at the very low abatement cost of \$2.09/tCO_2e.

Barriers:

- Financial barriers – low value of fuel gas makes many projects uneconomic, although carbon offsets can improve economics. There may also be minimal capital available for energy efficiency or emission reduction projects.
- Poor quality instrument gas may lead to additional downtime if low-bleed devices have smaller nozzles that are more prone to plugging or freezing.
- Unwillingness to modify proven facility designs that are reliable.
- Remaining asset life is limited.

Reliability

In most cases low-bleed devices can provide the same function as the previous high-bleed device, but low-bleed devices may not be appropriate for certain process control applications, such as where fast responses are required for critical infrastructure or where instrument gas quality is poor. In these cases, low-bleed devices with smaller nozzles could exacerbate problems with freeze-offs or other operational issues. It is always important to understand why the existing controller was installed in the first place and to assess the condition of the existing controller. If the baseline controller is in poor shape, then a retrofit kit should not be used and a new low-bleed controller should be swapped in instead.

Safety

For each retrofit project, it is important to assess the process being controlled by the pneumatic controller to ensure that the new controller can safely perform the same function with the appropriate level of responsiveness. For sour gas production facilities, it is important to specify controller makes/models that contain materials that are compatible with sour service.

Regulatory

Future Regulatory Considerations:
Both the Alberta Government[39] and the Federal Government[40] have announced their intentions to regulate methane emissions from pneumatic controllers. Draft regulations are expected in 2017 with compliance requirements by the 2020-2023 timeframe. It is expected that there will be specific limits on methane venting from pneumatic equipment, including different standards for new (greenfield) facilities as well as potential requirements to retrofit existing pneumatic equipment.

High to low bleed conversion projects are one of the most cost-effective options to significantly reduce methane emissions from pneumatic equipment to meet regulatory compliance. The highly-successful retrofit program mentioned above achieved GHG reductions at the very low abatement cost of \$2.09/tCO_2e.

Service Provider/More Information on This Practice

References:

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[39] https://www.alberta.ca/climate-leadership-plan.aspx#toc-5
[40] http://news.gc.ca/web/article-en.do?nid=1039219

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## 3.2.3. Instrument Gas to Instrument Air (IGIA) Conversion Projects for Pneumatic Control Systems	July 31, 2017

Description

Throughout the oil and gas industry, pressurized natural gas is used to operate pneumatic instruments and pumps in process control and chemical injection applications. Once the natural gas has run through the series of instruments or through a pump, it is vented to the atmosphere. The vented natural gas is primarily methane, a potent greenhouse gas (GHG) with a global warming potential (GWP)[41] of 25 times that of carbon dioxide. In the process, natural gas that could have otherwise been directed to sales is lost.

Converting pneumatic equipment to run on instrument air (an "IGIA Project") rather than instrument gas (pressurized natural gas or "fuel gas") eliminates the venting of natural gas to the atmosphere. A small amount of electricity is required to run the air compressor, but the magnitude of the GHG emissions from this energy input are an order of magnitude smaller than the baseline methane emissions from operating the existing instrument gas system (e.g. typically <5% of baseline emissions).

A typical instrument air system includes an air compressor package housed in a skid-mounted building with electric-drive motors, control panel, air filters, dual regenerative heatless desiccant air dryers, and a wet air receiver that is used as a volume buffer. Often dual air compressors are used in a lead-lag configuration for redundancy and ease of maintenance. For larger gas compressor stations or gas processing plants, a representative air compressor package would be a dual Eagle "Rota Nova NK-60" rotary screw air compressor.[42]

The air compressor package ties in to all air-consuming pneumatic devices at the oil and gas facility, and may require the installation of new piping or modification of existing piping to ensure safe and efficient operation.

Technology Group

Wellsite and Upstream Facilities Instrumentation and Controls – Recommended Practices

Site Applicability

IGIA sites require that sufficient electricity is available onsite to power the added electrical loads from the instrument air compressor, desiccant dryers, metering/communications equipment, and any added building lighting or electric heaters. Three-phase power is usually necessary to run an air compressor, so smaller sites with single-phase power will likely require electrical upgrades to accommodate the new instrument air package.

[41] On January 23, 2014 Alberta Environment updated the GWP of methane to be 25 (from 21). For further details refer to this bulletin: http://esrd.alberta.ca/focus/alberta-and-climate-change/regulating-greenhouse-gas-emissions/alberta-based-offset-credit-system/offset-credit-system-protocols/documents/MemoOnGlobalWarmingPotentials-Feb2014.pdf

[42] http://www.eagle-pc.com/industrial/indus_doc_comp.htm

Piping layout of the facility must also be assessed, as instrument air needs to be distributed to supply pneumatic equipment in each building and sometimes additional devices outside of the buildings, such as emergency shutdown valves (ESDVs). If possible, these should use above ground pipe racks to minimize trenching and hydrovac costs, especially at older plant sites where there may be a lot of underground piping.

Emissions Reduction and Energy Efficiency

Measurement:
It is necessary to install measurement and data-collection equipment to generate verifiable carbon offsets from IGIA projects in Alberta. This requires continuous direct measurement with a dedicated flow meter installed downstream from the air compressor and air dryers. Meters are normally tied into a supervisory control and data acquisition (SCADA) system for continuous data collection, similar to conventional gas production meters. Data is collected every 15 minutes and averaged daily. Meters are typically calibrated annually.

Baseline Emissions:
Methane is vented to the atmosphere from dedicated vent lines associated with the operation of pneumatic instruments and pneumatic pumps. Flaring of instrument gas is not normally practiced for safety and operational reasons (e.g. to prevent backpressure on the instruments).

Under the Alberta Offset System (AOS) Quantification Protocol for Greenhouse Gas Emissions Reductions from Pneumatic Devices the baseline GHG emissions are calculated[43] based on metered compressed air flow rates (after installation of air compressor package), a conversion factor called a gas equivalency factor, the site gas composition (% methane), the density of methane and the global warming potential of methane.

<u>A simplified formula to estimate baseline emissions:</u>
Baseline Emissions = (Estimated Natural Gas Savings in m^3/year)*(% Methane in gas)*(Density of Methane)*(0.001 t/kg)*(GWP of Methane).[44]

Net GHG reduction calculations must include the incremental emissions associated with the electricity used to operate the air compressor (and any other incremental energy inputs).

Estimated GHG Emission Reductions:
GHG reductions from nine IGIA projects completed at compressor stations or small gas processing plants in Alberta ranged from approximately 400 to 8,500 tCO_2e/year per project, with an average of approximately 3,000 tCO_2e/year per project.

Economic Analysis

Capital Cost: Capital costs are highly site-specific, but costs from IGIA projects completed in Alberta at compressor stations and small gas processing plants have ranged

[43] Refer to the AOS Protocol for the full calculation. https://open.alberta.ca/publications/9781460131633
[44] Global Warming Potential of Methane is 25 currently (but subject to change), per: http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/CarbonEmissionHandbook-Mar11-2015.pdf
Density of Methane gas at 15̊C and 1atmosphere is 0.6797 kg CH_4/m3, per https://encyclopedia.airliquide.com/methane

from approximately $75,000 to $350,000. In these sample projects, power was already available at the site. The capital costs may be much higher for off-grid sites that need to add power generation equipment (gensets), bring in power lines to the site, or make other major upgrades to the site electrical infrastructure.

Operating Cost: Operating costs stem from two main sources: The electricity used to run the air compressor, and maintenance of the air compressor and air dryers. For an air compressor that uses 10kW of power on average, the incremental electricity costs would be ~$8,700/year assuming an electricity cost of $0.10/kWh. Maintenance costs include compressor oil changes and servicing the air compressor(s) and dryers, and are estimated at between $2,000 and $5,000/year for a typical project. These costs may be partially or wholly offset by reduced maintenance on instruments if fuel gas previously contained significant impurities (wet gas, hydrocarbons etc.).

Maintenance Cost: Maintenance cost savings can be achieved through switching to clean, dry compressed air, which helps avoid the need to repair instrumentation and controllers, especially if fuel gas quality is poor at the site. The costs of operating and servicing an air compressor may be less than the cost of replacing entire instrumentation loops due to wet gas destroying instrumentation.

Carbon Offset Credits: The value of carbon offsets can be very significant for IGIA projects and, using an assumed carbon offset value of $25/offset in Alberta, would outweigh the value of the gas savings by a significant margin. Based on the GHG reductions achieved by the nine Alberta IGIA projects mentioned above (low of 400 tCO_2e to a high of 8,500 tCO_2e and an average of 3,000 tCO_2e), the value of the carbon offsets at $25/offset could be worth $10,000 on the low end; $212,500 on the high end; an average $75,000 per project per year.

Payback, Return on Investment and Marginal Abatement Cost: Gas savings are the primary benefit from IGIA projects and will be very site specific. Gas savings from nine IGIA projects completed in Alberta ranged from approximately 2.5 mcfd to 51mcfd, with the average at 18mcfd. At a flat $2.50/mcf AECO gas price, these gas savings would be worth from $2,300/yr (2.5mcfd) to $46,500/year (50mcfd) or an average of $16,400/year (18mcfd).

Overall Cost-Benefit: Generally, the larger the site, the better the economics, although other factors such as site layout/piping distances and proportion of high-bleed pneumatic devices will impact the economics. Although economics are very site specific, it is possible to achieve paybacks of <3 years if carbon offsets are generated. Most projects will be uneconomic without carbon offsets, unless the site suffers from high maintenance costs due to wet fuel gas.

Barriers:

- Financial barriers – low value of fuel gas makes many projects uneconomic, although carbon offsets can improve economics. Capital costs are high when retrofitting older facilities. Minimal capital available for energy efficiency or emission reduction projects;
- Inadequate electrical infrastructure to accommodate new loads from air compressor or no electrical connection to the grid;
- Difficulty estimating fuel gas usage associated with instrumentation loops (e.g. small volumes of fuel gas are used by instrumentation relative to larger fuel gas users like compressor engines;
- Unwillingness to modify proven facility designs that are reliable.

Reliability

Industrial instrument air systems provide high reliability, especially when designed with redundancy to use dual air compressors in a lead-lag configuration such that one air compressor can be serviced while the other unit is running. This approach also extends the lifespan of the air compressors as only one unit is running at a time. At sites where instrument gas quality is poor, the addition of an instrument air system can improve reliability and reduce maintenance of instrumentation.

If power outages are common, then it is wise to purchase a portable gasoline/diesel-powered air compressor that can be tied into a piping "t" to supply compressed air to the facility. This adds to cost, but avoiding production downtime will allow the incremental cost to be recovered quickly during upsets. Designing larger air storage buffer vessels is another tool to reduce risk of downtime. This is recommended if the facility's engines are started using compressed air in pneumatic starters.

Safety

IGIA conversion project must ensure that all the pre-existing instrumentation tubing and fuel gas piping that previously distributed instrument gas to the pneumatic devices is carefully isolated from the new compressed air pipelines to avoid any chance of air and gas mixing to create an explosive environment.

Regulatory

Operators must obtain and comply with relevant facilities codes and regulations.

Future Regulatory Considerations:
Both the Alberta Government[45] and the Federal Government[46] have announced their intentions to regulate methane emissions from pneumatic controllers and pumps. Draft regulations are expected in 2017 with compliance requirements by 2020-2023 timeframe. It is expected that there will be specific limits on methane venting from pneumatic equipment and different standards for new (greenfield) facilities and potential requirements to retrofit existing pneumatic equipment.

IGIA projects can be an excellent solution to meet regulatory compliance by completely eliminating methane emissions from pneumatic equipment.

[45] https://www.alberta.ca/climate-leadership-plan.aspx#toc-5
[46] http://news.gc.ca/web/article-en.do?nid=1039219

Service Provider/More Information on This Practice

References:

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Section 4.1. Injection Pumps – Facilities Design and Equipment

4.1.1. Sirius Solar Chemical Injection Pump – Star Injection System

July 31, 2017

Description

Chemical injection during the processing of oil and gas leads to increased productivity and profitability. This is most often accomplished with natural-gas-powered pneumatic pumps that vent significant methane to the atmosphere. The solar-powered Sirius Comet Solar Chemical Injection pump and Star control provides precise chemical injection while eliminating greenhouse gas emissions. The seals are chemically inert, which means the pump can moved to multiple applications without seal changes out required. Also, the Sirius pump can be installed with an 8-point injection manifold to inject the same chemical into 8 different points, eliminating multiple gas driven pumps with one solar pump. The Star controller's user interface is easy to calibrate and operate for day to day tasks and has extensive automation capabilities to further optimize injection. The equipment is suited to both new and retrofit installations.

Technology Group

Injection Pumps – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; wellsite, midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The Comet Pump operates with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost:	Capital costs are approximately $4,000 for a retro fit and $15,000 for a new installation. However, exact costs depend upon the specific application based on flow rate, pressure, location and optional accessories (to determine solar requirements).
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $200/yr, but exact costs are site- and application-specific.

Carbon Offset Credits:	The Comet Solar Injection Pump and Star controller are eligible for the Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically six months to three years, the payback period is project-dependent and affected by the following: purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, maintenance cost savings, and value of any GHG offset credit or carbon tax reduction awarded. Utilization of controller's automation features can expedite the payout.

Reliability

Expected Lifetime:	The equipment is expected to last approximately 20 years.
Maintenance:	Maintenance manuals are provided by the manufacturer. In addition, further training via online 'pumps schools' are available for trained technical sales staff if required. Operators will be able to do regular maintenance with no training.

Safety

No unusual safety requirements apply. Normal electrical and MSDS procedures must be followed.

Regulatory

- UL- & CSA-compliant Class 1 Div 1 for Pump and motor and Class 1 Div 2 for entire system.
- True secondary containment for the entire system ensures any leaks from tank, pump, sight glass, and tubing connections will be contained and prevented from leaking on the ground. Dual seals further reduce pump leaks by preventing chemical leaks.
- No AER directives apply.

Vendor Information

Company Name:	Sirius Controls
Company Website:	www.siriuscontrols.com
Product Website:	Product information is available on the company website above
Contact Person:	Sean Buffett
Contact Phone#:	780-436-6301
Contact Email:	sales@siriuscontrols.com

4.1.2. TRIDO Industries Inc. - Solar Chemical Injection Pump

April 26, 2019

Description

Across the upstream oil and gas industry, various chemicals are injected into oil and gas wells and into pipelines to maintain and increase productivity. Industry standard natural-gas-driven pneumatic pumps vent significant methane to the atmosphere. The TRIDO Mini-Mizer Solar Powered Actuator is field-proven to accurately deliver desired chemical amounts year-round with zero venting. Ultra-low power usage combined with ultra-high torque enables the unit to pump against higher than normal pressures. TRIDO's customizable fluid head carrier system can carry from one to eight heads to inject the desired volume of chemical or chemicals to eight injection points. The TRIDO system is compatible with most available fluid head technologies.

Features of the Mini-Mizer solar injection pump include:

- Controller performs as a variable frequency drive (VFD) and samples the motors performance 4000x per second and adjusts to deliver the precise amount of energy required to maintain the desired injection rate while using the lowest amount of power possible.
- Low power consumption on start-up (approximately 400 mA) mitigates premature battery failure and provides longest autonomy available.
- Pinpoint injection control from 0.5 litre to six barrels per day.
- Operates against extremely high pressures (10,000 psi+) utilizing extremely high torque.
- Can inject different volumes of different chemicals to up to eight injection points on a single system.
- Adaptable to fit the most common fluid heads on the market (ie, Texsteam 5100 series).
- Programmable VFD controller operates in several modes including variable, temperature, pressure, and supervisory control and data acquisition (SCADA) via MODBUS.
- Efficient motor allows the system to operate on fewer batteries and solar panels, reducing the systems footprint.

Technology Group

Injection Pumps – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The Mini-Mizer operates with zero emissions. However, exact calculations of the rate of methane emission reduction are commensurate with both the specific pump being replaced and the operating conditions.

Economic Analysis

Capital Cost:	Capital costs are in line with market prices. However, exact costs depend upon the specific application based on flow rate, pressure, location and optional accessories.
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none as there are no fuel costs. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	The maintenance costs are usually less than $500/year, but exact costs are site- specific.
Carbon Offset Credits:	The TRIDO Mini-Mizer Solar Powered Actuator is eligible for the Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the payback period is project-dependent and affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any greenhouse gas (GHG) offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment is expected to last 10 years.
Maintenance:	There are no expected maintenance costs. Operators will be able to conduct regular maintenance with no additional training. The pump uses a maintenance-free, 3-phase 24V brushless permanent magnet solar motor.

Safety

No unusual safety requirements apply.

Regulatory

- Solar motor rated CSA Class 1 Div. 1. Controller rated Class 1, Div. 2.
- No AER Directive applicable

Vendor Information

Company Name:	TRIDO Industries Inc.
Company Website:	www.tridoind.com
Product Website:	Product information is available on the company website.
Contact Person:	Russell Graham
Contact Phone#:	1-855-368-7438
Contact Email:	sales@tridoind.com

4.1.3. Zimco – GE Texsteam iCIP Solar Injection Pump	June 30, 2017

Description

Injecting chemicals during the processing of oil and gas helps to maintain and increase production. This is most often accomplished with natural-gas-powered pneumatic pumps that vent significant methane to the atmosphere. The GE Texsteam iCIP Series' solar-powered chemical injection pumps operate emissions-free. The pumps provide integrated communications and date-stamped data logging. These capabilities, combined with optional input/outputs, allow operators to monitor remotely and adapt to changes in well pressure and temperature, chemical use, and pump motor speed. This prevents well shutdown, pump repairs, and environmental damage due to chemical leaks.

Features of the equipment include:

- Optional secondary containment fluid end adapter which eliminates v-ring packing and the potential of chemical leaks
- Standard configurations utilize GE Texsteam packing, plungers and 316SS fluid ends, requiring no special components to be stocked.
- SDP packing and O-Rings are compatible with a broad range of chemicals, can operate for many times longer than other elastomer choices.
- Low-amp/high-torque motor (brushless, continuous duty, variable speed DC gear motor) allows for the use of fewer panels and batteries.
- Controller can be programmed locally and/or remotely via push-button menu tree, laptop USB connection, SCADA, or Modbus protocols.
- PLC controller allows the use of up to 11 I/O's utilizing 10 schedules and 10 alarm points to modify the performance of the pump and control other devices without requiring an on-site operator.

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The GE Texsteam iCIP Series' solar-powered chemical injection pump operates with zero emissions. However, exact calculations of methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost:	Capital costs are approximately $6,000 for a retro fit and $10,000 for a new installation. However, exact costs depend upon the specific application based on flow rate, pressure, location and optional accessories.
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/year, but exact costs are site-and application-specific.
Carbon Offset Credits:	The GE Texsteam iCIP Series' solar-powered chemical injection pump is eligible for the Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the payback period is project-dependent and affected by the following: Purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, maintenance cost savings, and value of any GHG offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime: The equipment is expected to last 20+ years.

Maintenance: Maintenance costs are minimal as operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

- CSA Class 1 Division 2 and CSA Class 1 Division 1 Groups C & D.
- No AER Directive applicable.

Vendor Information

Company Name: Zimco Instrumentation Inc.
Company Website: http://www.zimco.ca/
Product Website: http://zimco.ca/pdf/texsteam/TXT%20Solar%20Pump%20Bro%200412.pdf
Contact Person: Richard Hiebert / Ron Becker
Contact Phone#: 403-253-8320 / Cell 403-620-4587
Contact Email: richard.hiebert@zimco.ca / ron.becker@zimco.ca

4.1.4. CVS Controls Low Emission Chemical Pump

July 31, 2017

Description

Throughout the oil and gas industry, pressurized natural gas is used to operate pneumatic chemical injection pumps, and then is vented to the atmosphere. The CVS Low-Emission Chemical Injector Pump is a positive displacement reciprocating pump capable of discharge pressures up to 10,000 psi (690 bar). The stroke rate is controlled by adjusting the speed-control valve from one to 60 strokes per minute (SPM), allowing for capacities up to 60 gallons (230 litres) per day.

This low-consumption unit can run either air or gas. The inlet pressure ranges from a minimum of three psi (0.206 bar) to a maximum of 150 psi (10.342 bar). The choice of three plunger sizes, coupled with controllable strokes per minute (SPM) and a slow speed controller allows for a capacity ranging from less than 1 quart up to 60 gallons/day. This is a lightweight, reliable and rugged pump that can be serviced easily in the field.

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

Methane emission reductions are commensurate with the specific pump being replaced and the prevailing operating conditions.

Economic Analysis

Capital Cost:	Capital costs range from $500 to $5000. Costs depend upon the specific application, taking into account flow rate, pressure, location and optional accessories.
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/yr, but exact costs are site-specific.
Carbon Offset Credits:	The CVS Low-Emission Chemical Injector Pump is eligible for the Pneumatics Protocol Offset credits in Alberta.

Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the payback period is project-dependent and affected by the following: Purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, maintenance cost savings, and value of any greenhouse gas (GHG) offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The CVS Low-Emission Chemical Injector Pump is expected to last 10 years.
Maintenance:	Maintenance costs are minimal as operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

- CSA approved Class 1, Div 2, Group A, B, C.
- No AER Directive applicable

Vendor Information

Company Name:	CVS Controls
Company Website:	http://www.cvs-controls.com
Product Website:	http://www.cvs-controls.com/literature/CVS%20Low%20Emission%20Chemical%20Pump%20May%202016.pdf
Contact Person:	Garett Reimond
Contact Phone#:	(403) 250-1416
Contact Email:	garett@cvs-controls.com

4.1.5. MCI Solutions – Solar Electric Chemical Injection Pumps	July 31, 2017

Description

The oil and gas industry standard is to use natural-gas-driven pneumatic pumps for chemical injection, especially in Canada's North. However, these systems vent significant methane to the atmosphere. Canada's northern conditions pose significant challenges for solar powered equipment: cold temperature extremes, 1.6 peak sunlight hours daily, and geographic remoteness that demands reliability. MCI Solutions solar-electric pumps are designed to withstand conditions at Northern Canadian well sites and provide reliable chemical injection with no greenhouse gas (GHG) emissions.

The pumps are digitally-controlled either by a local operator through a simple keypad, or remotely through discrete analogue or Modbus input. Injection accuracy to fractions of a litre per day maximizes the chemical program effectiveness while managing its overall cost.

MCI Solar Electric pumps features include**:**

- Electric Drive (12V or 24V DC)
- Inject at fractions of a litre per day (LPD) down to 0.1 litres.
- Do not vary injection rate due to changes in well pressure or line pressure, avoiding over-injection of expensive chemical or under-injection that jeopardizes infrastructure.
- Patented secondary containment system that captures chemical leaks past the high-pressure plunger seal and redirects that chemical back to the suction side.
- Pump can be set accurately by starting the pump and inputting the desired injection volume in increments of 0.1 LPD.
- Controlled remotely through SCADA or ROC using Modbus, 4-20mA analogue or a discrete on/off input including a "pump state on or off" output.
- Equipped with a temperature sensor on a 10 foot length of wire that allows the pump to automatically start and stop based on the ambient temperature using user-defined set points. These set points can either be entered at the MCI factory or by using a free graphical user interface (GUI). The GUI also allows users to set the disconnect/ reconnect set points.
- CSA (C/US) certified for installation in class I, zone 2 areas.
- Automatic low-voltage disconnect/reconnect feature on battery-powered zone-1-certified pumps maintains battery charge in the event the charging system fails.
- Do not pause between strokes to modulate their injection volume, maximizing chemical dispersion.
- Three modes of operations:
- Pause between each stroke for maximum power efficiency.

- Continuous stroke where the suction stroke takes 3-seconds. The stepper motor controller can completely vary the motor behavior, slowing the injection stroke to match the desired injection volume.
    - Continuous chemical injection for maximum dispersion

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

MCI Solar Electric Chemical Pumps operate with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost:	Capital costs range from $4,000 to $14,000. However, exact costs depend upon the specific application based on flow rate, pressure, location, and optional accessories.
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/year, but exact costs depend on the site.
Carbon Offset Credits:	The MCI Solar Electric Chemical Pump is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the payback period is project-dependent and affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any GHG offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment is expected to last 10 to 20 years.
Maintenance:	Maintenance costs are minimal as operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

Pumps are certified to either CSA class 1, zone 1 or zone 2 depending on the model.
MCI solar-electric driven pumps are zero GHG emission devices and are compliant with zero GHG emission directives by Alberta Energy Regulator (AER).

Vendor Information

Company Name:	MCI Solutions
Company Website:	www.mcisolutions.ca
Product Website:	http://mcisolutions.ca/our-products/solar-pump-packages/
Contact Person:	Chris Kane
Contact Phone #:	Cell: (250) 262-7443
Contact Email:	chris@mcisolutions.ca

4.1.6. Sidewinder Pumps Inc. Solar-Powered Chemical Injection Pumps

July 31, 2017

Description

Across the upstream oil and gas industry, various chemicals are injected into oil and gas wells and pipelines to maintain and increase productivity. Industry standard natural-gas-driven pneumatic pumps vent significant methane to the atmosphere. Sidewinder Pumps Inc.'s solar-powered pumps provide reliable chemical injection while eliminating greenhouse gas emissions. The pumps run on 12VDC power supplied through Gel Cell Matt Batteries that are recharged with 12V solar panels. Equipped with the Sidewinder timer control and stroke length adjuster, the pumps maintain accurate and repeatable flow rates while handling discharge pressures to 5,000 psi & flow rates to 587 QPD.

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

Sidewinder Solar Chemical Injection Pumps operate with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost:	Capital costs range from $1,800 to $4,000 for a simplex to duplex setup and solar voltaic requirements, and from $2,450 to $4,000 for an XP Motor and solar voltaic requirements. However, exact costs depend upon the specific application based on flow rate, pressure, location and optional accessories.
Installation Cost:	Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.
Operating Cost:	Minimal additional operating costs are expected, and possibly none. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/year, but exact costs depend on the site.

Carbon Offset Credits:	The Sidewinder Solar Chemical Injection Pump is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the exact payback period depends upon the project and is affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any greenhouse gas (GHG) offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment is expected to last 20+ years
Maintenance:	Maintenance of the equipment requires only standard knowledge of DC motors, photo voltaic systems, and positive displacement pumps. Operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

- CSA Class 1 Div 2
- Meets AER Directive 84 Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area

Vendor Information

Company Name:	Sidewinder Pumps Inc.
Company Website:	https://www.sidewinderpumps.com/
Product Website:	Product information is available on the company website
Contact Person:	Guy Chachere
Contact Phone#:	337-235-9838
Contact Email:	Info@sidewinderpumps.com

4.1.7. Sidewinder Pumps Inc. Chemical Metering Injection Pumps	July 31, 2017

Description

Chemical injection metering pumps inject various chemicals for oil and gas production. Applications include, but are not limited to, the wellhead, pipeline, gas treatment plant, scrubbers, separators and compressors. However, natural-gas-powered pneumatic chemical injection pumps vent significant methane to the atmosphere. Sidewinder Pumps Inc's AC-powered pumps use available current 110VAC/60Hz/1 Phs power, which eliminates methane emissions. Equipped with the Sidewinder timer control and stroke length adjuster, the pumps maintain accurate and repeatable flow rates while handling discharge pressures to 5,000 PSI & Flow rates to 146 QPD.

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

Sidewinder AC Chemical Metering Injection Pumps operate with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost: Capital costs range from $1,800 to $2,400 for a simplex to duplex setup and from $2,450 to $2,800 for an XP Motor and timer control. However, exact costs depend upon the specific application based upon flow rate, pressure, location and optional accessories.

Installation Cost: Installation costs range from $500 to $4,000 depending on site location, chemicals, and pressures.

Operating Cost: Minimal additional operating costs are expected, and possibly none. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.

Maintenance Cost: Maintenance costs are usually less than $500/year, but exact costs depend on the site.

Carbon Offset Credits:	The Sidewinder AC Chemical Metering Injection Pump is eligible for the Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the exact payback period depends upon the project and is affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any GHG offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment is expected to last 20+ years.
Maintenance:	Maintenance of the equipment requires only standard knowledge of AC motors and PD pumps. Operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

- CSA Class 1 Div 2
- Meets AER Directive 84 'Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area'

Vendor Information

Company Name:	Sidewinder Pumps Inc.
Company Website:	www.sidewinderpumps.com
Product Website:	https://www.sidewinderpumps.com/product/sidewinder-ac-chemical-metering-pump/
Contact Person:	Guy Chachere / Paul George
Contact Phone#:	337-235-9838
Contact Email:	info@sidewinderpumps.com

### 4.1.8. LCO Technologies / Spartan Controls - The CrossFire	April 26, 2019

Description

Chemical injection during the processing of oil and gas leads to increased productivity and profitability. Unlike the standard pneumatic pumps driven by natural-gas, Spartan Controls' CrossFire is an ultra-low power electric pump that emits no greenhouse gasses (GHGs). The Crossfire pump has a wide range of applications in the upstream Oil & Gas Industry, including methanol injection, de-soaping agents, corrosion inhibitors, scaling inhibitors, and a variety of others. It can handle injection rates ranging from >1L/day to a maximum 720L/day, and pressures up to 10,000 psi. The pump features a robust controller design. Just one crossfire unit can replace up to four pneumatic pumps. The ability to easily field-swap 5100-series pumps with the Crossfire makes it well-suited to both retrofits and new installations.

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The Crossfire operates with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost:	Can range and vary but a good average is 4000$ - 10,000$ depending on accessories and other factors during engineering
Installation Cost:	Installation costs range from $500 to $4000 depending on site location, chemicals, and pressures.
Operating Cost:	Operating costs are dependent on the specific method of power generation. However, minimal additional operating costs are expected. No fuel is required. Operational adjustments can be completed as part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/year, but exact costs are site-dependent.
Carbon Offset Credits:	The Crossfire is eligible for Pneumatics Protocol Offset credits in Alberta.

Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the exact payback period depends upon the project and is affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any GHG offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment is expected to last 10+ years
Maintenance:	As the equipment uses the same fluid ends as the widely-used Texsteam 5100, operators will be able to do regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

CSA Cl I Div I on pump motor. CSA Cl I Div II on controller. As it is being reviewed by the AER, the LCO Technologies CrossFire is a form of no-bleed compliance.

Vendor Information

Company Name:	Spartan Controls
Company Website:	www.spartancontrols.com
Product Website:	Product information is available on the company website.
Contact Person:	Nik Belyk / Chris Breen / Steven Froehler
Contact Phone#:	403-589-1780
Contact Email:	Belyk.Nik@spartancontrols.com

4.1.9. ACE Instruments Ltd – Solar Chemical Injection Systems

July 31, 2017

Description

The oil and gas industry standard is to use natural-gas-driven pneumatic pumps for chemical injection. Although this process increases production, it also vents methane to the atmosphere. Ace Instruments' solar chemical injection pumps are entirely solar-powered, and require no gas, air, or electrical power source, so they generate no greenhouse gas (GHG) emissions. Each system is individually sized and assembled in a variety of configurations for specific customer requirements and locations. They can operate autonomously for days without sun, making the system well-suited to Canada's extreme climate conditions. The system can be used in a wide range of applications, from extremely remote areas to fabricated buildings.

The Ace Solar Chemical Injection System features include:

- No stalling problems associated with wet gas – no regulator problems
- Pre-wired/preassembled systems for quick installation
- State of the art piston and seal technology
- No springs or diaphragms to break or wear out
- Self-lubricated
- Accurate and dependable timer control
- No volatile organic compound (VOC) emissions
- Portability – if requirements change, systems can be easily relocated
- CSA certified packages
- Full range of chemical compatibility with proper seals

Technology Group

Injection Pumps - Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The Ace Instruments' solar chemical-injection system operates with zero emissions. However, exact calculations of the methane emission reduction rate are commensurate with both the specific pump being replaced and operating conditions.

Economic Analysis

Capital Cost: Capital costs range from $2,500 to $30,000. The cost is application dependent, based on flow rate, pressure, location and optional accessories.

Installation Cost: The installation costs range from $500 to $4,000. Installation costs are dependent upon site location, chemicals, and pressures.

Operating Cost:	Minimal to no additional operating costs are expected. Zero fuel is used. Operational adjustments can be part of normal operator rounds.
Maintenance Cost:	Maintenance costs are usually less than $500/year, but exact costs are site-dependent.
Carbon Offset Credits:	The Ace Instruments' Solar Chemical Injection System is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	Although typically one to three years, the exact payback period depends upon the project and is affected by purchase and installation costs, natural gas savings, chemical savings from improved injection accuracy, savings on well servicing costs, maintenance cost savings, and the value of any GHG offset credit or carbon tax reduction awarded.

Reliability

Expected Lifetime:	The equipment has proven to last 10+ years
Maintenance:	Maintenance is required as per the equipment installation guide. Operators will be able to complete regular maintenance with no additional training.

Safety

No unusual safety requirements apply.

Regulatory

CSA, Class1 Div 1pump / Control - Class1 DIv2 / No AER Directive

Vendor Information

Company Name:	Ace Instruments Ltd
Company Website:	www.ace95.com
Product Website:	http://ace95.com/products-services/sunpumper-solar-powered-pumps/
Contact Person:	Gerry Riel
Contact Phone#:	587 436 1209
Contact Email:	gerryr@ace95.com

Section 4.2. Injection Pumps – Recommended Practices

4.2.1. Solar-Powered Chemical Injection Pumps	July 31, 2017

Description

Across the upstream oil and gas industry, various chemicals are injected into oil and gas wells and into pipelines for operational reasons. The most commonly-used chemical is methanol, which is injected into gas production wells to prevent hydrate formation (freezing), but other chemicals include corrosion inhibitors, de-waxing agents, biocides, scavengers (for treating hydrogen sulphide), and surfactants.

Pneumatic pumps are typically classified as either diaphragm pumps or piston pumps. Both types of pneumatic pumps operate in the same manner, but use different reciprocating mechanisms to drive the chemical injection process.

