SASKATCHEWAN RESEARCH COUNCIL

Final Report

Mitigating Low Volume Methane Emissions
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Prepared for AUPRF

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Energy/Process Development

REPORT

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Abstract: The motivation for this project is the need to reduce the emissions from venting in the oil and gas industry. SRC has provided AUPRF with an updated scan of methane mitigation technologies, in order to determine which two are at a technical readiness level suitable for commercial validation and would be the most likely to succeed in a field trial. For the base case scenario of 900 m^3/d of wet sour gas production from a single well in a geographically isolated area, two technologies were of particular interest: tank covers, and biofilters. SRC recommends that AUPRF continue with Phase 2 of this project and measure the methane mitigation potential of tank covers and biofilters at a commercial demonstration scale.

EXECUTIVE SUMMARY

The Alberta Energy Regulator (AER) has several directives and bulletins that regulate the amount of associated gas that can be flared or vented. One of AER's primary goals is to have the upstream petroleum industry further reduce the volume of solution gas routinely flared, incinerated, and vented. Volumes of gas higher than 900 m^3 per day must be evaluated for conservation. If the economic evaluation of the conservation project has a net present value (NPV) of -$55,000 or better, then the producing company must implement the project. Even with these regulations, which are designed to reduce gas flaring and venting, there are 3.44 Mt CO_2e of associated gas emissions vented directly to atmosphere in Alberta (based on 2011 data) (Alberta Government, 2013).

For Phase 1 of this stage-gated project with AUPRF, SRC has proposed to provide an updated scan of methane mitigation technologies, revisit research on the top two, and determine which is at a technical readiness level suitable for commercial validation and would be the most likely to succeed in a field trial. Phase 1 had a budget $25,000 and required 4 months to complete. If the project proceeds to Phase 2, SRC proposes to partner with an oil and gas producer to build and implement a commercial demonstration of the chosen technology. Once installed, the unit would be monitored over the course of six months to characterize its performance. This phase of the project would require about $200K and would take one year to complete.

There are many technologies, both commercial and demonstration, that can be applied to reduce methane venting in the oil and gas industry. In this report we have classified these technologies by method (prevention, capture, combustion, or conversion of the vented gas), and by type. Each type of mitigation technology has differing flow requirements, costs, technology readiness levels, and other advantages, and disadvantages.

For the base case scenario of 900 m^3/d of wet sour gas production from a single well in a geographically isolated area, two technologies were of particular interest: tank covers, and biofilters. SRC recommends that AUPRF continue with Phase 2 of this project and validate the methane mitigation potential of tank covers and biofilters at a commercial demonstration scale. SRC is developing the Center for Demonstration of Emissions Reduction (C-DER) to facilitate this testing. It is also recommended that the scope of review of best practices in the oil and gas industry for reducing flaring and venting of methane be expanded to other jurisdictions world-wide.

TABLE OF CONTENTS

1. BACKGROUND

1.1 Methane Emissions

The energy industry is the second largest contributor to global non-CO_2 GHG emissions, behind only agriculture (EPA, 2012). In the oil and gas industry, stranded gas venting is the single largest contributor to methane emissions at 10% (ICF International, 2015). Given that methane, the primary component of associated gas, has a greenhouse gas (GHG) equivalence of 25 times that of CO_2, there is the potential for significant reduction. According to data from the *Alberta Environment and Sustainable Resource Development: Report on 2011 Greenhouse Gas Emissions*, venting and flaring accounted for 2.8% or 3.44 Mt CO_2e of the province's GHG emissions (Alberta Government, 2013). At $30/tonne CO_2e this represents a cost of approximately $103.3M per year.

The Alberta Energy Regulator (AER) has several directives and bulletins that regulate the amount of associated gas that can be flared or vented. One of AER's primary goals is to have the upstream petroleum industry further reduce the volume of solution gas routinely flared, incinerated, and vented. Volumes of gas higher than 900 m^3 per day must be evaluated for conservation. If the economic evaluation of the conservation project has a net present value (NPV) of -$55,000 or better, then the producing company must implement the project. Even with these regulations, which are designed to reduce gas flaring and venting, there are 3.44 Mt CO_2e of associated gas emissions vented directly to atmosphere in Alberta (based on 2011 data) (Alberta Government, 2013).

An oil well that produces 900 m^3 per day of vented associated gas assumed to be primarily methane would emit 235 tonnes of methane annually. At a CO_2 equivalence of 25:1, this would produce the same greenhouse effects as 5,880 tonne/year of CO_2. At $30/tonne, the existing tax in BC and projected 2018 tax in Alberta, the cost of this 900 m^3/d vent would be $176k/year. The federal government has announced that it will impose a carbon tax of $10/tonne starting in 2018, which will grow by $10/year to $50/tonne by 2022. A project that could eliminate the 900 m^3/d of methane gas emission for less than $1,250,000 ($176K at 10% return over 10 years) stands a very good chance of being economical to implement.

Despite the optimistic economics and the social pressure to implement mitigation technologies, there are several barriers that inhibit gas utilization (Svensson, 2013):

- Distance to market: transportation of captured or converted gas can be prohibitively expensive if there is no local demand.

- Lack of local infrastructure: this applies to transportation infrastructure such as roads, rails, and pipelines, but also power and personnel.
- Small/variable gas volumes: associated gas production is generally largest when the well is first produced and can decline rapidly. Some wells produce significant volumes of gas, but inconsistently.
- Lack of capital: small and medium enterprises may have difficulty raising capital for a conservation project, even with a positive economic forecast.

1.2 Project Background

Based on SRC's earlier preliminary research, two technologies stand out as the most likely to mitigate the GHG emissions of low volumes of associated gas. The first was a methanotrophic biofilter (MBF) developed at the University of Calgary. The MBF uses methanotrophic bacteria to convert low-volume methane emissions into carbon dioxide and water. The second technology of interest was electronic flare ignition, which uses a solar-powered sparking igniter to burn the methane when the stream is rich enough. Both of these technologies reduce the environmental impact of vented gas by converting methane to CO_2 and water for a relatively low capital cost.

For Phase 1 of this stage-gated project with AUPRF, SRC has proposed to provide an updated scan of methane mitigation technologies, revisit research on the top two, and determine which is at a technical readiness level suitable for commercial validation and would be the most likely to succeed in a field trial. Phase 1 had a budget $25,000 and required 4 months to complete. If the project proceeds to Phase 2, SRC proposes to partner with an oil and gas producer to build and implement a commercial demonstration of the chosen technology. Once installed, the unit would be monitored over the course of six months to characterize its performance. This phase of the project would require about $200K and would take one year to complete.

1.3 About the Saskatchewan Research Council (SRC)

Saskatchewan Research Council's Energy Division provides Smart Science Solutions™ to clients in the areas of applied RD&D, scale-up, demonstration and commercialization of energy technologies. The Energy Division is well positioned to participate in all forms of energy production, conversion and conservation leading towards the goal of significant economic and positive environmental impacts for Saskatchewan.

Our team of experts is multidisciplinary, encompassing a broad range of science and engineering. It is through integration of these diverse areas of expertise that we have become one of the best resources for sustainable energy solutions. We achieve this through research, development, and the transfer of innovative scientific and technological solutions, applications and services.

The Energy Division is comprised of three areas:

The **Enhanced Oil Recovery Field Development Group** applies scaled physical modelling, numerical simulation and petrophysical testing in a continuous feedback process with field operations to advance the understanding of enhanced oil recovery processes and accelerate the rate of technology deployment and widespread commercial application.

The **Enhanced Oil Recovery Processes Team** performs applied RD&D on innovative enhanced oil recovery technologies and laboratory engineering design for the petroleum industry's EOR field projects. R&D aims at minimizing clients' input costs, increasing reserves and recovery factors, and extending pool production life. Laboratory studies such as phase behaviour analysis, minimum miscibility pressure determination, corefloods and scaled physical modelling are complemented by numerical simulation.

The **Process Development Group** provides applied RD&D, scale-up and demonstration of value-added processing technologies for commercial application achieving impacts in Saskatchewan industries. This includes niche areas such as Saskatchewan oil sands, oil shales, coal liquefaction/gasification, biomass to biofuel and bioproduct processing.

2. METHODOLOGY

The deliverable for this project is a short report that details a technology scan, with some commentary on commerciality, and capital and operating costs of the identified technology. The investigative focus was to be on novel or "outside-the-box" technologies.

Information for the technology scan was obtained from published literature, patents, and publically available data from the respective companies. Figure 1 is a brief flowchart of the steps to produce this report.

