Cost Effective Wellsite Monitoring

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EXECUTIVE SUMMARY

Petroleum Technology Alliance Canada (PTAC) has engaged InnoTech to provide a summary of cost-effective wellsite monitoring methods and to identify where gaps still exist. The main focus of this report is on monitoring and measurement of leaks from wells. A separate report called 'Identify GHG Level for Well Repair to Identify Acceptable Leak Rate' has also been provided for this project.

Devices to detect and measure low leak rates from wells are evolving as it is recognized that quantifying all emissions will be required to understand and meet Canadian emission reduction targets. Canadian oil and gas producers are required by the federal Ministry of Environment and Climate Change to implement methane leak detection and repair (LDAR) programs 1-3 times annually across a range of assets commencing in 2020.

It is also anticipated that regulators will require reporting of surface casing vent flow (SCFV) and gas migration (GM) on thermal wells in the near future. Steam in SCVF and in GM on thermal wells has made the measurement of SCVF/GM emissions on these wells particularly difficult in all-weather conditions. Monitoring legacy wells that have been abandoned, cut and capped (or closed) is becoming more important as roughly 10% of these wells are believed to be leaking.

Several low rate and accurate measurement devices have been developed in recent years for SCVF. Testing over an extended period of time is critical as SCVF leak rates can be highly variable due to a wide variety of factors.

The quantification of GM leak rates is much more difficult than SCVF as a gas leakage though the ground is not contained in a pipe or vessel where a traditional measurement device can be attached. New technology is developing for this purpose and for remote leak detection using on-ground methods, aircraft and satellites. Some of these technology companies have developed algorithms and methods to provide an estimate of the emissions rates of methane and CO_2 with remote sensing equipment.

This report provides an overview of many tools and methods that are available and the technologies that are emerging for monitoring and measuring emissions from well sites.

After a leak has been detected from a well and the leak rate possibly quantified, the sources of the leak, either the geological formations or a soil biogenic source, still must be identified. Identifying the source or sources can be very difficult and misleading. There are advanced methods of forensics and fingerprinting to help identify the source of the leaks. This is a major subject area that is not addressed in depth in this report.

The Alberta Energy Regulator (AER) has targeted reductions in methane emissions with updated requirements in Directive 060 *Upstream Petroleum Industry Flaring, Incinerating, and Venting* which went into effect on January 1, 2020, and with updates in Directive *017 Measurement Requirements for Oil and Gas Operations* which was released in December 2018. Some definition changes were made for Petrinex reporting and revisions to both Directives were made in May 2020. Certain aspects of these requirements are discussed in this report.

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1.0 INTRODUCTION

Approximately 460,000 wells have been drilled in Alberta since the 1880s. Technology, best practices, and rules related to well integrity have changed immensely over the last 130 years. Alberta currently has roughly 40,000 wells that are leaking to surface and about seven percent of the new wells drilled in Alberta leak from the time they are drilled.

The issue of leaking wells is a world-wide concern and methane from leaking wells is understood to be a source of greenhouse gas emissions (GHGs). Many jurisdictions have public policy to address and reduce GHGs. In 2017, the Alberta Energy regulator (AER) estimated that Alberta wells were leaking at a combined rate of 86 million m^3 per year. This estimate is widely believed to be unrealistically low as industry reporting is not monitored or enforced.

Canadian targets for emissions reduction are stringent. Under the Paris agreement, Canada committed to reducing GHGs by 30% from 2005 levels by the year 2030. The federal government also announced an objective to achieve a net zero emissions future by 2050.

In recent years the Canadian oil and gas industry has experienced crippling economic conditions while there is an urgent need to address a massive inventory of inactive wells and well sites that require closure. Industry would like reliable and cost-effective means of determining if a well is leaking before closure activity commences. Industry also wants to know to what extent a well is leaking before starting remediation work. Most Alberta wells with surface casing vent flow (SCVF) and/or gas migration (GM) leak at very low rates which are difficult to quantify.

Methods of detecting SCVF and GM with 'boots on the ground' procedures have been utilized for decades. A ten-minute bubble test is still used for reporting low rate SCVF according to AER rules. Measurement of SCVF leak rates have also been done with positive displacement (PD) meters for many years. However, many low rate SCVF wells are leaking gas at rates below the turn down limit of PD meters. Other more accurate methods of measuring low leak rates have been developed.