Piston pumps are positive displacement type pumps with single acting heads that are piston powered with a return spring. The gas supply pressure is set to 35-150 psig, depending on the injection pressure, and gas is introduced to the pump to move the plunger the desired stroke length. This stroke length has a direct relationship to the amount of liquid being injected. The vent port is opened at the end of the stroke, allowing the supply gas to vent to atmosphere. The piston returns to its starting position via a spring return mechanism. The process then repeats until the desired volume is reached. These pumps are constantly pumping; control of speed or rate of strokes per minute is accomplished by means of an external controller.[47]

Diaphragm pumps are also positive displacement type pumps with single acting heads, but are diaphragm powered. The gas supply pressure is set to 35-50psi, depending on the model of pump, and gas is introduced to the diaphragm pump to move the plunger the desired stroke length. This stroke length has a direct relationship to the amount of liquid being injected. At the end of the stroke a trip mechanism is triggered on the diaphragm pump allowing the supply gas to fully exhaust to the atmosphere while returning the plunger back to its starting position via a spring return mechanism. The process then repeats until the desired volume is reached. Diaphragm pumps continuously pump: volume control is accomplished by regulating the exhaust gas discharge. A needle valve located on the exhaust port of the pump controls the number of strokes of the pump.[48]

A solar pump generally consists of the following components: an electric pump, pump controller, batteries, solar photovoltaic panels, a stand or mast for the panels, and a charge controller. Some solar pumps come pre-configured with a chemical tank, secondary containment, and skid assembly for quick deployments, while other vendors offer a pump drive that is designed for direct mounting on existing pumps, replacing the diaphragm cover and return spring with a motor driven actuator. A single pump can inject more than one fluid if the pump has multiple heads. Electric pumps are also more automated and can be programmed to operate at precise injection rates or even be adjusted remotely if connected to SCADA.

Baseline:

The baseline for a pneumatic pump replacement project is the venting of natural gas or “instrument gas” (containing primarily methane) to the atmosphere from dedicated vent lines. The exhaust tubing

[47] CAPP BMP for Efficient Use of Fuel Gas in Chemical Injection Pumps (Module 5)

[48] CAPP BMP for Efficient Use of Fuel Gas in Chemical Injection Pumps (Module 5)

from the outlet of a pneumatic pump is normally routed outside of the building to vent the gas to atmosphere. Flaring of instrument gas is not normally practiced for safety and operational reasons.

Throughout the oil and gas industry, it is standard practice to use pressurized natural gas to operate pneumatic chemical injection pumps. By design, pneumatic pumps take pressurized gas and use the energy of that gas to drive the pump. This results in gas at near atmospheric pressure which is subsequently vented to the atmosphere, resulting in lost natural gas that could have otherwise been directed to sales, as well as greenhouse gas (GHG) emissions. Methane is a potent GHG, with a global warming potential (GWP)[49] of 25 times that of carbon dioxide.

Due to the simplicity, reliability, and low capital cost of pneumatic pumps, as well as the lack of available electricity in many locations, pneumatic chemical injection pumps continue to be the standard in the oil and gas industry.

Technology Group

Injection Pumps – Recommended Practices

Site Applicability

The first step in identifying potential retrofit opportunities is to collect an inventory of pneumatic pumps including the following data:

- Pneumatic pump make, model, and stroke length;
- Injection rate (litres/day);
- Injection pressure;
- Estimated pump operating hours per year;
- Injection fluid type (methanol, corrosion inhibitor, de-waxing agents etc.)
- Other site-specific factors

The next step is to prioritize the baseline pumps with the highest vent rates (eg: Texsteam or Bruin 5000 or 5100 series, Williams P250 or P500 series, Morgan pumps). It is also useful to identify pumps that operate year-round and pumps that operate at high injection rates or high injection pressures because replacing these pumps generates the largest savings. Further information on typical pump vent rates for various types of pneumatic pumps is available in the references section of this document.

Site selection has a significant impact on the efficiency and cost-effectiveness of a solar-driven system, as the panels and batteries must be designed with enough autonomy or reserve capacity to reliably deliver power during the coldest (~-40°C) and cloudiest weeks of the year. Ideally the solar panels should be deployed far from any trees/tree line or should be properly secured on an elevated mast. While it is possible to design a solar-driven system to meet almost any site configuration, the system cost increases significantly as more panels and batteries are added for sites at higher latitudes and in cloudy regions with low levels of winter sunlight. However, latitude is not necessarily a limiting factor for solar. Several hundred solar chemical injection pumps have been successfully deployed as far north as Fort Nelson, BC and the Rainbow Lake area in Northern Alberta.

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[49] On January 23, 2014 Alberta Environment updated the GWP of methane to be 25 (from 21). For further details refer to this bulletin: http://esrd.alberta.ca/focus/alberta-and-climate-change/regulating-greenhouse-gas-emissions/alberta-based-offset-credit-system/offset-credit-system-protocols/documents/MemoOnGlobalWarmingPotentials-Feb2014.pdf

Emissions Reduction and Energy Efficiency

Estimated Gas Savings:

Determining the potential gas savings and GHG reductions from a pneumatic pump conversion project is relatively straightforward since most oil and gas facilities use common types of pneumatic pumps. The most common method for determining gas savings is to reference the manufacturer specifications for the pump. Most pneumatic pump manufacturers provide a curve or plot of the gas consumption per unit volume of chemical injected (scf natural gas/gallon chemical) versus the injection pressure for specific models and stroke lengths. By knowing the model of pump, the injection pressure, the chemical injection rate and the annual operating hours, the amount of gas vented (or saved) per year can be determined.

In the absence of site-specific data, rough estimates can be developed using published emission factors for generic piston or diaphragm pumps. The 2013 Prasino study[50] determined average vent rates of 1.0542m^3/hour for 'generic diaphragm pumps' and 0.5917m^3/hour for 'generic piston pumps'.

To qualify for offset credits in Alberta, additional data collection may be required. This may include monitoring and recording the volumes of chemical injected over time, tracking the number of pump strokes (I.e. using a stroke counter), and tracking operating pressures (supply pressure and injection pressure). It is also important to document the make and model of the previous pneumatic pump.

Measurement:

To generate verifiable carbon offsets in Alberta from pneumatic pump conversion projects it may be necessary to collect additional documentation that would not normally be recorded by operators. The Alberta Offset System (AOS) Quantification Protocol for Greenhouse Gas Emissions Reductions from Pneumatic Devices requires that baseline emissions be estimated by tracking either the count of pump strokes from the new solar pump or the volume of chemical injected by the new pump.

Estimating GHG Reductions:

Under AOS Protocol for Pneumatic Devices the net GHG emission reductions are calculated based on the following:

- The type of pneumatic pump being replaced, including make, model, plunger size, operating pressures and other information needed to determine a pump emission factor from manufacturer specifications for the baseline pneumatic pump;
- The chemical injection rate (e.g. in Litres/day). This may need to be estimated from other information, such as a count of the number of pump strokes per time increment, the volume of chemical injected per time increment, or other factors;
- Solar pump operating days (or hours) per year;
- The site fuel gas composition (% methane);
- The density of methane; and,
- The global warming potential of methane.

The full calculation is outlined in the AOS Protocol.

[50] Prasino Group. December 18, 2013. Final Report. For Determining Bleed Rates for Pneumatic Devices in British Columbia.
http://www.capopenergy.com/uploads/1/1/7/8/11781696/prasino_pneumatic_ghg_ef_final_report.pdf

A simplified formula to estimate GHG emission reductions:

Net GHG Reductions = Baseline Emissions = (Baseline Pump Vent Rate in m^3 natural gas/Litre of chemical injected)*(Injection Rate in Litres/Day)*(Operating Days per year)*(% Methane in gas)*(Density of Methane in kg/m^3)*(0.001 t/kg)*(GWP of Methane).[51]

Estimated GHG Emission Reductions:

GHG reductions from 86 solar pump projects completed by a major producer in Alberta averaged 320 mcf/pump/year, equivalent to approximately 140 tCO_2e/pump/year. Another 138 solar-pump projects completed by a major producer in southern Alberta achieved gas savings of 200 mcf/pump/year and reduced GHG emission by an estimated ~90 tCO_2e /pump /year. However, GHG reductions will vary significantly depending on the baseline pneumatic pump type, the required injection rate for the new solar pump, pump injection pressures, operating hours, percent methane in fuel gas, and other factors.

Economic Analysis

Capital Cost: Capital costs are pump- and site-specific, but costs from approximately 220 pump retrofit projects completed in Alberta have ranged from $8,000 to $13,400 per pump. The equipment costs make up the majority of the capital costs for solar pump projects since the installation of solar pumps is relatively straightforward and can typically be completed for <25% of the total cost.

Operating Cost: Operating Costs are typically lower for solar pumps than for pneumatic pumps. Battery replacements make up the main incremental operating costs for solar-electric pumps. Assuming a maximum of four batteries per site and a six-year battery life, with a replacement cost of $175/battery, the average operating costs for a solar pump are $116/pump/year over a six-year period. These costs are still lower than the operating savings from reducing chemical usage and eliminating fuel gas usage.

Maintenance Cost: Maintenance cost savings and chemical savings are significant, as electric pumps are typically more reliable and more precise at chemical injection. Electric pumps also allow for increased automation, including the ability to adjust injection rates remotely on pumps tied into SCADA. In addition, electric pumps' secondary seal mitigates the risk of chemical leaks around the pump seals (e.g. methanol destroys elastomers), a common problem with pneumatic pumps. For more expensive chemicals such as corrosion inhibitors, the chemical savings can be significant. Additionally, the precise, easily-adjusted injection rates of electric pumps (down to 0.5L/day) prevent over-injection, achieving significant methanol savings for lower pressure gas wells. A major producer completed 140 pneumatic pump replacement projects at shallow gas facilities in southern Alberta, achieving methanol savings of approximately

[51] Global Warming Potential of Methane is 25 currently (but subject to change), per: http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/CarbonEmissionHandbook-Mar11-2015.pdf

Density of Methane gas at 15̊C and 1atmosphere is 0.6797 kg CH_4/m3, per https://encyclopedia.airliquide.com/methane

	\$500/year/pump (based on an average 5L/day reduction in methanol injection rates)
Carbon Offset Credits:	The value of carbon offsets can be very significant for pneumatic pump retrofit projects, and would outweigh the value of the gas savings by a significant margin using an assumed carbon offset value of \$25/offset in Alberta. The ~220 sample projects by major producers in Alberta achieved estimated GHG reductions of 90 to 140 tCO_2e/ pump/ year, which could be worth \$2,250 to \$3,500/pump/year assuming a carbon offset value of \$25/offset. Therefore, the potential carbon offsets could be worth more than 4X the value of the gas savings!
Payback, Return on Investment and Marginal Abatement Cost:	Gas savings is one of the primary benefits of replacing a pneumatic pump with a solar pump. Gas savings depend on many factors, including operating hours, chemical injection rates, pump make/model, operating pressures, and other factors. Gas savings from over 220 solar pump installations completed in Alberta averaged between 200 to 325 mcf/pump/year. At a flat \$2.50/mcf AECO gas price, these gas savings would be worth \$500 to \$810/year. The all-in installed capital costs for the above 220 retrofits ranged from \$8,000 to \$13,400 per retrofit. Without carbon offsets, the payback for these types of projects is typically eight to 12 years. If carbon offsets are generated, the payback can be reduced to two to three years, although additional data collection is required for to be eligible for carbon offsets. One successful retrofit program at a major Canadian producer achieved an estimated 12,040 tCO_2e/year of GHG reductions from 86 solar pump installations at a low abatement cost of \$4.78/tCO_2e. Another project by a major producer achieved similar GHG reduction results at an abatement cost of approximately \$10.30/tCO_2e.

Barriers:

- Financial barriers – solar pumps are considerably more expensive than pneumatic pumps (often 5X higher capital costs) and when considering only gas savings, the low value of fuel gas makes many projects uneconomic. However, chemical savings and carbon offsets can improve economics. Minimal capital is often available for energy efficiency, optimization or emission-reduction projects;
- Solar reliability may be lower in areas with reduced sunlight, such as valleys, heavily treed areas, or regions with frequent cloud cover. In extreme cold weather and long periods without enough sunlight to charge batteries, this can lead to battery failure and incremental downtime and operating costs from battery replacements.
- Some electric pumps may not be able to overcome the high injection pressures (e.g. >3000 psig) required for new high pressure horizontal wells in the Montney, Duvernay and Deep Basin regions. In these situations, it may make sense to install the solar pump after 6-12 months, when the well pressure has declined.
- Unwillingness to modify proven facility designs that are reliable.
- Remaining asset life is limited for many conventional gas facilities.

Reliability

If designed properly, solar pumps can provide functionality equivalent to or better than the previous pneumatic pump. However, solar pumps may not be appropriate for all applications. The solar-driven system (batteries, panels and charging system) must be designed to provide sufficient autonomy (reserves) for extended periods of minimal sunlight (<2 hours per day) during the coldest days of the year when batteries are most prone to failure.

In some regions of the province, it may be advisable to add a thermoelectric generator or other remote power generator to supplement solar/battery power systems. This additional power source provides redundancy and ensures that sufficient power output is available at the site to power communication systems (SCADA, remote terminal units etc.) and chemical injection pumps. However, this dramatically increases costs, often by double.

Safety

Switching from a pneumatic pump to an electric pump reduces venting of flammable gas and improves worker safety. The solar pump components should be designed to comply with Canadian Standards Association (CSA) certification requirements for hazardous locations (e.g. Class 1, Division 1 or 2).

Regulatory

Future Regulatory Considerations:
Both the Alberta Government[52] and the Federal Government[53] have announced their intentions to regulate methane emissions from pneumatic pumps and other pneumatic equipment. Draft regulations are expected in 2017 with compliance requirements by the 2020-2023 timeframe. It is expected that there will be specific limits on methane venting from pneumatic pumps and different standards for new (greenfield) facilities and potential requirements to retrofit existing pneumatic pumps.

Solar-electric chemical injection pumps are an effective technology to eliminate methane emissions from pneumatic pumps to meet regulatory compliance.

Service Provider/More Information on This Practice

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[52] https://www.alberta.ca/climate-leadership-plan.aspx#toc-5
[53] http://news.gc.ca/web/article-en.do?nid=1039219

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(2011). *PRO Fact Sheet No. 202: Convert Natural Gas-Driven Chemical Pumps.* Washington, DC: Environmental Protection Agency. Retrieved from https://www.epa.gov/sites/production/files/2016-06/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf

4.2.2. Cold Weather Pump Alternatives

July 31, 2017

Description

Emissions from natural gas driven pneumatic pumps have been identified as a significant source of methane emissions. However, the cold Canadian climate poses challenges with respect to availability of sunlight, high-pressure, and reliability of alternative pump technologies. A study of several pump technologies, including operator surveys, determined that alternatives to gas-driven pumps are both available and effective. However, the installation of properly-sized systems is critical to the success of alternative pumps, and the preferred pump technology differs by production type and site-specifics. The study determined the preferred alternative pump type for six common site scenarios.

Production Type	Preferred Alternative Technology
Low-pressure, low rate well	Methanol Sphere
Multi-well pad (>8 wells)	Self-generation + instrument air or electric pumps
Methanol Injection (seasonal)	Vent gas capture system
Wet Fuel Gas	Solar Chemical
Sour site	Solar Chemical
Non-remote site	Grid-tied electric pumps

Preferred Alternative Pump Types

In addition, the study determined that the most important question in assessing the viability of pump alternatives is injection requirements, followed closely by site-specifics. The study developed a list of questions to help operators determine the best available alternative pump technologies for their sites.

INJECTION INFORMATION

- Target litres per day ____
- Injection Pressure___ (PSI)
- More than one chemical injected at site?
- Chemicals at different rates? (Yes/No)
- Chemicals injected:
  a. Methanol ___litres per day
  b. Corrosion Inhibitor ____litres per day
  c. Other ____litres per day
- Injection is seasonal (e.g.: Oct – Apr)
- Injection is 365 days per year (Yes/No)
- Production has delineated (Yes/No)

SITE INFORMATION

- How many pumps on site? ____
- How many gas-driven controllers on site? ______
- Is power available on site?
  a. Grid-led
  b. Self-generation
  c. Other
  d. None
- What is the distance from the pump to the tree line? (metres)
- Site latitude and longitude
- Wet fuel gas
- Sour site
- Cata-Dyne heaters in proximity to methanol pumps?

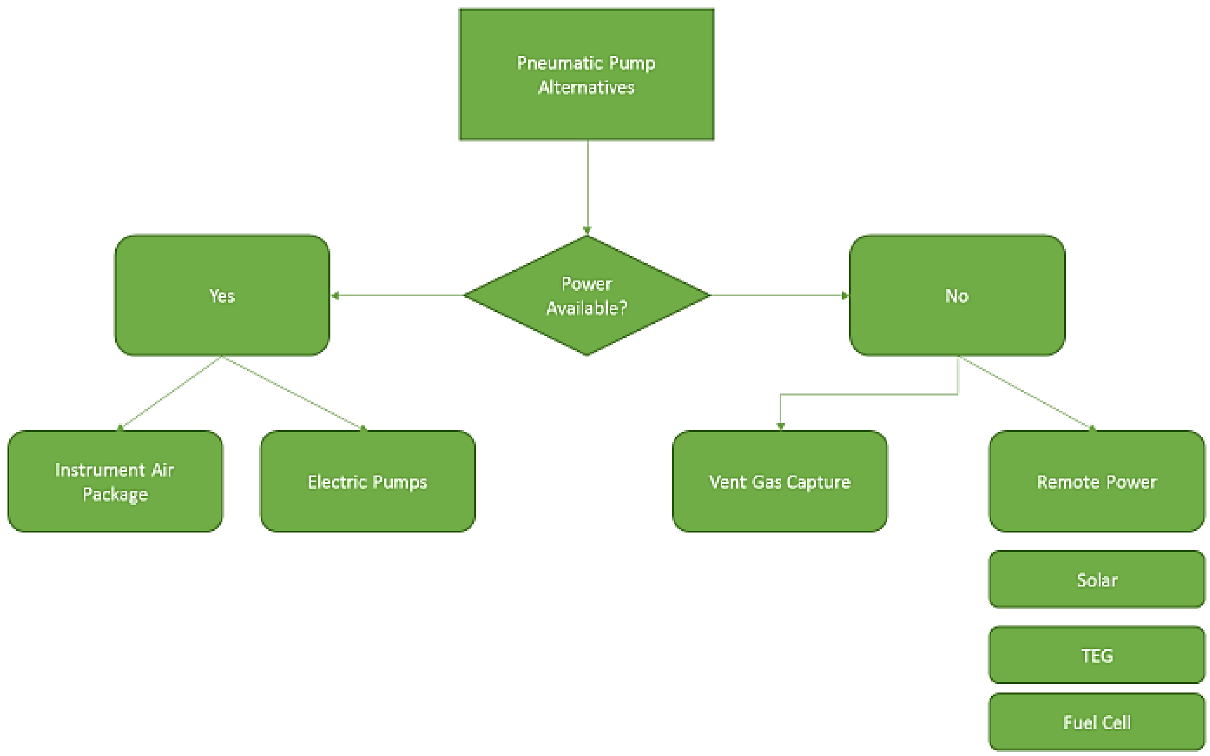
• How many valves are at site?

Technology Group

Injection Pumps – Recommended Practices

Site Applicability

Oil and gas facilities operating natural-gas-driven pneumatic pumps. Applicability of each alternative pump technology will vary by site.



Emissions Reduction and Energy Efficiency

Electrically-actuated pumps are preferred for multi-well pads (with >8 wells) and non-remote sites where electricity is available on site from an interconnection, a grid, or self-generation. When the total projected load (pumps and controllers) is known, the economics of interconnection or self-generation can be evaluated. Electric chemical injection pumps handle most expected pressure and deliver chemicals more accurately than pneumatic pumps. Pumps driven by electricity emit minimal greenhouse gasses (GHGs) related to the source of electricity. In Alberta, the grid intensity is 0.65tCO2e per Mwh of electricity consumed by the project. If power is self-generated via a fossil fuel source the intensity of that system should be calculated.

Solar Chemical systems are preferred for production sites with wet fuel gas and sites that are sour, specifically those with remote power. Many solar chemical systems can pump more than one chemical at a time, which may allow for one such pump to replace two or three gas-driven pumps. Although new high-pressure wells may exceed the capabilities of solar, injection into flowline targets is still possible. Pneumatic chemical injection can be used for startup and subsequently switched to solar when the well delineates and pressure becomes more manageable.

Vent-gas driven systems are preferred for production sites using Cata-Dyne heaters to proximate gas-driven chemical injection and injecting methanol on a seasonal basis. In winter at these sites, the exhaust from the injection process could be captured and used as fuel or make-up fuel for the Cata-Dyne heaters, not only reducing emissions but also reducing operating costs. Vent-gas capture systems reduce emissions by approximately 70%. Vent gas capture systems, which route pneumatic emissions to an engine, reduce emissions by <99%. For example, a pneumatic pump that operates all year round would result in approximately 150tCO_2e/year captured annually.

Methanol spheres are the preferred alternative in cases of low-pressure and low-volume chemical injection sites. Methanol spheres have no emissions during operation and therefore reduce emissions by 100% compared to gas-driven pumps.

Baseline:
Currently most sites use multiple natural-gas driven pumps, which have been identified as a significant source of methane emissions.

Economic Analysis

	Solar Chemical Pumps (Retrofit)	Solar Chemical Pumps (GreenField)	Vent Gas Capture
Capital Cost	\$12,000- \$16,000	\$7,500-\$10,000	\$4,000-\$7,000
Operating Cost	\$0-\$400/year	\$0-\$400/year	\$0
Payback Period (no offsets)	>10 years	>10 years	9 years
Payback Period (with offsets)	5 years	3 years	3 years
Marginal Abatement Cost	15-26 \$/tCO_2e	2-11 \$/tCO2e	2-7 \$/tCO_2e

Additional Considerations:

- Site location (latitude and longitude) impacts the economics of solar solutions. The more northern the latitude of a site, the more panels and batteries are required to power the system.
- In the cases of sites with wet fuel gas, a solar chemical pump may be more cost effective than maintenance related to dirty fuel gas.
- Non-pneumatic systems may also allow for automatic process optimisation, such as integrating the hydrate formation curve in the logic of the pump; on cold days more chemical injection, on warmer days, less chemical is injected.
- Process automation from an electric system may allow for reduced manual adjustment on the pump
- In the case of a sour site, solar may be less expensive than running propane or a clean fuel gas line.
- Recycling vent gas for fuel

Reliability

	Solar Pump	Vent Gas Capture
Expected Lifetime	Panels/Controller > 10 yeas	Same as pneumatic pumps
Maintenance	Battery replacement (annual to every 3 years) Batteries last longer if the system is sized properly.	Same as pneumatic pumps

Parts and Skills Required	• Fusing • Pump Parts • Sizing of System, should be done by qualified professional • Pre-installation measurement	• Sizing of vent rate to fuel requirements • Pump parts

Safety

Installation of alternative pumps do not pose additional health or safety risks.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.

Service Provider/More Information on This Practice

Alternative pump types are available from multiple manufacturers in a variety of sizes and configurations to meet varying needs.

Section 5.1. Engines and Compressors – Facilities Design and Equipment

5.1.1. Spartan Controls Ltd. – REMVue Air-Fuel Ratio (AFR)	April 26, 2019

Description

REMVue® Air-Fuel Ratio Control systems allow engines to operate at different air-fuel ratios than the original engine design, allowing them to run on less fuel gas. The REMVue®-AFR is a patented air-fuel ratio control system, providing rich-to-lean conversion and engine control optimization. It is the only patented rich-to-lean conversion system available for rich-burn engines. The system can be configured to operate as a stand-alone control system, or it can be integrated with other hardware or software systems. The REMVue®-AFR can be applied to a wide variety of rich burn or lean burn engines, resulting in an average of 15% fuel savings, improved runtime, and reduced NOx emissions (MSAPR compliance levels).

Technology Group

Engines and Compressors – Facilities Design and Equipment

Site Applicability

Oil and gas facilities; sweet and sour service, any rich-burn or lean-burn natural gas engine

Emissions Reduction and Energy Efficiency

Up to 2,000 tons CO_2e annually, depending on engine and tuning of the system.

Economic Analysis

Capital Cost:	Capital costs range from $40,000 to $60,000. However, these costs vary based on location, type of engine, and number of units purchased.
Installation Cost:	Installation costs range from $40,000 to $60,000 depending on the size of engine/compressor and the addition of optional features.
Operating Cost:	Improved engine optimization generally reduces operating costs by an average of 10%.
Maintenance Cost:	The REMVue®-AFR results in no additional maintenance costs as it does not require any special skills beyond existing operations.
Carbon Offset Credits:	The REMVue®-AFR is eligible for carbon-offsets as per the Alberta Offset System Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects.
Payback, Return on	Based on fuel savings, reliability improvements, and carbon offsets, payback

Investment and Marginal Abatement Cost:	can be expected within 3-16 months. This payback does not take into account the value of reduced equipment wear, such as cylinder heads, nor increased production.

Reliability

Expected Lifetime:	The equipment is expected to last the lifetime of the facility.
Maintenance:	No special maintenance considerations apply.

Safety

No additional safety considerations apply.

Regulatory

- CSA, Class1 Div 2 hazardous approval
- Recognized for NOx emissions compliance by AER and Environment and Climate Change Canada
- (MSAPR)
- Recognized as compliant solution for the Alberta Engine Fuel Management and Vent Gas Capture Protocol and the BC META protocol

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com
Product Website:	http://www.spartancontrols.com/applied-technology/rotating-and-reciprocating-equipment/engine-and-compressor/air-fuel-ratio-controllers/remvue-afr/
Contact Person:	Cam Dowler
Contact Phone#:	(403) 695-2318
Contact Email:	Dowler.Cam@spartancontrols.com

5.1.2. Spartan Controls Ltd. – SlipStream® Vent Gas Capture	June 30, 2017

Description

During normal operations, oil and gas facilities vent greenhouse gases (GHGs) to the atmosphere. The SlipStream® Vent Gas Capture system controls and monitors the addition of combustible vented emissions to a natural gas engine so that it can be used as supplementary fuel. Redirecting these vented gases not only reduces the main fuel consumption of the engine, but also frees up more sales gas while reducing GHG emissions from the site. The SlipStream® system is adaptable to handle vented emissions from various sources. Typical vented sources include: compressor packing vents, liquid storage tanks, glycol dehydrators, cactus dryers, instrument vents and chemical injection pumps. The SlipStream® system is designed to deal with large changes in flow.

SlipStream® technology can be easily integrated into new or existing installations and used on engines from 100 to 4,000 horsepower. PIC Solutions provides three different options for SlipStream® systems:

- SS3 - Maximum flow rate of 5kg/hr – designed for compressor packing vents
- SS10 - Maximum of 10% of total engine fuel flow can be supplemented by the SlipStream® system
- SS50 - Maximum of 50% of total engine fuel flow can be supplemented by the SlipStream® system

Technology Group

Engines and Compressors – Facilities Design and Equipment

Site Applicability

Oil and gas facilities; sweet service

Emissions Reduction and Energy Efficiency

200 to 4,000 tons CO_2e annually, depending on quantity of vented gases.

Economic Analysis

Capital Cost:	Capital costs range from $17,000 to $36,000. These costs vary based on location, quantity of vent gas, and number of units purchased.
Installation Cost:	Installation costs range from $20,000 to $30,000, depending on the size of engine/compressor and the addition of optional features.

Operating Cost:	Operating costs are minimal. Specific figures are not provided.
Maintenance Cost:	No additional maintenance costs are expected from the SlipStream® Vent Gas Capture system.
Carbon Offset Credits:	Carbon offset credits for the SlipStream® Vent Gas Capture system is eligible for carbon-offsets via the Alberta Offset System Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects
Payback, Return on Investment and Marginal Abatement Cost:	Based on fuel savings and carbon offsets, payback can be expected within three to 16 months.

Reliability

Expected Lifetime:	The equipment is expected to last the duration of the life of the facility.
Maintenance:	No special maintenance considerations apply.

Safety

No additional safety considerations apply.

Regulatory

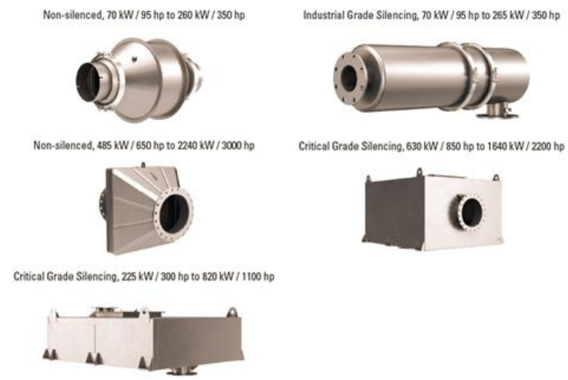
- CSA, Class1 Div 2 hazardous approval
- Recognized for Methane emissions compliance by AER Directive 60 and Environment and Climate Change Canada
- Recognized as compliant solution for the Alberta Engine Fuel Management and Vent Gas Capture Protocol and the BC META protocol

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com
Product Website:	http://www.spartancontrols.com/applied-technology/rotating-and-reciprocating-equipment/vent-capture/emissions-efficiency/slipstream/
Contact Person:	Cam Dowler
Contact Phone#:	(403) 695-2318
Contact Email:	Dowler.Cam@spartancontrols.com

5.1.3. Finning (Canada) Three-way Catalysts

July 31, 2017



Description

CAT® three-way catalysts reduce exhaust emissions from gas-fueled, spark-ignited reciprocating engines. Such engines are used extensively in the processing of oil and gas, especially rich-burn (stoichiometric) natural gas engines. The catalyst features a flow-through honeycomb substrate coated with a high-performance catalyst housed within a stainless-steel canister. It can be fitted with a silencing needle. Exhaust gas from the engine passes over the catalyst where a chemical reaction takes place to simultaneously reduce NO_x, CO, and HC emissions. A closed-loop air-fuel ratio controller is required to maintain the correct oxygen concentration in the exhaust to facilitate maximum catalyst performance. If a facility does not have a controller, Finning (Canada) can supply one. The Three-Way Catalyst performs two different functions during three-way conversion: oxidation and reduction.

Oxidation:
During the oxidation process, the catalyst transforms pollutants into harmless gases through oxidation (or burning), by combining them with an oxygen source in the exhaust. Carbon monoxide and hydrocarbons are combined with oxygen from the NO_x molecule to become carbon dioxide and water vapor.

Reduction:
Unlike oxidation, reduction is a process of removing oxygen from compounds. Nitrogen oxides (NO_x) formed in the combustion process are reduced by removing oxygen to form nitrogen and carbon dioxide (CO_2) through reduction, which is promoted by the catalyst.

Technology Group

Engines and Compressors – Facilities Design and Equipment

Site Applicability

Any facility operating a rich burn natural gas engine.

Emissions Reduction and Energy Efficiency

The Three-Way Catalyst reduces up to 98% of NO_x emissions, up to 95% of carbon monoxide emissions, and up to 90% of hydrocarbon emissions.

Economic Analysis

Capital Cost:	Capital costs vary depending on the size of equipment required and specific silencing needs.
Installation Cost:	Installation costs are site specific. Specific figures were not provided.
Operating Cost:	The Finning Three-Way Catalyst does not create any additional operating costs.
Maintenance Cost:	The Finning Three-Way Catalyst does not create any additional maintenance costs.
Carbon Offset Credits:	Although the catalyst itself does not qualify for carbon offset credits, it is possible the equipment could be used as part of a larger carbon reduction strategy.
Payback, Return on Investment and Marginal Abatement Cost:	As an emissions compliance device, the catalyst does not offer a specific, measurable ROI.

Reliability

Expected Lifetime:	The catalyst is expected to last 16,000 to 20,000 hours.
Maintenance:	The catalyst is a passive device, and therefore does not require any additional maintenance.

Safety

As an exhaust component, skin temperature of the three-way catalyst can be very hot. Some protection can be achieved by installing insulating blankets.

Regulatory

The catalyst is not subject to any CSA requirements. It may be used to assist in compliance to Multi-Sector Air Pollutants Regulation (MSAPR) and/or AER air emissions requirements.

Vendor Information

Company Name:	Finning (Canada)
Company Website:	http://www.finning.com/en_CA.html
Product Website:	www.cat.com – Select region and search for “three-way catalyst”
Contact Person:	Licinio Pereira
Contact Phone#:	(403) 731-4659
Contact Email:	lpereira@finning.com

5.1.4. Gaspro Compression- Hydraulic Compressor	April 26, 2019

Description

Gaspro Hydraulic Compressor utilizes hydraulic principles to compress the gas. It provides a solution to capture trace amounts of vented or flared gas (less than 0.2 e3m3/day) without the need of applying costly equipment. It is also a cost-efficient compressor technology as compared to the conventional gas compressor and it can help the oil and gas companies to economically achieve methane emission reduction targets as set by the regulatory board.

Technology Group

Engines and Compressors – Facilities Design and Equipment

Site Applicability

Gaspro Hydraulic Compressors are good for sweet and sour service applications and it can be applied to casing gas wells and at locations where trace amount of methane gas is vented or flared.

Emissions Reduction and Energy Efficiency

Gaspro Hydraulic Compressor provides a solution to well-sites where trace amount of methane gas is either vented or flared due to uneconomical available solutions. Gaspro can provide a low-cost solution without the need of venting or flaring. It will capture vented gas, reducing the GHG emissions and improves regulatory compliance. Gaspro Hydraulic Compressor can capture below 0.2 e3m3/day (1,186 tCO_2e/year) to around 5.0 e3m3/day (29,656 tCO_2e/year), removing the same from the environment and putting it back into the pipelines for additional profit.

Economic Analysis

Capital Cost: Capital cost for Gaspro Hydraulic Compressor would be less than half of the conventional gas compressor. It also depends upon the control system that client is looking for. Savings would depend upon the flowrate of the methane gas captured through it.

Installation Cost: Installation cost depends upon site location, accessibility, power option etc. and it can be done easily within 2-4 hours.