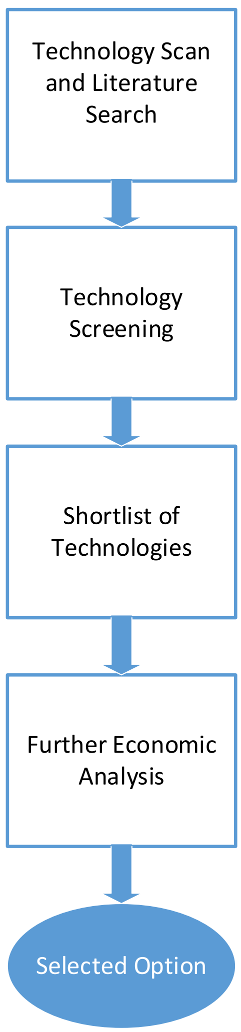

Fig. 1: Project Methodology

3. Results and Discussion

The methane mitigation technologies identified through the course of the literature search were classified into one of four basic goals:

- prevent methane emissions,
- capture the vented methane
- combust it,
- or convert it to another product.

Each category is discussed in more detail in the following sections.

3.1 Prevention

Technologies which can prevent associated gas from being released in the first place will theoretically yield a 100% reduction in greenhouse gas emissions for the producer. Prevention technologies are only useful if the captured gas is not eventually vented or flared from another location (i.e. used as a fuel gas stream and displaces other fuel or injected into a sales gas pipeline).

3.1.1 Leak Detection and Repair (LDAR)

Leak detection and repair (LDAR) is a technique rather than a specific technology. It is used to locate and eliminate fugitive emissions. The U.S. has instituted 25 federal regulations requiring operators to implement LDAR, and the EPA has released a best practice guide to increase the effectiveness of LDAR programs (2007). LDAR consists of 5 steps:

1. Identifying components,
2. Leak definition,
3. Monitoring components,
4. Repairing components,
5. Recordkeeping.

In general, it has been found that increasing inspection frequency decreases GHG emissions (ICF International, 2015) (EPA, 2007).

According to the EPA best practice guide (2007), valves, connectors, and open pipes/sampling points account for 90%+ of uncontrolled VOC emissions at a typical petroleum or chemical facility. Leaks caused by gasket failures, improperly tightened connectors, or open pipes can be detected and repaired. "Leakless" valves and "sealless" pumps can replace their traditional counterparts to reduce or eliminate emissions, where the material selection and design allows (EPA, 2007).

Further information about LDAR can be found in EPA LDAR guide (2007) and ICF International's methane emission reduction report (2015).

Status: Commercial

Companies: There are many companies offering this service, which can include monitoring, measuring and/or database recordkeeping. Examples include Target Emissions Services, Grid Environment, Calvin Consulting Group, Clearstone Engineering, Inspectionlogic (leakDAS), Camcode, TeamFurmanite, Apogee Scientific, etc...

Flow range: Applies to fugitive emissions

Cost: EPA estimates a capital cost of \$1,000-\$10,000 USD to replace leaking valves (EPA PRO Fact Sheet #601); ICF's 2015 report estimates \$258,000 USD capital, \$292,000 USD operating, for a 60% reduction in GHG emissions, or \$0.31/m^3 (\$8.87/mscf) (ICF International, 2015)

3.1.2 Pneumatics Replacement

In situations where instrumentation was required, such as a treater or chemical addition pump, and natural gas was available, pneumatic instruments were often installed. These older pneumatic instruments are often so-called "high bleed" and vent a significant amount of pressurized gas during normal operation. The EPA Natural Gas STAR program recommends replacing high bleed pneumatics with low bleed ones, instrument air, or with electric alternatives (EPA, 2006a). The use of electric instruments requires the well pad to be electrified, which is not always cost-effective. If there is no grid connection to site it may be possible to utilize solar.

Status: Commercial

Companies: Existing instrumentation companies

Flow range: A "high-bleed" device releases $\geq 4\ m^3/d$ (144 scfd) (EPA, 2006a).

Cost: Replace gas-driven pump $1,000-$10,000 USD; entire facility >$50,000 USD (EPA, 2006a); $4,500 USD capital, $0 USD operating, 97% GHG reduction, $0.32/m^3 ($9.07/mcf) (ICF International, 2015)

3.2 Capture

Technologies which can capture vented gas will also theoretically yield a 100% reduction in greenhouse gas emissions for the producer. Like prevention, capture technologies are only useful if the captured gas is not eventually vented or flared from another location.

3.2.1 Vapour Recovery Units (VRU)

Vapour recovery units were first conceived of in 1952 by the founder of HY-BON (HY-BON, 2016a). A VRU captures vented gas and compress it to be sold or used onsite. Instead of venting to atmosphere, a line connects the tank headspace to a scrubber which will condense and return any liquids to the tank. After the compressor, the dry high pressure natural gas is directed to a sales gas pipeline, or other use. The EPA estimates between 7,000 and 9,000 VRU's are currently installed on oil tanks or tank batteries in the US (EPA, 2006b).

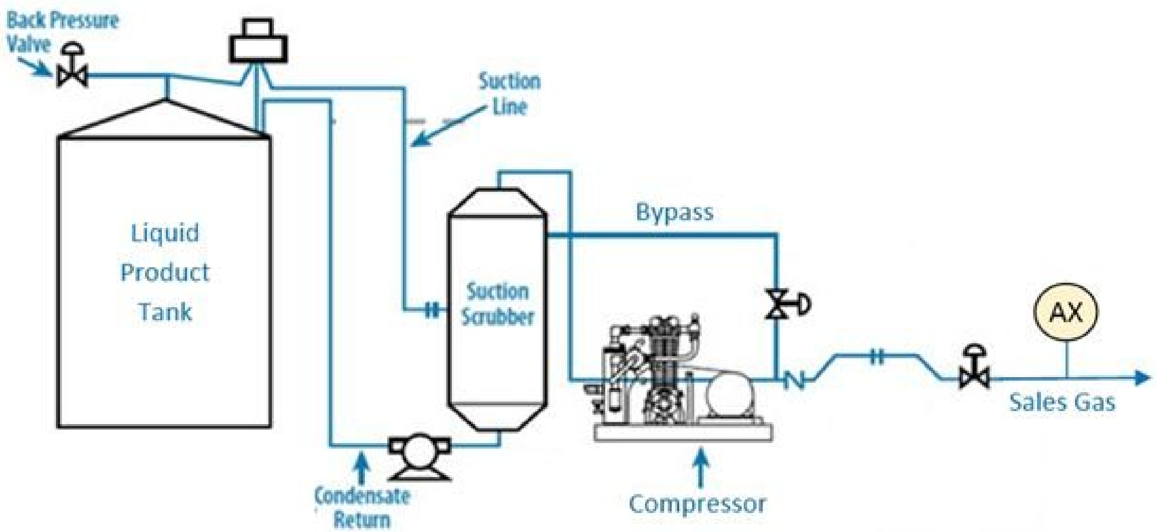

Fig. 2 Vapor Recovery Unit (Apgar, 2015)

VRU's have proven to be effective and commercially viable for tanks with a gas flowrate of 140-3,100 m^3/d (5-110 mscfd). However, like all capture technologies, they require a local use for the gas or access to a pipeline. This technology is not usually useful for single tank or stranded applications. More information on VRU advantages and challenges can be found in Sentio Engineering's CHOPS report (2015) and EPA's lessons learned report (2006b).

Status: Commercial

Companies: HyBon/EDI, Unimac, Corken, Enerflex, Aereon, etc…

Flow range: 140 – 3,100 m^3/d (5-110 mscfd) HY-BON NK Series (HY-BON, 2016b)

Cost: $20-$60K USD capital, an additional $10-$60K USD for installation, ~ $7-$17K USD operating; generally >$50K USD (EPA, 2006b); $76,000 USD capital, $13,750 USD operating, 95% GHG reduction, $0.10/$m^3$ ($2.83/mscf) (ICF International, 2015)

3.2.2 Gas to Gas (GTG)

Similar to a VRU, gas to gas (GTG) refers to compressing natural gas for re-injection to pipelines. Compressing associated gas is only practical if the operator has pipeline access or a local use for the gas. Many small scale compressors have been designed for the natural gas vehicle industry, and may find applicability at remote oil wells (Ingersol-Rand, 2016; Bauer Compressors, 2016a,b; Aereon, 2016; Emerson, 2016; PC Compression, 2016) . There may be additional requirements, however, such as a dryer or gas conditioner, prior to sending associated gas to a natural gas compressor. On-site electricity may also be required. These compressors are operable at much lower flow rates, but may not be economically viable.