There is a growing need to accurately identify low leak rates on wells. Adopting new technology and improved practices is important to meet the challenges with intermittent SCVF/GM flow and seasonal conditions. Advanced methods of measuring SCVF on thermal wells, which can contain methane and steam, need to be applied broadly. Improved identification and quantification of emissions will help set priorities for wellbore remedial action and will verify the effects of emission reduction initiatives.

Several leak detection systems have been developed which also capture appropriate fluid samples used to help determine the source or sources of leaks from or near a well.

After wells have been decommissioned and closed, or abandoned in legacy terminology, the licensee/permit holder retains responsibility for the abandoned well and wellsite. It is critical to have low cost and efficient means of monitoring closed wells for leaks on surface reclaimed sites.

The AER emission reduction rules in Directive 60 and Directive 017 have targeted the highest sources of fugitive emissions and venting from compressors, pneumatic devices, and glycol dehydrators. The requirements also focus on improved measurement, monitoring, and reporting of methane emissions. The AER Fugitive Emissions Management Program (FEMP) outlines these requirements but companies may apply to use an alternate fugitive emissions management program (Alt-FEMP). Alberta service providers are generally well informed and compliant with current regulations.

2.0 DETECTION OF A WELL LEAK

2.1 LEGACY TECHNOLOGY AND ALBERTA RULES

Hand-held lower explosive limit (LEL) detectors are used by oil and gas field personnel as the most common method of identifying the presence of combustible gas and for personal safety. These devices are used to detect wellhead gas leaks, SCVF, GM and other potential sources of leaks at production facilities.

Gas leaks from abandoned wells which are cut and capped below ground are typically identified visually with vegetation impacts above the well. During the growing season, this may present as a circle of distressed vegetation surrounded by a halo of more lush or green growth relative to the background vegetation.

Bubbling in standing water is also a common method of identify a gas leak from a subsurface source.

Trained dogs have been deployed to detect pipeline leaks, but canines are generally not used for wellsite leak detection. There are reports that some animals such as cattle are attracted to methane leaks.

Landfills have often been monitored for fugitive methane with hand-held flame ionization detectors and these systems can also be used for detecting wellsite leaks.

The Alberta rules related to monitoring for wellbore leaks are:

- AER Interim Directive (ID) 2003-01: *1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements*
- AER Directive 020 *Well Abandonment*
- AER Directive 079 *Surface Development in Proximity to Abandoned Wells*
- AER Directive 083 *Hydraulic Fracturing – Subsurface Integrity*

ID 2003-01 states that within 90 days of a drilling rig release, licensees must test new wells for a vent flow. After reporting a nonserious SCVF, the licensee must perform a SCVF test on the well on an annual basis for the next five years. If there is no change in the flow and build-up pressure after five years of testing, or if the vent flow dies out, no further testing is required. This Interim Directive may be replaced with a Directive in the near future.

Within 90 days of a drilling rig release, licensees must test new wells for GM problems in Townships 45-52, Ranges 1-9, West of the 4th Meridian, and Townships 53-62, Ranges 4-17, West of the 4th Meridian.

AER Directive 020 *Well Abandonment* states that it is advisable to perform GM and SCVF tests prior to beginning downhole abandonment operations and the source of the leak must be identified and repaired prior to surface abandonment. Before conducting a surface abandonment, the licensee must conduct a SCVF test to determine if gas, liquid, or any combination of substances is escaping from the casing vent assembly. A bubble test must be conducted with a hose 2.5 cm below the water surface for a minimum of 10 minutes. The AER recognizes that there are other methods of testing for a SCVF and will accept the use of other more advanced technologies. Details are described in Appendix 3 of Directive 020.

If any bubbles are present during the 10-minute test, the well is deemed to have a vent flow and a SCVF rate test must be conducted. This test should be continued until a stabilized rate is obtained. The licensee must use either a positive displacement gas meter or an orifice well tester to measure vented gas volumes. The surface casing vent must be shut in until a stabilized pressure is obtained. The pressure is considered stabilized if the change in pressure is less than 2 kPa/hour over a six-hour period.

A ten-minute bubble test for SCVF is very unreliable for detecting and measuring low leak rates due to its short duration. A very simple method of determining the presence of such a leak is by taping a latex, nitrile or soft rubber glove to the surface casing vent piping for up to 24 hours and observe if the glove inflates or goes on vacuum.

GM testing must be conducted on cased-hole well abandonments where the well does not have a surface casing vent assembly and on all wells that are located in the following areas:

- Townships 45–52, Ranges 1–9, W4M, and
- Townships 53–62, Ranges 4–17, W4M.