Operating Cost: Operating cost would be very minimal due to fewer moving parts. This will mainly include electricity cost for motor.

Maintenance Cost:	Maintenance cost is very minimal and only requires oil change and level check.
Carbon Offset Credits:	Clients can use the captured amount of gas for carbon offset credits depending upon the site location and application.
Payback, Return on Investment and Marginal Abatement Cost:	Savings from provincial fines for carbon emissions can provide a pay back just within a year. For e.g. 1 e3m3/day (5930 tCO_2e/year) of methane emission would save around $118,600/year.

Reliability

Expected Lifetime:	Expected lifetime would be around 25+ years with regular servicing (including seal change, oil change, etc.)
Maintenance:	Regular oil change/refill would be required for maintenance.

Safety

Standard industry safety practices apply.

Regulatory

Meeting all codes and standard required installation in Canada

- AER Directive 060
- Electrical Codes including CSA 22.2 No. 14 UL 508A.
- ABSA AQP for pressure piping, COR, Complyworks, ISN,
- ASME Section VIII Div 1

Vendor Information

Company Name:	GasPro Compression Corp.
Company Website:	www.gaspro.ca
Product Website:	http://www.gaspro.ca/index.php?page=products
Contact Person:	Ayaz Mahmood / Tom Nichols
Contact Phone#:	403-443-8886 / 403-443-1115
Contact Email:	ayaz.mahmood@gaspro.ca / tom.nichols@gaspro.ca

Please refer to other equipment sheets included in the handbook as examples

Section 5.2. Engines and Compressors – Recommended Practices

5.2.1. Plant Consolidation	July 31, 2017

Description

In natural gas production, compressors are used to raise the pressure of natural gas so that it can flow into pipelines and other facilities. Compressor plants consist of many compressors, auxiliary equipment, and pipeline installations. Over time, production at legacy well sites naturally decreases. As a result, site compression facilities that were designed for the initial production volume become oversized and less energy efficient.

One option to improve energy efficiency and reduce costs of underutilized facilities is to consolidate well site gathering lines. For example, if three well sites each feed into a high-pressure pipeline, they could be consolidated by feeding two satellites into the third one at lower pressure so that only one fully-loaded, high-pressure compressor is needed.

Significant economic benefits and emissions reductions can be realized by modifying plants to re-route gathered gas or oil to more completely load facilities. Consolidated plants operate at optimal efficiency and the total number of compressors is reduced. Plant consolidation not only reduces fuel consumption and greenhouse gas emissions, but also reduces maintenance, administrative, and labour costs. However, plant consolidation must be determined based on the specific needs of the sites and facilities involved.

Technology Group

Engines and Compressors – Recommended Practices

Site Applicability

Satellite compression facilities not operating at optimal capacity.

Emissions Reduction and Energy Efficiency

Plant consolidation reduces fuel consumption by eliminating the number of gas-driven compressors in use. The emissions related to those compressors are likewise eliminated.

<u>A simplified formula to estimate baseline emissions:</u>

Annual GHG Emissions Reduction (tCO_2e/yr) = Annual GHG Emissions from gas-driven compressors on-site before plant consolidation (tCO_2e/yr) - Annual GHG Emissions from gas-driven compressors on-site after plant consolidation (tCO_2e/yr)

Baseline: Currently many compressor plants are running multiple compressors at less than optimal efficiency.

Economic Analysis

Economics for plant consolidation are complex and site specific. They can vary from facility to facility. It is best practice to collect complete cost data for specific plants being considered for consolidation. Feasibility of a plant consolidation project can then be determined based upon the capital and operating costs, such as new pipelines, engineering design, labour, and equipment. The following metrics should be calculated to understand the economic benefits of the project.

Capital Cost:	Net Capital Costs (\$) = Compressor moving costs (\$) + Additional transmitters costs (\$) + Piping modification costs (\$) + Installation of slug catching/flaring facilities (\$) – Salvage value of compressors to be eliminated (\$)* *Salvage value of compressors to be eliminated is the estimated resale value of the equipment at the end of its useful life.
Operating Cost:	Total Annual Savings (\$/yr) = Annual operation cost before plant consolidation (\$/yr) Annual operation cost after plant consolidation (\$/yr)
Payback Period:	Payout period = Net Capital Costs (\$) / Total Annual Savings (\$/yr)
Marginal Abatement Cost:	GHG Cost Abatement (\$/tCO_2e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital Costs of Consolidation (\$)

Reliability

Expected Lifetime:	Consolidation will not change the expected lifetime of equipment, which will remain in line with standard life-expectancy for gas compression and transportation infrastructure.
Maintenance:	Consolidated plants require no additional maintenance or special skills beyond existing operations.

Safety

There are no additional safety considerations associated with plant consolidation.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.

Vendor Information

Many vendors and contractors can perform this type of upstream facilities construction.

5.2.2. Fuel Gas Source Re-Connection – Utilization of Inter-Stage Gas

July 31, 2017

Description

A significant amount of the equipment used in oil and gas production runs on fuel gas, usually high-pressure sales gas. However, equipment fuel gas systems can be modified to connect to appropriate inter-stage gas sources instead. This optimizes fuel usage, and reduces the amount of inter-stage gas (consisting primarily of methane) vented to the atmosphere. Economic benefits are realized from the optimized use of resources, and additional sales gas is made available for market.

Technology Group

Engines and Compressors – Recommended Practices

Site Applicability

Any site where equipment runs using fuel gas.

Emissions Reduction and Energy Efficiency

Optimizing equipment by connecting the fuel gas source to an inter-stage source results in less inter-stage gas being vented to the atmosphere, eliminating the associated heavier hydrocarbon emissions. A major operator completed successful trials on four reciprocating compressors at three of their facilities, determining that the technology can be extrapolated for use on any equipment that runs on fuel gas. However, appropriate connection points must be determined based upon specific pressure requirements.

A Simplified Formula to Estimate GHG Emission Reductions:

Annual GHG Reduction (tCO_2e/yr) = Reduction of fuel gas used (mcfd) x Emission Factor of fuel via stationary internal combustion x operational days/year

Baseline:

Currently many compressor plants are running multiple compressors at less than optimal efficiency.

Economic Analysis

A Simplified Formula to Calculate Production Efficiency

Production Efficiency (PE) = Capital cost of the modification (installation, materials, design) ($) / Total fuel savings (mcfd)

A Simplified Formula to Calculate Annual Savings

Total Annual Savings = Fuel gas savings (mcfd) x Value of Fuel Gas ($/mcf) x # of operational days (days/year)

The economic analysis will be site-specific. The following metrics should be calculated to understand the economic benefits of the project.

Capital Cost: Installation + Materials + Design

Operating Cost: Total Annual Savings ($/yr) = Annual operation cost before modification

	(\$/yr) - Annual operation cost after modification (\$/yr)
Payback Period:	Simple Payout (years) = Capital cost of the modification (installation, materials, design) (\$) / Total Annual Savings (\$)
Marginal Abatement Cost:	GHG Cost Abatement (\$/tCO_2e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital cost of the modification (installation, materials, design) (\$)

Reliability

Expected Lifetime	The project life time is expected to be 8-10 years.
Maintenance	Systems with modified fuel-gas connections do not require additional maintenance, nor special skills beyond existing operations. However, if additional equipment is added to a wellsite, the maintenance workload would increase accordingly.

Safety

There are no additional safety considerations associated with modifying the fuel gas source.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.

Service Provider/More Information on This Practice

Although the fuel gas modifications were initially performed by the team at a major operator's facility, teams at other sites and companies could adapt this methodology to their specific equipment.

5.2.3. Low-Emissions Rod Packing

July 31, 2017

Description

Reciprocating compressors are fitted with pressure packing, a series of precision-machined mechanical rings that form a tight seal around the piston rod to prevent compressed gas from escaping but still allow the piston to move freely. Leaks in the packing system are common, with the size of the leak depending on fitting, cylinder pressure, and alignment of packings parts. These leaks can be one of the largest sources of emissions at natural gas compressor stations. Piston rods wear more slowly than packing rings, so as systems age, leak rates increase due to the uneven wear. These leaks allow methane gas to enter the atmosphere through the packing vents on the flanges. Replacing traditional packing rings and piston rods with low-emissions packing not only reduces methane emissions[54], but also achieves operational benefits such as increasing the lifespan of existing equipment, improving operating efficiencies, and realizing cost savings.

Technology Group

Engines and Compressors – Recommended Practices.

Site Applicability

Natural Gas Compressor Stations.

Emissions Reduction and Energy Efficiency

Installation of low-emissions rod packing has the potential to drastically reduce emissions.

A Simplified Formula to Estimate GHG Emission Reductions:

Annual GHG Reduction (tCO_2e/yr) = Reduction of vented gas via measurement (mcfd) x 1000 scf/mcf x 1 m^3/35.315 scf x 0.6784 $tCO_2e/1000\ m^3$ x mole fraction of CH_4 in natural gas x 21 $GWPCH_4$ x # of operational days (days/year)

Calculations of emissions reduction rates and economic analysis require pre- and post-installation measurements. It is important to measure the rate of gas leak before installing any new low emissions packing. Once the low emissions packing systems are installed, the new leak measurement must be performed immediately after installation of new seals, as this serves as the default baseline for the new packings.

Baseline:

Most natural gas compressors operate using standard rod packing with the expectation of some leak and loss of compressed gas over time.

Economic Analysis

The economic analysis will be site-specific. The following metrics should be calculated to understand the economic benefits of the project.

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[54] An EnCana presentation regarding the CECO LEP trial given at the 2010 Gas Processing Association Annual Meeting reports an average venting reduction of >90%. http://www.tryceco.com/parts_repair/downloads/CECO%20Low%20Emission%20Packing.pdf

Capital Cost:	Capital costs including installation, materials, and design are estimated at <$100,000. However, installation costs vary depending upon the site location and specifics.
Operating Cost:	Total Annual Savings ($/yr) = Annual operational cost before implementation ($/yr) – Annual operational cost after implementation ($/yr)
Payback Period:	Simple Payout (years) = Capital cost of the project ($)/Total Annual Savings ($). The prevailing natural gas price has a significant impact on the economics of the project.
Marginal Abatement Cost:	GHG Cost Abatement ($/t$CO_2$e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital Costs of Installing Low Emissions Packing ($)

Reliability

Expected Lifetime:	Installation of LEP will not change the expected lifetime of equipment, which will remain in line with standard life-expectancy for compressors. Regular monitoring is required to ensure proper lubrication and cooling to help reduce wear, as high operating temperatures accelerate ring deterioration. It is important to continue to monitor for leaks even after installation of low-emissions packing as the rings or the rods can still become worn out in a few years.
Maintenance:	Low-emissions packing does not require additional maintenance nor special skills beyond existing operations. However, if additional equipment is added to a wellsite, the maintenance workload would increase accordingly.

Safety

Low-emissions packing does not pose any additional safety hazards compared to standard packing.

Regulatory

- Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.
- Alberta Climate Change and Emissions Management Act

Service Provider/More Information on This Practice

Low-emission rod packing is available from various vendors in an assortment of sizes and specifications for application in different operating and process conditions.

5.2.4. Lower Pressure Fuel Gas Transportation

July 31, 2017

Description

Often, two oil and gas facilities owned by the same corporation operate within a similar geographic region. In some cases, one of those facilities draws fuel gas from the very pipeline being fed by another one of their own production facilities. Establishing a direct low-pressure fuel gas route between the two facilities significantly reduces fuel gas usage, cuts the corresponding greenhouse gas (GHG) emissions, conserves energy that can be redistributed, and creates operational efficiencies and cost savings through reduced maintenance and staff. For example, one major operator was producing gas and compressing it to approximately 7,500 kPa (1,100 psig) to deliver it to the nearby transmission pipeline. About 10 km away, the same operator was drawing gas from a transmission pipeline to use as fuel for steam generation. They launched an energy efficiency project to build a lower pressure (approximately 400 kPa, or 60 psig) gas pipeline between the two facilities, significantly reducing both the financial and energy cost of compression. The construction of the lower pressure gas pipeline reduced fuel gas consumption by removing the need for the extra compression by 1.5 bcf, reduced GHG emissions by about 25,000 tCO_2e/year and reduced operational expenses due to reduced maintenance and staff. This also freed up about 6,000 horsepower in compression which could then be applied.

Technology Group

Engines and Compressors – Recommended Practices

Site Applicability

Facilities that use high-pressure pipelines to draw fuel gas from another of their own geographically-proximate gas production facilities.

Emissions Reduction and Energy Efficiency

In the above example, significant energy was being wasted compressing the gas produced at the gas-producing facility to the pipeline requirement, passing it through a transmission pipeline system, and then depressurizing it at the gas-consuming facility. The company implemented a direct low-pressure fuel gas between the two facilities. This led to a reduction of fuel gas consumption through the extra compression by 1.5 bcf, and a corresponding reduction of GHG emissions by about 25,000 tCO_2e/year.

Baseline:
Gas produced at one facility is compressed to 7,500 kPa (1,100 psig) pipeline specifications for transport through a third-party pipeline and then is depressurized at the facility where it is used for fuel gas.

A Simplified Formula to Estimate GHG Emission Reductions:

Annual GHG Reduction (tCO_2e/yr) = Overall reduction of energy used x Emission Factor of energy x operational days/year.

Economic Analysis

The economic analysis will be site-specific. The following metrics should be calculated to understand the economic benefits of the project.

Capital Cost: Capital Cost = Installation + Materials + Design
An engineering review is needed to identify and anticipate potential additional

capital costs (for example, the gas processing facility may begin to produce wet gas and additional capital costs could be incurred for the installation of a treatment facility).

Payback Period:	Simple Payout (years) = Capital cost of the modification (installation, materials, design) ($) / Total Annual Savings ($)
Marginal Abatement:	GHG Cost Abatement ($/tCO$_2$e) = Annual GHG Reduction (tCO$_2$e/yr) x Project Life (year) / Capital cost of the modification (installation, materials, design) ($)
Annual Savings:	Annual Savings ($/yr) = Overall Reduction in Operational and Maintenance Costs
Production Efficiency:	Production Efficiency (PE) = Capital cost of the modification (installation, materials, design) ($) / Total fuel savings (mcfd)

Additional Considerations:
Should production at either facility be compromised, the direct low-pressure fuel gas transportation reduces some of the options provided by the third-party high-pressure pipeline. In the original configuration, if the producing facility went down, the other facility had the flexibility to pull fuel gas from the third-party pipeline, and if the fuel gas facility went down the producing facility had the option to process their gas to pipeline specifications and sell it. With the direct low-pressure pipeline, the facilities become exclusively dependent on one another.

Reliability

Expected Lifetime:	Connecting the direct low-pressure fuel gas transportation will not change the expected lifetime of equipment, which will remain in line with standard life-expectancy for buried pipelines.
Maintenance:	Connecting the direct low-pressure fuel gas transportation does not require additional maintenance nor special skills beyond existing operations. However, the produced gas could become wet gas. In such cases, an injection facility must be built to treat the water in the gas.

Safety

Operators of both facilities must comply with all safety regulations associated with operation of a low-pressure pipeline. However, the lower-pressure pipeline does not pose additional safety risk compared with the fuel-gas transport system being replaced.

Regulatory

Operators must obtain and demonstrate compliance with relevant pipeline and facilities codes and regulations. Pipelines must be installed following approved routing and may require consultation. Companies work closely with regulatory bodies to manage the execution of the lower-pressure pipeline installation as safely, transparently, and efficiently as possible.

Vendor Information

Many vendors and contractors can perform this type of upstream facilities construction.

5.2.5. Air Fuel Ratio (AFR) Controllers	**July 31, 2017**

Description

An Air-Fuel Ratio Controller (AFRC) project is broadly defined as the implementation of a new engine control system that allows an engine to operate at a different range of air fuel ratios from that of the original engine design, which in turn can result in a reduction in fuel consumption. An AFRC system provides a rapid-response control system that delivers the proper amount of fuel for the combustion air taken in by the engine, depending on engine tuning, load, process gas operating conditions, and ambient air conditions. This improved process control results in better fuel efficiency (for the same amount of torque), lower greenhouse gas (GHG) emissions, and reduced emission of pollutants such as nitrogen oxides (NOx) and carbon monoxide.

The main component of an AFRC is an electronic control system that manages the overall operation of the engine and the associated control valves and sensors. The AFRC kit typically includes a fuel control valve, fuel meter, engine manifold pressure transmitter, temperature transmitters, turbocharger waste-gate controller (that provides air control), magnetic speed sensor, and a local operator interface display. The most common configuration of engine management system that has been installed in Canada is the REMVue® technology developed by Spartan Controls[55].

Typically, AFRC retrofit projects involve "rich-to-lean" conversion, where a lean-burn combustion condition is established within an engine previously designed to operate under rich-burn conditions. When the air to fuel ratio is exactly in line with the combustion reaction chemistry (a "stoichiometric" ratio) it results in perfect combustion and produces only carbon dioxide and water vapour. In cases where excess air is fed to a combustion chamber the ratio is termed "lean", and when excess fuel is added the ratio is termed "rich." Typically, engines operating under lean-burn conditions have better fuel economy, while engines operating under rich-burn conditions have lower fuel economy but are more powerful and easier to operate. A rich-to-lean conversion can provide the best of both worlds using adaptive air-fuel ratio control by adding turbocharger speed control and control over the fuel supply to the engine.

Baseline:

Reciprocating engines are used throughout the oil and gas industry to convert fuel energy into mechanical energy to power loads such as compressors, pumps and generators. The baseline is the combustion of natural gas ("fuel gas") in a reciprocating engine that is operating at the engine's original configuration, prior to the modification of that engine with the installation of an air-fuel ratio control (AFRC) system.

Direct GHG emissions result from the combustion of natural gas to operate the engine. The baseline emissions are engine and site specific and depend on the operating characteristics and performance requirements of the facility. Key variables include engine make, model, operating set points, loads, speed (RPM), age, elevation, maintenance practices and many other factors. Engine manufacturer data sets (fuel consumption curves) are generally not suitable for use under the baseline condition as these data represent the engine's lowest achievable fuel consumption determined under ideal conditions in the laboratory and typically underestimate fuel consumption in the field. For this reason, field

[55] http://www.spartancontrols.com/rem-technology/rem-technology-products/slipstream/

measurements are usually used to develop a baseline, using the procedure described in the Alberta Offset System Quantification Protocol for Engine Fuel Management and Vent Gas Capture (the "AOS Protocol")[56]. The procedure to determine engine fuel gas savings relies on direct measurement of various parameters to determine the brake specific fuel consumption (BSFC)[57] of the original un-modified engine at several different set points, and then to subsequently perform the same set of measurements at the same set points for the modified engine. These before and after measurements are referred to as 'Pre-Audits' and 'Post-Audits' and are used to provide a snapshot of the fuel gas savings from the AFRC installation. Completing a before and after comparison helps to establish a specific performance baseline for a particular engine, since field fuel consumption results may vary between seemingly identical engine models due to subtle mechanical design differences and load variables.

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Site Applicability

The main opportunity to improve fuel efficiency will be at oil and gas production facilities that have stoichiometric[58] or rich-burn engines, such as Waukesha VHP GSI series, White Superior and Caterpillar 3500 series engines >600 horsepower in size. After successfully completing a major retrofit program, engineers at one major operator recommended that project evaluators focus their efforts on AFRC retrofits of the Waukesha L7042GSI, L5108GSI and F3521GSI engine models. Additionally, engineers at another major operator have determined that air-fuel ratio controller retrofits onto lean-burn engines are unlikely to generate significant fuel efficiency improvements.

Other opportunities exist to retrofit engines to comply with upcoming NOx regulations. In these scenarios, retrofitting the highest NOx-emitting engines with AFRC systems can achieve fuel savings and regulatory compliance. Note that capital costs may be higher for projects that require expensive panel upgrades, but reliability will be improved by replacing obsolete pneumatic panels.

Emissions Reduction and Energy Efficiency

Estimating Gas Savings:

The best way to estimate potential fuel gas savings and GHG emissions reduction is to conduct pre-audit and post-audit measurements of the engine at several loads and RPMs. This method allows the operator to develop a load map to document the engine fuel efficiency by conducting a set of short duration snap shot measurements of engine fuel consumption rates at different compressor loads and engine speeds.

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[56] Alberta Offset System Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects (v1 Oct 2009);
(http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/ProtocolEngineFuelVentGasProjects-Oct2009.pdf)

[57] The industry standard in Alberta is to present fuel consumption in terms of the brake-specific fuel consumption (BSFC), which is defined as the rate of fuel energy flow into an engine divided by the mechanical power produced by the engine. Engine performance is commonly presented as a load map showing the fuel consumption of the engine (in BTU/hour or kJ/hour) at various loads (in BHP or BkW) at specific engine speeds (RPMs).
Canadian Association of Petroleum Producers (CAPP) Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Engines. May 2008

[58] the chemically correct quantity of air is present in the combustion chamber during combustion

The AOS Protocol provides a detailed method to complete pre- and post-audits to calculate a fractional change in fuel consumption. The fractional change is typically calculated at several different set points and then "mapped" to the actual engine operating conditions (e.g. loads and RPMs) over the course of a year to determine the aggregate gas savings based on the measured fuel input to the engine. Essentially the savings equal the measured fuel consumption rate at a particular set-point times the fractional change in fuel consumption (as determined by the pre- and post-audits) at that same set point.

On average, most rich-to-lean conversions have achieved a 5%-15% improvement in fuel savings. One major operator's rich-to-lean conversion projects delivered 9%-24% improvement in fuel efficiency, while the addition of AFRC to lean-burn engines did not generate any efficiency gains. Fuel savings ranged from 0 to 50 mcfd with significant variability from engine to engine. Twenty-five rich-to-lean conversion projects completed by another major operator generated 28mcfd of fuel gas savings on average.

Measurement:
The standard measurement approach is continuous direct measurement with a dedicated flow meter installed on the piping that delivers the fuel gas into the engine. Meters are normally tied into a Supervisory Control and Data Acquisition (SCADA) system for continuous data collection, similar to conventional sales gas meters, and data is usually collected every 15 minutes and averaged daily. Meters are calibrated annually. Engine fuel gas usage must be measured on an ongoing basis to qualify for carbon offsets under the Alberta Offset System.

Net GHG Emissions Reductions:
The net GHG reductions from an AFR project are determined based on the fractional change in fuel consumption from the baseline (engine operating without an AFR) to the project condition (engine operating with the new AFR in place). The net GHG emission reductions are calculated based on a "pre-audit" and "post-audit" comparison of engine brake specific fuel consumption at different engine speeds and engine loads. This snapshot comparison of the previous engine configuration against the new configuration is the basis for determining the fractional change in fuel consumption. The ongoing fuel consumption of the engine is monitored with continuous direct metering of the amount of fuel gas combusted by the engine after installation of the AFR.

<u>A simplified formula to estimate GHG emission reduction:</u>
Net GHG Emission Reductions = (Metered Fuel Gas Usage in m^3/year) * (Fractional Change in Fuel Gas Usage)*(Fuel Combustion Emission Factor in kg CO_2e/m^3 natural gas)*(0.001 t/kg)

Note that this is a simplification of the Alberta Offset System Quantification Protocol for Engine Fuel Management and Vent Gas Capture. The full calculation is available in the protocol document.

Estimated GHG Emission Reductions:
GHG reductions from 25 AFR projects completed in Alberta by a major operator averaged approximately 700 tCO_2e/engine/year. Some successful installations have exceeded 1,500 tCO_2e/engine/year. GHG reductions are site-specific and depend on the type of baseline engine, the condition of the engine, the load on the engine, the engine speed, and other factors.

Economic Analysis

Capital Cost: Capital costs are highly site specific, but costs from REMVue® AFR projects completed by a major operator at 25 compressor stations in Alberta averaged

$220,000, with a range from $150k to $250k. Other projects completed by another major operator (39 retrofits comprised of 28 SlipStream vent gas capture systems and 11 REMVue engine fuel management systems) averaged $197,000. Since the scope of these 39 projects included vent gas capture equipment, the costs are not directly comparable to the other operator's 25 projects.

Operating Cost:

Operating Costs are typically lower for engines with AFRC systems relative to the previous rich-burn configuration, and uptime can also be improved. Quantitative savings should be estimated on a site-specific basis.

Carbon Offset Credits:

The value of carbon offsets can be significant for AFR projects using an assumed carbon offset value of $25/offset in Alberta. Based on the average GHG reductions of 702 tCO_2e/engine/year achieved by the 25 Alberta AFR projects mentioned above, the value of the carbon offsets at $25/offset could be worth $17,550/engine/year.

Payback, Return on Investment and Marginal Abatement Cost:

Gas savings are the primary benefit from AFR projects and will be very site specific. Gas savings from 25 REMVue®AFR projects completed in Alberta by a major operator averaged approximately 28 mcfd. At a flat $2.50/mcf AECO gas price, these gas savings would be worth from $25,500/year. The results from another operator's 39 retrofit projects were more variable with savings ranging from 0 to 51mcfd.

Although project economics are very site specific, it is possible to achieve paybacks of ~5 years from fuel gas savings and carbon offsets. However, the best projects will incorporate regulatory upgrades (to comply with NOx regulations) and involve upgrades to outdated equipment (e.g. removal of pneumatic panels etc.) to achieve further cost savings or compliance benefits. Without these additional maintenance, regulatory, and GHG-reduction benefits, most projects would be uneconomic on fuel savings alone at a $2.50/mcf gas price.

Barriers:

- Financial barriers - low value of fuel gas makes many projects uneconomic without carbon offsets or other regulatory benefits.
- Capital costs are high when retrofitting older facilities.
- Limited reserves life in conventional reservoirs makes it hard to justify capital expense of retrofits.
- Unwillingness to modify proven facility designs that are reliable.

Reliability

AFR systems are highly-reliable and have been deployed at commercial scales by a number of large oil and gas producers. Often companies can replace outdated pneumatic panels and complete upgrades to the compressor intercooler and the engine ignition system to further improve reliability. One operator's AFRC projects achieved optimized control, easier starting, reduced downtime and included remote operations capabilities. Since installation of an AFRC may take 3-5 days to complete, it is worth piggybacking other maintenance work or upgrades into the shutdown period where possible to minimize downtime.

Safety

It is critical to ensure that the AFRC system is properly integrated with the existing site safety systems (e.g. compressor safety shut down keys) and to provide proper training to operators. If a vent gas capture system is also installed along with the AFRC, operators must ensure that the vent gas system is always set to vent to the atmosphere when the engine is not operational so that gas is never introduced into the engine before it has been started. It may also be necessary to complete an electrical assessment of the engine/compressor package and to re-evaluate the area classifications to ensure code compliance.

Regulatory

Future Regulatory Considerations:
Both the Alberta Government and the Federal Government have announced their intentions to tax carbon dioxide emissions from fuel combustion. In Alberta, a carbon levy came into force effective January 1, 2017, but an exemption applies to "natural gas produced and consumed on-site by conventional oil and gas producers (until Jan 1, 2023)."[59] This exemption is very significant for oil and gas producers since the conventional (non-oilsands) upstream oil and gas industry consumes approximately 7% of the natural gas produced in the province to power its operations. Approximately 60% of that gas is used to fuel engines.

From 2021 to 2026, the Federal Canadian Multi-Sector Air Pollutants Regulations (MSAPR) will be phased in to set limits for NOx emissions intensity for new and pre-existing reciprocating engines that have a rated brake power of >75kW. A rich-to-lean conversion using an AFRC is a good alternative for reducing NOx emissions from rich-burn engines versus installing an exhaust after-treatment system such as a three-way catalyst, which would serve to increase operating costs and increase fuel usage.

AFR projects can be an excellent solution to improve energy efficiency by reducing fuel gas consumption from engines and to control NOx emissions to meet regulatory compliance. Once on-site fuel gas usage in the conventional oil and gas sector does become subject to the Alberta carbon levy in 2023 (or if it becomes subject to a federal carbon tax), there will be an even greater incentive for producers to improve engine fuel efficiency.

Service Provider/More Information on This Practice

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[59] https://www.alberta.ca/climate-carbon-pricing.aspx#p184s1

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5.2.6. Vent Gas Capture (VGC) Systems

July 31, 2017

Description

Significant natural gas is vented to the atmosphere during the course of normal oil and gas operations. The capture and combustion of vented natural gas (a "VGC Project"), consisting of primarily methane, reduces greenhouse gas emissions by combusting methane and converting it to carbon dioxide, water vapour, and other combustion by-products. A portion of the vent gas may still be emitted to the atmosphere if the collection system is not 100% effective (e.g. downtime, not all sources tied in, partial collection down to low pressures etc.) or if the combustion device is not 100% effective at destructing the methane.

A typical vent gas capture project includes piping, controls, regulators and a combustion device. However, additional energy inputs may be required to boost low-pressure vent gas to high pressures to enable beneficial use (e.g. vapour recovery units).

The most common configuration of vent gas capture system that has been installed in Canada is the SlipStream® technology developed by Spartan Controls[60]. The SlipStream® technology captures vented hydrocarbons and safely redirects these gases into the air intake of a reciprocating engine in a controlled manner. The vent gas can then be used as a supplemental fuel source (the vented gas is completely destructed in the engine, while also helping to reduce the fuel usage from the primary fuel supply). The SlipStream® technology includes a valve train for process control and metering of the vent gas, and includes software and hardware to integrate the system with the facility's control panel and shutdown systems. No incremental compression or other energy inputs are required to utilize the atmospheric pressure vent gas since the gas is input into the engine air intake, where the turbochargers operate at negative pressure and draw the gas into the engine.

Spartan Controls has also developed a version of SlipStream® that works with fired heaters (e.g. dehydrator re-boiler burners, tank heaters or line heaters). Other vendors offer variations of this type of technology to reduce vented emissions from glycol dehydration by condensing out water vapour to dry the vent gas before burning it in a fired-heater.

Other vent gas capture configurations are possible and may include vapour recovery units with small compressors to boost the pressure of the vented gas to enable productive use or sales of the gas.

Baseline:
Significant methane is vented to the atmosphere from dedicated vent lines associated with the operation of reciprocating compressors, glycol dehydrators, pneumatic instruments and pumps, and solution gas from oil/condensate production.

Pneumatic devices are not normally tied into flares for both safety and operational reasons, such as preventing backpressure on the instruments. Flaring may be the baseline for certain glycol dehydrators that are subject to benzene emission limits.

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[60] http://www.spartancontrols.com/rem-technology/rem-technology-products/slipstream/

Estimating Gas Savings:
The best way to estimate potential fuel gas savings and GHG emissions is to conduct a vent gas measurement survey. This includes documenting all venting sources (compressor packing vents, pneumatic equipment etc.) and taking short duration or snap shot measurements. It is helpful to have an infrared camera (FLIR camera) on site while conducting measurements to ensure that all of the gas is being metered. For example, gas will often leak from pneumatic controller boxes when a small amount of back pressure is applied, but will not go through the meter.

Note that due to the low pressures of atmospheric vents, the captured quantity of vent gas (after installation) may not add up to the total sum of the vent gas sources identified. Low pressure gas will follow the path of least resistance, so all vent totals may not be captured.

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Site Applicability

Sweet natural gas production facilities that are not currently flaring the waste gas emitted from reciprocating compressor packing vents, glycol dehydrator still column vents, or other production equipment (tanks, casing etc.).

One of the key criteria is the availability of a suitable combustion device at the site to combust the captured vent gas. In many cases, this will be a reciprocating engine or a fired-heater (burner); however, the control system of the combustion device must be dynamic enough to be able to respond to the change in combustion conditions caused by the addition of a supplemental fuel source (vent gas). For example, turbo-charged engines require an air-fuel ratio (AFR) control system that will prevent over-fueling of the engine. Some original engine manufacturer AFRs can be used, but often an after-market AFR such as REMVue® will be used along with the vent gas capture system (e.g. SlipStream®). For any candidate project, it is important to assess what upgrades to the combustion device might be required, such as control systems and panels, as these costs can be significant.

It is important to assess the layout of the facility as the vent gas may need to be distributed from one process (e.g. dehydrator) to another building where the combustion device is located (e.g. compressor building). Any water content in the vent gas could present a freezing risk, so gas should be dried, heat-tracing should be added, and/or the piping should be sloped appropriately. Compressor oil in packing vent gas may need to be removed as well.

Emissions Reduction and Energy Efficiency

Measurement:
Continuous direct measurement is needed with a dedicated flow meter installed on the piping that connects the captured vent gas stream to a combustion device (e.g. engine, flare). Meters are normally tied into a Supervisory Control and Data Acquisition (SCADA) system for continuous data collection, similar to conventional gas production meters, and data is usually collected every 15 minutes and averaged daily. Meters are typically calibrated annually.

Baseline Emissions:

The baseline for a VGC project is the venting of methane to the atmosphere from dedicated vent lines associated with the previous configuration (this assumes that the waste gas stream was not previously flared). The baseline emissions can be calculated based on the metered amount of vent gas that has been captured (after installation of VGC system), the site gas composition (% methane), the density of methane, and the global warming potential of methane. Note that this is a simplification of the Alberta Offset System (AOS) Quantification Protocol for Engine Fuel Management and Vent Gas Capture, and the full calculation is available in the protocol.

A simplified formula to estimate baseline emissions:
Baseline Emissions = (Estimated Natural Gas Savings in m^3/year)*(% Methane in gas)*(Density of Methane)*(0.001 t/kg)*(GWP of Methane).[61]

Estimated GHG Emission Reductions:
GHG reductions from 104 VGC projects completed at compressor stations and gas processing plants in Alberta ranged from approximately 450 to 3,700 tCO_2e/year per project, with an average of approximately 920 tCO_2e/year per project. GHG reductions are site-specific and depend on the type of vent gas being captured and the design of the facility.

Economic Analysis

Capital Cost: Capital costs are highly site-specific, but costs from VGC projects completed by a major producer in Alberta at 60 compressor stations ranged from $55,000 to $250,000, with an average of approximately $90,000 (per compressor). Capital costs for another VGC project completed by a major producer completing 39 retrofits, including 28 SlipStream vent gas capture systems and 11 REMVue engine fuel management systems, averaged $197,000. A third project by a major producer installed five SlipStream vent gas capture systems, averaging capital costs of $254,000. Note that capital costs may be much higher for projects that capture vented gas from multiple compressors or dehydrators and for projects that require expensive engine upgrades, such as a new control panel or the addition of an air-fuel ratio control system.