A scroll type compressor operates by positive displacement of the fluid between a fixed and an orbiting scroll. They have a higher volumetric efficiency, making them more compact, and lower vibration levels than traditional piston compressors. They can also be constructed with tubing, similar to peristaltic pumps, which provides greater protection from hazardous materials. They are typically used for air conditioning or refrigeration in residential and commercial buildings. The Copeland scroll compressor for oil and gas can handle a maximum of 24 ppm by volume H_2S in the inlet gas, though they have been working toward a 2% sour gas model (Emerson, 2016).

In a 2015 report, Sentio Engineering mentions a company called Can-Gas that has developed a system to transport dried compressed gas in a trailer. The gas is picked up periodically and delivered to a sales gas pipeline. The storage trailers have a stated capacity around 4,000 m^3 (150 mscf) (Sentio Engineering, 2015). This company has been acquired by Certarus (HHP Insight, 2016).

Status: Commercial

Companies: Ingersoll Rand, Bauer, Aereon (offers rental of Wildcat compressor), Emerson (Scroll compressor), PC Compression (Quincy QRNG compressor)

Flow range: Minimum volumes: Ingersoll Rand – 1,140 to 4,720 m^3/d (40.3 to 167 mscfd) (Ingersoll-Rand, 2016); Bauer C-120 – up to 367 m^3/d (13 mscfd) (Bauer Compressors, 2016a); Bauer C-15 – up to 900 m^3/d (32 mscfd) (Bauer Compressors, 2016b); Aereon – 500 m^3/d (18 mscfd) (Aereon, 2016); Scroll – 280 to 16,900 m^3/d (10 to 600 mscfd) (Emerson, 2016); Quincy 325NG – 900 m^3/d (32 mscfd) (PC Compression, 2016)

Cost: $10,000 - $50,000 USD capital (EPA, 2011a); $110K-$140K USD capital (Sentio Engineering, 2015)

3.2.3 Liquefied Natural Gas (LNG)

Liquefied natural gas (LNG) occupies 1/600th the volume of gaseous methane, which makes it much more economical to transport. The difficulty lies in maintaining the required temperature of -160°C. Shell is working with Kogas, Mitsubishi and Petro China on the LNG Canada project to bring LNG from their oil wells to a newly built port in BC and finally to eastern markets. The Shell Pearl GTL project was designed for 140,000 bpd and had a capital cost upward of $20 billion USD (Wood, 2008; LNG Canada, 2016). This installation and those like it are large scale and not of interest in the current study.

There has been significant recent research into mini and micro-LNG (Wood, 2008; The World Bank, 2004). GE has 17 small-scale “plug and play” modular LNG trains in production. However, their lowest flowrate appears to be 60,000 m^3/d, producing ~94,600 L/d (25,000 gpd) of liquid (GE Oil & Gas, 2014). LNG Global produces a mini-LNG plant with a capacity of 15,000 L/d (4,000 gpd), which corresponds to a rate of consumption of 9,000 m^3/d (LNG Global, 2016). Dresser-Rand produces the LN*Go* system for small-scale applications in the range of 30,000 L/d (7,000 gpd) liquid production (Dresser-Rand, 2016).The system includes a molecular sieve dehydrator to remove liquid. There doesn’t appear to be an H_2S removal unit in the standard process. Theses volumes are still outside the range of interest.

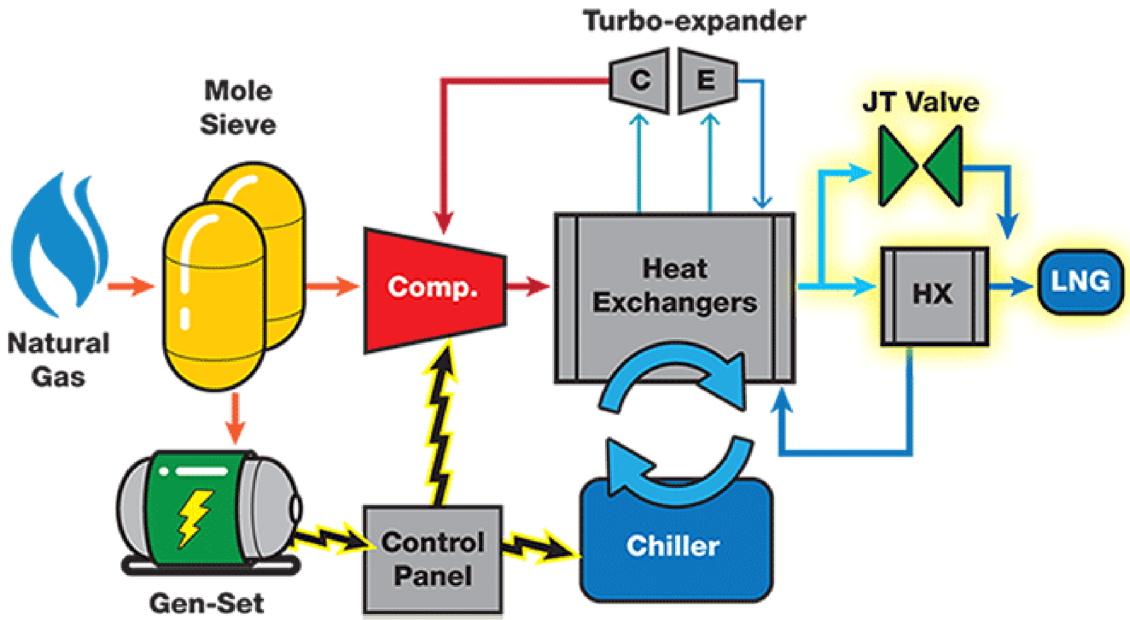

Fig. 3 LNG Flow Diagram (Dresser-Rand, 2016)

Status: Commercial

Companies: Shell, Chevron = large scale. GE, LNG Global = small scale

Flow range: 15,000-94,600 L/d **(**4,000-25,000 gpd) LNG = 9,000-60,000 m^3/d gas (320-2,120 msfcd) (LNG Global, 2016)

Cost: 4.76 billion USD to $20 billion USD; $683,000 USD capital, $109,000 USD operating (ETI Energy Corporation, 2015a)

3.2.4 Gas to Solids (GTS)

Natural gas hydrates (NGH), also called clathrates, occur when methane molecules become trapped in a lattice "cage" of crystalline water molecules. Methane gas hydrates occur naturally on the ocean floor and can often cause agglomeration and plugging in pipelines. Significant prior research has focused on how to prevent methane hydrate formation, but recently there has been an increase in research attempting to create NGH (Kanda, 2006; Nakai, 2012; Rehder et al, 2012).

Trapping methane in a solid form can substantially reduce the volumes and cost of transportation, as NGH occupies 1/170 of the gas volume. Due to the "self-preservation effect" NGH are relatively stable at -20°C and atmospheric pressure despite the unfavourable thermodynamics of these conditions to hydrate formation. This effect is enhanced but not entirely caused by ice shielding, and is not completely understood. NGH shipping is also predicted to be safer than LNG, as the risk of leaks or fires are reduced (Kanda, 2006; Nakai, 2012; Rehder et al, 2012).

Mitsui Engineering & Shipping (MES) is currently developing production, storage, and transportation systems for NGH. Methane hydrates are generated in a continuously stirred tank reactor, then dewatered, pelletized, and cooled and de-pressured for storage; see Figure 4. MES predicts CAPEX 25% lower than LNG. Mitsubishi has a 2003 patent for a methane hydrate formation process, but no more recent information on any projects (Yoshikawa et al., 2003).