Gas Migration testing has typically involved taking gas detection readings using hand-held devices in a pattern around a wellhead. Companies that specialize in this work may take readings on the surface and below ground level with high tech devices that detect methane. More advanced methods, such as using flux chambers as a sealed 'tent' over the leak, are under development.

When GM is identified above ground it is sometime referred to as a non-intrusive method and methods below ground are sometimes called intrusive because ground disturbance occurs.

Ground disturbance may require a permit for locating buried lines before augering a hole in the ground or by making a hole using other means.

There are a number of factors which can impact the results of GM testing. Some of these are soil type, previous hydrocarbon and chemical spills, moisture content, the depth to the water table and climate conditions. Bacterial activity and air in the soil can also affect the ability to collect a representative and uncontaminated sample when GM testing.

Traditional methods of GM testing can provide highly variable results as indicated in Figure 1 which was an evaluation of GM measurement approaches to detect fugitive gas migration around energy wells and which was presented at the May 13-17, 2019 GeoConvention in Calgary.

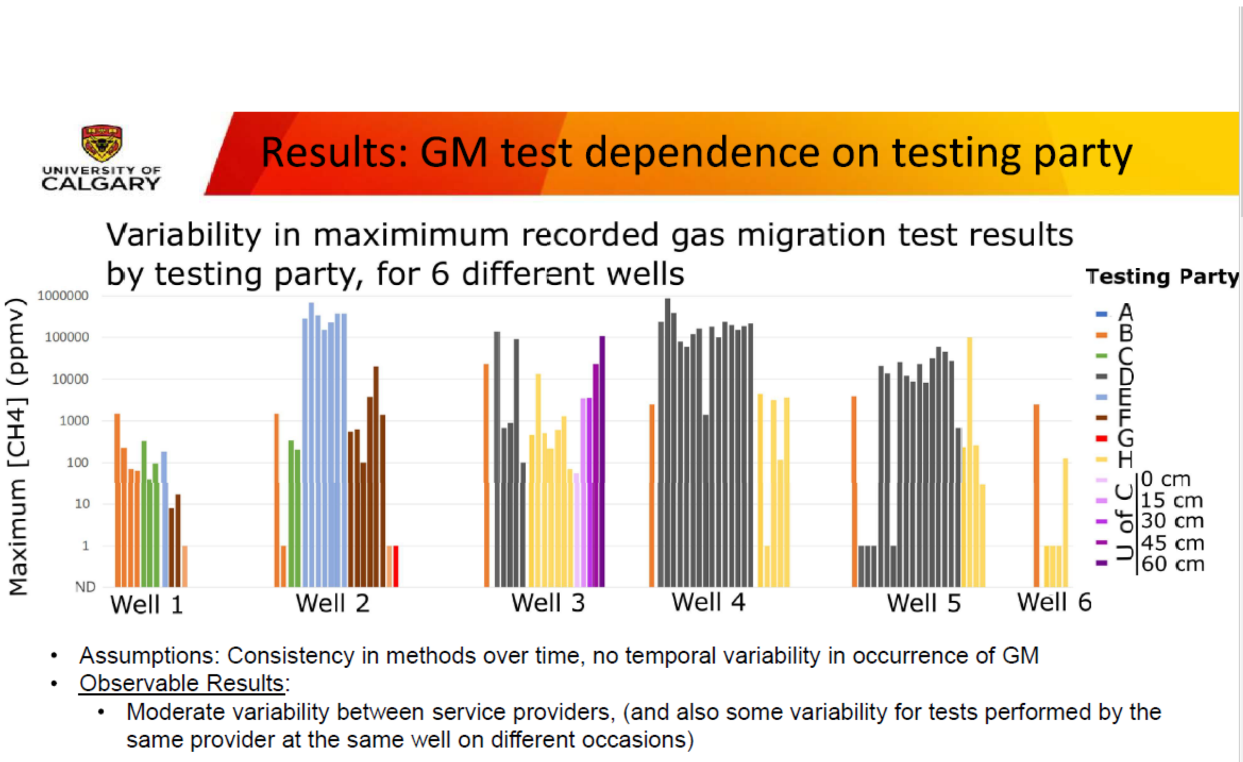

Figure 1: Geoconvention poster: Fleming, N., Morais, T., Kennedy, C., Ryan, C. 2019

AER Directive 079 *Surface Development in Proximity to Abandoned Wells* specifies requirements for establishing background methane levels by measuring a minimum of three test points within +/- 2 ppm of each other at a minimum of 10 m from an abandoned well. After background levels are established, a gas detection survey is required using one of the following methods:

1. In-soil gas detection—includes auguring holes in the soil and measuring methane concentrations as described in AER Directive 020.
2. Soil surface gas detection—includes measuring methane concentrations at the air-soil interface.