Installation Cost:

Operating Cost: Operating Costs are minimal for vent gas capture systems, provided they do not require incremental compression (e.g. a vapour recovery unit or booster compressor is not required).

Maintenance Cost: Maintenance costs are estimated at $500-$1,000/year for meter calibration and periodic site visits (e.g. troubleshooting units that trip offline).

Carbon Offset Credits: The value of carbon offsets can be very significant for VGC projects and can outweigh the value of the gas savings by a significant margin using an assumed carbon offset value of $25/offset in Alberta. Based on the GHG reductions

[61] Global Warming Potential of Methane is 25 currently (but subject to change), per: http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/CarbonEmissionHandbook-Mar11-2015.pdf
Density of Methane gas at 15̊C and 1atmosphere is 0.6797 kg CH_4/m3, per https://encyclopedia.airliquide.com/methane

	achieved by the 104 Alberta VGC projects mentioned above (Low of 450 tCO_2e to a high of 3,700 tCO_2e and an average of about 920 tCO_2e), the value of the carbon offsets at \$25/offset could be worth from \$11,250/year to \$92,500/year; \$23,000/year on average per project.
Payback, Return on Investment and Marginal Abatement Cost:	The primary benefit of VGC projects is gas savings, and these are site-specific. Savings from 60 VGC projects completed in Alberta ranged from approximately 2.5 mcfd to 10 mcfd, with the average of about 6 mcfd. At a flat \$2.50/mcf AECO gas price, these gas savings would be worth from \$2,300/yr (2.5 mcfd) to \$9,000/year (10 mcfd) or an average of \$5,500/year (6 mcfd).

Barriers:

- Financial barriers – Small volumes and low value of recovered/conserved vent gas makes many projects uneconomic without carbon offsets. Capital costs are high when retrofitting older facilities.
- Low pressure (atmospheric pressure) of vented gas is difficult to capture/use.
- Combustion equipment, such as reciprocating engines, may require expensive modifications to be able to utilize or combust vented gas. For example, engines may require an air-fuel ratio controller or control panel upgrades, or fired heaters may need to replace the burner and control system. In addition, new combustors (e.g. flares or incinerators) may be required at sites that do not have an existing combustion source, and these devices would require a supplemental fuel gas source to burn the vented gas (e.g. pilot, purge and dilution gas).
- Vented gas is often saturated with water (e.g. glycol still column overheads) and is difficult to manage without freeze-offs in winter, and often contains other impurities (e.g. oil from compressor packing vents)
- Difficulty estimating vent gas rates due to lack of metering (e.g. compressor rod packing vents).
- Minimal capital available for energy efficiency or emission reduction projects
- Unwillingness to modify proven facility designs that are reliable.

Reliability

Vent gas capture systems are highly-reliable. They are usually designed so that if an issue arises with the vent gas capture system, it trips-offline and vents back to atmosphere by default, preventing downtime for the compressor/facility. However, this system design can lead to inefficient collection of vent gas and a lack of urgency in getting the vent gas capture unit back online. This is especially true when the system needs to be manually re-set or requires trouble shooting. Since the vent gas capture system is usually a low-priority item, it may take several weeks before a technician is able to visit the site.

Reliability may be more difficult to maintain if there are impurities in the gas stream, such as oil from packing vents or water from dehy still columns. The process is prone to upsets/significant changes in operating conditions if the combustion device (e.g. engine) is in poor condition.

Safety

The VGC system must be properly integrated with the existing site safety systems (e.g. compressor safety shut down keys) and proper training must be provided to operators. It is important to ensure that the vent gas system is always set to vent to atmosphere when the engine is not operational so that gas is never being input into the engine until after the engine has been started.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations.

Future Regulatory Considerations:
Both the Alberta Government[62] and the Federal Government[63] have announced their intentions to regulate methane emissions from a variety of equipment, including reciprocating compressor packing vents, dehydrators vents[64], pneumatic controllers, pneumatic pumps and production tank and casing gas venting. Draft regulations are expected in 2017 with compliance requirements by 2020-2023 timeframe. It is expected that there will be specific limits on methane venting from each of the above sources and different standards for new (greenfield) facilities and potential requirements to retrofit existing pneumatic equipment. VGC projects can be an excellent solution to meet regulatory compliance by significantly reducing or nearly eliminating methane emissions from these sources. Vent gas capture systems are a natural solution for reducing methane emissions from reciprocating compressor packing vents since the compressor engine is an ideal methane destruction device and the vented gas can displace part of the primary fuel supply.

Service Provider/More Information on This Practice

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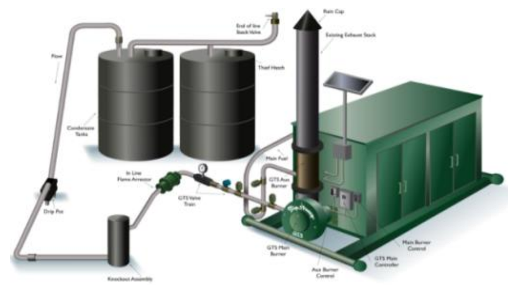
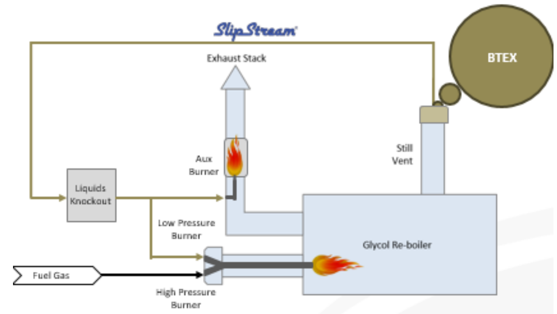
[62] https://www.alberta.ca/climate-leadership-plan.aspx#toc-5
[63] http://news.gc.ca/web/article-en.do?nid=1039219
[64] Alberta only.

Section 6.1. Dehydration Units and Gas Treatment – Facilities Design and Equipment

## 6.1.1. [Spartan Controls Ltd. – SlipStream® GTS – DeHy]	**April 26, 2019**

Description





The SlipStream® GTS-DeHy is a vent capture system designed specifically to capture vented hydrocarbons from condensate tanks, glycol dehydrators, and oil storage tanks. These captured hydrocarbons are instead redirected for use as supplementary fuel, significantly reducing greenhouse gas (GHG) emissions and destroying volatile organic compounds (VOCs) like benzene, toluene, ethylbenzene, and xylene (BTEX).

The GTS-DeHy easily integrates into new or existing installations, eliminating the need for stand-alone combustors or costly vent gas compressors. On a typical glycol dehydrator application, the GTS-DeHy routes the captured vent gases to either the main burner or auxiliary burner depending on heat demand, and has a BTEX destruction efficiency of 99.5% approved by the AER.

Technology Group

Dehydration Units and Gas Treatment – Facilities Design and Equipment

Site Applicability

Oil and gas facilities; sweet service

Emissions Reduction and Energy Efficiency

- BTEX emissions: 99.5% destruction
- CO_2e emissions: 200 to 1000 tCO_2e reduction
- Methane emissions: 99.5% destruction

Economic Analysis

Capital Cost:	Capital costs range from $30,000 to $75,000, depending on dehydrator Btu capacity or burner size.
Installation Cost:	Installation costs range from $30,000 to $40,000, depending on dehydrator Btu capacity.
Operating Cost:	Operating cost figures are project-specific. However, in all cases the GTS DeHy reduces operating costs by using condenser tank vapours as replacement fuel.
Maintenance Cost:	The GTS DeHy incurs no scheduled maintenance costs.
Carbon Offset Credits:	The GTS DeHy is eligible for carbon offset credits in Alberta through the

	Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects.
Payback, Return on Investment and Marginal Abatement Cost:	Fuel savings range from $3,000 to $6,000 per year.

Reliability

Expected Lifetime:	The equipment is expected to last the lifetime of the facility.
Maintenance:	No special maintenance considerations apply.

Safety

No additional safety considerations apply.

Regulatory

- CSA, Class1 Div 2 hazardous approval
- Alberta AER approved technology for BTEX reduction
- Recognized for Methane emissions compliance by AER Directive 60 and Environment and Climate Change Canada
- Recognized as compliant solution for the Alberta Engine Fuel Management and Vent Gas Capture Protocol and the BC META protocol
- U.S. EPA and Quad-O approved technology

Vendor Information

Company Name:	Spartan Controls Ltd.
Company Website:	http://www.spartancontrols.com
Product Website:	http://www.spartancontrols.com/applied-technology/rotating-and-reciprocating-equipment/vent-capture/emissions-efficiency/slipstream-gts/
Contact Person:	Cam Dowler
Contact Phone#:	(403) 695-2318
Contact Email:	Dowler.Cam@spartancontrols.com

6.1.2. Gas Pro Compression BTEX VRU

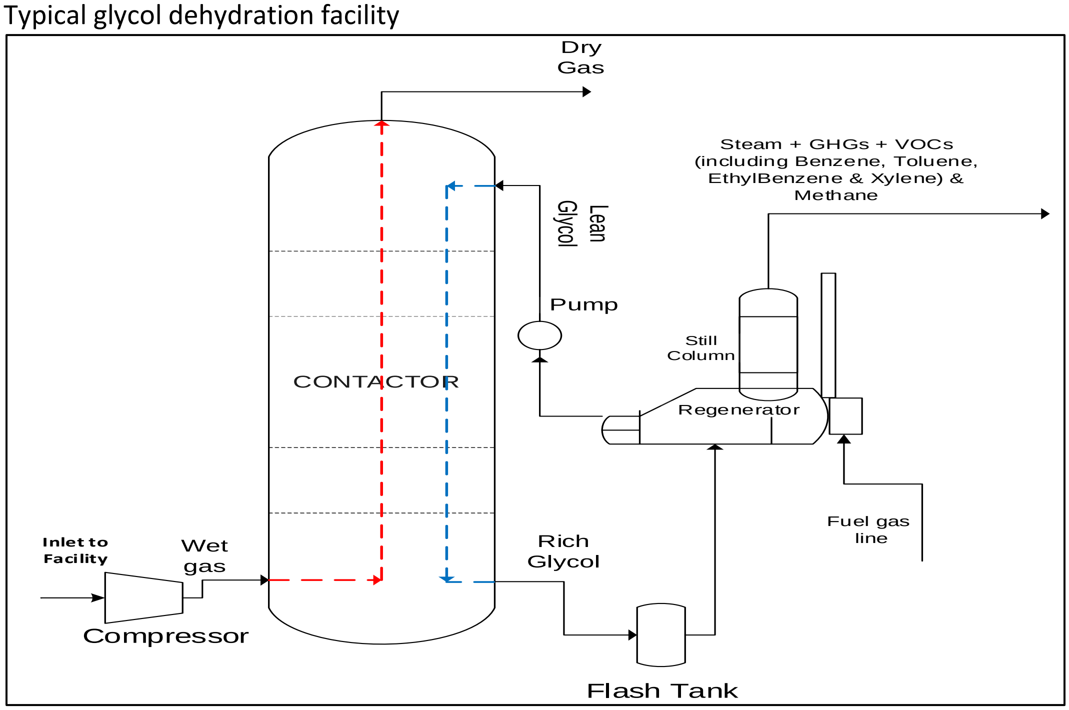
April 26, 2019

Description

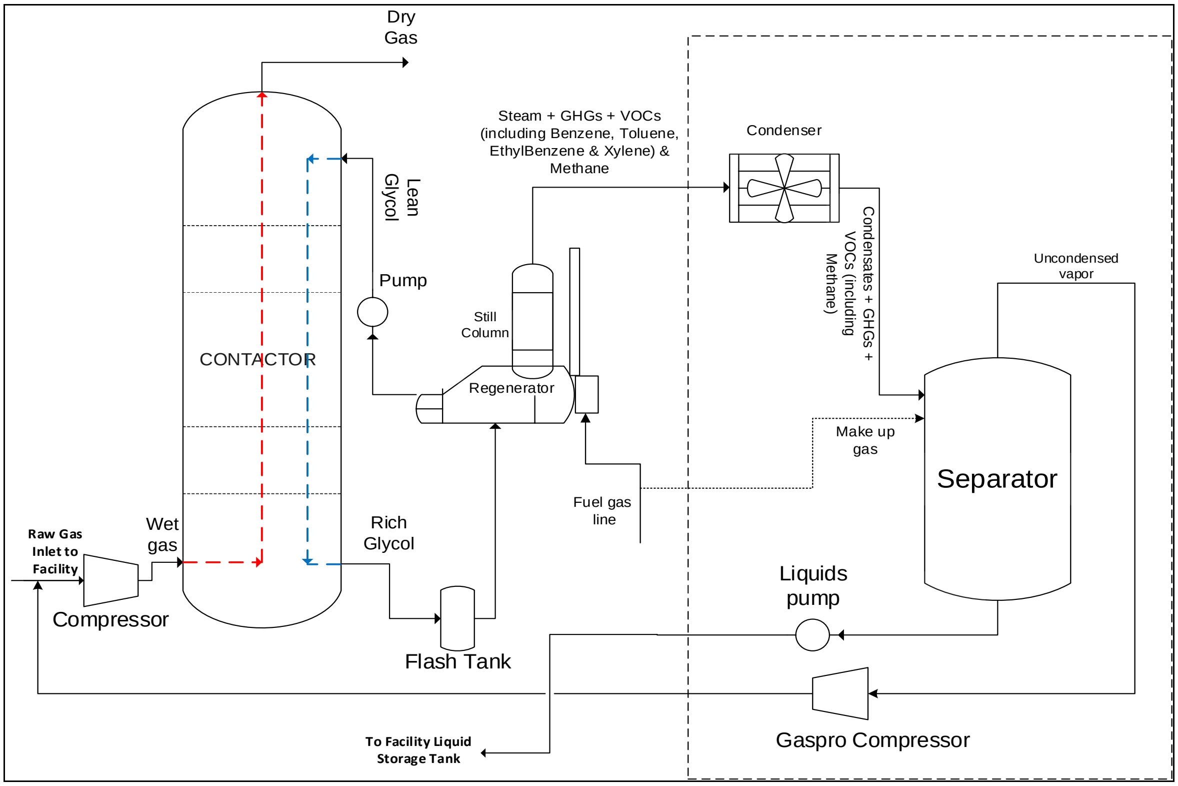
Glycol dehydration is a common and economical process to reduce the water content in natural gas to meet downstream sales pipeline specifications. In a typical dehydration operation, the gas is put in contact with glycol, which absorbs water from it. However, the glycol also absorbs methane, ethane, and several other volatile organic compounds (VOCs) including benzene, toluene, ethylbenzene and xylenes (BTEXs). This rich glycol is then sent to a regenerator, where it is heated to vaporize the water and regenerate the glycol. During this regeneration process, dissolved BTEX, greenhouse gases (GHG) (Methane, CO_2), and other organic compounds are also released along with water.

Gas Pro compression has developed a BTEX VRU system that allows 100% recovery of the emissions from the glycol regenerator. In this system, the regenerator emissions are condensed and then sent into a separator where the liquids drop out. The uncondensed vapor above the liquid then goes into a compressor, which delivers the gas back into the inlet of the facility. The condensed liquids from the separator are pumped to a storage tank.

Typical glycol dehydration facility



Gas Pro BTEX VRU system added to a typical glycol dehydration facility



Technology Group

Dehydration Units and Gas Treatment – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service

Emissions Reduction and Energy Efficiency

Gas Pro's BTEX VRU eliminates BTEX, GHGs and VOC emissions. Based upon uncontrolled emissions data from GlyCalc for two dehys operating on one site, the technology eliminated approximately 247 tCO_2e/year. However, exact emissions reduction varies depending on the specific dehydrator being used.

Economic Analysis

Capital Cost:	Equipment costs range from $65,000 to $120,000 depending on the type of compressor, cooler, level of controls, and safety and other options. The complete package is a simple 'plug and play' that includes all the components and the controls, while the client must provide the controls and electrical if purchasing the stripped-down version.
Installation Cost:	Exact installation cost figures are application-specific. However, installation costs are comprised of the piping and electrical components needed to hook up the unit.

Operating Cost:	Exact operating cost figures are application-specific. However, operating costs are comprised of the energy needed to operate the motors. The motors are equipped with VFDs that provide a soft start and prevent constantly running at full speed.
Maintenance Cost:	Maintenance costs are expected to be minimal, consisting of periodic oil changes for the compressor.
Carbon Offset Credits:	Carbon offset eligibility is application-specific.
Payback, Return on Investment and Marginal Abatement Cost:	The payback period, ROI, and marginal abatement costs are application-specific. However, the BTEX VRU eliminates the need for expensive destruction efficiency tests, tank maintenance costs, and constant upgrades to meet regulatory requirements. The BTEX VRU system can also handle tie-ins from other vent sources.

Reliability

Expected Lifetime:	With proper maintenance, the equipment is expected to last 25+ years.
Maintenance:	Maintenance can be completed with basic industry knowledge about gas compressors.

Safety

Standard industry safety practices apply.

Regulatory

- Meets all codes and standards for installation in Canada.
- AER Directive 039
- ABSA AQP for pressure piping, COR, Complyworks, ISN, CSA 22.2 No. 14, UL 508A.
- Client can request CSA SPE 1000, CSA 22.2 No. 30, Special Fugitive emissions study

Vendor Information

Company Name:	Gas Pro Compression
Company Website:	www.gaspro.ca
Product Website:	http://www.gaspro.ca/index.php?page=products
Contact Person:	Ayaz Mahmood / Tom Nichols
Contact Phone#:	403-443-8886 / 403-443-1115
Contact Email:	ayaz.mahmood@gaspro.ca / Tom.nichols@gaspro.ca

6.1.3. TRIDO industries Inc. - Glycol Heat Exchange Pump

April 26, 2019

Description

Canada's cold temperatures pose a significant challenge for oil and gas processing. Heat trace systems help pipes to maintain consistent temperatures, usually through natural-gas-driven diaphragm-style pumping units that circulate glycol around the wellsite. The solar-powered TRIDO heat exchange unit eliminates the venting common with diaphragm pumps, and the conserved fuel gas enables the recapture of lost gas revenue. The TRIDO glycol heat exchange unit incorporates a high-capacity pump designed for use with the TRIDO motor. Although extremely compact and well-suited to mobile or temporary placement, the TRIDO heat exchange units can be set up in parallel to handle increased volumes.

Technology Group

Dehydration Units and Gas Treatment – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Converting pneumatic devices from fuel gas to solar power eliminates methane emissions. Exact greenhouse gas (GHG) reduction figures vary from site to site depending on the equipment being replaced.

Economic Analysis

Capital Cost:	Capital costs are approximately $2,500. However, exact figures vary depending on the level of application.
Installation Cost:	Installation costs are extremely low. The equipment is designed to be delivered and installed by a field rep or operator.
Operating Cost:	Operating costs are low, and gas no longer being vented can be sold for additional cost savings.
Maintenance Cost:	Maintenance costs are low. However, regular basic maintenance is required.
Carbon Offset Credits:	The TRIDO Heat Exchange Unit is eligible for carbon offset credits in Alberta through the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Payback, Return on Investment and Marginal Abatement Cost:	The payback period, ROI, and marginal abatement costs are application-specific. However, retaining vented gas for sale can augment project economics.

Reliability

Expected Lifetime:	The equipment is expected to last 10 years.
Maintenance:	The equipment requires minimal maintenance.

Safety

No unusual safety requirements apply.

Regulatory

- Motor/pump Class 1, Div. 1. Controller Class1 Div 2
- No AER Directive applicable

Vendor Information

Company Name:	TRIDO Industries Inc.
Company Website:	www.tridoind.com
Product Website:	http://tridoind.com/top-performers/heat-exchange-unit/
Contact Person:	Russell Graham
Contact Phone#:	1-855-368-7438
Contact Email:	sales@tridoind.com

6.1.4. Zirco – JATCO Gas Dehydrator BTEX Eliminator

July 31, 2017

Description

The BTEX Eliminator System is a counter flow stainless-steel shell and tube heat exchanger condensing system used to capture and recycle benzene, toluene, ethylbenzene, and xylene (BTEX) and volatile organic compound (VOC) vapours from dehydrator still columns. BTEX emissions are reduced by more than 95%.

Condensed liquids, mainly water and BTEX, are collected into the JATCO Tank, which is a blowcase triggered by a level sensor. This allows for automatic transfer to storage. The residual vapours, mainly light hydrocarbons, are sent to the re-boiler main burner.

This closed-loop system not only eliminates BTEX and VOC emissions from the still gas, but also creates burner fuel savings and potential for condensate recovery.

Technology Group

Dehydration Units and Gas Treatment – Facilities Design and Equipment

Site Applicability

Upstream gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The BTEX Eliminator achieves a >95% BTEX reduction, and any residual vapours, such as methane, are sent to the re-boiler main burner. However, the exact reduction in vented methane depends upon the optimization of triethylene glycol (TEG) flow.

Economic Analysis

Capital Cost:	Capital costs are system- and application-dependent. However, average estimated hardware costs range from $30,000 to $100,000 plus field labor.
Installation Cost:	Exact installation costs vary depending on labour rates. However, the installation is simple and is estimated to take approximately 20 hours.
Operating Cost:	Operating costs are very low, and may actually be zero, given that valves are operated pneumatically and the unit operates by gravity.
Maintenance Cost:	Instrumentation (mechanical) will require regular maintenance. Recommended spare parts include valves for tank, level control and pilot, repair kit for relay, mist pad, and flame cell for burner mixer adapter.
Carbon Offset Credits:	When coupled with additional equipment, such as metering, the BTEX

	eliminator is eligible for carbon offset credits in Alberta through the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices
Payback, Return on Investment and Marginal Abatement Cost:	The payback period, ROI, and marginal abatement costs are application-specific and depend upon fuel gas savings

Reliability

Expected Lifetime:	The stainless steel equipment is expected to last from 10-20 years, with the longest lifetime for equipment operating in sweet service.
Maintenance:	Annual scheduled maintenance is required on instrumentation (mechanical). Recommended spare parts include valves for tank, level control and pilot, repair kit for relay, mist pad and flame cell for burner mixer adapter.

Safety

Operators must comply with all safety regulations, although the BTEX Eliminator does not present additional safety hazards outside regular site operation.

Regulatory

- All required regulatory requirements in place. AER Directive 39 compliance would require site analysis including storage tank.
- Non-electrical device, does not require CSA approval

Vendor Information

Company Name:	ZIRCO
Company Website:	http://zirco.com
Product Website:	http://zirco.com/brands/jatco/ and additional product information at: http://www.oilandgasproductnews.com/article/2559/heat-exchanger-and-condensing-system-exceeds-98-percent-btex-elimination
Contact Person:	Ryan Sperling
Contact Phone#:	403 259 3303
Contact Email:	ryans@zirco.com

Section 6.2. Dehydration Units and Gas Treatment – Recommended Practices

## 6.2.1. Right-sizing Gas-Driven Triethylene Glycol (TEG) Recirculation Pumps in Dehydration Units	July 31, 2017

Description

Glycol dehydration units (dehys) in western Canada commonly over-circulate glycol, using more energy and creating more emissions despite a negligible reduction in dry gas water content. Likewise, the process of stripping gas is completed year-round to ensure gas is adequately dried, although the process may only be needed seasonally or, in some cases, may not be necessary at all. Optimization of the operating conditions of dehydration units reduces both operating expenses and emissions of greenhouse gases (GHGs) and other air contaminants.

The first step in the optimization process is to complete an analysis of dehy performance and identify options for cost and emissions reduction. Options include replacing the existing gas-driven recirculation pump with a "right-sized" gas-driven pump. A spreadsheet-based Glycol Circulation Estimator (GCE) Tool can be used to quickly assess energy and GHG emission optimization opportunities for TEG dehydrators, without the need to run more complex simulation models. The GCE Tool is available from Process Ecology.

Technology Group

Dehydration Units and Gas Treatment – Recommended Practices.

Site Applicability

Sites with existing gas-driven TEG pumps.

Emissions Reduction and Energy Efficiency

Gas-driven TEG pumps (generally Kimray pumps) are driven by natural gas which is vented to the atmosphere after use. Methane from natural gas has 25 times more GHG impact than CO_2. Optimization of the dehy process, often including replacing the existing pump with a smaller one, will result in fuel gas savings and in less methane being vented to the atmosphere. Project-specific

GHG reductions vary significantly, depending primarily on the amount of glycol over-circulation and stripping gas use. For example, an optimization project performed in 2016 replaced an existing Kimray 210-15 with a Kimray 1720 PV. In this case, the GHG reductions varied from 100-2,400 tCO_2e per year, with an average of 1300 tCO_2e per year.

Key parameters to consider are:

- Over-circulation of glycol
- Use an energy exchange (Kimray) pump
- Recover fuel gas in a flash tank
- Vent still gas overheads
- Use of stripping gas

Economic Analysis

- The economic benefits will be strongly project-dependent and will be affected by the following factors:
- Purchase and installation
- Value assigned to natural gas savings
- Value of any GHG offset credit applied and awarded

Capital Costs:	Total purchase and installation costs for the sample project were \$6,300. However, purchase costs depend upon pump size and vendor, and installation costs are site-dependent.
Operating Costs:	Operating costs are expected to decrease with optimization, resulting in savings of ~\$10,000 per year. In the sample case, the smaller pump and optimized operations saved fuel gas.
Maintenance Costs:	Maintenance costs are not dependent on pump model and size, and are expected to remain the same following optimization.
Carbon Offset Credits:	Dehy optimization projects are eligible for offset credits in Alberta through the Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects.
Payback, Return on Investment and Marginal Abatement Cost:	Although payback for individual projects may vary, the payback period for the sample project was less than one year. The abatement potential for right-sizing and optimization of dehy pumps is estimated to be \$5 per tCO_2e/year.

Reliability

Expected Lifetime:	Gas-driven pumps are very reliable. No changes are expected from right-sizing the pump model.
Maintenance:	No additional maintenance is expected after right-sizing and optimizing gas driven pumps.
Parts and Skills Required:	Gas driven pumps can be serviced by most qualified technicians.

Safety

Gas-driven pumps are commonly used in process industries and do not create unusual safety hazards.

Regulatory

The vendor of the gas-driven pump must obtain and demonstrate compliance with relevant petroleum facilities codes and regulations.

Vendor Information

Several vendors provide suitable gas driven pumps. Below are examples of major pump vendors that are seen in dehydration facilities:

- Kimray/Bruin

- Union
- Rotor-Tech
- Wheatley
- Bear
- FMC
- Hydra-Cell
- Milton Roy
- National

More information about the Process Ecology Glycol Circulation Estimator (GCE) Tool can be downloaded at: https://www.ptac.org/glycol-dehydration-pump-optimization-2

6.2.2. Benzene Emissions Model	July 31, 2017

Description

The oil and gas industry uses glycol dehydrators at many facilities to remove moisture from natural gas streams. The glycol used in these processes also absorbs other components from the gas stream, including benzene, a known carcinogen. A portion of these components are vented to the atmosphere via the glycol regenerator still vent. Regulations restrict allowable benzene emissions from glycol dehydrators, and producers often use condenser equipment to limit the amount of vented benzene. Operators can minimize emissions by following identified best practices for each benzene mitigation method. These methods may be used alone or in combination, whichever is the most effective for specific facilities.

Process Optimization Methods for Reducing Benzene	
in TEG dehydration facilities:	
Circulation Rate Reduction	Do not over-circulate. Over-circulation increases emissions. Recommended circulation rate is three gallons TEG per lb water removed.
Stripping Gas Reduction	Stripping gas significantly reduces the capability of condensers and tanks to efficiently remove benzene emissions. Use of stripping gas should be confined to situations where wet gas is routed to the contactor or when lean glycol is above 40^{o}C.
Reboiler Operating Temperature	Temperature should remain close to 200^{o}C. Too high a temperature promotes degradation and reduction in performance, while too low a temperature may over-circulate the glycol.
With Equipment Replacement:	
Pump reduction	Reduce pump size if lower circulation rates cannot be achieved with current pump.
Energy Exchange	Replace Kimray pump with electric pump, provided there is a readily-available source of electricity. Kimray pumps introduce extra gas in the regenerator that limits benzene reduction.
Flash tank	Install a flash tank to increase efficiency of condenser.
Using Other Methods	
Thermal Combustion	Combust overhead vapours through incineration or flaring, significantly reducing benzene.
Vapour Recovery and Combustion in Reboiler	Using commercially-available technologies, recover the overhead gas for use as fuel gas in the regenerator burner.
Vapour Recovery and Combustion in Compressor Engine	Use vented hydrocarbons as supplementary fuel for a nearby natural gas compressor engine.
Vapour Recovery Unit	Recover all still column overhead emissions using compression equipment

In addition to mitigating benzene emissions, operators can also improve the benzene removal performance of condensing equipment by following the identified best practices.

Best Practices
• Ensure proper sizing of condensing equipment. • In facilities using Kimray glycol pumps, ensure a flash tank is installed to reduce the amount of methane and light hydrocarbons being routed to the regenerator. • Ensure proper operation/maintenance of condenser equipment. • Ensure proper operation/maintenance of regeneration equipment. • Avoid the use of stripping gas. • If stripping gas is necessary, ensure the lowest effective amount is introduced using needle valves and accurate measurement. • Ensure TEG reboiler temperatures operate consistently at ~200^{o}C. • Ensure DEG boiler temperatures operate consistently ~160^{o}C. • Ensure EG reboilers operate consistently ~120-130^{o}C. • Ensure clear communication to operators regarding changes to condenser performance. • Evaluate process performance on a regular basis, adjusting as needed.

Technology Group

Dehydration Units and Gas Treatment – Recommended Practices

Site Applicability

Facilities operating glycol dehydrators with condensation tanks

Emissions Reduction and Energy Efficiency

Still vapours in glycol regenerator units are often routed to a condenser to remove hydrocarbons and water, thereby reducing benzene emissions emitted to the air. The TankSafe condenser is commonly used in Western Canada, as it offers a proven substantial reduction in benzene emissions. Other benzene mitigation methods are also available. Specific strategies to minimize the emission of benzene into the atmosphere have been developed for multiple scenarios. The selection of a specific benzene mitigation method depends on facility-specific factors. In general, the best condenser emissions removal performance is expected for units with an electric pump and a flash tank installed.

No matter what method is selected, the process should be altered as needed to ensure optimal processes and minimal emissions and energy use.

Implementing recommended practices will have a positive impact on air quality by reducing benzene emissions. However, this may or may not have an impact on climate change given that condensers and tanks do not themselves reduce GHG-emissions because CO_2 and methane are not condensed in devices.

Baseline:
Benzene emissions are managed using glycol regenerators with condensation tanks. Regulations require field measurement at regular intervals to monitor efficacy.

Economic Analysis

Implementing the Benzene Emissions model's recommended practices is not expected to have a significant impact on costs and economics. However, implementing other recommendations, such as the addition of vapour recovery units or combustion devices, will result in additional capital and operating costs that must be analyzed on a case-by-case basis.

Reliability

All equipment must be evaluated to verify that the equipment and processes follow all relevant industrial specifications and standards. Regardless of which mitigation method for benzene emissions is selected, all equipment and processes should be revisited on a regular schedule and altered as needed to ensure ongoing optimal processes and continued minimal emissions and energy use.

Safety

Measuring benzene in the field is costly and dangerous, as it involves working at high heights and carries an increased risk of exposure to benzene. As a known carcinogen, working with benzene requires appropriate personal protective equipment (PPE). All work must be completed in compliance with applicable safety regulations at all times.

Regulatory

Operators must ensure they always comply with all applicable regulations.

- Alberta Directive 039

Service Provider/More Information on This Practice

The Condenser Application can be accessed on the PTAC website at:
http://auprf.ptac.org/air/development-of-a-model-to-predict-benzene-emissions-from-glycol-dehydrators-with-condensation-tanks-project-continuation-potential-release-into-the-atmosphere-of-additives-used-in-the-hydraulic-fract/

References:

Alberta Energy Regulator. (2013, January 22). *Directive 039*. Retrieved from Alberta Energy Regulator Rules and Directives: https://www.aer.ca/rules-and-regulations/directives/directive-039

Alberta Upstream Petroleum Research. (2017). *Development of a Model to Predict Benzene Emissions from Glycol Dehydrators with Condensation Tanks: Project Continuation*. Retrieved from Alberta Upstream Petroleum Reasearch - Air: http://auprf.ptac.org/air/development-of-a-model-to-predict-benzene-emissions-from-glycol-dehydrators-with-condensation-tanks-project-continuation-potential-release-into-the-atmosphere-of-additives-used-in-the-hydraulic-fract/

Process Ecology Inc. (February 17, 2016). *Development of a model to predict benzene emissions from glycol dehydrators with condensation tanks Revision 4.* Calgary: Alberta Upstream Petroleum Research. Retrieved from http://auprf.ptac.org/wp-content/uploads/2015/11/15-ARPC-01-Development-of-a-Model-to-Predict-Benzene-Emissions-from-Glyc...-1.pdf

6.2.3. Use and Environmental Impact of Amines

July 31, 2017

Description

Amine solvents, such as mono ethanol amine (MEA), are used extensively in the natural gas sweetening process to remove acid gas from produced sour gas. Amine-based solvents are also considered the most suitable medium for the CO_2-capture process using the best-available current technology. These two processes are major sources of amine emissions. In the natural gas sweetening process, the most common losses of amines are entrainment loss, vaporization loss, and degradation loss. In the amine-based CO_2 capture process, most amine losses occur through vaporization and degradation and release amines directly to the atmosphere. However, amine emissions from sour gas sweetening and from CO_2 capture can be minimized by following identified best practices for each application.