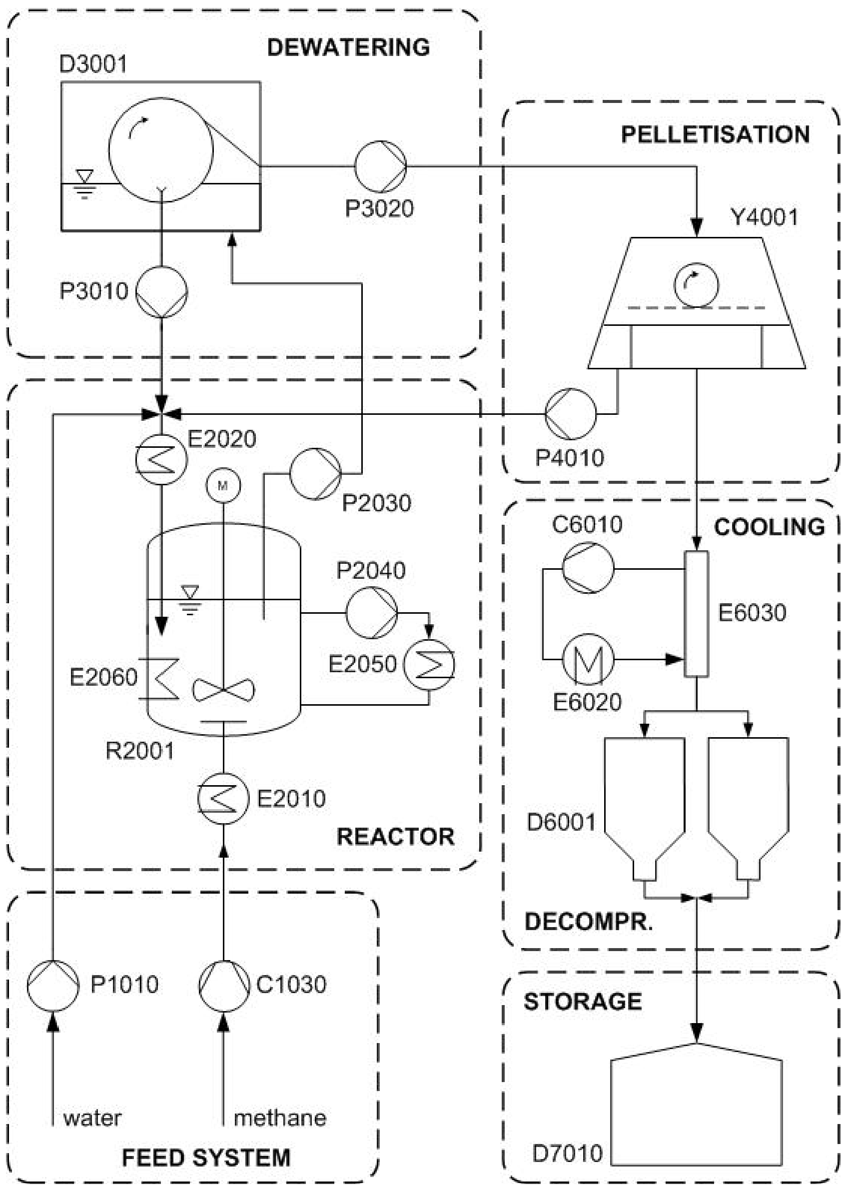

Figure 4: MGH conceptual flow diagram (Rehder et al, 2012)

Status: Demonstration

Companies: Mitsui Engineering & Shipbuilding (MES), Mitsubishi

Flow range: Demonstration operates at 935 m^3/d (5 tonne/d) of methane gas hydrate; economic flow range is unknown (Rehder et al, 2012)

Cost: MES estimates the final cost will be approximately 75% of LNG (Rehder et al, 2012)

3.2.5 Gas Storage Bladder

Gas can be stored onsite in an uncompressed form in an expanding bag or bladder. This would require a local use for the gas, as transporting uncompressed gas by truck is impractical. However, it could provide an inexpensive option to buffer the input to another capture or conversion process.

Status: Commercial

Companies: Interstate Products Inc, Stak Properties, Albers Alligator, Sattler Corp

Flow range: < 900 m^3/d (0.5 - 100 m^3 per bladder) (Stak Properties, 2016; Interstate Products, Inc., 2016)

Cost: \$100-\$1,000 USD capital (Stak Properties, 2016; Interstate Products, Inc., 2016)

3.2.6 Tank Covers

Venting can occur from storage tanks as new oil is added and the gas headspace is reduced and when liquids expand during daytime temperature changes. A CO_2 or gas tank blanket, or Hexa-Covers ®, can provide a floating cover and reduce emissions. Hexa-Covers are plastic hexagonal tiles that float on the surface of the oil. They are relatively inexpensive and can be installed through a tank hatch. In field trials they reduced C6+ emissions by 93%. They also help insulate the tank, reducing the amount of energy required for heating (Greatario, 2016a). According to a report for PTAC by Sentio Engineering (2015), tank venting accounts for 5% of methane emissions in a typical heavy oil installation.

Status: Commercial

Companies: Greatario Covers (Hexa-Cover)

Flow range: Low

Cost: $4,600 USD capital plus $800 USD installation (Greatario, 2016b)

3.3 Combustion

Burning methane reduces its global warming potential by converting it to CO_2.

3.3.1 Flares

Flares are commonly used in the oil and gas industry to deal with stranded associated gas. They combust natural gas and volatiles to form CO_2, which has a 25 times lower global warming potential than methane. Flares have the added benefit of destroying volatile organic compounds (VOC) and other hazardous air pollutants. If the heating value of the vented gas is below 11,100 kJ/m^3 (300 Btu/scf) additional fuel will be required to maintain combustion (EPA, 2011b). Flares that rely on a pilot gas stream to light can be blown out by the wind.

The World Bank Group has the goal of reducing flaring and venting of methane to zero by 2030. There are economic and environmental arguments for reduced flaring: Methane flaring is a waste of a potentially valuable fuel, as well as a major greenhouse gas contributor (The World Bank, 2004).

Status: Commercial

Companies: Aereon, Clearstone, Zeeco, Questor, Flare Gas Industries, etc…

Flow range: Minimum 48 m^3/d (1.68 mscfd) (EPA, 2011b)

Cost: Capital costs are estimated to be $21,000 USD (EPA, 2011b); $94,050 USD capital, $9,000 USD operating, 98% GHG reduction, $0.11/$m^3$ ($3.17/mscf) (ICF International, 2015)

3.3.2 Electronic Ignition Flares

Electronic ignition flares have the same benefits as a regular flare, with the addition of spark ignition to eliminate pilot gas requirements. This ensures gas is not sent to an unlit flare, which may have gone out due to wind or previous flow interruptions. Electronic ignition requires electricity; solar power is possible if the well pad is not electrified.

Status: Commercial

Companies: Zeeco, Aereon, Tornado, etc.

Flow range: Minimum 48 m^3/d (1.68 mscfd) (EPA, 2011b)

Cost: Estimated cost to convert an existing flare to electronic ignition is ~$5,000 USD (EPA, 2011c)

3.3.3 Methanotrophs/Biofilters (MBF)

Rather than a flame, it's possible to use methane consuming bacteria to convert CH_4 to CO_2 (and biomass) (Hanson and Hanson, 1996). This is sometimes done in a biofilter reactor in the agricultural industry. HY-BON offers a filter that attaches to the outlet flange of a tank and can destroy 80-90% of vented VOC's (HY-BON, 2016c). The University of Calgary has begun testing on a similar, but more economical version. The methanotrophic biofilter (MBF) routes the vented gas through a box of manure and soil impregnated with methanotrophic bacteria. The box can be buried underground to provide insulation in the winter months (U of C, 2014).

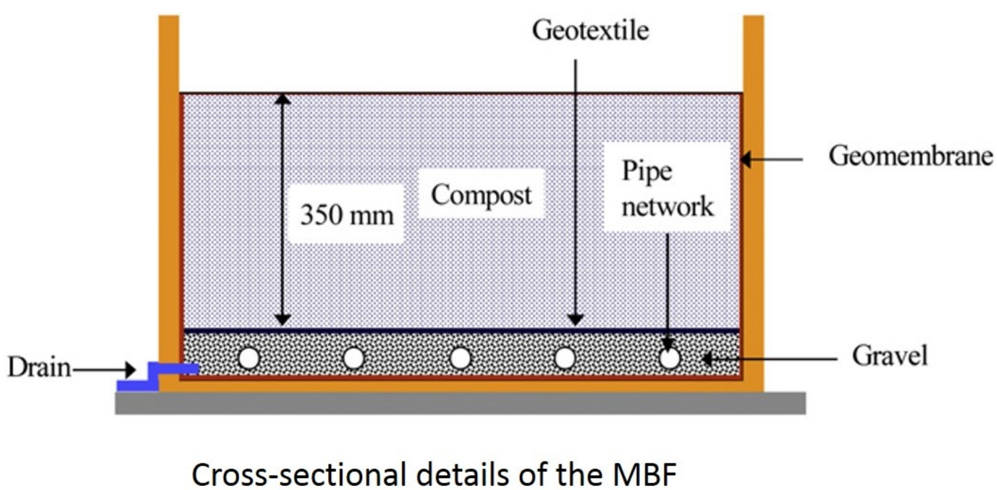

Figure 5: Methanotrophic Biofilter (MBF) (U of C, 2014)

Status: Demonstration, commercial in other industries/applications

Companies: University of Calgary, HY-BON

Flow range: 0-140 m^3/d **(**0-5 mscfd) (HY-BON, 2016c)

Cost: The manufacturer did not reply to a request of cost information by the time of printing. An approximate cost of $15,000 USD is assumed.