Directive 079 also states that gas detection testing must be conducted by trained and competent personnel. Appropriate safety procedures, standard operating procedures, and quality assurance and quality control measures must be documented and available for verification by a third party.

Sample data must be collected using an electronic datalogger capable of sampling at time intervals of one second with automatic date and time stamp. GPS data referenced to NAD83 should be collected to provide additional geospatial data and to supplement sample point location identification for audit purposes.

Directive 079 also specifies the acceptable methane detection instruments that may be used and the required specifications for the equipment.

Directive 083 stipulates the requirements for SCVF testing when conducting fracturing operations. For a single barrier system this testing is required before fracturing and between 60 and 90 days after completing fracturing operations. It is a good practice to follow the same procedure when fracturing with a dual barrier system.

In July 2020, the AER released a new edition of Directive 60, outlining revised requirements for flaring, incinerating and venting in Alberta at all upstream petroleum industry wells and facilities. These requirements have been developed in consultation with the Clean Air Strategic Alliance. In May 2020, the AER released a new edition of Directive 17 outlining new measurement requirements for oil and gas operations. AER Manual 15 may be used to estimate methane emissions.

2.2 ADVANCED TECHNOLOGIES

Optical Gas Imaging (OGI) is a generic term used for portable infrared (IR), or thermal imaging, camera systems that are used to detect methane emissions.

There are two general categories for optical leak detection, passive and active. Active methods require illuminating the scanned area using a radiation source while passive methods do not require a source and rely only on background radiation or the radiation emitted by the gas.

Some optical methods are listed below:

- LIDAR - LIght Detection And Ranging
- Diode laser absorption
- Tunable Diode Laser Absorption Spectroscopy (TDLAS)
- Millimeter wave radar systems
- Backscatter imaging
- Broad band absorption
- Optical fiber.

LIDAR is a remote sensing method for measuring distances by illuminating the target with pulsed laser light and measuring the reflection with a sensor. Differences in laser return times and wavelengths can then be used to make digital 3-D representations of the target. It has terrestrial, airborne, and mobile applications.

TDLAS is similar to LIDAR but uses less expensive diode lasers. TDLAS is used to measure the concentration of methane, water vapor and other species in a gaseous mixture. The advantage of TDLAS over other techniques for concentration measurement is its ability to achieve very low detection limits of the order of parts per billion (ppb). It is also possible to estimate the temperature, pressure, velocity and mass flux of the gas under observation. TDLAS is the most common laser-based absorption technique for quantitative assessments of species in gas phase.

Diode laser absorption is suitable for close-range hand-held detectors and for high-altitude aerial detection.

Infra-red spectrum (IR) cameras are a type of thermographic camera or a thermal imaging camera. Forward-looking infrared camera (FLIR) is a technology in which a thermography camera is configured for methane leak detection. A photo current responsivity profile is generated in response to an irradiance at the active surface. The peak response is within the wavelength range 10.4 to 10.8 µm (micron or micrometer or 10^{-6} m).

Airborne thermal-infrared (TIR) imaging spectrometry techniques have been used to detect and track methane and other gaseous emissions from a variety of discrete sources in diverse environmental settings, and to enable estimation of the strength of each plume. Specific molecules can be identified by their characteristic absorption spectrum because each molecule absorbs infrared radiation at its characteristic frequencies.

TIR airborne measurements offer a means for refining the accuracy of methane emission estimates and provide snapshots of sub-pixel detail to assist in the calibration and validation of satellite deployed technologies to detect methane.

The high spatial resolution (1–2 m) of TIR help identify a leak source, while the moderate spectral resolution provides identification and quantification of the gaseous plume constituents. Fourier transform infrared spectroscopy (FTIR) is a spectrometer which measures all the IR wavelengths simultaneously and produces a full spectrum used for simultaneous identification of multiple mixed gasses.

A commonly used leak monitoring system on wells is the Sensit Portable Methane Detector (PMD) from Sensit Technologies. It is utilized above ground by organizations that specialize in SCVF / GM detection and is often deployed for GM. The device is also used by environmental companies, by pipeline leak detection firms and other industrial organizations.