Natural Gas Sweetening Process	
Loss due to…	Minimization strategies
Entrainment (from foaming, emulsions, etc.)	• Ensure proper operation and proper sizing of the equipment • Add a three or four tray water-wash section at the top of the contactor column to recover entrained amine from the gas leaving the contactor. • Install a demister pad on the vapour outlet to limit entrainment of amine from the contactor
Vaporization (due to exothermic absorption reaction in the contactor)	• Reduce contactor operating temperatures as much as practicable • Install a water wash section to recover vaporized amine from the gas leaving the contactor
Degradation (occur in the regenerator, especially in the bottom of the regenerator where reboiler skin temperature is high)	• Avoid excessive temperature of the regenerator reboiler. Refer to GPSA for recommended temperature range. Use low- or medium-temperature heat instead of high temperature heat with medium or direct firing. • Limit the concentration of free oxygen in the feed gas • Use reclaiming technologies such as a thermal reclaimer, ion exchange, or vacuum distillation.
Tank Emissions	• Use a blanket gas, like nitrogen or fuel gas, to preserve the quality of amine and reduce losses. However, tank emissions of amines are quite low.
CO_2 Capture Process	
Loss due to…	Minimization strategies
Entrainment and Vaporization	• Reduce contactor operating temperatures as much as practicable • Reduce MEA concentration, which can also reduce the loss of MEA • Install a water wash at the top of the absorber, and an acid wash in the final water-washing section • Install high-efficiency demisters
Oxidative Degradation	• Limit the concentration of free oxygen in the flue gas • Limit concentration of NOx in the flue gas[65] • Reduce operating temperature of the contactor

[65] NH3, an oxidative degradation product of amines, increases with increasing NOx concentration

Formation of nitrosamines and nitramines	• Limit concentration of NOx in the flue gas[66] • Reduce operating temperature of the contactor
Thermal degradation	• Avoid excessive temperature of the regenerator reboiler. Refer to GPSA for recommended temperature range. Use low- or medium-temperature heat instead of high temperature heat with medium or direct firing

Technology Group

Dehydration Units and Gas Treatment – Recommended Practices

Site Applicability

Sites engaged in **a**mine-based CO_2 capture process and/or natural gas sweetening process

Emissions Reduction and Energy Efficiency

In natural gas sweetening and in CO_2 capture, amines are used to capture CO_2 and other acid gases with the intention of preventing them from entering the atmosphere. The specific scope of this recommended practice is prevention of amine emissions into the atmosphere. Amine emissions impact air quality, but may or may not have an impact on climate change.

Economic Analysis

This recommended practice provides several recommendations regarding the optimization of operations to minimize amine emissions into the atmosphere. In general, adoption of these operating recommendations has minimal impact on costs. However, implementing some recommendations, such as the addition of a wash section or blanket gas, will result in additional capital and operating costs that must be analyzed on a case-by-case basis.

Reliability

Implementation of this recommended practice will not negatively affect process reliability and, in some cases, may improve reliability.

Safety

The recommended mitigation measures do not pose additional health or safety risks beyond those already in place for the natural gas sweetening process and the CO_2 capture process.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations. However, due to insufficient data, no regulations are yet established with regards to amine and amine-degradation product emissions for the CO_2 capture process.

Service Provider/More Information on This Practice

Additional information about this recommended practice can be found at http://auprf.ptac.org/air/literature-review-use-environmental-impact-of-amines-2/

[66] The formation of nitrosamine and nitramines cannot be completely avoided in the presence of NOx

6.2.4. Electrification of Triethylene Glycol (TEG) Pumps in Dehydration Units	July 31, 2017

Description

Replacing gas-driven TEG pumps with electric-driven pumps can cost-effectively reduce energy usage and greenhouse gas (GHG) emissions at sites with an accessible source of electricity. Using electricity as the alternative power for the pumps reduces both methane and GHG emissions on site. This also facilitates opportunities for using electricity generated from clean sources, such as solar energy, which would further reduce GHG emissions.

Technology Group

Dehydration Units and Gas Treatment – Recommended Practices

Site Applicability

Sites with existing gas-driven pumps.

Emissions Reduction and Energy Efficiency

Gas-driven TEG pumps (generally Kimray pumps) are driven by natural gas which is vented to the atmosphere after use. Methane from natural gas has 25 times more GHG impact than CO_2. Electric pumps do not emit any GHGs to the atmosphere.

It is estimated that for an average-size electrified pump, the annual natural gas savings are 11 mcfd/pump and the annual average reduction in CO_2e emissions are almost 1,600 tCO_2e/year/pump. However, natural gas savings and CO_2e emissions reductions will be strongly dependent on the specifics of a particular project. Key parameters to consider are:

- Size of the dehy unit and associated pump
- Existing opportunities onsite to capture and utilize vented gas such as SlipStream and catalytic heaters
- Emissions associated with the source of electrical power.

Economic Analysis

Purchase Cost:	Purchase cost is listed at $34,000. However, the exact cost will vary depending on pump size and vendor.
Installation Cost:	Installation cost depends upon site specifics.
Operating Cost:	Operating costs consist of the cost of electricity required to power the electric pump, and are offset by the net natural gas savings.
Maintenance Cost:	Maintenance costs for electric TEG pumps are $260/year. Typical maintenance costs for gas-driven TEG pumps are in the range of $270 to $530/year.
Carbon Offset Credits:	Electric TEG pumps are eligible for offset credits in Alberta through the Quantification Protocol for Engine Fuel Management and Vent Gas Capture Projects.

Payback, Return on Investment and Marginal Abatement Cost:	The payback period is project-dependent, and is affected by the following factors: • Purchase cost of the electric pump • Installation and commissioning cost • Value assigned to natural gas savings • Cost of purchased electricity • Maintenance cost savings • Value of any GHG offset credit applied and awarded The marginal abatement cost is affected by these same factors, as well as onsite opportunities for capture and utilization of vented gas.

Reliability

Expected Lifetime:	The motors in electric TEG pumps are commonly used in process industries and offer long working life when properly maintained.
Maintenance:	Electric TEG pumps require typical maintenance for electric rotating equipment.
Parts and Skills Required:	The motors in electric TEG pumps are commonly used in process industries and can be serviced by most qualified technicians.

Safety

The motors in electric TEG pumps are commonly used in process industries and do not create unusual safety hazards beyond those commonly associated with electrical equipment.

Regulatory

The vendor of the electric pump must obtain and demonstrate compliance with relevant electric and petroleum facilities codes and regulations.

Vendor Information

- Several vendors provide suitable electric pumps.
- The most common electric pumps tend to be Union SX-3 and DX-5. Solar pumps are not typically used for glycol circulation applications.

Section 7.1. Tanks –
Facilities Design and Equipment

7.1.1. Greatario Hexa-Cover

July 31, 2017

Description

Tank odours, emissions, and evaporation pose a challenge for oil and gas operators. Engineered and manufactured in Canada under license from Hexa-Cover® Denmark, the Hexa-Cover® Oil and Gas Duty is a modular floating roof system that can be deployed inside tanks or on ponds to control odours and prevent evaporation in hot heavy oil applications such as CHOPS, diluted bitumen, diluent, SAGD and boiler-feed water tanks. Hexa-Covers are also used in refined product storage tanks to reduce benzene, toluene, ethylbenzene, and xylene (BTEX) emissions, and in waste-water treatment facilities for refiners and terminal operations.

C.O.V.E.R.S. (Crude Oil Vapour Emission Reduction System) consists of hexagonal-shaped tiles with symmetric ribs on both sides that allow floating structures to distribute naturally and uniformly on the liquid surface. The helical scalloped edge allows the C.O.V.E.R.S to interlock and form a blanket barrier at the surface of the hydrocarbon fluid, impeding odours and vapours. A low density ensures that the C.O.V.E.R.S will float above the surface of the hydrocarbon liquid. The covers significantly reduce VOC emissions, prevent heat loss, and minimize evaporation. Operating costs are reduced as chemical de-foamer is conserved as well as burner fuel for heated storage tanks or boiler feed water tanks.

The C.O.V.E.R.S are:

- Chemically compatible with hydrocarbon components up to continuous temperatures of 100C including Thermal Produced Oil and Diluted Bitumen and light hydrocarbons such as Diluents
- Resistant to weight gain to enable long term buoyancy on top of the fluid.
- Made of polymer classified as static dissipative with a surface resistivity value of 3.7 x EO9Ω sq" ASTM Test method D257.
- Resistant to thermal shock. Tested at -40 °C to +100 °C for sudden rapid temperature exposure.
- Easily installed while existing tanks are in operation, minimizing facility downtime.

Technology Group

Tanks – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The C.O.V.E.R.S technology is particularly suited to containing non-methane volatile organic compound (NMVOC) and BTEX emissions. Reductions of odours and emissions have been measured between 66% and 93%. However, the emission reduction efficiency depends upon the system design of the actual site, the specific hydrocarbon liquids involved, and the operating conditions.

Economic Analysis

Capital Cost:	Capital costs for the various grades of Hexa-Cover® products range from $50/m² to $297/m² USD, depending on the actual duty required, size to be covered, location, and accessibility (open surface ground level, thief hatch etc.)
Installation Cost:	Installation costs depend upon site location and access.
Operating Cost:	The Hexa-Cover® Oil and Gas Duty C.O.V.E.R.S does not create any additional operating costs.
Maintenance Cost:	Maintenance costs are minimal, and possibly null.
Carbon Offset Credits:	Eligibility of the Hexa-Cover® for carbon offset credits is application-specific.
Payback, Return on Investment and Marginal Abatement Cost:	The specific payback period, ROI, and marginal abatement costs are application-specific. For example, when deployed in heated tanks, the primary source of cost-savings is reduced heating costs, whereas for diluent tanks, the cost savings mainly result from reduced loss of diluent vapor. ROI has been recorded as low as a few months depending upon the circumstances of the client and the application.

Reliability

Expected Lifetime:	Hexa-Cover® Oil and Gas Duty C.O.V.E.R.S are expected to last the duration of the life of the tank or outdoor pond.
Maintenance:	Hexa-Cover® Oil and Gas Duty C.O.V.E.R.S requires no mandatory maintenance.

Safety

All routine safety considerations apply, so no unusual safety requirements apply.

Regulatory

- Recognized for odour emissions abatement by AER.
- Polymer is classified as static dissipative with a surface resistivity value of 3.7 x EO9Ω sq" ASTM Test method D257.
- The Greatario Hexa Covers are a non-electrical device and so does not require CSA approval.

Vendor Information

Company Name:	Greatario Covers Inc.
Company Website:	http://www.greatariocovers.com/
Product Website:	Product information is available on the company website.
Contact Person:	Terry Frank

Contact Phone#:	Tel. 403-444-6851 Cell. 519-831-0409
Contact Email:	tfrank@greatariocovers.com

7.1.2. ZIRCO – FNC Vent Gas Capture Pressure Vacuum Relief Valve (PVRV) with Position Switch	June 30, 2017

Description

In oil and gas processing, low-pressure storage tanks hold liquids until they are moved to the next step in a production or supply chain process. The pressure in these storage tanks is subject to change due to fluctuations in liquid levels or temperature. Historically, tank pressure-control devices have not included the monitoring and feedback loops common to other pressure-control devices. In a recent study on storage tanks, it was found that an undetected maintenance issue is the number one concern of tank safety engineers and managers.

The ZIRCO PVRV integrates a position switch connected to a transmitter. An installed sensor detects the position of pressure and vacuum vents, and can notify operators of activation so they can respond. This improves response time impacts:

- Safety – reduce operational emergencies and the climbing onto tanks
- Emissions – reduce unintended emissions that may result in environmental issues and fines
- Assets – protect the valuable tank contents and the tank itself.

The ZIRCO PVRV comes with the option of venting to the atmosphere, or piping emissions away for vapour recovery for emissions reduction and fuel savings.

Technology Group

Tanks – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

Emissions reduction is site- and application-dependent. An analysis of the site and specific applications of the technology must be performed to quantify emissions reduction. However, significant emissions reduction may be achieved by piping vent gas to a vent gas capture system to displace fuel gas, or even through flaring.

Economic Analysis

Capital Cost: Capital costs of the PVRV are application-dependent. Hardware ranges from $2,000 to $17,000, while the transmitter costs up to $1,700 depending on whether the wired or wireless option is selected.

Installation Cost:	Installation costs, consisting of labour hours, vary depending on factors such as whether it is a retrofit or new installation and the severity of service.
Operating Cost:	Operating costs are very low to nil. There are minor costs associated with the wireless transmitter.
Maintenance Cost:	Maintenance costs are minimal and may even be nil, as they consist of routine maintenance of valve seats.
Carbon Offset Credits:	Eligibility for carbon offset credits depends upon the specific application and site. If vent gas is piped to a vent gas capture system and displaces fuel gas, or if vent gas goes to flare, the resulting emissions reduction may qualify.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs are all site- and application-specific, depending on if fuel gas savings are realized, if carbon credits are earned, and if lower compliance costs are realized.

Reliability

Expected Lifetime:	The PVRV is expected to last the life of the storage tank.
Maintenance:	PVRV regular maintenance includes reviewing soft goods as required based on service, but at least annually. Regular checks are also needed to confirm the signal from the position transmitter.

Safety

The PVRV includes working at heights, but does not pose any additional safety issues not covered by regular site and equipment safety regulations. All site and equipment safety regulations apply.

Regulatory

- All required regulatory requirements in place.
- Non-electrical device, does not require CSA approval
- No AER Directive applicable

Vendor Information

Company Name:	Zirco
Company Website:	http://zirco.com
Product Website:	Product information is available on the company website.
Contact Person:	Ryan Sperling
Contact Phone#:	403-259-3303
Contact Email:	ryans@zirco.com

7.1.3. Enecon Alberta – VOC-Free Polymers Coating

July 31, 2017

Description

Over time, the interior and exterior of tanks and pipes suffer material loss and wear due to erosion and corrosion. Enecon's volatile organic compound (VOC)-Free 100%-solids polymer coating extends the lifetime of tanks and pipes by preventing and repairing wear and corrosion. In addition, the risk of spills or unintended emissions is mitigated, and a significant amount of worn equipment is kept out of landfills.

Tanks exteriors and interiors:
Enecon's VOC-free Polymers coating can be applied to both new tanks at point of manufacture or to existing tanks in the field. Tank exteriors are prepared for the polymer application using pressure washing with biodegradable soaps rather than traditional sandblasting. This not only limits the environmental impact and the cost of clean-up by allowing water to absorb into the surrounding soils and evaporate, but it also takes less time and costs significantly less money than sandblasting and containment. The applied polymer is weather resistant, fire-proof, and reduces solar heat transfer by 30% after curing, which may reduce the respective cost of both insurance and cooling. Application of the appropriate polymer coating to a corroded or damaged interior tank wall can bring it back up to code compliance. The cost of polymer-coating-repair typically ranges from 10%-30% of the cost of traditional methods. A hot ticket is not required. All products are VOC-free, so containment and collection are not required.

Pump and pipe repairs:
Pumps, pipes, and platforms often experience material loss due to erosion and, in some cases, corrosion. Application of the polymer coating builds up wall thickness and can also be used to repair ruptures. The polymer is more resistant to corrosion than the original materials. Repairs can be done quickly on-site, with no need for a hot ticket, for a fraction of the price of traditional replacements and repairs. This solution has proven to be very cost effective for several large producers in Western Canada.

Technology Group

Tanks – Facilities Design and Equipment

Site Applicability

All of Enecon's VOC-free polymer coatings can be applied either at point of manufacture or on site with minimal disruption to ongoing operations.

Emissions Reduction and Energy Efficiency

Polymer coatings extend the life of products, thereby keeping tanks, pumps etc. out of landfills, and reducing the associated carbon footprint and costs.

Economic Analysis

Capital Cost:	Capital costs depend upon the site and application. However, polymer coatings extend the life of capital assets, lowering expenditures on replacements.
Installation Cost:	Installation costs depend upon the specific site and application. However, in general, extending the life of an asset with polymer coating is a fraction of the

cost of replacement.

Operating Cost:	There are no ongoing operating costs associated with VOC-free polymer coating.
Maintenance Cost:	Maintenance costs are minimal as spot repairs can be conducted quickly and cost-effectively.
Carbon Offset Credits:	VOC-free polymer coating has a zero-carbon footprint, so it is not eligible for carbon-offset credits.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs depend upon the specific site and application. Cost savings in some applications have been up to 90% of the cost of replacement.

Reliability

Expected Lifetime:	In most cases, polymer coatings exhibit higher wear- and corrosion-resistance than the original construction material.
Maintenance:	Polymer coated tanks, pipes, and platforms require repairs only if they have been mechanically damaged down to the substrate. Spot repairs are easy to conduct. Unapplied material has an indefinite shelf life in most cases.

Safety

Since the product is 100% solid, it offers very safe application and handling. It is VOC-free, so ventilation and air particulates do not pose a hazard. The product has no flash point, so the coating cannot be a contributing factor to explosions or fire.

Regulatory

- All products meet the relevant regulatory requirements for Alberta and Canada.
- Non-electrical device, does not require CSA approval
- No AER Directive applicable

Vendor Information

Company Name:	Enecon Alberta
Company Website:	http://www.enecon.com/
Product Website:	Product information available on company website.
Contact Person:	Christopher Smith / Zane Novak
Contact Phone#:	enecon1@eneconalberta.com/ znovak@zkoindustries.com
Contact Email:	403-669-1902 / 780-237-5558

7.1.4. Hawkeye Industries – Series 5000 Emergency Pressure Relief Vent (EPRV) with Composite Soft-Seal Gasket	February 23, 2018

Description

Emergency pressure relief vents (EPRV) are used to relieve large amounts of vapor in the event of a sudden unplanned and undesired rise in internal pressure in low-pressure and atmospheric storage tanks and processes used in the petroleum industry. Hawkeye's Series 5000 EPRV is a self-resetting weighted manway with a compound lever design that improves performance and reduces the overall size and weight of the vent. The Series 5000 EPRV incorporates a unique composite soft-seal design that maintains a bubble tight seal beyond 90% of the set pressure of the device. The high pressure seal tightness of the soft-seal design allows a greater operating pressure range for the tank or process and avoids interference with normal venting valves. The reduced potential for fugitive emissions can result in lower evaporative product losses, reduced heat loss and assist in meeting environmental regulations. The vent comes standard with Viton sealing components and a powder coated finish for weather and chemical resistance.

Technology Group

Tanks – Facilities Design and Equipment

Site Applicability

The Series 5000 EPRV is suitable for low-pressure and atmospheric storage tanks and processes, both sweet and sour service, used in the petroleum industry.

Emissions Reduction and Energy Efficiency

The Series 5000 EPRV can reduce emissions due to normal venting by eliminating leakage at lower pressures and allowing greater operating and set pressure ranges. Lowering total emissions results in a reduction of evaporative product loss, heat loss, environmental pollution and health and safety concerns from potentially harmful vapors.

Economic Analysis

Capital Cost: Depending on the application, size, configuration and options, the capital cost can range from $3000 to $9000.

Installation Cost: Often installed during tank construction or installation, the cost of installation is the additional labor to prep and mount the vent to the corresponding flange

	connections. This may range from \$0 to \$500. A variety of mounting flange options are available and adapter spools are available to suit almost any tank or process connection. Standard lightweight aluminum construction and compact design allow the vent to be installed without the use of expensive heavy equipment or a crane.
Operating Cost:	With no direct operating costs, the Series 5000 EPRV can reduce overall operating costs by reducing product and heat loss. When this self-closing vent is used as an alternative to a frangible roof attachment for emergency venting, the cost savings can become significant after a single unintended overpressure event.
Maintenance Cost:	A maintenance schedule should be developed to inspect the vent and maintain the valve seal. This can be incorporated into the scheduled maintenance of other site components.
Carbon Offset Credits:	Depending on the application, the reduction of fugitive emissions may be eligible for carbon offset credits.
Payback, Return on Investment and Marginal Abatement Cost:	When used as an alternative to a non-resetting emergency venting method such as a frangible roof connection, the cost savings can be tens of thousands of dollars in tank and equipment repair, or replacement, per emergency relief event. Cost savings due to a reduction of product loss and heat loss depend on the site-specific application, but can amount to thousands of dollars per month. Emissions regulations may require the reduction or control of emissions and the Series 5000 EPRV may be used to meet regulatory requirements and avoid costly fines upwards of \$10,000 per infraction.

Reliability

Expected Lifetime:	The Series 5000 EPRV is designed to last for the lifetime of the tank or process on which it is used.
Maintenance:	Inspection and greasing of the valve seal is recommended annually unless service conditions require more frequent maintenance.

Safety

Before servicing any venting device ensure the internal pressure is relieved to atmosphere. No additional safety considerations are relevant to the installation or use of the EPRV beyond the site, equipment and jurisdictional requirements.

Regulatory

Designed and tested in accordance with API Standard 2000: Venting Atmospheric and Low-Pressure Tanks. Can be used to meet the venting requirements of, but not limited to, tank design standards such as API-650, API-620, API-12B, API-12D, API-12F, API-12P and AER directives such as Directive 055 and Directive 060. CSA approval is not applicable.

Vendor Information

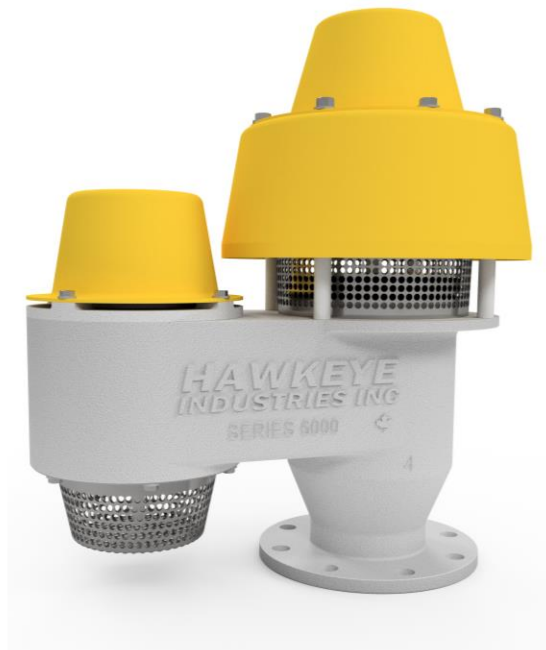
Company Name:	Hawkeye Industries Inc.

Company Website:	www.hawk-eye.com
Product Website:	http://www.hawk-eye.com/products/vapor.html
Contact Person:	Jeff Eliuk
Contact Phone#:	403-999-8909
Contact Email:	jeliuk@hawk-eye.com

7.1.5. Hawkeye Industries – Series 6000 Pressure and Vacuum Relief Vent (PVRV) with Unidirectional Binary Relief (UBR) Valve

February 23, 2018

Description



Pressure and vacuum relief vents (PVRV) are used to maintain a desired internal pressure range for a variety of low-pressure and atmospheric storage tanks and processes used in the petroleum industry. Hawkeye's Series 6000 PVRV incorporates the patent-pending Unidirectional Binary Relief (UBR) Valve which emulates the snap-open action of a pilot-operated valve while maintaining the reliability, simplicity and cost effectiveness of a direct-acting (weight or spring loaded) valve. The operation of the UBR Valve provides higher relative relieving flow rates at pressures close to the set pressure of the valve and inherent blowdown that separates the opening and closing pressures of the valve. This allows the set pressure to be much closer to the design pressure or maximum allowable working pressure of the tank or process than conventional direct-acting valves. As a result, fugitive emissions are reduced, higher operating pressures are permitted and relief frequency is reduced along with the risk of failure due to freezing.

The Series 6000 PVRV comes standard with Hawkeye's composite soft seal design that allows the valve to remain bubble tight beyond 90% of the set pressure. Options are available to vent relieved vapors to atmosphere or send them via pipeline for processing or utilization.

Technology Group

Tanks – Facilities Design and Equipment

Site Applicability

The UBR Valve can be utilized anywhere a PVRV is required. This includes, but is not limited to, low-pressure and atmospheric storage tanks and processes, both sweet and sour service, used in the petroleum industry.

Emissions Reduction and Energy Efficiency

The UBR Valve can reduce emissions due to normal venting by increasing the set pressure of the vent, eliminating leakage at lower pressures and by piping away the relieved vapors with the optional pipe-away system. Lowering total emissions results in a reduction of evaporative product loss, heat loss, environmental pollution and health and safety concerns from potentially harmful vapors.

Economic Analysis

Capital Cost:	Depending on the application, size, configuration and options, the capital cost can range from $1000 to $8000.
Installation Cost:	Often installed during tank construction or installation, the cost of installation is the additional labor to prep and mount the vent to the corresponding flange connections. This may range from $0 to $500. A variety of mounting flange options are available and adapter spools are available to suit almost any tank or process connection. Standard lightweight aluminum construction and compact design allow the vent to be installed without the use of expensive heavy equipment or a crane.
Operating Cost:	With no direct operating costs, the UBR valve can reduce overall operating costs by reducing product and heat loss.
Maintenance Cost:	A maintenance schedule should be developed to inspect the vent and maintain the valve seals. This can be incorporated into the scheduled maintenance of other site components.
Carbon Offset Credits:	Depending on the application, the reduction of fugitive emissions and ability to capture and process or utilize the relieved vapor, through the use of the optional pipe-away system, may be eligible for carbon offset credits.
Payback, Return on Investment and Marginal Abatement Cost:	Cost savings due to a reduction of product loss and heat loss depend on the site-specific application, but can amount to thousands of dollars per month. Emissions regulations may require the reduction or control of emissions and the Series 6000 PVRV may be used to meet regulatory requirements and avoid costly fines upwards of $10,000 per infraction.

Reliability

Expected Lifetime:	The Series 6000 PVRV is designed to last for the lifetime of the tank or process on which it is used.
Maintenance:	Inspection and greasing of the valve seals is recommended annually unless service conditions require more frequent maintenance.

Safety

Before servicing any venting device ensure the internal pressure is relieved to atmosphere. No additional safety considerations are relevant to the installation or use of the PVRV beyond the site, equipment and jurisdictional requirements.

Regulatory

Designed and tested in accordance with API Standard 2000: Venting Atmospheric and Low-Pressure Tanks, data collected and verified by a third-party. Can be used to meet the venting requirements of, but not limited to, tank design standards such as API-650, API-620, API-12B, API-12D, API-12F, API-12P and AER directives such as Directive 055 and Directive 060. CSA approval is not applicable.

Vendor Information

Company Name:	Hawkeye Industries Inc.
Company Website:	www.hawk-eye.com
Product Website:	http://www.hawk-eye.com/products/vapor.html
Contact Person:	Jeff Eliuk
Contact Phone#:	403-999-8909
Contact Email:	jeliuk@hawk-eye.com

Section 7.2. Tanks – Recommended Practices

## 7.2.1. Heavy Oil Odour Management	July 31, 2017

Description

Gas streams containing odours are emitted by various sources throughout heavy oil production sites: tanks storing crude oil, wellheads, dirty water ponds containing chemicals, piping systems, heaters, waste storage piles, or even transport trucks. Reduced-sulphur compounds (RSCs) can smell like rotten eggs or rotten cabbage, and volatile organic compounds (VOCs) evaporate easily and spread through the air. Wind and weather also impact the intensity of odours. Some emissions, such as venting or flaring from stacks, are a regular part of operations; others, called fugitive emissions, escape unintentionally. Several technologies can help stop the spread of odorous emissions. Gas streams containing odours released from vents or stacks can be either cleaned and recovered or destroyed. Common cleaning technologies include adsorption, absorptions, and condensation. Common destruction technologies include biotreatment, combustion, and non-thermal oxidation processes (NTOPs). Many of these same methods can be used to treat fugitive emissions once the source has been identified. This recommended practice will guide operators in identifying the most effective technology for treating odorous gas streams at their site. The first step is to consider the following list of questions:

Questions for Evaluating Odour Treatment Technologies:
a. What is the amount of odorous chemicals that can be removed by the technology?
b. What is the cost of setting up the technology at the site?
c. What is the cost to continually use this technology?
d. Is the technology well-known to industry?
e. Can workers be easily trained to use the technology?
f. Is there need for a lot of space to place the technology on site?
g. Is the gas stream flowing fast or slow?
h. Is the amount of odorous chemicals in the gas stream high or low?

Several technologies have been developed to halt the spread of odorous emissions. Gas streams containing odours released from vents or stacks can be either cleaned and recovered or destroyed.
A numbered scoring system has been developed for each condition based on a common gas stream released from a typical source and a common concentration of odorous chemicals. The recommended ranking order for selection of technologies is:
Adsorption >> Absorption >> Biotreatment >> NTOPs >>Incineration >>Condensation

Technologies to Mitigate Odorous Gas Emissions
a. Adsorption Technologies: Removes odours from the gas stream by passing it through a penetrable material, such as activated carbon. Odour-causing chemicals are captured onto the surface while the now odour-free gas stream can be reused in other processes.
b. Absorption Technologies: Removes odours from the gas stream using a liquid that dissolves odorous chemicals
c. Condensation Technologies: Removes odours from the gas stream by reducing the temperature and physically changing the gas stream to liquid so that waste can be treated.
d. Biotreatment Technology: Removes odours from the gas stream by passing it through material that traps odour chemicals on a surface where they are consumed by micro-organisms.

e. NTOPs Technologies: Removes odours from the gas stream using electricity or a stream of electrons to turn the odorous chemicals into carbon dioxide and water.
f. Incineration Technologies: Removes odours from the gas stream using very high temperatures combined with oxygen to burn the gas leaving fewer odorous chemicals.

In addition, Best Management Practices inform the implementation of the selected technologies:

Best Management Practices
a. Normal Operating Conditions: a. Use quality fuel b. Adjust temperature or pressure to optimal levels c. Apply maintenance, housekeeping, and training plans d. Existing Direct Inspection and Maintenance (DI&M) plans can be used for odorous emissions e. Complete tracking records for all equipment inspection, repairs, and maintenance b. Unusual/Unexpected Conditions: a. Conduct routine equipment inspections b. Monitor delicate equipment during extreme weather conditions c. Repair the source of emissions immediately d. Use masking or neutralizing agents to hide smells if emissions cannot be stopped immediately c. Maintenance Conditions: a. Conduct maintenance during cold weather to discourage chemical evaporation

Although adjustments may need to be made for specific conditions, by following newly-established best management practices, operators can effectively implement measures to reduce odorous emissions in heavy oil sites.

Technology Group

Tanks – Recommended Practices

Site Applicability

Heavy Oil Facilities with odorous gas streams.

Emissions Reduction and Energy Efficiency

The purpose of these recommended practices is to prevent odour-causing compounds from being released into the atmosphere. Implementation will reduce air emissions. However, odour-causing compounds generally make up a very small fraction of the gas stream, and may or may not have a greenhouse gas impact. Therefore, while this recommended practice will have a critical impact on neighbours and quality of life, the overall volumetric outcome for air emissions, energy efficiency, and greenhouse gas impact will be minimal.

Economic Analysis

The purpose of this recommended practice is to provide a tool to guide site owners in selecting the most appropriate odour-management technology. The economics of the selected odour-management solution will depend on the specific technology and site considerations, and therefore are beyond the scope of this recommended practice.

Reliability

Reliability and operability impacts will depend on the specific technology selected. Nevertheless, workers must remain aware of any unusual smells present on the work site.

Safety

Safety impacts will depend on the selected technology. However, in general technologies for odour management at heavy oil sites do not pose additional safety hazards.

Regulatory

Operators must ensure they comply with all applicable regulations at all times.

- AER Hydrocarbon Odour Management Protocol for Upstream Oil and Gas Point Source Venting and Fugitive Emissions
- AER Directive 84

Service Provider/More Information on This Practice

- SNC – Lavalin Report for Heavy Oil Management Technology and Best Practices: http://auprf.ptac.org/wp-content/uploads/2016/04/BMP-15-ARPC-08.pdf

Section 8.1. Equipment Leaks – Facilities Design and Equipment

8.1.1. Triangle Fluid Controls Ltd. – Flange Cover

June 30, 2017

Description

Bolted flanged connections are often overlooked in the technology improvements space. There are tens of thousands of bolted connections in any refinery. An estimated 60% of these connections visibly leak, and that if vapour testing techniques are applied, the number climbs to 80%. Flange covers **c**apture fugitive gas from leaking flange connections, reducing methane emissions until a scheduled outage, such as a plant turnaround, allows for a gasket replacement without yard venting. Proper installation can reduce flanged connection emissions to nearly zero for liquids and less than 5ppm for gases (fugitive emissions).

Technology Group

Equipment Leaks – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The exact reduction in methane emissions depends upon the severity of the leak being mitigated.

Economic Analysis

Capital Cost:	The capital costs of range from $10 to $20 per flange, depending on the quantity and size of flange purchased.
Installation Cost:	Installation costs depend upon the volume and size of gaskets. Correct installation can take 15 minutes for small flanges and one hour for large flanges.
Operating Cost:	No additional operating costs are expected.
Maintenance Cost:	No additional maintenance costs are expected. Installed correctly, there is no anticipated maintenance due to direct gasket failure. Peripheral equipment and valves fail first.
Carbon Offset Credits:	Flange covers are not currently eligible for carbon offset credits.
Payback, Return on Investment and Marginal Abatement Cost:	The payback considerations for flange covers are dependent upon the volume of leakage. Payback considerations include the captured gas that is made available for sale to end consumers. There are additional benefits such as safety improvements from being able to avoid leakage, especially in enclosed areas, without having to do a pipe isolation or a facility blowdown (large vented volume to repair a small venting volume). In addition, the consequences of regulatory violations can be avoided.

Reliability

Expected Lifetime:	The flange covers are expected to last five years.

Maintenance: No special tools or training are required for maintenance. Installation efficiency can be enhanced with free customized manufacturer training. Yearly inspection is required.

Safety

No unusual safety requirements apply.