3.3.4 Thermal Oxidation (RTO, CTO)

Regenerative thermal oxidizers (RTO) are used in coal mines to oxidize fugitive methane. They operate at high temperature (>800°C) and are highly efficient in converting low concentration methane flows to CO_2 and heat. (EnivroTherm International, 2013) EnviroTherm International produces an RTO suitable for treating gas flows of 141,200 m^3/d (5,000 mscfd) with an energy content of <186 kJ/m^3 (<5 BTU/scf). Catalytic thermal oxidizers (CTO) are also available. They use a metal catalyst to operate at a much lower temperature (Wikipedia, 2016).

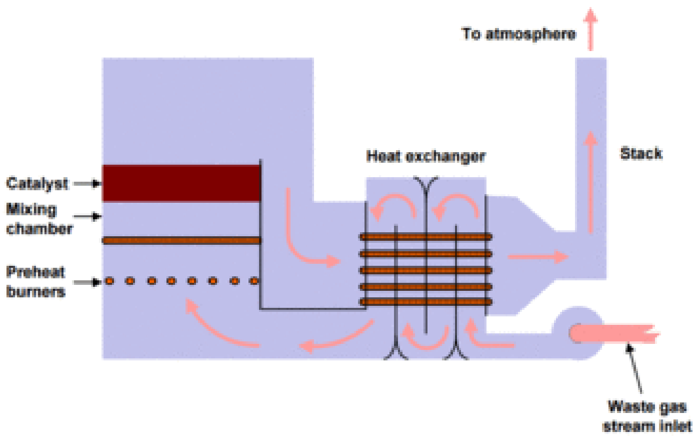

Figure 6: Catalytic oxidizer (Wikipedia, 2016)

Status: Commercial

Companies: EnviroTherm Inc , Zeeco, Combustion Control Solutions and Environmental Services Inc

Flow range: 141,200 m^3/d (5,000 mscfd) (EnviroTherm International, 2013)

Cost: EPA estimates $53,000 - $190,000 USD per m^3/s capital, $11,000 - $160,000 operating (EPA, 2016b); $106,000-$150,000 USD capital, $10,600 USD to $15,000 USD (10%) operating (ETI Energy Corporation, 2015b)

3.4 Conversion

Excess methane can be converted to a variety of liquid products, or to useful heat or work, depending on the volume, infrastructure, and nearby users. GHG emissions will depend on the conversion technology and the final use of the converted product.

3.4.1 Gas to Liquids (GTL)

Natural gas can be converted directly to products such as methanol or DME, or indirectly to liquid products through syngas (a mixture of hydrogen and carbon monoxide). In the indirect route, methane is first reformed to syngas via auto-thermal reforming or steam-methane reforming, and then converted to synthetic crude, diesel, or gasoline via the Fischer-Tropsch (FT) process. FT liquids can be blended with crude oil and returned to the tank/pipeline (The World Bank, 2015).

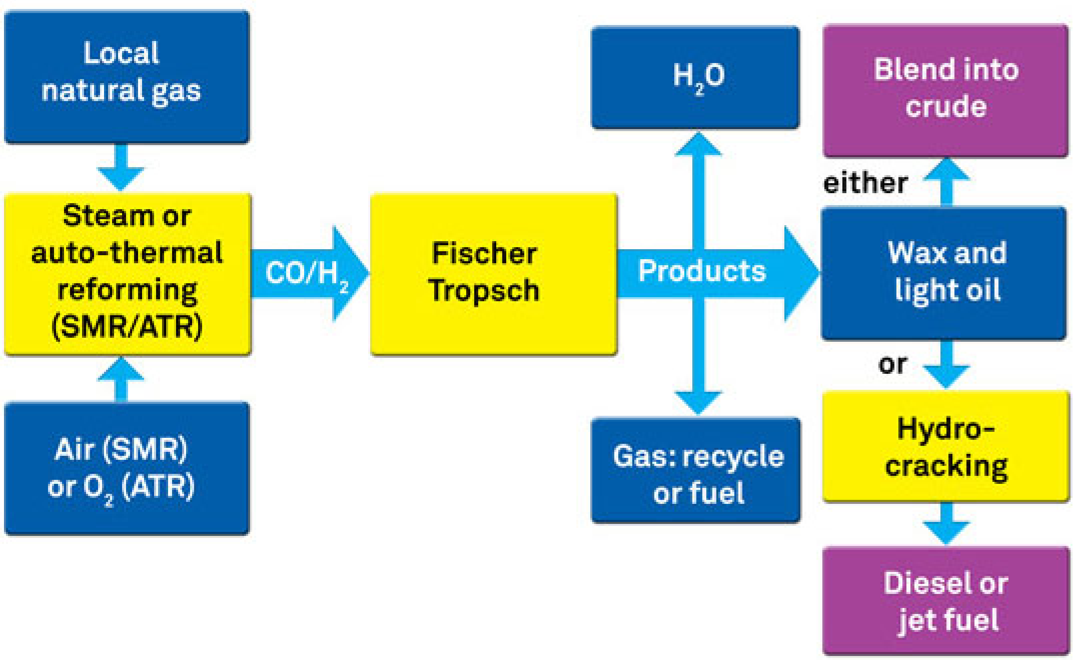

Figure 7: Conversion of Natural Gas to Liquids via Fischer Tropsch (Velocys, 2016a)

Velocys provides 424,000 m^3/d (15 mmscfd) commercial FT reactors. They are participating in the Envia joint venture to build a small-scale GTL demonstration plant in Oklahoma. The 795,000 L/d (5,000 bpd) plant will convert landfill gas and pipeline gas into liquid fuels. Velocys is in the process of building another demonstration plant at 31,800-47,700 L/d (200-300 bpd) (Velocys, 2016b; The World Bank, 2015). This plant size is suited for gas flares of about 56,500 m^3/d (2 mmscfd) (The World Bank, 2015), which is still higher than our flow rate of interest.

Greyrock offers a "Flare-to-Fuels" product line and are in the process of building a demonstration plant. Their M-class model can convert 14,100 m^3/d (500 mscfd) (minimum) of pipeline quality natural gas to 50 bpd of liquid fuel. Greyrock's direct fuel production (DFP) technology converts methane to syngas, then to liquid fuel (diesel) using a proprietary "Greycat" catalyst. (The World Bank, 2015; Greyrock, 2016)

Borderland Energy has entered an arrangement with ME Resource Corporation (MEC), a Canadian exploration company which has developed and patented a mini-GTL. MEC's mini-GTL technology is based on catalytic partial oxidation and FT technology. MEC had previously announced a 1 bpd field test with Carson Petroleum on one of their Alberta based test wells for 2016 (The World Bank, 2015). However, their website was last updated in 2014, and they seem to have become inactive (Boderland Energy, 2016).

CompactGTL offers a small scale gas to liquids reactor of 3,180 L/d (20 bpd). Their demonstration plant was operated by Petrobras in Brazil for three years (The World Bank, 2015). They settled a patent-infringement case with Velocys in 2015, and have not updated their website since (CompactGTL, 2015).

Status: Commercial, demonstration

Companies: Greyrock, Envia/Velocys, MEC/Borderland, CompactGTL

Flow range: Greyrock = 14,100 m^3/d (500 mcsfd); Envia/Velocys = 56,500 m^3/d (2 mmscfd); CompactGTL = 1,420,000 m^3/d (50 mmcfd) (The World Bank, 2015; Wood, 2008)

Cost: Greyrock = $4-6 MM USD capital; CompactGTL $300 MM USD capital (Wood, 2008)

3.4.2 Gas to Chemicals/Catalytic Oxidation (GTC)

Methanol, formaldehyde, dimethyl ether, and ammonia are possible products of the catalytic oxidation of methane. Most of these processes require a pure methane stream as input, so some form of gas conditioning will be required (The World Bank, 2015).

Oberon Fuels has a commercially available unit which turns 35,000 m^3/d (1.24 mmscfd) of natural gas into dimethyl ether (DME) via syngas and methanol. Their process can also work to convert biogas to bio-DME, which they have demonstrated in California, USA. The DME is used as a diesel alternative in commercial trucking (Oberon Fuels, 2016; The World Bank, 2015).

Proton Ventures is a Dutch company that provides small-scale ammonia plants which can run off of flare gas. The technology in use is the well-known Haber Bosch process used in fertilizer plants around the world. Their NFUEL1 unit consumes 2,328 m^3/d of gas to produce 2,880 kg/d (1000 t/y) of ammonia (Proton Ventures, 2016; The World Bank, 2015).