The Sensit PMD uses infrared (IR) Absorption Spectroscopy with an electronic narrow band pass filter and can be deployed by walking on site or from a vehicle. It detects methane from 1 ppm to 100% volume and has optional GPS and data logging capability. Methane concentration levels can be displayed in PPM, percent LEL and/or percent volume. Bluetooth data transmission communicates real time and stored data to other devices.

Instrumentation for methane detection and quantification deployed on the ground with utility terrain vehicles has made it possible to locate and measure methane emissions from remote sites. Researchers have used hand-held devices like Eagle II methane detectors to check sites for leaks. The lower detection limit of these hand-held units is five parts per million (ppm) above background.

The University of Calgary (UofC) has developed a truck mounted leak detection system called PoMELO (Portable Methane Leak Mounted Observatory). According to Tom Barchyn of UofC, detection involves laser spectrometers, wind measurement instruments and GPS technology, while analysis is provided through computer techniques such as machine learning. Tom has indicated that the equipment mounts on the roof rack of a truck and costs about half as much as a hand-held optical gas imaging camera.

In recent years significant advancements have been made in collecting data via drones, manned aircraft and satellites equipped with systems designed to detect emissions, specifically methane and carbon dioxide emissions.

Best practices are emerging as producers address the recent AER emission reduction rules in Directive 60 and Directive 017 for surface facilities and Directive 079 for abandoned wells inside of urban areas. Producers may develop an overall plan in which site assessments are initially conducted with aircraft or satellite surveillance. Acquiring aircraft and satellite data can be cost effective due to the vast areas that can be quickly covered.

The aircraft or satellite data may then be used to prioritize the highest emission sites. The producer could then use ground deployed detection methods at these locations and thus obtain more precision data. If a truck deployed system is used by the producer’s field operators this can be a very cost-effective method of locating gas emissions and leaks. Remedial action may be taken at the time when a leak source is identified.

In some cases, a hand-held method such as OGI may be utilized to identify a leak source that cannot be located with a system deployed on a ground vehicle. Using a hand-held method is the only detection method that may work inside of buildings and on certain facility sites with complex piping, instrumentation and pneumatic devices. This is a relatively slow and labor-intensive method so it is important to ensure that the OGI operator has guidance as to what they should and should not conduct surveillance on.

Several designs of flux chambers have been invented, and continue to be developed, for detecting GM and to a limited extent measuring GM. These are an enclosed vapor shroud placed on the ground and are intended to seal and contain GM above a leak source.

With recent AER rule changes under FEMP and alt-FEMP, service providers have emerged with tools to help producers track and report their field emissions. Some of these companies have site monitoring for emissions detection and measurement devices and they have been included in Appendixes A and B.

A variety of instrumentation companies have also been developing specialized equipment for mobile and fixed platforms for the purpose of detecting emissions. An inventory of these companies has not been included in this report.

2.3 IDENTIFYING THE SOURCE OF A LEAK

Techniques have been developed to assess the source of a SCVF leaks and GM leaks by taking surface measurements and with fluid analysis. This report does not examine the many subsurface methods that may be deployed in a wellbore to identify the source of leak.

Regarding surface methods, the build-up pressure in a surface casing vent can be helpful in assessing the possible subsurface formations that the gas is originating from. Acquiring representative fluid sample for chemical and isotope analysis are also established methods used to help identify potential sources of emissions.

Methane detection at ground level can be misleading near a wellhead. When methane is detected it is important to determine if leaks are originating from the wellhead and casing assembly or from surface casing vent piping buried underground or from biogenic activity in the soil.

A GM leak can experience lateral dispersion in the ground due to several reasons. On pads with multiple wells the source may be from an offset well. Both GM and SCVF leaks have occurred on legacy wells when nearby coal bed methane wells were fractured with nitrogen. Many organizations will take methane readings at different depths below ground level to characterize the leak profile. It is common to record higher gas concentration quantities as readings are taken deeper below surface and closer to the leak source. Some experts recommend taking readings as deep as 1 meter even if no readings are recorded on surface.

Highly specialized service providers have developed techniques to collect GM samples for isotope analysis and chemical analysis by sealing a conduit into the ground and taking samples which are not contaminated with air or other substances. If there is shallow ground water, care must be taken to recover samples above the top of the water in the head space.