Regulatory

- NACE, only dimensional standards (ASME B16.20 and B16.21, CSN EN 1514-1) are applicable on-site applicability referenced above.
- No AER Directive applicable
- Gaskets do not require CSA approval

Vendor Information

Company Name:	Triangle Fluid Controls Ltd.
Company Website:	www.trianglefluid.com
Product Website:	http://trianglefluid.com/project/durtec-premium-corrugated-metal-core-3/
Contact Person:	Chett Norton
Contact Phone#:	(613) 968-1100
Contact Email:	info@trianglefluid.com /chett@trianglefluid.com

Section 8.2. Equipment Leaks – Recommended Practices

8.2.1. Leak Detection and Repair (LDAR) Data Capture	July 31, 2017

Description

The three most critical components to an LDAR program are frequency of facility inspections, measurement standards, and repair requirements. Industry must capture consistent and credible data because good data drives good decisions, but this is not happening consistently. To that end, GreenPath Energy has developed a standardized data capture template and developed best practice recommendations.

Data Capture Template**:**

The following table illustrates the minimum technical standard for the data that should be captured via fugitive emissions management programs.

Emission Description	Written description of the emission source. Users should use (3) points of reference in a combined sentence as to help demonstrate and locate emission source. Example "Compressor K100, Stage 1 Scrubber, Upper Sight Glass, Upper Isolation Vale, Stem Seal"
Component Type	Users select the component type the closely matches the component in which the fugitive emission source is associated with
Emission Service Type	Fuel = Emission sources associated with on-site fuel gas that powers pneumatic loops and combustion Process = Emission sources associated with production Liquid = Those component sources that are in hydrocarbon liquid service
Emission Composition	Users select a generic emission composition type based on the process / production type associated with the fugitive emission source
Make	Users define Make of equipment / device associated with emission source.
Model	Users define Model of equipment / device associated with emission source.
Serial #	Users define serial # of Make/Model of equipment / device associated with emission source
Quantification Rate (cfm)	Volumetric rate of emission source in cubic feet per minute
Quantification Method	The method is which the emission source was quantified
ATM TEMP (degrees C)	Atmospheric temperature in which the emission source was quantified. Allows users to standardized flow rates to 15 degrees C
ATM Pressure (kPa)	Atmospheric barometric pressure in which the emission source was quantified. Allows users to standardized flow rates to 101.3 kPa
DIM Recommendation	Users recommendation of when emission source should be repaired / eliminated. Process and facility design characteristics will influence user selection
Type of Repair Recommendation	Users assign the repair action that will be associated with repair activities
Status	Users select "Emitting" if emitting source is still active, "Non-Emitting" if emission source is not-active.
Repair BY	Name and/or Company that eliminated emission source
Repair WO#	WO# assigned to initiate repair/elimination activities

Facility Location (LSD/NTS)	All locations need to be in 00-00-000-00W0 DLS or A-000-A/000-A-00 NTS format
Well Location ID (LSD/NTS)	All locations need to be in 00-00-000-00W0 DLS or A-000-A/000-A-00 NTS format
Field	Field is the names the geographical area in which oil & gas assets are located
Facility Name	Unique name of facility. Well sites usually do not a facility. Users should assign a facility name in which production from the wellsite is attributed to
Facility Type	Users assigns a facility type classification that closely matches the intended design and purpose of the facility
Regulatory License ID	Designates the facility regulatory license
Sour Facility	If facility is handling sour gas or oil users should select "yes"
Date Emission Detected	This is the original date of detection of an emission source
Date Emission Last Inspected	This is the date of the last inspection of the emission source
Client Process Block (Step 1 Derived)	Based on input into Step 1. Users assign the emission source to appropriate process block
Equipment / Process ID #	This is the unique ID or description of the equipment/process which the emission sources is emitting from. This selection is a subtype to the Process Unit ID previously defined
Emission Serialized Tag #	This is the serialized number printed on the tag that is physically attached to the emission source
Emission Media #	This is the serialized number as defined by the media capture device i.e. FLIR GF320, Digital Camera, etc.
Emission Type	If the emission source in "un-wanted" or "un-engineered" classify as leak. If the emission source is "wanted" or "engineered" classify as vent. Exception to the rule is if "vents" are cause of potential HSE issue, then classify as "Leak"
Emission HSE Issue?	If the emission source poses a threat or risk to people, equipment and/or the environment, users select "yes"

Technology Group

Equipment Leaks – Recommended Practices

Site Applicability

All sites

Emissions Reduction and Energy Efficiency

LDAR programs are critical to reducing air emissions and, indeed, are often required by regulations. Effective leak detection results in fewer leaks and shorter duration leaks, resulting in lower total emissions volumes. This recommended practice does not speak to specific LDAR methodologies but its recommendations for a standardized data capture template is applicable to, and would improve the performance outcomes of, all LDAR techniques.

Economic Analysis

LDAR is generally provided as a service by the site owner or by a third-party contractor. As such, LDAR does not generally involve site-related capital costs. Operating costs depend upon the specific LDAR methodology used, and other service considerations. Implementation of this recommended practice for standardized data capture is not expected to have an impact on costs.

Reliability

The reliability and effectiveness of leak detection is generally related to the specific LDAR methodology used. Implementation of this recommended practice is not expected to influence the reliability of LDAR methodologies.

Safety

The LDAR service provider must adhere to site safety procedures.

Regulatory

The LDAR methodology used must comply with existing regulations.

Vendor Information

Recommended practices were prepared by GreenPath Energy. The complete document is available at: http://auprf.ptac.org/wp-content/uploads/2017/02/Report-FUGITIVE-EMISSIONS-16-ARPC-02.pdf

Section 9.1. Lighting and Utilities – Facilities Design and Equipment

## 9.1.1. SuperGreen Solutions – Energy Efficient Solutions – LED Lighting to Solar / Wind	July 31, 2017

Description

Oil and gas facilities are often 24-hour operations that require reliable lighting and power. Oil and gas companies have begun to demand more energy efficient solutions for these basic needs. SuperGreen Solutions offers light emitting diodes (LED) lighting solutions. For many years the standard has been 100 Lumen/watt (LPW) lighting, but current technology is available at 150 LPW and even up to 180 LPW. In addition, LEDs that are 50% more efficient are now on the market, although lumen depreciation (L70) metrics must be considered. Supergreen evaluates and recommends lighting ranging from class 1 div 1/2 to standard commercial lighting; from LED pot lights and wall packs to powerful floodlights and high bays.

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service, office buildings and warehouses.

Emissions Reduction and Energy Efficiency

The average reduction in energy use achieved by replacing standard lighting fixtures with LED is between 50%-90%, whereas replacement of mid-efficient technology such as compact fluorescent lamps (CFL) or T5 fluorescent tubes is between 30-35%.

Economic Analysis

Capital Cost: Capital costs of LEDs are:

- 600W incandescent replacement LEDs are almost on par with CFL bulbs at under $3 per LED in 2017.
- LED tubes are approximately $12 to $15 per tube.
- High-power LED floods and high bays are still more than $1,000, but they are about 50% less expensive than they were two years ago and the quality and efficiency continues to improve.
- Standard High Bay LEDs can range from about $300 to $600 to replace warehouse lighting.
- Class 1 Div 1&2 have substantially dropped in price since their introduction.

Installation Cost: Installation costs for LED lights are commensurate with labour hours. Sometimes, installing LEDs takes 20%-30% more time than installing incandescent. However, the time to change the LED ballast is almost equivalent to the time required to rewire a standard fixture. Changing T12 to T8 technology carries equivalent labour costs to LEDs. Many new technologies are ballast-compatible as well, so they are as simple as inserting LEDs.

Operating Cost: Operating costs for LED lights are reflective of reduced energy use. LED lights usually cost between 50%-90% less to operate than standard lighting and 30-40% less than mid-efficiency products like CFL and T5.

Maintenance Cost: LED lights can last more than 200,000 hours with minor lumen loss, and many have commercial five- to ten-year full replacement warranties, which can drastically reduce or eliminate maintenance costs.

Carbon Offset Credits: Eligibility for greenhouse gas (GHG) offset credits will depend on the specific application.

Payback, Return on Investment and Marginal Abatement Cost: The average payback period for LED lighting is between one to four years, depending on maintenance and power costs. Generally, a 20% rate of return or better is achieved. The best return on investment is 24-hour lighting and lighting that requires lifts to change. Often 24-hour lighting can have a return on investment of less than two to three years.

Example – January 2017- 32W T8 Fluorescent Tubes vs. LED Tubes in 24-hour application.

SuperGreen Solutions
Energy Efficient Products

Example of Savings!

Existing Light Fitting	*Watts*	*Qty*	*Total Wa*	*LED Replacement*	*Watts*	*Qty*	*Total Wa*	*Watts sa*	*Total Sale $*
32W T8 Fluorescents Tubes - 4'	32	200	6400	15W LED T8 Magic	15	200	3000	3400	$ 3,150.00
	0	0	0		0	0	0	0	$ -
Total	32	200	6400		15	200	3000	3400	$ 3,150.00

Return on Investment:				
Watts saved with LED's per hour =	3400	watts	ENERGY / POWER SAVI	53%
Which is	3.4	kW		
If Above Lights used (X) Hours per	24	hrs.	Replacement Lights (2 replaced over 5 y	$1,600
Price per kW	$0.10		Ballasts (10% failure= 10)	$50
Dollars saved per day	**$8.16**		Maintenance ($75 X 3 X 1/2yr)	$0
			Equipment ($400 / day X 3/year)	$0
Dollars saved per year	$ 2,978.40		Total	$1,650
ROI Payback Period	1.06	years	ROI Payback with Maintenance	0.50

ROI calculation does not factor in annual energy price rise. ROI figures will improve with each energy price increase.

Full Building Analysis – January 2017- – Primarily T8 Tubes and Bulbs throughout Office and Storage Facility

EXAMPLE
Municipal Facilities LED Lighting Conversion

SuperGreen Solutions
Energy Efficient Products

Example of Savings!

Existing Light Fitting	*Watts*	*Qty*	*Total Watts*	*LED Replacement*	*Watts*	*Qty*	*Total Watts*	*Watts saved*	*Total Sale $*
*32W T8 Fluorescent Tubes - 4'	32	878	28096	15W LED Tube 4' (15-17W range)	15	878	13170	14926	$10,211.14
*17W T8 Fluorescent Tubes - 2'	17	8	136	15W LED Tube -2'	15	8	120	16	$ 109.52
*32W T8 Fluorescent Tubes - U Tube	32	22	704	15W LED Tube -U Tube (15-17W)	15	22	330	374	$ 741.18
65W BR30 Downlight (some may be CFLs @ 17W)	65	147	9555	11W LED BR30	11	147	1617	7938	$ 1,274.49
50W Candelabra - Pendant Chandelier	60	18	1080	5W LED Candelabra	5	18	90	990	$ 112.50
60W A19 Bulb	60	1	60	9W LED A19	9	1	9	51	$ 3.00
	0	0	0		0	0	0	0	$ -
* Ballast Factor not added - generally 8W / ballast	0	0	0		0	0	0	0	$ -
Total	266	1074	39631		70	1074	15336	24295	$12,451.83
							Note: not a quoted cost - just for ROI		
Return on Investment:							See RPF section labeled costs		
Watts saved with LED's per hour =	24295	watts		ENERGY / POWER SAVINGS	61%				
Which is	24.295	kW							
If Above Lights used (X) Hours per day	10	hrs.		Replacement Lights (2 rep. over 5 years X $4.00 AVG est)			$8,592		
Price per kW	$0.08			Ballasts (10% failure)			$524		
Dollars saved per day	$19.44			Maintenance ($75 X 3 X 1/yr)			$1,125		
				Equipment ($400 / day X 3/year)			$0		
Dollars saved per year	$ 7,094.14			Total			$10,241		
ROI Payback Period	1.76	years		ROI Payback with Maintenance			0.31		
ROI calculation does not factor in annual energy price rise. ROI figures will improve with each energy price increase.									

Reliability

Expected Lifetime: LEDs often carry a 5-year to 10-year commercial warranty. SuperGreen Solutions has DLC-approved[67] commercial LEDs that are up to 220,000 hours. This means the quality of the LEDs to the heat sync used has the potential to last up to 220,000 hours, which is 25.1 years at 24 hours or 50 years at 12 hours per day.

Maintenance: LEDs require no specific maintenance. However, it is possible to change drivers or LED boards in some fixtures.

Safety

Safety requirements for LEDs are the same as traditional lighting. LEDs do not contain harmful gases or mercury, which reduces safety risk. Solar and wind power require certified personnel, but there is no increased safety risk.

Regulatory

- In Canada, LEDs must be certified by Underwriter Laboratories (cUL) or a nationally recognized Testing Laboratory (eTL). In some instances CSA-certification is also required.
- No AER Directive applicable

Vendor Information

Company Name: SuperGreen Solutions
Company Website: www.supergreensolutions.com
Product Website: Product information is available on the company website.

[67] DLC Approved means an outside entity has tested the quality and verified the fixture delivers what is says it does. They also review the performance of the fixture.

Contact Person: Francis Gough, President
Contact Phone#: (780) 439-0292
Contact Email: francisgough@supergreensolutions.com

9.1.2. ZKO In-Pipe Turbine Generator (IPTG)

July 31, 2017

Description

The In-Pipe Turbine Generator is a Canadian Standards Association (CSA)-certified Class “H” Fitting with a Canadian Registration Number (CRN) that fits in pipe, typically after the separator building or gas measuring device. A turbine-style device, it generates electricity from the flow of the natural gas creating approximately 60 to 300 watts of continuous power depending on well-flow parameters. Magnetic flux produced by rotation of magnets on the turbine within the pipe produce non-arcing, electrical current in coils mounted around the exterior of the pipe. Electricity is created at the wellhead with zero emissions and zero fuel consumption.

The generator outputs through an umbilical cable to its control box. This box can be mounted conveniently near the site batteries and or the supervisory control and data acquisition (SCADA) system for remote generator system-monitoring utilizing the existing SCADA system.

The IPTG is designed to generate power 24/7 regardless of weather, ambient conditions, or whether the process gas is sweet or sour, overcoming the inherent drawbacks of solar panels, thermal-electric generators, and wind.

Technology Group

Lighting and Utilities – Facilities and Design Equipment

Site Applicability

Gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The IPTG, used in conjunction with electric chemical injection pumps, eliminates fugitive emissions and provides power to all SCADA requirements, replacing solar panels or a TEG style system.

Economic Analysis

Capital Cost: Capital costs of the IPTG system are $20,000 US dollars per fitting, not taking volume discounts into consideration.

Installation Cost: Installation costs are minimal. However, exact figures depend upon whether it is new construction of retrofit.

Operating Cost: There are no operating costs for the IPTG. No fuel is consumed.

Maintenance Cost: The primary maintenance cost is a slip out/slip in repair kit, although exact cost

	depends upon the model. The anticipated repair kit life cycle is 3+ years.
Carbon Offset Credits:	The eligibility for greenhouse gas (GHG) offset credits or other carbon cost reduction will depend on the application and the jurisdiction.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs depend upon the current configuration. The ZKO IPTG will offset fuel consumption, vented fuel gas, and existing equipment maintenance costs.

Reliability

Expected Lifetime:	Although the IPTG lifecycle is indefinite, it is expected to outlast the life of the well.
Maintenance:	The maintenance requirements are very minimal. Inspections are recommended every 18 months. The bearings are the only typical wear point. To change the bearings, the fitting can be taken out of service and the internals removed easily and quickly, then a new internal kit can slide into place. The owner can recondition the used internal assembly, or they can return it to ZKO to be rebuilt.

Safety

Standard operating and safety procedures apply.

Regulatory

- CSA certified, Class 1 Div 1. The CRN is for a Class "H" Fitting for sweet and sour service. No AER Directive applicable.
- The In-Pipe Turbine Generator is CSA certified and also meets the requirement set out by Pressure Piping regulatory board. It has a CRN number certifying it to operate within the required pressure envelop.

Vendor Information

Company Name:	ZKO Oilfield Industries Inc.
Company Website:	www.zkoindustries.com
Product Website:	www.lightningmaster.com
Contact Person:	Zane Novak
Contact Phone#:	780-237-5558
Contact Email:	znovak@zkoindustries.com

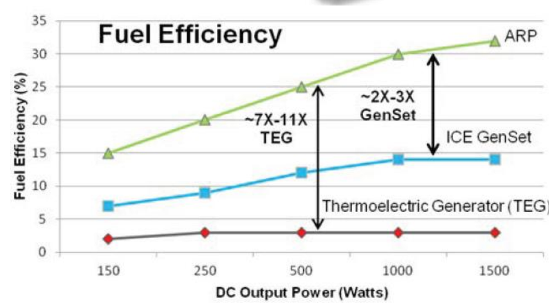
9.1.3. Spartan/Atrex Energy Solid Oxide Fuel Cell ARP Series

July 31, 2017

Description

Based on state-of-the-art solid oxide fuel cell technology, the ARP Series remote power generator takes natural gas or propane and, using an electrochemical process, converts the fuel's energy into DC electricity. Unlike other power-generation technologies, this process does not burn or combust fuel. It emits no harmful NO_x or SO_x emissions; the only emissions are small amounts of water vapor and CO_2. The process is quiet, safe, and clean.

User Interface Panel



A state of the art user interface panel with touchpad and LED screen increases the ability to monitor, control and adjust system parameters. An industrial grade computer and 4G communication system improves on-line availability to systems deployed in the field.

With a power output range of 150 watts to 1,500 watts at 5VDC to 60VDC (requiring a supply pressure of 2 to 5 psig), these DC generators offer a very high power density in a very small package. Increased fuel efficiency translates into lower fuel consumption and significant fuel cost savings.

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and limited sour service.

Emissions Reduction and Energy Efficiency

The reduction in methane emissions varies depending upon the existing electric generation system. For example, a typical candidate site for replacement may be 4.7 $kgCO_2E/hr$ with existing equipment, whereas with the ARP500 the emissions would be reduced to 0.3 $kgCO_2E/hr$.

Economic Analysis

Capital Cost:	Capital costs vary depending on specific model and construction materials selected.
Installation Cost:	Installation costs vary depending on site specifics, such as availability of tie-in points, greenfield vs. retrofit, piping specifications etc. However, labour is estimated at approximately \$1000, and wiring costs are similar to competitive technologies.
Operating Cost:	Operating costs are highly dependent on fuel cost. Sites that have an indigenous source of natural gas will have far lower costs than sites that are

forced to transport fuel to site.

Maintenance Cost:	Annual general maintenance is estimated at $500. The fuel cell bundle is a consumable, and must be replaced when expired, and bundle life expectancy depends upon application. However, Atrex has units deployed in the field that are beyond 45 months. The cost of bundle replacement is approximately 13% of capital expenditure.
Carbon Offset Credits:	Carbon offset credits have yet to be determined.
Payback, Return on Investment and Marginal Abatement Cost:	The payback considerations for the unit are the dependent on landed cost of fuel. In certain scenarios payback can be less than one year.

Reliability

Expected Lifetime:	Contingent on regular maintenance intervals, the expected equipment life is 10 years or more.
Maintenance:	No special tools or training are required for general maintenance. Yearly maintenance and inspection recommended.

Safety

No unusual safety requirements apply. All routine safety considerations are applicable.

Regulatory

Atrex is the first and only solid oxide fuel cell to be CSA-certified to CSA FC-1-2014. This equipment meets all regulatory requirements for operation in non-hazardous areas in oil and gas applications.
No AER directive applicable.

Vendor Information

Company Name:	Spartan / Atrex Energy.
Company Website:	www.spartancontrols.com/http://www.atrexenergy.com/
Product Website:	http://www.spartancontrols.com/~/media/resources/atrex%20energy/data%20sheets/atrex%20arp%20series%20remote%20power%20generators.pdf?la=en
Contact Person:	Mack Andrews (Spartan) / Mike Brennan (Atrex)
Contact Phone#:	(403)589-2647 / (802) 233-2348
Contact Email:	andrews.mack@spartancontrols.com

9.1.4. Black Gold Rush Industries Ltd. – Rush Power

April 26, 2019

Description

Black Gold Rush Industries' Rush Power unit converts waste gas into power using a Stirling engine. The hermetically sealed 50Hz engine is ultra-quiet and uses less than 10m^3/d of fuel gas to operate at pressures between 0.3 psi and 0.75 psi. Despite this low fuel consumption, it provides either a continuous 1000W of power suited to operating supervisory control and data acquisition (SCADA), process valves, burner management systems (BMS), or even lighting at 24 VDC. Peak power is 5000W. The modular design allows for pairing to provide increased power output to run equipment with a wider range of power requirements.

The Rush Power unit only runs on demand and stores power in the onboard battery bank, reducing fuel gas usage and resulting in significant cost savings when compared to traditional thermoelectric generator (TEG) units. The Rush Power unit is designed to run on waste gas, natural gas, or propane as needed. However, using waste gas eliminates methane and other GHGs from being vented to the atmosphere.

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Rush Power can be installed either indoors or outdoors at facilities, buildings or remote wellsite locations.

Emissions Reduction and Energy Efficiency

Rush power can be fueled by vent gas from pneumatics, tank vapours, or casing gas. The maximum amount of fuel gas required for continuous 1kW of power is less than 10 m^3/d. Emission reduction depends on the amount of power being used onsite and the resulting amount of fuel gas needed to recharge the onboard battery bank.

Economic Analysis

Capital Cost:	Capital costs are estimated at approximately $65,000
Installation Cost:	Installation costs vary depending on specific operational requirements, the level of automation, quality of insulation, and heat tracing and piping configuration. No specific installation figures were provided.
Operating Cost:	Operating costs are extremely low. Fuel gas is the only operating cost.

Maintenance Cost:	Maintenance costs are low to nil, as the only maintenance is for existing personnel to inspect the unit. In rare circumstances, it is possible a battery would need to be replaced and commensurate costs would apply.
Carbon Offset Credits:	Eligibility for carbon offset credits or other carbon cost reduction instrument will be application specific and is impacted by the amount of fuel gas required.
Payback, Return on Investment and Marginal Abatement Cost:	Payback varies depending on whether it is a replacement of an existing thermoelectric generator (TEG) system or being deployed on a new site. In all cases, payback is commensurate with the level of reduced fuel gas consumption, reduced vented gas, and the corresponding carbon tax savings. Replacement scenarios are likely to have a shorter payback period than new site installations.

Reliability

Expected Lifetime:	Although the expected lifetime of the equipment depends upon the amount of operating hours, the Stirling engine carries a warranty guaranteeing 7 years or 50,000 hours maintenance-free.
Maintenance:	Regular maintenance is required including checking the battery, cleaning the radiator, and checking connection for leakage. However, the Stirling engine guarantees seven years or 50,000 hours maintenance-free.

Safety

The Rush Power unit incorporates multiple safety shut downs, such as a 1-1 air-to-gas-ratio valve and alarm status outputs, so operators can automate as required.

Regulatory

- General area classification.
- Class 1 Div 2 certification is pending at time of report.
- Meets all AER regulatory requirements

Vendor Information

Company Name:	Black Gold Rush Industries Ltd.
Company Website:	www.bgrindustries.com
Product Website:	http://www.bgrindustries.com/bgri-products/rush-power/
Contact Person:	Dallas Rosevear
Contact Phone#:	403-507-0485
Contact Email:	dallas@bgrindustries.com

9.1.5. Zimco–Parker TEC Thermo-Electric Battery Charger	July 31, 2017

Description

Automation and communication systems at critical and remote locations require sustained power with no down-time. Parker PGI's thermo-electric battery charger uses low-emission catalytic technology to convert on-site natural gas or propane to electric power. The units consume only a small amount of fuel (TEC-8 uses 3.0 CFH gas (0.08 m^3/h) or 1.0 CFH propane (0.03 m^3/h). The catalyst heats one side of an array of Peltier thermoelectric modules while the other side is cooled by natural convection through aluminum fins to the environment. The temperature difference developed across the modules generates safe electrical power. The TEC battery charger supplies 12- or 24-volt batteries with up to 6.3W of continuous power, and multiple TEC units can be run in parallel to accommodate larger power requirements.

TEC battery chargers are well-suited to deliver power to data, communication, and automation applications, especially at remote sites.

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution.

Emissions Reduction and Energy Efficiency

The expected reduction in methane emissions is dependent on system design and operating conditions.

Economic Analysis

Capital Cost:	Capital costs vary depending on site-specific power requirements and optional accessories. No specific figures were provided.
Installation Cost:	Installation costs are minimal, as installation is simple and can typically be completed by existing engineering and installation staff.
Operating Cost:	Operating costs are minimal. No specific figures were provided.
Maintenance Cost:	Maintenance costs are minimal, and vary depending on the specific required service.

Carbon Offset Credits:	Eligibility for greenhouse gas (GHG) offset credits or other forms of carbon cost reduction is highly application specific.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs are application- and site-dependent. The primary payback is generated based on reduced fuel cost. Additional value is generated from the compact design of the TEC battery charger that serves as a deterrent for theft and vandalism, as well as eliminating the cost of tying into grid power.

Reliability

Expected Lifetime:	The expected lifetime of the equipment varies depending on operational hours and battery charging time.
Maintenance:	The expected maintenance for the equipment varies depending on operational hours and battery charging time.

Safety

No unusual safety requirements apply. All routine safety considerations are applicable.

Regulatory

- CSA Class 1 Division 2
- No AER Directive applicable.

Vendor Information

Company Name:	Zimco Instrumentation Inc.
Company Website:	http://www.zimco.ca/
Product Website:	Not provided
Contact Person:	Richard Hiebert / Ron Becker
Contact Phone#:	403-253-8320 / 403-253-8320 Cell 403-620-4587
Contact Email:	richard.hiebert@zimco.ca / ron.becker@zimco.ca

9.1.6. Zimco – Parker Zeus DB1 Differential Pressure Wellsite Battery Charger

July 31, 2017

Description

Parker's Zeus Class 1 Div 1 DB1 Differential Pressure Battery Charger is a supplement (alternative or backup) to solar panel systems used to power electronic instruments. Unlike solar panels, the DB1 can be installed in almost any location and is unaffected by shade, snow, freezing rain, ice, or dust build-up. The DB1 provides emission-free continuous power 24/7 by utilizing existing differential pressure in natural gas or air-driven applications.

The DB1 produces a 12- or 24-volt power output to keep the batteries fully charged. The battery's temperature and charge level are continuously monitored and the DB1 produces up to 100 watts to keep it charged. The DB1 battery charger is used in many applications such as chemical injection pumps, wireless communications, gas quality analyzers, and wellsite instrumentation.

Additional features:

- Current models include 10, 20, 50 and 100 watt units with field selectable 12 or 24 VDC
- The communication package utilizes RS-485 Serial / Ethernet MODBUS protocols
- Severe service option - wetted parts suitable up to 8% H_2S and 8% CO_2
- Compact design eliminates theft and vandalism

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and downstream pipeline distribution, municipalities

Emissions Reduction and Energy Efficiency

Parker Zeus DB1 Differential Pressure Battery Chargers are zero-emission. The expected reduction in methane emissions from reduced fuel gas consumption depends upon the original equipment being replaced.

Economic Analysis

Capital Cost: Capital costs range from $5,000 to $12,000, depending on power requirements and optional accessories.

Installation Cost: Installation costs are minimal, as the installation is usually handled by existing electrical and instrumentation (E&I) staff.

Operating Cost:	Minimal additional operating costs are expected.
Maintenance Cost:	Inspections should be conducted after 5,000 operating/battery-charging hours. At this point, it is possible the bearing will need to be replaced for a cost of $250.
Carbon Offset Credits:	Eligibility for greenhouse gas (GHG) offset credits or other forms of carbon cost reduction is highly application specific.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs are application- and site-dependent. The primary payback is generated based on reduced fuel cost. Additional value is generated from the design that serves as a deterrent for theft and vandalism, and eliminating both the cost of tying into grid power and reliance on Thermoelectric generator (TEG) units.

Reliability

Expected Lifetime:	Specific data on until lifetime have not yet been collected. However, existing units have been in service for 5+ years with zero maintenance.
Maintenance:	Maintenance should be conducted after every 5,000 operation hours, with potential for bearing replacement.

Safety

No unusual safety requirements apply. All routine safety considerations are applicable.

Regulatory

- CSA Class 1 Division 1 Group D
- No AER Directive applicable.

Vendor Information

Company Name:	Zimco Instrumentation Inc.
Company Website:	http://www.zimco.ca/
Product Website:	Product information is available on the company website
Contact Person:	Richard Hiebert / Ron Becker
Contact Phone#:	403-253-8320 / 403-253-8320 Cell 403-620-4587
Contact Email:	richard.hiebert@zimco.ca / ron.becker@zimco.ca

9.1.7. GTUIT, LLC – Wellsite Fuel Gas Processing, Flare Reduction, and Natural Gas Liquids (NGL) Recovery Units	**July 31, 2017**

Description

GTUIT designs and builds modular and mobile well site gas processing units used for both flare gas recovery and natural gas fuel conditioning.

Instead of flaring wellhead gas at locations without midstream pipelines, the GTUIT flare gas recovery units can recover value and reduce air emissions. GTUIT's equipment works in the thermodynamic sweet spot for field gas treatment with proprietary flow-control, compression, and mechanical refrigeration sized for each project.

The GTUIT FCS field gas conditioning equipment takes raw gas from the wellhead and conditions it. The conditioned gas is dry, and a consistent BTU at a constant pressure with a majority of the NGLs removed. The conditioned gas can be used for field power generation, compressed natural gas, liquefied natural gas, and gas-to-liquid feed stock.

GTUIT flare gas recovery and FCS conditioning units are modular and mobile, and either skid- or trailer-mounted. The units are available in 250 MCFD, 500 MCFD, or 1000 MCFD capacity and can be combined to process up to 5000 MCFD and recover over 70% of the C3+ constituents. Units have large turn-down capacity to fit variable wellsite conditions and are purpose-built for remote, extreme oilfield conditions with over 400,000 hours of dependable operation. Integrated safety systems and satellite-based remote monitoring provide safe operation worldwide.

Technology Group

Lighting and Utilities – Facilities Design and Equipment

Site Applicability

Oil well sites with rich, high BTU, natural gas

Emissions Reduction and Energy Efficiency

The GTUIT flare capture and FCS field gas conditioning equipment enables the recovery of natural gas and liquids that would otherwise be flared and wasted and turns unusable natural gas streams into a valuable fuel. The equipment recovers and captures more than 80% of volatile organic compounds (VOCs). The dry gas can be shipped to market or used on site for power generation or other uses. Each 1000 MCFD flare capture system prevents more than 12,000 tons per year of CO_2 emissions from gas flares.

Economic Analysis

Capital Cost:	Capital costs for typical equipment ranges from US$0.80 to $1.40 per SCFD of processing capacity. However, exact costs depend on the gas quality, flow rate, and site location. The value stream of the processed NGL stream alone may offset capital equipment cost.
Installation Cost:	Installation takes approximately three to five days. No installation cost figures were provided.
Operating Cost:	Operating costs vary depending on the site and specific application. No operating cost figures were provided.
Maintenance Cost:	Maintenance costs vary depending on the site, specific application, and operating conditions.
Carbon Offset Credits:	Eligibility for greenhouse gas (GHG) offset credits or other carbon cost reduction instruments can only be determined based on the specifics of the application.
Payback, Return on Investment and Marginal Abatement Cost:	The payback period, return on investment, and marginal abatement cost depends upon the site, commodity prices, and distance to market.

Reliability

Expected Lifetime:	The GTUIT system is expected to last 15-20 years.
Maintenance:	Regular maintenance is required, but maintenance training is provided.

Safety

All site and equipment safety protocols must be followed. Applicable safety regulations govern field wellsite conditions with high-pressure gas and low-temperature gas, high-voltage, and rotating equipment.

Regulatory

- Equipment can be CSA Certified where required.
- No AER Directive applicable

Vendor Information

Company Name:	GTUIT
Company Website:	www.GTUIT.com
Product Website:	Not provided
Contact Person:	Dean Cervenka, VP Sales
Contact Phone#:	(406) 867-6700
Contact Email:	DCervenka@GTUIT.com

9.1.8. OilPro Oilfield Production Equipment Ltd.: PowerGen by Qnergy	April 26, 2019

Description

PowerGen is a remote power solution that uses vent gas, fuel gas or propane to generate electricity through a Stirling engine. PowerGen is available in two models that produce either 1200 or 5,650 Watts of grid-quality electricity. The combustion can directly help reduce site venting and as part of an electrification solution to achieve lower overall emissions.

The engine design is called the Free Piston Stirling Engine (FPSE) and is recognized by NASA as the "most reliable generation technology in history". When heated at the absorber, the FPSE transforms heat into a steady electrical output by using linear alternators and advanced heat exchanger designs within the harmonically resonating thermo-mechanical structure. The PowerGen design breakthroughs result in extremely reliable, long-life, virtually maintenance-free, quiet electricity generation.

Further efficiencies can be realized by using waste heat (about 3 times the power rating) as a heat source for additional hot glycol.

Technology Group

Lighting and Utilities

Site Applicability

We provide power solutions to anyone requiring critical remote power solutions in response to AEP (Alberta Environment and Parks) regulations to create offsets usable under CCIR (Carbon Competitiveness Incentive Regulation) for advanced environmental compliance.

Emissions Reduction and Energy Efficiency

OilPro's PowerGen technology can burn vent gas or propane to help address site emissions. It uses a near-perfect blower-assisted stoichiometric ratio combustion process, which in turn creates electric power in the Stirling Engine's built-in linear alternators. This power is used for any combination of:

- Instrument air for pneumatic pumps and instruments (60-90 low bleed instruments)
- site cathodic protection and pipeline ICCP
- remote power generation
- heat tracing/heaters/water tank heating
- flow control
- metering

- monitoring
- lighting
- actuators
- pumps (10 gpm for 1,000-3,000’ or 2-5 gpm for 5,000’ well)
- compression power for flowline pressure reduction
- analytics

Emissions reductions are realized through diversion of vent gas to the engine and by instrument air retrofits of fuel gas energized pneumatics. This is especially evident at remote sites without easy access to grid power. Major gains in efficiency are made by retrofitting on-site vented wellhead gas pneumatics with air systems, and/or straight conversion to electrical power without the need to tie into external electrical infrastructure. Significant torque available allows larger electrical systems to be powered compared to other remote power sources. Efficiency increases with colder weather. The expected GHG reductions are:

- Vent Gas Capture: 180 to 250 tCO2e / year
- Instrument Air Pneumatics retrofits; 60 to 90 instruments: 1000 to 2000 tCO2e / year

Economic Analysis

Capital Cost:

PowerGen is available in two power classifications (1200 W and 5650 W). Available options include: glycol heat trace, low temperature reliability, remote control and diagnostics, SCADA connectivity package:
PowerGen 1200: $43,000 to $57,000
PowerGen 5650: $57,000 to 71,000

OilPro can supply PoweGen turnkey packages to facilitate your specific needs such as Instrument Air, glycol tracing, remote power hub, etc.