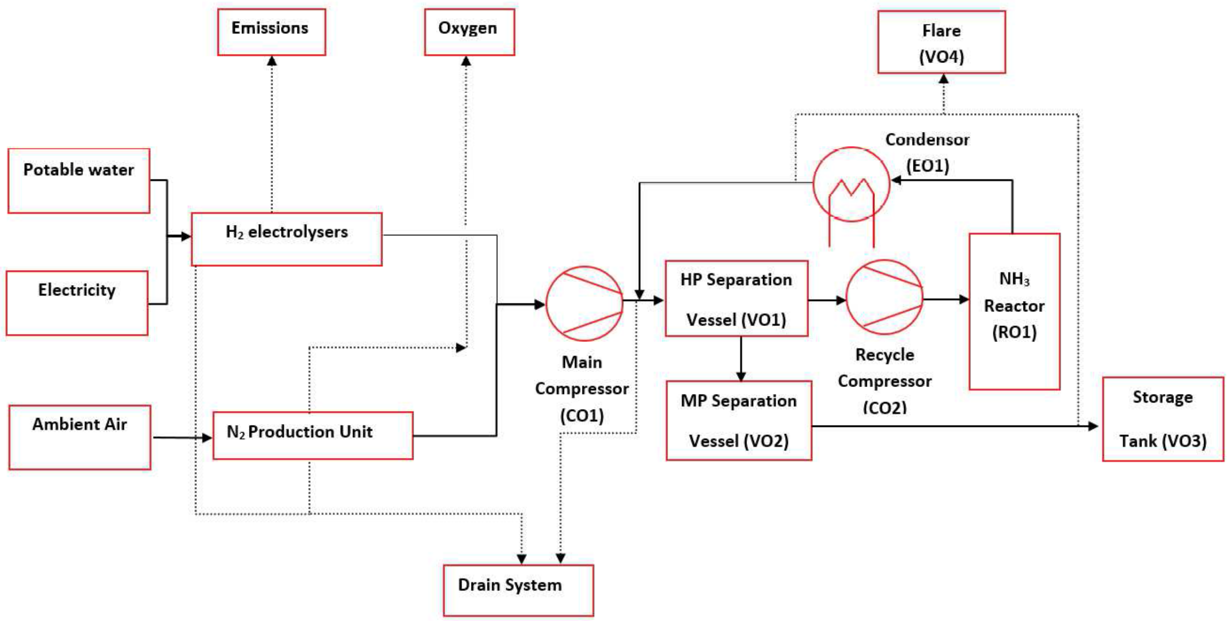

Fig. 8: Proton Ventures GTL Process (Proton Venture, 2016)

Siluria Technologies uses oxidative coupling of methane (OCM) to convert methane into ethylene. A proprietary catalyst is used to perform reaction 1 at moderate conditions.

Reaction (1) $2CH_4 + O_2 \rightarrow C_2H_4 + 2H_2O$ (Siluria, 2016a)

They have a 0.97 tonne/d (1 ton/d) demonstration plant in Texas, USA, which has been in operation since 2015. Siluria predicts its small-scale commercial unit will produce on the order of 228,800 tonnes/year (250,000 tons/y) of ethylene (The World Bank, 2015; Siluria, 2016b), which will require a larger amount of methane than the situation of interest for this report.

Status: Commercial/demonstration

Companies: Oberon Fuels, Proton Ventures

Flow range: 35,000 m^3/d (1.24 mmscfd) (Oberon Fuels, 2016); 2,328 m^3/d (82 mscfd) (Proton Ventures, 2016)

Cost: Approximately \$100,000 USD/bpd capacity, i.e. \$1MM USD for a 28,250 m3/d (1 mmscfd) plant (The World Bank, 2015)

3.4.3 Gas to Wire (GTW)

Natural gas can be used to produce power and heat. High voltage DC lines are the most feasible option for moving large quantities of electric power without significant line losses. However, installing the required infrastructure (transmission lines, converter stations) can be very costly (Wood, 2008). Better by far if there is a local use for the electricity and waste heat such as heating the oil in the treater or storage tank, or replacing pneumatic instruments with electric ones, for example.

REM Technologies/Spartan Controls produces the Slipstream™ GTS which can manage casing or vent gases, or both. The auxiliary burner is added to the progressive cavity pump engine, along with a sophisticated control system (Spartan Controls, 2016). According to Sentio Engineering's report (2015) the auxiliary burner is sized for 500 m^3/d (20 mscfd). Encana, with funding from the CCEMC, implemented 17 units in 2012 and estimated a GHG reduction of 20,378 tonnes CO_2e and 52 MMscf/y in fuel gas savings (REM Technology Inc., 2014). This particular technology is not compatible with sour streams higher than 1% H_2S.

Alphabet Energy has a similar technology, a flare/combustor which also generates power. The power generating combustor model 2.5 generates 2.5 kW of power at a gas flowrate of 330 to 1,000 m^3/d (Alphabet Energy, 2016). Black Gold Rush Industries also sells a waste gas to power solution based on the Stirling engine. It can provide 1 kW of continuous 24VDC power (Blac Gold Rush Industries, 2016).

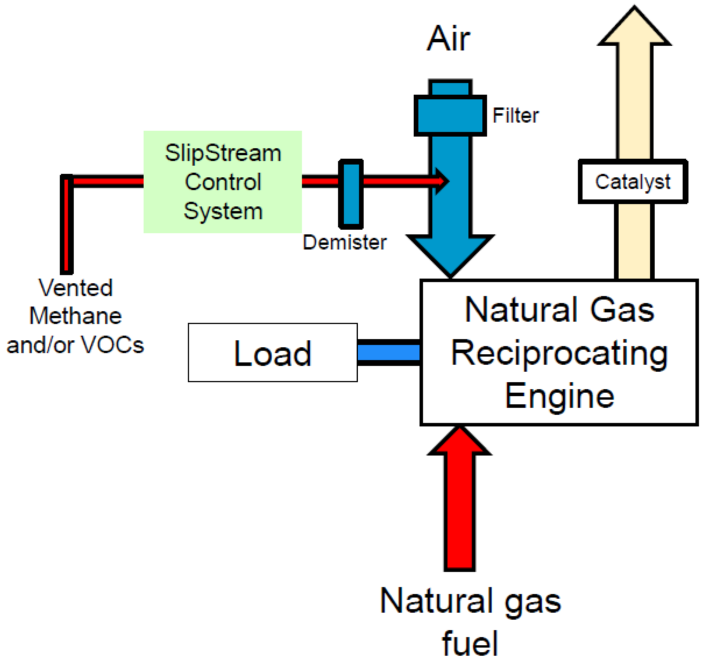

Fig. 9: Slipstream SA Technology (REM Technology Inc., 2014)

Newco Tank Corp has developed and patented Thermal Optimized Production (T.O.P.) Tank, which uses casing/vented gas to heat the heavy oil in the production tank. The engine and hydraulics are built in to the bottom of the tank, allowing the waste heat from the engine to be recovered in heating the oil. The downhole progressive cavity pump engine operates the same as before, only its location has changed. The company claims it can reduce greenhouse gas emissions by 90% vs. a conventional heated production tank. The need for a firetube heater is eliminated. However, excess casing/vent gas above what is used to run the engine will still be vented (Sentio Engineering, 2015; T.O.P. Tank, 2016).

Status: Commercial

Companies: Alphabet Energy, REM Technology/Spartan Controls (Slipstream engine), Top Tank (heat)

Flow range: 330-1,000 m3/d (11.7-38.4 mscfd) for Alphabet Energy's PGC-2.5(Alphabet Energy, 2016); 500 m3/d (20 mscfd) for the SlipStream (Sentio Engineering, 2015); 784 m^3/d (27.8 mscfd) for the TOP Tank (Sentio Engineering, 2015)

Cost: \$478,500 capital USD, \$44,000 operating USD (ETI Energy, 2015a); T.O.P. Tank \$158,175 USD (\$210,900 CAD) capital (T.O.P. Tank, 2014)

3.4.4 Other Technologies

The Go Technologies M-160 skid is a gas conditioning system. It contains a dryer and instrumentation so that wet casing gas can be sent to a compressor or other technology. The company also produces a high volume blower compressor that can be used to increase the pressure on a casing or vent gas stream before feeding it to another technology (Go Technologies, 2016).

It could be that some combination of existing technologies will provide a good solution. For example, an M-160 gas conditioner to pretreat input gas before a VRU. Or a Scroll compressor, with a built-in zeolite dryer, could send dry, compressed gas to a storage bladder for shipping off-site. A gas bladder could be used as a surge tank before feeding to a flare. Which of these combined solutions is ideal will vary depending on the site-specific conditions.

3.5 Screening Criteria

As previously mentioned, there are several barriers to implementation that methane mitigation technologies face. These include:

- Distance to market
- Lack of local infrastructure
- Small/variable gas volumes
- Lack of capital

The mitigation technologies can therefore be screened on their ability to overcome these barriers, as well as some technical considerations. The screening criteria used in this report are:

Cost: A rigorous cost analysis would include capital, installation, and operating costs. For the purposes of this screening capital costs only will be used, with a more complex cash flow analysis performed on the shortlisted technologies.

Flow rate: because vented gas had a variable flowrate, the mitigation options will be sorted by the minimum flowrate required.

Greenhouse gas reduction: capturing vented gases has a GHG reduction of 100%, while burning it converts one kg of 25 CO_2e methane to 2.75 kg of CO_2 for an 89% GHG reduction.

Distance to end use: some technologies require a local use for the gas or product, while others are more easily transported.

Technology readiness level (TRL): is the technology commercially available (TRL = 10), proven at scale (TRL = 7), or in the lab scale phase (TRL = 4)?

Ability to treat impurities: most associated gas includes impurities, including the possibility of H_2S. Some technological options can treat impurities while others will required gas conditioning, at an added expense.

Table 1: Summary of methane mitigation technologies and their capabilities

Technology	Capital Cost (USD)	Minimum flowrate (m^3/d)	Maximum GHG reduction	TRL	Distance to end user	Impu -rities
LDAR	\$1K-\$10K	—	100%	10	Close	Good
VRU	\$30K - \$120K	140-3,100	100%	10	Close	Poor
Pneumatics replacement	\$1K-\$10K	4	50-100%	10	Close	Good
GTG	\$10K- \$50K	367-1,140	100%	10	Close	Poor
LNG	\$683K	9,000	100%	10	Moderate	Good
GTS	~\$512K	Unknown	Unknown	4	Moderate	Poor
Gas bladder	\$100-\$1K	0.5-100	100%	10	Close	Good
Tank covers	\$4.6K	<900	5%	10	N/A	Good
Flare	\$21K- \$94.5K	48	89%	10	N/A	Good
Electronic ignition flare	Additional \$5K	48	89%	10	N/A	Good
MBF	\$15K	0-140	89%	4	N/A	Mod erate
RTO, CTO	\$53MM- \$190MM	141,200	89%	10	N/A	Mod erate
GTL	\$4MM- \$6MM	1,000	100%	10	Moderate	Mod erate
GTC	\$1MM	2,300	100%	8	Moderate	Mod erate
GTW	\$158K- \$479K	500-3,100	89%	10	N/A	Mod erate

3.6 Technology Shortlist

As can be seen from Table 1, there are many commercially available technologies for treating large volumes of clean gas, particularly those that are close to existing infrastructure or end users. However, heavy oil production in Alberta is generally done in single well facilities where electricity may or may not be available. These wells produce into a heated tank which is periodically emptied by truck. A sales gas pipeline is not necessarily nearby, and the produced gas will be wet and may contain H_2S. Any technology selected must also be simple and robust. As such, the base case scenario for technology screening is: 900 m^3/d (32 mscfd) of stranded, wet, sour, vented gas.

Table 2: Application of screening criteria to methane mitigation technologies

Technology	Capital Cost (USD)	Flowrate <900 m3/d	GHG reduction	TRL Commercial	Applicable to stranded gas	Able to handle impurities
LDAR	$1K-$10K		100%			
VRU	$30K-$120K		100%			
Pneumatics replacement	$1K-$50K		50-100%			
GTG	$10K-$50K		100%			
LNG	$683K		100%			
GTS	$3.75B		100%			
Gas bladder	$100-$1K		100%			
Tank covers	$4.6K		5%			
Flare	$21K-$94.5K		89%			
Electronic ignition flare	$26K-$100K		89%			
MBF	$15K		89%+			
RTO, CTO	$53MM-$190MM		89%			
GTL	$4MM - $6MM		100%			
GTC	$1MM		100%			
GTW	$158K-$479K		89%			

After applying the screening criteria to the mitigation options, several technologies stand out: Tank covers, electronic ignition flares, regular flares, biofilters (MBF), and gas to wire (GTW).

Tank covers are the lowest capital cost option, and are already commercially available. They are also relatively simple to implement, without additional operator knowledge. Their wide range of projected GHG reduction is problematic – if they mitigate only 5% of emissions, they may only be worth implementing on very low emission tanks. Further emissions testing in a real-world facility may help quantify their effectiveness.

Flaring is a well-established technology which would not benefit from additional research of this type. Electronic ignition on flares is still relatively new, and is one of the lower cost options identified. A real-world demonstration could prove useful to oil producers who are considering implementing this option.

Biofilters are already commercially available for use in the agricultural industry, but have not been widely applied to oil and gas. The methanotrophic biofilter is only at the demonstration stage; it would benefit greatly from further study.

Gas to wire, or gas to heat in the case of TOP Tank, is a promising area. Most well sites could become local users of the produced electricity to power the pump or heat tracing, or heat to maintain temperature in the tank. Larger scale engines are already commercially available, but the application to very low, variable flowrates is still in question.

3.7 Additional Analysis

After examination of the screening criteria four technologies have been shortlisted:

1. Tank cover
2. Electronic ignition flare
3. Biofilter
4. Gas to wire

This shortlist will be reduced to the top two technologies recommended for testing in Phase 2 of this project by performing a basic cash flow analysis. In the chemical process industries the depreciating time period, s has a value of 10 years. In this analysis the “sum-of-the-year’s-digits” method of calculating depreciation is used, which yields the following:

$$\sum_{s} = s_0 + (s_0 - 1) + (s_0 - 2) + \cdots = \frac{s_0(s_0 + 1)}{2} = \frac{10(10 + 1)}{2} = 55$$

Fractional depreciation per year is given by:

$$\frac{s_j}{\sum_s} = \frac{s_0 + 1 - n_j}{\sum_s}$$

Where n_j is the year, s_j is the remaining life, and s_o is the depreciation period (Ulrich, 1984).

Unless explicitly stated by the manufacturer or in literature, installation costs are calculated using a Guthrie factor taken from Ulrich (1984): flare = 4, filter = 2.2, engine = 2.0. The installation factors are lower than the 4.8 Lang factor usually assigned to an oil refinery; however most of the equipment in question is modular and designed for ease of installation. Unless otherwise indicated in an earlier section of this report, operating costs are assumed to be 10% of capital.

The cash flow analyses for each of the four technologies in question are included in Appendix A. The assumptions applied to perform this analysis are given in Table 3 and a summary of the results is provided in Table 4 and Figure 10.

Table 3: Assumptions for Cash Flow Analysis

Economic Inputs		
Depreciation period	10	
Inflation rate	3.2%	
Exchange rate	0.75	USD = 1 CAD
Cost of natural gas	0	USD/mmBTU
Cost of GHG	22.5	USD/tonne
Tax rate	30	%

Table 4: Results of Cash Flow Analysis on Shortlisted Technologies

Technology	NPV (CAD)
Tank Cover	-$ 7,157
Electronic Ignition Flare - new installation	-$ 427,588
Electronic Ignition Flare - retrofit	-$ 58,781
Methanotrophic Biofilter	-$ 43,632
Gas to Wire - engine	-$ 1,688,802
Gas to Wire - TOP tank	-$ 335,695