Installation Cost:

Installation of PowerGen requires either timers, piles or a gravel/concrete pad where costs vary widely depending on site conditions.
Other installation costs are dependent on the application and vary based on site conditions and functional requirements.

Operating Cost:

$500 to $1200 per year depending on size and fuel gas price.

Maintenance Cost:

The PowerGen engine has an 80,000 hr design life and the overall system requires no more than 1-2 hours of scheduled maintenance/year. Expected maintenance costs are less than an average of $500/year.

Carbon Offset Credits:

PowerGen can be used as the power source in the following offsets protocol:

- Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices

Payback, Return on Investment and Marginal Abatement Cost:

PowerGen’s most favorable economics are seen in remote power generation and compare very well to other generation, such as fuel cell or TEG options.

Reliability

Expected Lifetime:	PowerGen engine is designed for 80,000 maintenance-free operational hours: at a NASA testing facility, units have run continuously for 13 years.
Maintenance:	None to engine itself. One to two hrs/yr. of scheduled maintenance: clean air intake filter, check glycol level, periodic scheduled maintenance to glycol circulation system, blower, seals, onboard system battery.

Safety

PowerGen has a General Area classification, and can cope with onsite gas emissions without catastrophic failure.

Regulatory

Meets the following certifications and standards:
cETLus UL2200
CSA C22.2#100
C22.2#14
IP54 Enclosure rating

Vendor Information

Company Name:	OilPro Oilfield Production Equipment Ltd.
Company Website:	https://oilpro.ca/product/powergen/
Product Website:	https://remotepowergen.com/
Contact Person:	Olav Cramer
Contact Phone#:	+1 403 215-3373
Contact Email:	info@oilpro.ca

Section 9.2. Lighting and Utilities – Recommended Practices

9.2.1. Electric Power Generation Using Waste Gas

July 31, 2017

Description

During production, processing, refining and other oil and gas operations, vast quantities of waste heat are sometimes produced. This abundant low-quality waste heat could be used to generate considerable electricity with no incremental emissions or additional fuel consumption, thereby reducing greenhouse gas emissions. In addition, this produced electricity can be used internally to reduce purchased electricity costs, and any surplus can be sold into the market.

A study by Neill and Gunter[68] identified several potential waste-heat streams, and evaluated advantages, disadvantages and specific characteristics of each technology's viability for power generation.

The study identified and examined the following potential waste heat streams:

- Reciprocating engine and gas turbine exhausts
- Flue gases from fired heaters, steam generators, and incinerators
- Warm liquid streams, such as warm produced water and boiler blowdown
- Miscellaneous applications where heat is most commonly rejected in aerial coolers, such as amine trim coolers, regenerator reflux condensers, produced gas coolers, column overhead condensers, and glycol system trim coolers

The study also identified and evaluated three fully-commercial technologies to convert recovered waste heat to power.

- Steam-based Rankine cycle, where a heat recovery steam generator (HRSG) is used to produce steam from hot exhaust gases, which in turn powers a steam turbine generator unit
- Organic Rankine Cycle (ORC), where recovered waste energy is transferred to an organic working fluid, such as propane, pentane, or other low boiling point organic fluid, which then drives a turbine expander
- Kalina cycle, another Rankine cycle variation where the unique properties of an ammonia-water working fluid provide some marked advantages in terms of efficiency and allowable waste heat temperatures

Technology Group

Lighting and Utilities – Recommended Practices

Site Applicability

Natural gas facilities, oil facilities, SAGD operations, specific downstream operations

Emissions Reduction and Energy Efficiency

When fuel is combusted, waste heat results from efficiency losses in the process. Between 10% and 70% of the energy contained in a fuel is lost as waste heat in typical industrial processes, and the magnitude

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[68] The full 148-page report for this best practice can be found on the PTAC website at: http://www.ptac.org/projects/389

of waste heat resulting from oil and gas operations is on the order of tens of gigawatts of thermal energy.

Fossil Fuel Industry Emissions		
Sector	GHG Emissions from Internal Fuel Combustion (Mt CO_2e)[69]	Energy Consumption (GJ)[70]
Crude Oil Production	25.4	508 million
Natural Gas Production	10.6	212 million
Oilsands (including coal)	26.6	532 million
Natural Gas Transmission	8.5	170 million
Downstream Fossil Fuel Industry	17.0	340 million
TOTAL	88.1	1762 million

Implementation of waste heat power generation indirectly results in greenhouse gas (GHG) reductions. While the process producing the waste-heat may continue to operate as usual and emit GHGs, the installation of waste heat recovery and power generation produces additional electricity that results in no incremental GHG emissions. In turn, an equivalent amount of electricity that would have otherwise been supplied via the grid is no longer required. If the electricity being offset is generated from fossil fuels, the result is GHG emissions reductions, meaning that waste heat power projects could produce emissions offsets by offsetting electricity that would have otherwise been produced with fossil fuels. However, the actual emissions reductions are dependent on regional factors, such as the dominant generation technology and the type of fuel used to meet marginal demand.

Baseline:
Current waste-heat from several sources is not being used and site electrical requirements are mainly met through purchased electrical power

Economic Analysis

Summary of Economics for Power Generation from Various Waste Heat Sources			
Pricing Case	IRR (Internal Rate of Return)		
	<10%	10 to 15%	>15%
\$85/MWh+\$15/tonne CO_2e	• Individual Reciprocating Engines • Fire-tube Immersion Heaters • Steam Generator Blowdown • Steam Generator exhaust without condensing HX's	• <20,000hp Gas Turbines • Steam generator exhaust with condensing HXs • Surplus steam >5,000kg/hr • Trim coolers / reflux condensers in large sweetening plants (>100m^3 /hr amine	• >20,000hp Gas Turbines • >5000m^3 /day warm produced water in upper temp range • Surplus Steam >10,000kg/hr • Large SAGD glycol cooling systems • Overhead coolers etc. with duty >15MWth in upper

[69] From National Inventory Report (Environment Canada, 2006)
[70] Based on average 50 kg CO_2 per GJ energy intensity, as natural gas is dominant fuel used in operations

		circulation)	temp range

The impact of operating costs, greenhouse gas credit value, and the escalation of annual revenue or costs have a relatively minor impact on project economics for this practice.

Capital Cost: Cost estimates are for total "all-in" installed capital costs, including equipment supply and erection, commissioning, engineering, and administration costs.

Operating Cost: Annual electricity cost before using waste heat ($/yr) = electricity usage per day (kW) x Value of electricity ($/kW) x # of operational days (days/year)

Annual fuel cost after using waste heat ($/yr) = electricity usage per day (kW) x Value of electricity ($/kW) x # of operational days (days/year)

Payback Period: An example payback calculation is as follows:
Annual revenue per installed kW:
(0.9)(8,760 hr/yr)(1kW/kW)($0.10/kWh) – ($50/kW-yr) = $740/kW-yr
This yields a payback of approximately 3.8 years, or a simple IRR of about 26%.

Project Life:
even the most economically viable waste heat projects have typical payback periods <4 years, and as such, facilities with expected lives >15 years (at rated capacity) should be targeted. Operations where plant throughput could decline significantly over time will not be good candidates for waste heat power generation.

Marginal Abatement Cost: GHG Cost Abatement ($/t$CO_2$e) = ((Capital Costs of Installing waste-heat capture technology($) + (Incremental operating costs ($/yr) * Project Life (year)) / (Annual GHG Reduction (tCO_2e/yr) x Project Life (year))

Additional Considerations:

- Load factor, electricity price, capital cost, and project life are the most influential variables on project viability, and these factors must be closely considered when searching for prospective waste heat power generation opportunities.
- Due to inevitable variations in site-specific factors, generalizations have been employed to assess "typical" waste heat sources and characteristics. No site-specific assessments have been completed, and performance, cost and economic feasibility estimates are indicative only. A detailed and site-specific investigation should be conducted, in consultation with technology providers, to determine expected performance and cost of technologies prior to implementation.
- Electricity generation from waste heat typically has only between 5% and 25% thermal efficiency, and relatively high capital costs. In addition, investment is power generation is often characterized by moderate financial returns over a long period.
- The following key assumptions were used in this study:
  - Cash flows are assumed to occur at the end of each year
  - Construction costs are incurred on an "overnight" basis

- Project life is 20 years
- The project costs are covered by 100% equity—no debt financing or equipment leasing is considered
- Escalation of annual revenues (or cost savings) and operating costs is assumed to be 2% per year
- No cost associated with lost production during construction is considered—it is assumed that construction of any new waste heat projects would be coordinated with planned outages as required to avoid unnecessary disruption to existing facilities.

Reliability

Expected Lifetime: Load factor, electricity price, capital cost, and project life are the most influential variables on project viability, and these factors must be closely considered when searching for potentially successful projects.

Maintenance: Periodic inspection and maintenance is required for various installations and technologies and should be verified based on the type of implementation. To maintain reliability, waste-heat electricity systems must be designed so that an outage of the power generation unit would not impact the availability of the engine. Heat exchange between the jacket water loop and power generation cycle would be in parallel with the engine radiator, and exhaust heat recovery could incorporate bypass arrangements if warranted.

Acid dew point issues must be considered for exhaust heat recovery equipment for engines using fuel gas containing sulphur.

Parts and Skills Required: This parameter will vary based on the type of implementation.

Safety

All electrical equipment must be grounded and installed in accordance with Alberta Electrical and Communication Utility Code (AECUC) and Canadian Electrical Code's electrical and safety codes.

Regulatory

Operators must obtain and demonstrate compliance with relevant facilities codes and regulations. The specifics of regulatory compliance will need to be determined once the specifics of the technology and the application are determined.

Service Provider/More Information on This Practice

The full 148-page report for this best practice can be found on the PTAC website at:
http://www.ptac.org/projects/389

Several technical options are available and outlined in the full best practice report for producing electricity from waste heat, such as:

Rankine Cycles

Steam-based Rankine cycles are well-established technology, and numerous North American suppliers are available for the major system components.

Some steam turbine manufacturers with products in the size range appropriate for upstream waste heat projects include:

- Dresser-Rand
- General Electric
- Siemens
- Turbosteam

Heat Recovery Steam Generators

Some HRSG manufacturers with products in the size range appropriate for upstream waste heat projects include:

- Rentech
- TIW Western
- IST

Organic Rankine Cycle Generators

Some North American vendors of ORC technology include:

- Ormat
- Barber Nichols
- UTC Power-Pure Cycle
- Wow Energy

Kalina Cycles

Recurrent Engineering is the North American technology licensee and process designer for the Kalina Cycle. They have worked with various EPC firms to develop projects.

Stirling Engines

Kockums, a subsidiary of ThyssenKrupp Marine Systems, has developed a 25kW Stirling engine for use in the Swedish submarine fleet. This engine has been modified to be used with a solar dish collector by Stirling Energy Systems.

Thermal Hydraulic Systems

The companies developing these technologies are:

- Deluge Inc.—Natural Energy Engine
- Encore Clean Energy—Heat Seeker

9.2.2. Energy Efficient Light Bulb Installations

July 31, 2017

Description

Upgrading standard incandescent light bulbs to more efficient compact fluorescent (CFL) or light-emitting diode (LED) lights at remote field sites and campsites, where electricity is generated by diesel or natural gas generators or supplied by the local power grid, can reduce electricity usage and cost.

Technology Group

Lighting and Utilities -> Facilities Design and Equipment -> Energy Efficient Light Bulbs

Site Applicability

Non-Explosive locations

Emissions Reduction and Energy Efficiency

Use of fuels such as natural gas or diesel used to power light bulbs on site will be reduced due to more efficient CFL or LED light bulb use. Current rebate information is available through Energy Efficiency Alberta.

Baseline:
Incandescent Light Bulbs

Emission Reduction Forecast:
The annual average energy savings and CO_2e emissions reductions achieved depend on the source of the electricity used to power the light bulbs (i.e. grid-sourced or on-site generation by fuels such as natural gas or diesel).

Economic Analysis

Capital Cost:	Average capital costs are $13 per CFL lightbulb assuming non-explosive locations.
Operating Cost:	Operating costs vary depending on site-specific annual electricity needs and annual fuel costs.
Payback Period:	Payback period varies by site depending on site specifics. However, in general the payback is quick.
Marginal Abatement	Calculation: GHG Cost Abatement (\$/tCO_2e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital cost of installation (\$)

Reliability

Expected Lifetime:	Both CFL and LED lights have a longer lifetime than standard bulbs, although exact hours and L70s vary by specific product.
Maintenance:	Maintenance for CFL and LED lights is very minor. Longer-life lighting requires replacement much less often.
Parts and Skills	Sites require electricity supplied by a local power grid or by diesel/natural

Required: gas generators.

Safety

CFL bulbs contain <5mg mercury, and carry the risk of mercury exposure in the event the bulb breaks. Should breakage occur, specific clean-up instructions including pre- and post-cleanup procedures must be followed. The cleanup process varies depending on if the breakage occurred on a hard or a soft surface. Step-by-step instructions are available[71].

Light bulb wires should not be touched.

Regulatory

Operators must notify the AER in the event of a fixture change.

Service Provider/More Information on This Practice

Bulbs are available for purchase from many vendors. Three examples are General Electric, SuperGreen Solutions, and Nemalux Industrial

[71] https://www.epa.gov/cfl/cleaning-broken-cfl.

Section 10.1. Well Completions – Facilities Design and Equipment

10.1.1. General Magnetic - Permanent Magnet Motor Top Drive	July 31, 2017

Description

The General Magnetic International Inc. Permanent Magnet Motor Direct-Drive Top Drive is an energy-efficient alternative to the conventional top drive for fluid-producing wells using progressing cavity pump (PCP) production. It has been deployed at Alberta and Saskatchewan well sites since 2009. The top drive's permanent magnet motor technology is extremely energy efficient, while still delivering the necessary speed, torque, and power density. The motor does not use speed reduction components such as belts, sheaves, and gearboxes, nor mechanical brakes so maintenance is drastically reduced. A proprietary electronic brake ensures backspin and maintenance stops are controlled safely without any wearable parts, significantly increasing safety.

Technology Group

Well Completions – Facilities Design and Equipment

Site Applicability

Upstream oil facilities, sweet and sour service.

Emissions Reduction and Energy Efficiency

Permanent magnet motor top drive technology saves 50 to 80 tons of CO_2e per year based on Alberta power production equivalents. General Magnetic has measured up to 10% electrical energy savings against highly-optimized conventional systems, with much greater savings achieved against systems that had not been optimized.

Economic Analysis

Capital Cost:	Capital costs vary depending on motor size. No specific capital costs figures were provided.
Installation Cost:	The concentric design simplifies installation so associated costs are reduced compared to conventional systems. No specific installation costs were provided.
Operating Cost:	Exact operating costs were not provided. However, a reduction in operating costs is expected due to energy savings.
Maintenance Cost:	Maintenance costs are minimal.
Carbon Offset Credits:	Although the Magnet Motor Direct-Drive Top Drive alone is not eligible for carbon offset credits, they could be generated through project aggregation.

Payback, Return on Investment and Marginal Abatement Cost:	The payback period typically ranges from 12 to 16 months. After this, the technology continues to cumulatively save operating expenses for the remainder of its lifetime.

Reliability

Expected Lifetime:	The equipment is expected to last 15 to 20 years.
Maintenance:	The only required maintenance is changing the thrust bearing oil once per year.

Safety

The magnet motor direct-drive top drive offers enhanced safety compared to conventional systems. There are fewer rotating parts, and they are contained inside the motor. There are no belts to maintain or sheaves to break, nor mechanical brake systems to fail.

Regulatory

- CSA Class 1, Div. 2. approved
- No AER Directive applicable

Vendor Information

Company Name:	General Magnetic
Company Website:	http://generalmagnetic.ca/
Product Website:	Product information is available on the company website.
Contact Person:	Aaron Brassard
Contact Phone#:	403.279.9133
Contact Email:	sales@generalmagnetic.ca

Section 11.1. Wellhead Venting – Facilities Design and Equipment

## 11.1.1. GO Technologies - The 2" M160 Moisture Skid Unit	July 31, 2017

Description

In oil production, excess gas is typically vented or flared. The 2" M160 Moisture Skid Unit reduces the environmental impact of flaring, venting, and incinerating, while also helping maintain oil production by converting unused vent gas into useable energy. Gas is monitored and scented for distribution. All instrumentation is run by two solar panels, eliminating fuel gas emissions. Benefits of the M160 Moisture skid include:

- The moisture skid may be used in combination with a compression unit or several compression units.
- Dry 'speck' gas can be easily obtained with current dryer systems on small compressor packages.
- With the use of this skid, the compressed vent gas may be compressed and sold back into the pipeline that was intended to serve the well.
- The moisture skid unit can be utilized on a single well or a larger system that has excess gas to be used. (In most cases, natural gas pipelines are run to heavy oil wells to aid in production, run engines, fire burners etc. Not all wells produce casing gas, so often propane is needed to run equipment. This is more expensive than natural gas).
- When the gas is set up for use with a co-op or utility gas, the discharge pressure is increased and overcomes the utility's gas pressure. The gas is then sold back to the utility.
- As the discharge pressure decreases or stops, the well or system is then backed up by the co-op or utility meter to maintain a set pressure. This ensures that no pressure is lost and the well is not shut down. The excess gas is sold on to the low-pressure line and there is no venting.

Technology Group

Wellhead Venting – Facilities Design and Equipment

Site Applicability

This unit applies to all CHOPS sites with excess amounts of vent gas.

Emissions Reduction and Energy Efficiency

Emissions will be reduced to zero, or to minute amounts, on these CHOPS sites, as gas is sold into low-pressure or mid-pressure lines serving residential systems.

Economic Analysis

Capital Cost:	Capital costs vary by pressure requirements. A low-pressure unit is $76,000. The High-pressure unit costs up to $130,000 (including a high-pressure meter and equipped with an H_2S analyzer.)
Installation Cost:	Installation costs are approximately $2,500 for systems that are already tied into existing low-pressure lines. However, if pipelines need to be installed to tie into the site, costs will be significantly higher, with exact figures depending on pipeline size, distance, pressure, etc.
Operating Cost:	Operating costs are minimal, limited to monthly gas analysis costs, mercaptan, and supervisory control and data acquisition (SCADA) costs for monthly data charges if modems are used. Estimated operating costs for a low-pressure site starts at $400.00 per month.
Maintenance Cost:	Maintenance Costs are limited to meter inspections every six months and recertification every seven to ten years. The primary cost is maintaining the compressor to ensure continued production of pipeline spec gas.
Carbon Offset Credits:	Sites under the .5 E3M3 can qualify for carbon credits.
Payback, Return on Investment and Marginal Abatement Cost:	Payback depends on the oil production and vent gas produced on the well or well sites. Payouts have been achieved in as little as weeks if significant oil production is lost because of shut in wells from high gas/oil ratios (GOR)'s.

Reliability

Expected Lifetime:	With proper maintenance, the M160 moisture skid unit will last indefinitely.
Maintenance:	Operators working on well sites using the M160 moisture skid unit should have completed the gas utility operator course or have sufficient knowledge and experience operating regulating, measuring, and odourization systems (RMOs).

Safety

No unusual safety considerations apply, although regular on-site PPE is required for meter inspections and maintenance.

Regulatory

- These units have the option of being CSA approved, if required.
- Each unit is built to Pipeline Facilities Code B31-3 and are Class 1 Div 1 inside the unit.
- Each unit includes a Full Quality Control Package.
- These units also help resource companies meet AER venting requirements.
- Meters are Measurement Canada Approved, which is a tighter tolerance than the AER.

Vendor Information

Company Name:	GO Technologies Ltd
Company Website:	www.gotechnologies.ca

Product Website:	http://gotechnologies.squarespace.com/m160/
Contact Person:	Greg O'Hare
Contact Phone#:	780-808-9420
Contact Email:	greg@gotechnologies.ca

Section 11.2. Wellhead Venting – Recommended Practices

11.2.1. Maximizing Use of Solution Gas as Lease Fuel

July 31, 2017

Description

Oil well leases, especially primary heavy oil leases, can be modified so that the majority of the energy used on the lease is supplied by stranded produced solution gas. Modifications should allow for year-round use of solution gas on the lease. On typical oil well leases, solution gas may be wasted when it could be otherwise maximized as lease fuel.

Technology Group

Wellhead Venting - Recommended Practices

Site Applicability

This practice is applicable to any oil well lease where solution gas is not gathered with oil and water to a central battery for conservation. This is typically due to lack of gathering lines, or a specific lack of gathering line to take the gas to sales. Based on ST-60 for July 2016[72], a significant number of sites would achieve some potential savings (by Petrinex Battery Type (flaring or venting)):

- 311/331/343 = >2,000 batteries
- 321/341 = >900 batteries
- 322/342 = >400 batteries

Emissions Reduction and Energy Efficiency

Modifying leases to supply energy for oil sites using stranded produced solution gas significantly curtails the use of external fuels and energy. Emissions related to production and transportation (pipeline and trucking) of gas from external wells, purchased gas, and purchased propane are reduced. At the same time, reported flare and vent volumes are minimized.

Baseline:
Currently, solution gas causing odours or containing hazardous substances is routinely flared on leased oil sites. Solution gas mainly composed of methane with no odours is vented or flared.

Economic Analysis

Directive 060[73] in Alberta and S-10[74] in Saskatchewan specify economic conditions requiring conservation for larger flows, but should first be applied to smaller flows for meeting lease gas demand.

Capital Cost:	Capital costs range from \$10,000 - \$50,000 per lease depending on number of wells, lease layout, method used for winterization, and whether the modification is installed at start-up or retrofitted. Costs include insulation, tracing, piping or hoses to site engines/tanks.
Operating Cost:	Operating costs are minimal, but must take into account adjusting burner operation and engines as produced fluid and gas rates change.

[72] https://www.aer.ca/data-and-publications/statistical-reports/st60
[73] https://www.aer.ca/rules-and-regulations/directives/directive-060
[74] http://publications.gov.sk.ca/documents/310/85153-Directive%20S-10%20Saskatchewan%20Upstream%20Petroleum%20Industry%20Associated%20Gas%20Conservation%20Directive.pdf

Payback Period: Payback periods and ROI vary depending on type of fuel being replaced. Estimated ranges based on type of fuel backed out:

a) Propane <0.2-0.5 years after initial well start-up (max rates)
   i. $300m^3/d$ *3 (adjust for higher initial rates) * 34 MJ/m^3 = 30 GJ/d
   ii. 30 GJ/d * 365 d/yr * $9/GJ for purchased propane = $100,000/yr savings
   iii. Payout <2 months to <6 months depending on capital cost
b) Purchased gas <0.8-1.5 yr after initial well start-up (max rates)
   i. Initial saving ~$30,000/yr
c) Royalty-free gas from local gas well <2-5 yrs after initial well start-up (max rates)
   i. Initial saving ~$10,000/yr
   ii.

Marginal Abatement: Marginal abatement costs vary depending on if gas is flared or vented. Estimated ranges based on flared vs. vented:

a. Flared gas – Abatement cost varies widely. Assume 300 sm3/d/site reduced flaring at cost of $30,000/site = $30,000/(200 t/yr for 8 years) = $18-21/$tCO_2e$ (without credit for savings)
   i. (30,000 - (100,000 x 4 (for project life savings)))/(200 * 8) = -$230/t with credit for propane
   ii. (30,000 - (30,000 x 4 (for project life savings)))/(200 * 8) = -$55/t with credit for purchased gas
   iii. (30,000 - (10,000 x 4 (for project life savings)))/(200 * 8) = -$6/t with credit for royalty-free gas
b. Vented gas – Abatement cost varies widely. Assume 300 sm^3/d/site reduced venting = $30,000/(1800 tCO_2e/yr for 8 years) = $1.80-2.1/$tCO_2e$ (without credit for savings)
   i. (30,000 - (100,000 x 4 (for project life savings)))/(1800 * 8) = -$2,000/t with credit for propane
   ii. (30,000 - (30,000 x 4 (for project life savings)))/(1800 * 8) = -$500/t with credit for purchased gas
   iii. (30,000 - (10,000 x 4 (for project life savings)))/(1800 * 8) = -$50/t with credit for royalty-free gas

Reliability

Modifications are relatively simple and static, easily repaired by operators in their normal daily rounds.

Expected Lifetime: The equipment is expected to last the duration of the project life.

Maintenance: Maintenance costs are low, but vary depending on specific site conditions.

Parts and Skills Required: No special skills are required, although insulation may need to be replaced.

Safety

Using stranded produced solution gas should not present any more safety issues than use of other fuel sources. In fact, doing so reduces the potential for exposure to VOCs (Volatile Organic Compounds) and emissions, assuming gas not used is vented or flared with lower conversion efficiency than a tank burner.

Regulatory

This technology has already been implemented at many sites in Alberta and Saskatchewan. Directives 060 and 017 require conservation over flaring and venting. Use of produced gas as lease fuel effectively conserves vent gas, and making this practice a mandatory requirement is recommended.

Service Provider/More Information on This Practice

1) Simple options for maximizing solution gas are found in Appendices 3.0 and 4.0 of Heavy Oil Vent Mitigation Options – 2015 (Second Edition) as referenced below.
2) New Paradigm Engineering and other engineering firms provide guidance and information on methods to convert sites.

References:

Directive 060. (2016, March 22). Retrieved from Alberta Energy Regulator Website: https://www.aer.ca/rules-and-regulations/directives/directive-060

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## 11.2.2. Solution Gas Separation and Flow Stabilization for Primary Heavy Oil Sites	July 31, 2017

Description

In the primary production of heavy oil, the solution gas drive sometimes results in foamy oil. In older wells using cold heavy oil production with sand (CHOPS)[75], the flow of vent gas can become irregular. Solutions such as portable line heaters and low-pressure gas storage deal with initial foamy oil flow or periodic gas flows while also allowing the capture and use of solution gas.

Technology Group

Wellhead Venting - Recommended Practices

Site Applicability

Any new foamy heavy oil well lease where solution gas does not separate in the well or reservoir, or where the flow of gas in older wells becomes sporadic.

Emissions Reduction and Energy Efficiency

Foamy Flow:
During foamy oil flow, oil and gas do not separate in the well annulus, resulting in all the produced oil and gas going through the progressive cavity pump in the well, and then into lease storage tanks. As the foam in the tanks breaks down after heating, gas is released and vented to the atmosphere. Operators often bring in extra heated tanks to help heat and store the foam, which results in extra costs and more vent sources. Foamy flow may last days, weeks, or months, during which vented gas cannot be used for lease fuel gas. A line heater/separator installed between the well and the tank can heat the oil efficiently and separate the gas before it reaches the tank, allowing the solution gas to be used for lease fuel and reducing greenhouse gas (GHG) emissions.

Natural Gas Storage Bags:
After stable CHOPS flow is lost, gas may either surge or may sporadically enter the well. While total average produced vent gas may be enough to provide lease fuel, the irregular flow may result in too much fuel gas during some days, and not enough gas on other days, which will require the use of make-up fuel for tank heating and engines. Natural gas storage bags enable excess gas to be temporarily stored on site for use during periods of insufficient gas flow.

Baseline:
Solution gas venting in high volumes from tank tops during initial foamy flow period and venting when there is surging in vent gas flows hinders its use as lease fuel gas.

Economic Analysis

Foamy flow and surging vent gas conditions are usually only experienced in either new wells or older wells. They are not typically observed during the stable CHOP or CHOPS operation when most of the oil

[75] CHOPS is an increased recovery method popular in the Canadian Heavy Oil industry. The method involves introducing an influx of sand during completion, and then maintaining it during the productive life of the well. Recovery of heavy oil from the reservoir is improved, although a further process to separate the sand from the oil is subsequently applied.

and gas is produced. Economics is based on use of portable or leased equipment that can be deployed as needed to capture gas.

Capital Cost: Capital costs to manage foamy flow range from $50,000 (one well) to $250,000 (five or more wells) per line separator.

Capital costs for storage bags vary depending on size, supplier, and durability in natural gas service.

Operating Cost: Operating costs are estimated at $20,000 - $50,000 per year, assuming an additional 20% of the capital cost of unit per year to allow for relocation. Alternatively, capital costs to lease equipment range from $40,000 to $100,000 per year, including relocation. Additional credit should be taken for not requiring use of additional lease storage tanks to handle foam, and for saving the cost of tank vapour recovery systems to recover gas from tank top vents.

Payback Period: Payback periods vary based on the type of fuel backed out. Estimates are for a small single lease:

d) Propane <1 year.
   i. 1,500m3/d * 34 MJ/m^3 = 50 GJ/d
   ii. 50 GJ/d * 200 d/yr. utilization * $9/GJ for purchased propane = $90,000/yr. savings - $40,000 rental cost.
   iii. Payout ~6 mos. Or <1 yr. depending on utilization
e) Purchased gas – No payout for renting units without carbon pricing credits. Payout on purchased unit @$50,000 + $20,000/yr. ~5yrs
   i. Fuel saving ~$30,000/yr.
f) Royalty free gas from local gas well - No payout for renting or purchase without carbon pricing credits.
   i. Fuel saving ~$10,000/yr.

Marginal Abatement: Estimated ranges are based on venting and renting a heater/separator to avoid foamy flow:

g) Vented gas – Abatement cost varies widely. Values would be lower than shown if equipment was purchased instead of rented.
   a. Annual Cost/Benefit for Abatement - Assume benefit based on 1,500 sm^3/d/site reduced venting. $40,000/yr. rental/relocation cost * 200/365 for utilization per year.
   b. Propane = ($40,000-$90,000)/(9,000 tCO_2e/yr.*200/365) = -$10/t
   c. Purchased Gas = ($40,000-$30,000)/(9,000 tCO_2e/yr.*200/365) = $2/t
   d. Royalty Free Gas = ($40,000-$10,000)/(9,000 tCO_2e/yr.* 200/365) = $6/t

Reliability

Reliability and availability are impacted by the number of units either purchased or available for rent in a region. Therefore, adoption will fluctuate based upon industry adoption of this best practice in a region, and the willingness of producers to delay production start-up for new wells to await a unit being available.

Expected Lifetime:	Equipment is expected to last at least 10 years.
Maintenance:	The majority of maintenance costs is for the relocation of heater/separator units. However, this allows for in shop maintenance during downtime.
Parts and Skills Required	Equipment is standard in the industry for both parts and operating skills.

Safety

Portable line heaters and low-pressure gas storage do not present any additional safety issues, assuming the unit can be located on the site within spacing guidelines. These solutions offer improved safety compared to tank-top vapour recovery units.

Regulatory

Spacing on leases and carbon pricing impact this option.

Service Provider/More Information on This Practice

1) There are several vendors of heater/separators and natural gas storage bags. Some contacts are provided in Appendices 3.0 and 4.0 of Heavy Oil Vent Mitigation Options – 2015 (Second Edition) as referenced below.

References:

Peachey, B. (April 30, 2015). *Heavy Oil Vent Mitigation Options - 2015 Second Edition.* Calgary: Environment Canada Environmental Stewardship Branch. Retrieved from https://www.ptac.org/wp-content/uploads/2017/07/Heavy-Oil-Venting-2nd-Ed-2015.pdf

Schlumberger. (2017). *The Oilfield Glossary: Where the Oil Field Meets the Dictionary*. Retrieved July 10, 2017, from http://www.glossary.oilfield.slb.com/

## 11.2.3. Produced Gas Measurement Standard for Heavy Oil Sites	July 31, 2017

Description

The current standards for measurement and estimation of produced gas from various types of primary heavy oil sites are contained in Directives 017[76] and 060[77] in Alberta, and Directives PNG17[78] and S-10[79] in Saskatchewan. These documents describe the need for and timing of tests, as well as general methodologies and calculations for estimating well gas-to-oil ratios (GORs) for reporting produced gas volumes. However, they do not define what constitutes an acceptable test. This best practice seeks to improve the current standards by adding testing of the quality of the measurements to establish a standard acceptable test and estimation of the GOR for a well. These standardized metrics will help in estimating total gas production, fuel use, and venting/flare volumes.

Recent information from the Alberta Energy Regulator (AER) indicates that significant differences persist between estimates of produced gas volumes before and after conservation practices are implemented, which contributes to continuing problems with equipment sizing. In many cases actual volumes captured can be two to three times higher than the volumes estimated, which may result in either production cut-backs to avoid odour violations, or continued venting until facility modifications are made.

Background:

In 2002, a group of producers identified large errors and a lack of consistency in how primary heavy oil solution gas GORs were being determined. These errors led to issues with evaluating and designing vent gas mitigation options, as facilities were either over- or under-sized.

A 2003-2004 joint industry project sought extensive industry input and developed a vent gas quantification standard requiring assessment of the produced gas flow profile to determine acceptability for use in determining a stable GOR. Additional recommendations were made related to determining fuel use and oil production to allow calculation of a repeatable GOR. The focus was on GOR calculation on any heavy oil lease site where gas streams are not continuously measured. The Directives are based on the assumption that a GOR is a consistent characteristic of the oil in the reservoir that remains relatively constant for any given well or pool over its producing life. However, many operators found that GORs reported by field operations were highly variable over time, in which case either continuous metering of gas should be required, or testing methods must be improved until consistent GORs are being obtained. The 2004 standard was not widely adopted at the time and, as a result, the problems persist, creating potentially large errors in estimations of produced gas and GORs for heavy oil leases. The intent of this best practice is to adopt the produced gas (vent gas) quantification standard from 2004, adapted to recognize additional changes that have occurred since that standard was developed.