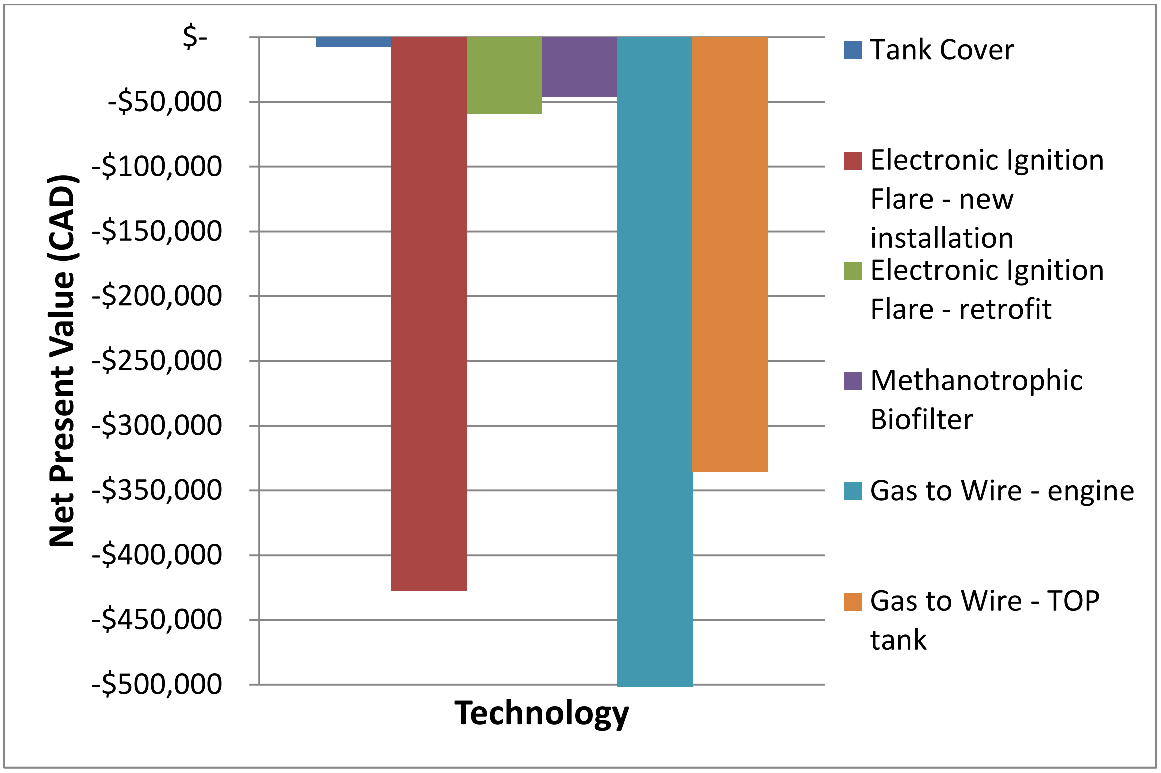

Figure 10: Results of Cash Flow Analysis on Shortlisted Technologies

The calculated net present value (NPV) for each technology was negative; i.e. no mitigation technology will earn back enough to compensate for the capital expenditure at a carbon tax rate of $30/tonne. However, two technologies had a NPV above -$55,000, which is the threshold for implementation mandated by Alberta's Directive 60. Of the technologies investigated, tank covers such as Greetario's Hexa-Covers and the newly developed methanotrophic biofilter are recommended for further study.

From this analysis it seems that capital cost has the largest influence on whether a technology would be economically feasible. Figure 11 places each of the investigated methane mitigation technologies on a capital cost vs. flow range chart. The 900 m^3/d flowrate is indicated by the vertical red line.

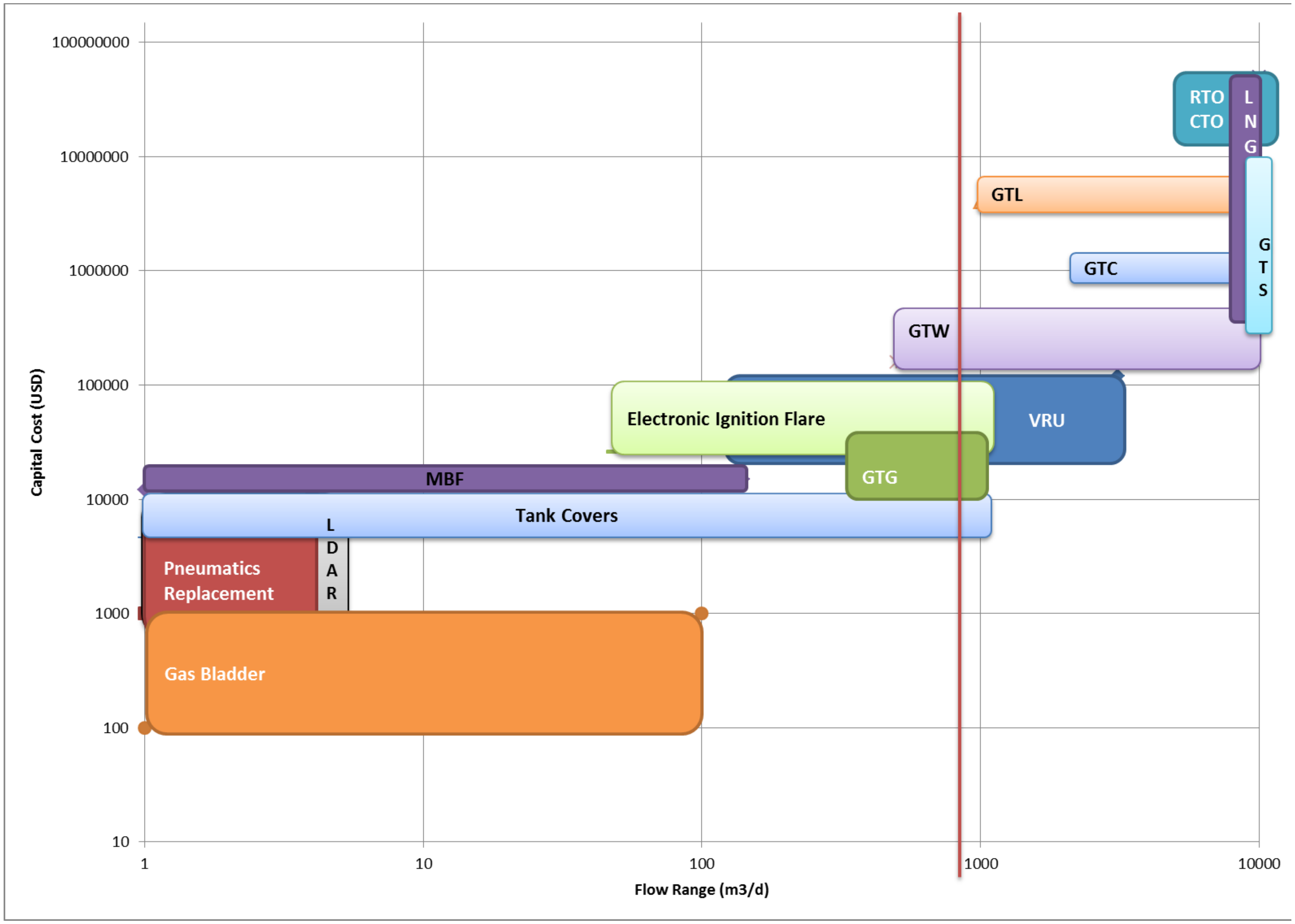

Figure 11: Methane Mitigation Technology Options

4. Conclusions and Recommendations

4.1 Conclusions

There are many technologies, both commercial and demonstration, that can be applied to reduce methane venting in the oil and gas industry. In this report we have classified these technologies by method (prevention, capture, combustion, or conversion of the vented gas), and by type. Each type of mitigation technology has differing flow requirements, capital costs, advantages, and disadvantages.

For the base case scenario of 900 m^3/d of wet sour gas production from a single well in a geographically isolated area, two technologies were of particular interest: tank covers, and biofilters. The rest of the technologies investigated had significantly higher capital costs, and as such undesirable cash flows under current carbon tax levels.

Tank covers, such as Hexa-Covers, may prevent venting from production tanks. Tank venting is estimated to be only 5% of total venting from an oil well, so the GHG mitigation potential is limited. However, they are very low cost (capital and operating), such that even with a 5% GHG mitigation they have a NPV of above -$55,000. More research is recommended to quantify the amount of GHG reduction that can be expected in a real-world demonstration. A systemic technology validation from a neutral third party can provide trustworthy data on performance under different conditions.

The methanotrophic biofilter (MBF) has the potential to reduce GHG emissions by 89%, through the conversion of methane into the lower global-warming-potential CO_2. MBF are in the demonstration phase, which makes economic estimates prone to uncertainty. However, they have the potential to be above the -$55,000 NPV investment cut-off mandated by the government of Alberta. This technology needs to be proven at demonstration scale to move to the next technology readiness level. It too would benefit from a systemic technology validation.

The Centre for Demonstration of Emissions Reduction (C-DER) is a facility where technology providers will have the opportunity to test their technology in a real-world situation and measure its effectiveness. Development of new technologies to address methane emissions is incapacitated by the lack of field test facilities. Innovators require access to representative “real world” sites, but companies are reluctant to allow unproven technologies on active production sites due to safety, environmental and financial risks. C-DER allows SRC to perform stage-gated technology validation tests in these “real world” situations.

4.2 Recommendations

Given the information compiled in this report, SRC recommends:

1. Continue with Phase 2 of this project and validate the methane mitigation potential of tank covers and biofilters at a commercial demonstration scale. SRC is developing the Center for Demonstration of Emissions Reduction (C-DER) to facilitate this testing.
2. Review best practices in the oil and gas industry for reducing flaring and venting of methane, in other jurisdictions and world-wide.

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