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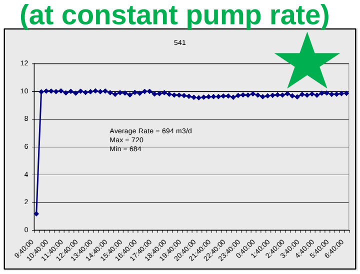
[76] https://www.aer.ca/rules-and-regulations/directives/directive-017
[77] https://www.aer.ca/rules-and-regulations/directives/directive-060
[78] http://publications.gov.sk.ca/documents/310/87388-Directive%20PNG017%20-%20Version%201.2%202015%2011-13.pdf
[79] http://publications.gov.sk.ca/documents/310/85153-Directive%20S-10%20Saskatchewan%20Upstream%20Petroleum%20Industry%20Associated%20Gas%20Conservation%20Directive.pdf

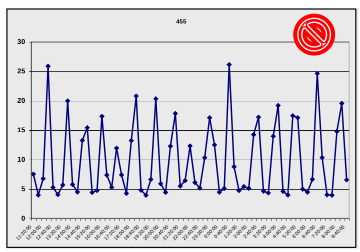
The main sources of error in GOR estimates were identified as:

- Gas flow rate variations: While produced gas flows from many wells were steady and shown to be consistent over days and weeks (Designated “Type A” in the Standard), others showed significant flow fluctuations. As a result, 24-hour flow tests were being used to determine GOR, despite being deemed unacceptable for use in GOR estimates because they do not provide repeatable results. Other deviations were seen on leases where some of the produced gas was being used as fuel, and in foamy wells where no gas was vented from the well annulus so all the produced gas was venting off tanks. The graphs below show a range of flow behaviours observed in various primary heavy oil wells operated by one producer. A consistent GOR can only be assured with data from a 24-hour test using wells with a Type A gas flow profile. All others require either longer gas flow tests or continuous measurement to determine produced gas volumes, unless operating conditions in Types B or D can be adjusted to get Type A. Type C indicates production of associated gas or gas build up in a developing solution gas cap adjacent to the well. Type F is usually seen only in older wells when there is communication between adjacent wells.

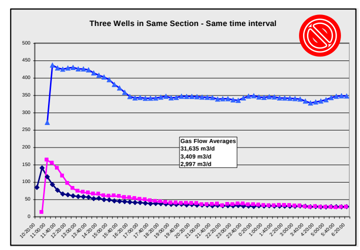
Type A -75-80% of Wells (at constant pump rate)



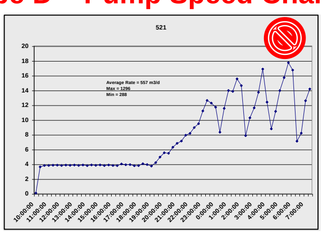
Type B –Well Pumped off



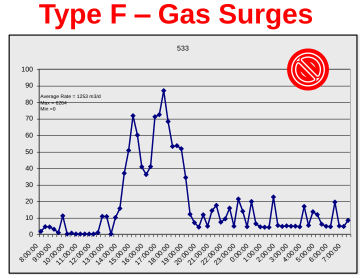
Type C – Gas Pocket



Type D – Pump Speed Change



Type F – Gas Surges



Examples of Gas Flow Variability in 24-hour Tests. Only Type A is Valid for Determining a GOR for Production Reporting of Facility Design Purposes

- Non-representative oil volumes used for GOR calculations: To obtain a valid GOR, the gas rates measured either over a 24-hour or a longer produced gas flow test, MUST be matched to oil volumes produced over the same period, or over a longer period when the well was in steady operation with constant pump speeds and operating conditions. Often one month’s worth of heavy oil production is matched with a 24-hour gas test. If the pump rate changes, other conditions change, of if volumes of oil are transferred or allocated from other wells, then the regulations state that the test is invalid and must be redone.

Site Applicability

Any primary heavy oil site where produced gas is not continuously metered, and where a GOR is determined through periodic gas measurements combined with representative oil production volumes. For multi-well sites, each well on the lease must be tested separately while it is isolated from other wells on the lease.

Emissions Reduction

This best operating practice is focused on ensuring that estimates of total produced solution gas, and fuel, vent, and flare volumes are realistic and accurate enough to be used for planning and designing mitigation actions. Implementing this practice at the appropriate facilities will ensure that the produced gas volumes reported as having been produced from a well are more consistent and representative of actual well production. This will in turn allow more accurate determinations of volumes and potential revenues related to conservation of the stream and for reporting or mitigating greenhouse gas (GHG) emissions.

Accurate equipment sizing is an additional benefit of accurate measurement. The AER has noted that on a large number of facilities of this type, the gas being produced following implementation of mitigation measures has been significantly higher than what was previously reported, so equipment was undersized. Some companies have had the opposite experience where they thought they had a lot of gas, but facilities installed turned out to be over-sized. Right-sizing equipment will not only provide financial benefit, but will avoid generation of excess GHGs through operating oversized equipment.

Baseline:

Current solution gas flare and vent emissions from crude and bitumen batteries are estimated and reported in the latest ST-60B 2016 report as Flared 419 10^6 m^3/yr (Limit 670 10^6 m^3/yr) and 354 10^6 m^3/yr (no limit set) respectively. This translates to ~1.3 to 1.7 $MtCO_2e$/yr from flaring and 6.0 $MtCO_2e$/yr from venting. However, there is a large uncertainty inherent in these numbers due to the lack of standards for measuring and reported solution gas and vent/flare gas volumes.

Economic Analysis

Capital Cost:	Implementing the 2004 Vent Quantification Standard prepared by New Paradigm Engineering Ltd. as a Best Practice should not incur any capital costs. However, it will eliminate the various increased costs associated with installing improperly sized equipment.
Operating Cost	Implementing the 2004 Vent Quantification Standard prepared by New Paradigm Engineering Ltd. as a Best Practice should not incur any operating costs. However, it may take a few more minutes for a production engineer to review tests for wells to ensure they are acceptable, and potentially retest (cost variable depending on how testing is managed in a field) if the gas measurements do not result in repeatable, representative GOR values. This may not result in any net additional time as retesting may already be required to meet the requirements of the directives.
Payback Period:	The payback period varies depending on how current measurements differ from actual volumes, and on the specific impacts inaccurate design information has had on capital facilities additions due to sizing problems.

Marginal Abatement: Implementation of the 2004 Vent Quantification Standard should directionally reduce abatement costs of options by reducing over/under sizing and rework of mitigation installations.

Reliability

The key to installation of reliable and appropriate mitigation measures, such as compressors for gas conservation or use of lease produced gas for purchased fuel displacement, is to ensure that the data being used to make decisions or to design equipment is reliable. Ensuring that consistent GOR determination procedures are followed should result in better data for equipment design.

Expected Lifetime: The Vent Quantification Standard from 2004 is still valid. In a recent report for Environment Canada and Climate Change, New Paradigm Engineering recommended updating the Vent Quantification Standard to reflect changes in regulations, measurement devices/methods, and industry's growing use of multi-well leases. The Standard would then be expected to continue to be valid until major changes are made in regulations, such as implementation of a carbon tax on these streams which would require continuous metering for accounting purposes.

Maintenance: Directive 60 requires GORs to be determined every six months depending on the volumes. GORs should be consistent between tests if the testing and calculations are done properly.

Parts and Skills Required: Measurement methods and skills should be found in every operation already, and personnel involved in produced gas or vent/flare gas determinations should already be familiar with and understand the requirements of Directives 060 and 017 in Alberta, and Directives S-10 and PNG17 in Saskatchewan. The only required skill change is to ensure that personnel involved in GOR determinations are familiar with the 2004 Vent Quantification Standard, and that they are provided with gas measurement devices that allow them to determine the type of flow characteristics for each gas flow test. Production accounting and reporting personnel should be aware of when tests are being done to ensure oil production volumes used for GOR determinations are correct.

Safety

Adoption of the Vent Quantification Standard should not present any safety issues beyond the scope of normal operations.

Regulatory

Ensuring that GORs determined for a well are representative of actual reservoir GORs is a basic requirement to meet the intent of Directives 017 and 060 in Alberta and Directives PNG17 and S-10 in Saskatchewan. These directives are all based on the assumption that the GOR in a given formation is consistent, so major deviations or errors in GOR are due to inadequate measurement standards or a lack thereof. Significant changes in GOR of oil or gas flows between consecutive tests should be flagged and potentially audited by regulators to ensure reported gas volumes are being properly estimated.

Service Provider/More Information on This Practice

References:

Alberta Energy Regulator. (2016, March 31). *Directive 017.* Retrieved from Alberta Energy Regulator Website: https://www.aer.ca/documents/directives/Directive017.pdf

Directive 060. (2016, March 22). Retrieved from Alberta Energy Regulator Website: https://www.aer.ca/rules-and-regulations/directives/directive-060

New Paradigm Engineering Ltd. (2017). *Information on Venting Emissions Quantification and Control Options at Upstream Crude Oil Facilities - Appendix A.* Calgary: Environment Canada. Retrieved from https://www.ptac.org/wp-content/uploads/2017/07/Appendix-A-Env-Can-Review-of-CHOPS-Vent-Standard-20170331-Final.pdf

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New Paradigm Engineering Ltd. (November 2004). *Conventional Heavy Oil Vent Quantification Standards.* Calgary: Petroleum Technology Alliance Canada. Retrieved from https://www.ptac.org/npe-2004-cho-vent-quantification-standards/

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11.2.4. Using Stranded Produced Gas for Well Stimulation on Multi-well Pads as an Alternative to Venting or Flaring	July 31, 2017

Description

Surplus gas at multi-well sites can be used to stimulate oil wells for enhanced production and recovery. The initial assumption in most cases is that, after primary production, wells are not in communication with each other. However, several options originally proposed for single well sites may be easier to implement at pad sites. Potential methods might include, but are not limited to:

- Methane reinjection – compress and inject
- Hot water flood – water heater or use tank to heat
- Steam flood – portable generators or direct contact generation
- Flue gas – 10% CO_2 to 25% CO_2 generated on-site. Multiply volume of gas by ~9 times
- CO_2 or nitrogen – brought in by truck
- Pressure cycling
- Water saturated gas – hot water vapour recovery
- Polymer flood – if well-to-well communication with water is established

Technology Group

Wellhead Venting - Recommended Practices

Site Applicability

Any multi-well crude oil or bitumen battery. Based on ST-60 for July 2016, the number of multi-well heavy oil sites with pad-based stimulation (by Petrinex Battery Type):

- 321/341 = >900 batteries
- 322/342 = >400 batteries

Emissions Reduction and Energy Efficiency

Implementing value-added processes on the producing lease to better utilize surplus produced gas has the potential to increase revenues and recovery while reducing greenhouse gas (GHG) emissions. This process would benefit from staggered start-up dates for multi-well pad wells, so that one well might be depleted before the others.

Baseline:

Gas volumes produced on multi-well sites are too low to justify capture based on the value of the gas, but may provide fuel and injectants to increase production of oil which has a higher value and is easier to move off the leases.

Economic Analysis

Each of the potential recovery methods has different costs, potential recoveries, and state of maturity, so the economics of each must be assessed by the producer on a site-by-site basis and implemented where appropriate.

Capital Cost:	As these are opportunistic processes to take advantage of surplus gas, they are designated as "stimulations". To minimize capital costs all stimulations should be carried out with portable or relocatable equipment. All proposed processes could re-use various combinations of oilfield equipment previously used in pilots or other processes. Renting or leasing equipment is preferred until there is confidence in the stimulation process, and will likely be a preferred method for most producers to maximize return on capital. In some case there may be a need for capital workovers on wells before they are stimulated.
Operating Cost:	The main operating cost is usually fuel for compression or heating. The most expensive options would be CO_2 or nitrogen injection, assumed to be purchased in cryogenic form and trucked in, with surplus lease gas being used to evaporate the pressurized liquefied gases.
Payback Period:	The payback period depends on relative costs and incremental oil recoveries. Oil recovery from primary heavy crude and oil sands leases with high-vent emissions is generally less than 7-10%, so any incremental recovery could add considerable value.
Marginal Abatement Cost:	If the stimulation is economic, the marginal abatement costs for any stimulation will be negative.

Reliability

The equipment required for most potential recovery options has known reliabilities. However, since they are stimulations that may last from a few months to a few years with relocatable equipment, opportunities exist for major upgrades or inspections in a shop environment. Results of stimulation processes are not entirely predictable, so the reliability of the stimulation process to increase recovery will require testing over time.

Expected Lifetime:	Equipment is expected to last more than 10 years. Effectiveness of stimulations or repeated stimulations cannot be assessed without first building some experience with these options.
Maintenance:	Maintenance schedules depend on the specific application, equipment, and wells.
Parts and Skills Required:	Most components are standard. However, the skills required depend upon the specific equipment and application selected.

Safety

Energizing depleted reservoirs always carries incremental risk compared to the "do nothing" approach of allowing production decline.

Regulatory

Discussions or negotiations between producers and regulators or resource owners may be necessary to determine the regulatory and economic regime (royalties) that may be applied to "stimulations" which are not major enhanced oil recovery (EOR) schemes.

Service Provider/More Information on This Practice

References:

Peachey, Bruce. *Heavy Oil Vent Mitigation Options - 2015 Second Edition*. Calgary: Environment Canada Environmental Stewardship Branch, April 30, 2015. <https://www.ptac.org/wp-content/uploads/2017/07/Heavy-Oil-Venting-2nd-Ed-2015.pdf>.

11.2.5. Increasing Conversion of Methane to Avoid Venting

July 31, 2017

Description

Alberta Directive 060 and Saskatchewan Directive S-10 both state that capture and combustion of produced gas is preferred over venting of solution or associated gas. Regulations require that combustion must be sustained at all times, and that concerns must not arise with residents near the conversion sites. A number of technologies allow combustion of gas to avoid venting.

Technology Group

Wellhead Venting - Recommended Practices

Site Applicability

Any crude oil or bitumen battery or wellsite currently venting solution gas.

Emissions Reduction and Energy Efficiency

Converting methane to CO_2 through combustion provides a net reduction in CO_2e greenhouse gas (GHG) emissions, as well as destroying any volatile organic compounds (VOCs) or other hazardous or odour-causing components that may be emitted. Each ton of methane (CH_4) combusted will produce about 2.75 tons of CO_2, based on the conversion reaction. The emissions reduction achieved depends on the value assumed for the global warming potential of CH_4 vs. CO_2.

- Conversion reaction: $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$
- Approximate Mass Basis: 1 ton CH_4 + 4 tons O_2 → 2.75 tons CO_2 + 2.25 tons H_2O
- 100 year GHG GWP for Methane – 21-36 tCO_2e/tCH_4 (depending on reference)
- 20 year GHG GWP for Methane – 84-87 tCO_2e/tCH_4 (depending on reference)

Baseline:
The baseline is the greenhouse gas (GHG) emissions from the methane vented on the lease.

Economic Analysis

Regulations do not yet require flaring or conservation at sites that either produce no odours or that vent <500 m^3/d. Reducing GHG emissions at these sites remains a voluntary practice, and there is no specific economic benefit.

Capital Cost: Capital costs depend on the volumes being combusted at a given site, consistency of flow, the type of conversion method being used, and other factors. Based on Clearstone Engineering's 2016 report[80], some ranges are:

h) Large volume sites >1500 m^3/d – Assume flare system installed requiring an increase in lease size. Cost range $70k to $145k
i) Moderate volume sites 250 to 1500 m^3/d – Assume vapour combustors $95k to $190k; Auxiliary burners $200k to $420k
j) Small volume sites < 250 m^3/d – Assume catalytic converter $35k to $75k with an individual unit cost of $7.5k to $15K per 50 m^3/d/unit.

[80] http://auprf.ptac.org/air/flaring-cost-benefit-analysis/

Operating Cost: Operating costs generally range from 4% - 10% of the capital cost per year, depending upon the technology selected. Equipment requiring pilot gas to maintain combustion is more expensive to operate.

Maintenance: Maintenance costs are generally low, although they vary depending on the technology selected.

Payback Period: None of the options provide a payback unless a carbon price is assessed, and then the payback is based on the value of the carbon.

Marginal Abatement: Marginal abatement costs vary. If it is assumed that all sites are already using the maximum amount of produced gas for fuel, then for an assumed eight-year life:

Abatement Cost = (Capital cost + Operating Cost*8)/(volume of gas converted over 8 years e^3m^3 x 17) – (i.e. 1000 m^3 methane at $25tCO_2e/tCH_4$ ~17 tCO_2e)

a. Large volume sites 8 yr average 500 m^3/d, Capital Cost $100k
   ($100k + $5K*8)/(500/1000*365*8*17) = $5.6/$tCO_2e$
b. Moderate volume sites 250 m^3/d, Capital Cost – $140k
   ($140k + $7K*8)/(250/1000*365*8*17) = $15.8/$tCO_2e$
c. Small volume sites 75 m^3/d, Capital Cost - $50k
   ($50k + $3K*8)/(75/1000*365*8*17) = $13.5/$tCO_2e$
d. Catalytic unit at capacity 50 m^3/d, Capital Cost - $7.5k to $15k
   ($15k + $1K*8)/(50/1000*365*8*17) → $5-$10/tCO_2e (depending on unit cost)

Reliability

Most combustion systems operate reliably under steady flow conditions, provided feed lines are winterized and equipment is maintained. However, regulations require that the gas rate must be sufficient to ensure that 'combustion can be sustained'. Of the possible options, the higher-volume flare system has the greatest issue with sustaining combustion, as the flare is unprotected and may be blown out by the wind. In addition, flares often suffer from a low turndown that can result in a loss of combustion efficiency as the flow rate drops. If flow is intermittent, they require a pilot or spark ignitor. Enclosed flares, combustors, and catalytic units can generally handle much larger changes in flow rate but will have upper limits on throughput.

Expected Lifetime: The equipment is expected last at least eight years.

Maintenance: Flares rarely require maintenance, and when they do it is low-cost.

Parts and Skills Required: Generally, these technologies are based on combustion devices that are widely used in the oil and gas industry, so operators are sufficiently familiar with the equipment without additional training. Obtaining parts may be an issue for any combustors with specialized control systems.

Safety

Approved practices are already in place for the design and installation of combustion systems, and many of these leases already have combustion devices. Safety concerns may arise should producers try to convert tank top vents, which may result in additional hazards requiring greater attention to gas make-up systems and flame arrestors on lines to combustors to prevent tank explosions/fires.

Regulatory

Regulations generally already require flaring or conservation at sites that emit odours, or where vent volumes exceed 500 m^3/d.

Service Provider/More Information on This Practice

References:

Clearstone Engineering Ltd. (2017, February 26). *Cost Benefit Analysis of Heavy Oil Casing Gas Conservation and Conversion Technologies.* Retrieved from AUPRF PTAC Website: http://auprf.ptac.org/wp-content/uploads/2017/06/Report-Flaring-Cost-Benefit-Analysis.v2.0.pdf

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Section 12.1. Surface Casing Vent Flows – Facilities Design and Equipment

12.1.1. CalScan Solutions - Hawk 9000 Low-Flow Vent Gas Meter	April 26, 2019

Description

When quantifying vent flow rates, especially greenhouse gases (GHGs), highly-accurate measurements are needed to create accurate audit trails. This can be difficult information to capture when the flow is very low. The Hawk Vent Gas Meter accurately measures and digitally logs low-flow vent gas, such as methane, from **various sources including surface casing vent**s, compressor seals, and tanks. An optional second pressure sensor and 24hr flow timer can be used to monitor for surface casing buildups.

The Hawk uses a precision pressure-sensor and an external temperature probe to compensate for atmospheric pressure and temperature changes, resulting in a flow measurement accuracy greater than +/-2%. Extremely low flow rates can be measured, down to 0.50 cubic feet per day (0.014 m^3/d), and sample rates can be measured as fast as once per second.

All data settings are logged for the audit trail, and PDF data reports can be generated easily. The information collected by the Hawk can be used to inform emissions reduction and energy efficiency initiatives, such as a vent gas capture program.

Technology Group

Surface Casing Vent Flows – Facilities Design and Equipment

Site Applicability

Upstream gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The Hawk measures surface casing vent volumes, so it in itself does not reduce emissions. However, once accurately measured, the vented volume can be vented or used in a vent gas capture program at the user's discretion.

Economic Analysis

Capital Cost:	Capital costs vary depending on the specific application. The Hawk unit can be purchased or rented.

Installation Cost:	Installation costs are very low. The unit is a ‘plug and play’ device designed to be delivered and installed by a field rep or operator.
Operating Cost:	Operating costs are very low, and may even be nil.
Maintenance Cost:	Maintenance costs are estimated at $210/year. The positive displacement (PD) meter requires annual calibration at a cost of $60. The Hawk flow computer must be verified annually at a cost of $150.00.
Carbon Offset Credits:	The Hawk is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost	Payback period and return on investment are dependent upon the specific application and corresponding offset credit savings. Measuring the vent volume of devices is typically better than the default emission rates provided by the manufacturer, resulting in additional savings.

Reliability

Expected Lifetime:	The equipment is expected to last for the life of the facility.
Maintenance:	The PD meter must be sent for annual calibration; otherwise, the rest of the equipment is suitable for standard instrumentation tech qualifications.

Safety

No unusual safety requirements apply.

Regulatory

- Hawk Flow Computer complies to AER Directive 17 for flow measurement. No Limitations.
- Class 1 Div 1 CSA Approved

Vendor Information

Company Name:	CalScan Solutions
Company Website:	http://www.calscan.net
Product Website:	http://www.calscan.net/solutions_GreenGasMeasurement.html
Contact Person:	Henri Tessier
Contact Phone#:	(780) 944-1377
Contact Email:	HTessier@CalScan.net

Section 13.1. Others –
Facilities Design and Equipment

13.1.1. Integrated Sustainability – Sulphur Recovery Units

June 30, 2017

Description

Oil and gas facilities recover H_2S and light-end mercaptans from gas streams for several reasons, most commonly compliance with AER regulations, sales-gas specifications, or pipeline specifications. Integrated Sustainability's sulphur recovery units (SRUs) use a triazine-based, non-regenerative H_2S scavenger chemical to sweeten the gas stream in a contactor vessel. Outputs from the SRU are a sweet gas and a spent scavenger chemical stream. Each SRU can be customized to achieve the desired H_2S concentration, gas flow rate, and pressure.

Technology Group

Others – Facilities Design and Equipment

Site Applicability

Oil and Gas, Sweet and Sour.

Emissions Reduction and Energy Efficiency

The SRU reduces H_2S content of natural gas by >99%, and requires less energy than most alternative methods for H_2S removal from natural gas.

Economic Analysis

Capital Cost: Capital cost is primarily driven by system size, which is dependent on gas flowrate requirements and operating pressure. Increased level of instrumentation/automation also contributes to capital costs. Capital costs can vary between $0.45 million for small single train units with minimal instrumentation and control devices, up to $3.6 million for larger dual train systems with more complex instrumentation and control devices. SRUs are customized based on the Client's specific operating requirements and constraints.

Installation Cost: Installation costs depend on site characteristics and tie-in requirements. SRUs can be designed to minimize on site tie-in requirements, and are typically supplied on a self-contained structural skid for installation onto structural piles or suitable foundations. Specific ranges for estimated installation costs were

	not provided.
Operating Cost:	Operating costs depend on specific chemical providers and their chemical pricing. The amount of chemicals required depends on gas flowrate and H_2S concentration. Chemical operating costs can range from a few thousand dollars per day for treatment of low flow, low H_2S concentration gas, up to tens of thousands of dollars per day for treatment of high flow, high H_2S concentration gas.
Maintenance Cost:	Primary maintenance operations include routine pump maintenance and routine H_2S analyzer calibrations, which carry a minimal cost.
Carbon Offset Credits:	SRU installations are generally not eligible for carbon offset credits.
Payback, Return on Investment and Marginal Abatement Cost:	Payback, ROI, and marginal abatement costs vary depending on specific facility and stream variables. In general, increased production may be limited by the need to meet Sulphur recovery requirements. However, sweet service pipelines and equipment can be used downstream of the SRU. These have lower associated costs as the sweet gas is less corrosive than the sour gas.

Reliability

Expected Lifetime:	SRUs are expected to last for the life of the facility, provided operators follow all recommended chemical injection rates and conduct all routine maintenance. Severe under-injection of chemical may lead to build up of solids in equipment.
Maintenance:	Daily walk downs are recommended for SRUs where chemical optimization is a priority or unit downtime has significant impact. Chemical providers often include service technicians as part of chemical supply contracts.

Safety

Working in proximity of sour gas process lines.
Potential to handle small volumes of scavenger chemical when performing pump maintenance.

Regulatory

The SRUs can be used as part of a process to comply with AER Interim Directive ID 2001-3 and Section 9 of AER Directive 060. Each SRU comes with a comprehensive documentation package which can include Canadian Standards Association (CSA) approvals for the individual components and equipment that make up the complete SRU.

Vendor Information

Company Name:	Integrated Sustainability
Company Website:	www.integratedsustainability.ca
Product Website:	Not provided
Contact Person:	Andrew Melvin
Contact Phone#:	403-801-3970
Contact Email:	andrew.melvin@integratedsustainability.ca

13.1.2. Tarpon - Vent Gas Capture and Destruction System

July 31, 2017

Description

The Tarpon Vent Gas Capture System captures vent gas and measures vent gas usage. When installed as part of a vent gas destruction system, captured vent gas, such as methane from a pneumatic chemical injection pump, is directed to a bottle to dampen the pulsation, and then metered through a positive displacement (PD) meter before being directed to a low-pressure combustion device for destruction. Combusting vent gas significantly reduces greenhouse gas emissions vented to the atmosphere.

In addition to providing a permanent solution as part of a vent gas destruction project, the system can be transported easily, making it well-suited for establishing existing pump vent rates at temporary installations.

Technology Group

Others – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities and well sites; midstream and pipelines; sweet locations and sour locations utilizing sweet instrument gas.

Emissions Reduction and Energy Efficiency

The expected reduction in methane emissions is dependent on system design and operating conditions. However, estimates for a single pump are 45 tCO_2e/year. The vent gas capture system also reduces fuel gas usage by approximately 12scfh.

Economic Analysis

Capital Cost: The capital costs range from $4,500 to $5,500, depending on specific configurations such as the number of pumps, building requirements and site location.

Installation Cost: Installation costs vary depending on specific installation requirements, such as availability of tie-in points, green field vs. retrofit, and piping specifications.

Operating Cost: Operating costs are minimal, and may be nil. Operational adjustments can be completed as part of normal operator rounds. The unit does not require utility power and does not consume any gas.

Maintenance Cost: Maintenance costs are limited, given the unit can be isolated and bypassed

	from the venting system, enabling equipment maintenance without shutting down heater or pumps.
Carbon Offset Credits:	The Tarpon Vent Gas Capture System is eligible for Pneumatics Protocol Offset credits in Alberta.
Payback, Return on Investment and Marginal Abatement Cost:	The payback period and ROI varies based on site and application specifics. However, payback considerations include displaced fuel gas used for heating and credits associated with vent gas destruction.

Reliability

Expected Lifetime:	The Tarpon Vent Gas Capture System is expected to last 15- 20 years.
Maintenance:	No special tools or training are required for maintenance or installation. Yearly inspections are required. Meter readings are on a continuous count register with no reset. Upcoming pneumatics methane regulations will determine the frequency of calibration procedures and meter-reading requirements.

Safety

No unusual safety requirements apply.

Regulatory

- Suitable for use with sweet service instrument gas. The pulsation bottle is a non-code vessel and the gas is not fuel until after the final shutoff valve.
- Non-electrical, so does not require CSA approval.
- Applicable for the AER Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.

Vendor Information

Company Name:	Tarpon Energy Services
Company Website:	www.tarponenergy.com
Product Website:	Not provided
Contact Person:	Blake Wickland / Chris Mathison
Contact Phone#:	(403) 701-7597 / (403) 801-1337
Contact Email:	bwickland@tarponenergy.com / cmathison@tarponenergy.com

13.1.3. Sidewinder Pumps Inc. – Gas Recovery Pumps

July 31, 2017

Description

Chemical injection metering pumps usually run on natural-gas-driven pneumatics that vent methane to the atmosphere. The Sidewinder gas recovery chemical metering pump captures the exhaust gas from the pump and pipes it to an approved disposal or recycling point using a closed-loop system. Greenhouse gas (GHG) emissions are eliminated and 100% of the wasted exhaust gas is recovered and made available for use. When exhaust gas is recycled, fuel gas is also reduced.

The pump uses a timer control and stroke length adjuster to achieve accurate and repeatable flow rates. It operates at pressures up to 10,000 PSI, and flow rates to 275 QPD. Recovery pressure is a function of air/gas supply pressure, and pressure differential between maximum discharge pressure and recovery pressure.

Technology Group

Other – Facilities Design and Equipment

Site Applicability

Upstream oil and gas facilities; midstream and pipelines; sweet and sour service.

Emissions Reduction and Energy Efficiency

The Sidewinder gas recovery chemical metering pump eliminates 100% of the exhaust gas vented to the atmosphere. In the event the exhaust gas is routed to a flare, GHG emissions are significantly reduced. When exhaust gas is recycled, GHG emissions are eliminated and fuel gas consumption is reduced.

Economic Analysis

Capital Cost:	Capital costs range from $1,200 to $3,000 depending on material requirements and chemical compatibility (i.e. 316SS, Titanium, Hastelloy etc.)
Installation Cost:	Installation costs vary depending on site-specifics. However, they are generally very low, consisting mostly of the cost of tubing.
Operating Cost:	Operating costs are in line with those of similar systems. However, they do vary depending on cycle duty requirements.
Maintenance Cost:	Maintenance costs are approximately $500/year, but the exact figures vary depending on the cycle duty of the pump.

Payback, Return on Investment (ROI), and Marginal Abatement Cost:	Payback period and ROI vary depending on the amount of gas captured and if captured gas is flared or used to displace fuel gas.

Reliability

Expected Lifetime:	The equipment is expected to last 20+ years.
Maintenance:	Maintenance required standard knowledge of pneumatic motors and positive displacement (PD) pumps.

Safety

- Hazardous locations requirements apply

Regulatory

- These pumps are currently in use in Canada. Non-electrical device, does not require CSA approval.
- Meets AER Directive 84 Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area

Vendor Information

Company Name:	Sidewinder Pumps Inc.
Company Website:	www.sidewinderpumps.com
Product Website:	Product information is available on the company website.
Contact Person:	Guy Chachere / Paul George
Contact Phone#:	337-235-9838
Contact Email:	info@sidewinderpumps.com

Section 13.2. Others – Recommended Practices

13.2.1. Process Re-Route

July 31, 2017

Description

To allow for economic future growth, facilities are designed to handle flow rates in excess of the need at the time of build. However, if growth fails to occur or production needs change, powered equipment is left underutilized or processing small loads inefficiently. Concentrating production at a single facility, either by re-routing streams or shutting down facilities, achieves efficiencies and reduces overall energy consumption. Emissions from retired equipment are eliminated and fuel gas is not wasted on processing inefficient loads.

For example, a major operator successfully implemented the following two re-routing solutions:

- Redesign of current pipeline inlet riser onsite to eliminate pressure loss using a loop-line that allowed low-pressure gas to flow to a centralized booster compressor, eliminating a field booster compressor at another facility. Before modifications, gas was compressed in the field and sent to an oil plant where it was throttled or expanded. The gas was mixed with the plant solution gas and then compressed. Avoiding this wasteful process saved approximately 1.2 e^3m^3/day just from the booster engine, as well as the vented gas that was likewise conserved.
- Installation of piping and control valves to connect the stabilizer overhead gas to the compressor suction. This allowed gas with a high concentration of light ends to be recycled through the refrigeration plant rather than being flared during the warm weather. Before modification, this rich stream was used as fuel for the plant engine except during warm weather when it caused detonation in the engine. Rather than risking engine damage, the gas was routed to flare instead. Installing piping and proper control valves directed the stream to the compressor suction instead of the engine, avoiding the detonation risk and eliminating flaring emissions.

Technology Group

Others – Recommended Practices

Site Applicability

Oil and gas production facilities operating powered equipment with poor efficiency and low loads.

Emissions Reduction and Energy Efficiency

Re-routing streams or shutting down facilities to concentrate production at a single facility reduces overall energy consumption and improves efficiency. Emissions from retired equipment are eliminated, and fuel gas is not wasted on processing inefficient loads.

Annual GHG Reduction (tCO_2e/yr) = Overall reduction of energy used x Emission Factor of energy x operational days/year

Baseline:
Sour solution gas is routinely flared

Economic Analysis

As with any process re-route project, the economics are:

Annual Savings ($/yr) = Reduction in Operational and Maintenance Costs

Production Efficiency (PE) = Capital cost of the project (installation, materials, design) ($) / Total fuel savings

Capital Cost:	Capital Costs = Installation + Materials + Design
Operating Cost:	Operating costs are estimated to be lower, but they were not measured after the re-route was completed.
Payback Period:	Simple Payout (years) = Capital cost of the project (installation, materials, design) ($) / Total Annual Savings ($)
Marginal Abatement Cost:	GHG Cost Abatement ($/t$CO_2$e) = Annual GHG Reduction (tCO_2e/yr) x Project Life (year) / Capital cost of the project (installation, materials, design) ($)

Reliability

Expected Lifetime	The equipment is expected to last approximately eight years, but this may vary depending on the facility.
Maintenance	Maintenance following a process re-route should remain the same. However, the addition of new equipment may impact maintenance routines and requirements.
Parts and Skills Required	The process re-route does not require special parts or skills beyond regular operation. However, the addition of new equipment may impact maintenance routines and requirements.

Safety

Process re-routing does not introduce any additional safety concerns.

Regulatory

Operators must ensure they comply with all applicable regulations. All equipment must be evaluated by engineering and operations teams to verify that the equipment and process work comply with all relevant industrial specifications and standards.

Service Provider/More Information on This Practice

This recommended practice was contributed by a PTAC member who is a major oil and gas producer. Other oil and gas producers who have questions about implementing this practice may contact PTAC.