Sample collection from a leak and conducting isotope analysis usually includes methods of identifying if a leak is thermogenic and from subsurface formations or biogenic and from recent bacterial activity in the soil. When used properly, isotope analysis can help determine which specific geological formation a thermogenic leak is originating from. This is sometime referred to as forensic analysis or fingerprinting.

With isotope analysis, the source of methane is identified by conducting isotope analysis mainly on the carbon atom in the methane molecule. This type of analysis determines the number of neutrons in the carbon atom which in turn is related to geological age and if the methane is biogenic or not. Isotope analysis is also applied to ethane, propane, butane, deuterium (heavy hydrogen), sulfur and produced water to help identify the source of fluids.

Isotope analysis used to identify geological formations is controversial because some legacy databases were built using contaminated samples which provided incorrect guidance. It is essential to ensure that reliable isotope information is used when attempting to identify the source of leaks.

There are significant operational risks associated with collecting samples and conducting isotope analysis on hydrocarbon samples which can lead to incorrect results. These risks must be mitigated with correct and careful procedures and by using the appropriate equipment. Some of the risks are as follows:

1. Samples must be collected and transported in a manner that eliminates the potential for contamination, particularly from air. Tedlar bags are permeable to atmospheric gases and also cannot preserve H2S. Consequently, Tedlar bags are not considered by the leading experts to be adequate for collecting and transporting samples for isotope analysis.
2. Biogenic methane can be altered by methanotrophic bacteria which preferential oxidizes 12C isotope over 13C isotope. Sampling may be advisable in the anerobic level of soil where methanotrophic bacteria may not be present.
3. Gas samples that are captured can sometimes be mixed from several sources. This can occur from different thermogenic sources (porous formations) or from a thermogenic and a biogenic source (in the soil). Where possible, a protocol must be followed to ensure that the laboratory analysis and the data analysis can identify each source to provide accurate results.
4. Baseline isotope analysis from a specific geological formation can vary in different geographic regions and measures must be taken to ensure that representative baseline samples are used. It is critical to have accurate baseline data for the specific area and formation of interest.
5. As indicated, baseline isotope samples from geological formations must be validated to ensure that the original samples were not contaminated resulting in corrupt analysis.
6. Laboratory analysis must also be conducted in a manner, and possibly within a timeline, that eliminates the potential for sample degradation, contamination and misinterpretation.

Some specialized companies such as Gchem Ltd. have developed methods of applying isotope analysis to other fluids besides methane and have structured databases to help identify the source of leaks. The specialized companies also have advanced methods of taking samples, transporting the samples and analyzing the samples to minimize contamination and the risks identified above. They have constructed reliable databases to significantly reduce the risk of misinterpreting the source of a leak.

2.4 Emerging Technologies

Methods of collecting data via drones, manned aircraft and satellites to detect emissions, specifically methane and carbon dioxide emissions, are rapidly progressing. These methods can be cost effective when covering vast areas but have lower resolution limits when compared to 'on-site' methods. They are also significantly impacted by weather conditions, especially wind.

There are nearly 5,000 satellites orbiting the earth and various technologies are advancing to collect and analyze data to identifying emissions. Companies like GHGSat Inc. use both fixed wing aircraft and their own satellites to gather data on methane and carbon dioxide emissions. Their technology uses optical systems to visualize a plume and the results are enhanced by inputting weather information.

Bluefield Technologies is a competitor to GHGSat in the use of satellites and allegedly have sensors to see 20,000 spectral lines. A spectral line is a dark or bright line in an otherwise uniform and continuous spectrum, resulting from emission or absorption of light in a narrow frequency range, compared with the nearby frequencies. Spectral lines are used to identify atoms and molecules. These "fingerprints" can be compared to the previously collected "fingerprints" of atoms and molecules and are thus used to identify the atomic and molecular components. Bluefield is planning to deploy their own proprietary technology on their own satellites.

Other companies like Skywatch Space Applications Inc. 2000 (Skywatch) are aggregators of satellite data from a multitude of sources. Skywatch has a mandate to make data available at a low cost to innovators who are developing new technology including emissions detection and quantification. Skywatch can also task satellites to acquire high resolution images for future use.

MethaneSat LCC is a wholly owned subsidiary of Environmental Defense Fund focusing on emissions from oil and gas sector. MethaneSat acquires data from existing satellites and is planning to launch its own satellite to detect methane sources.

2.5 TECHNOLOGY GAPS

A database containing representative gas, water and oil chemical and isotope analysis from all formations for all regions in the Western Canadian Sedimentary Basin would be very helpful when producers are trying to verify the source of a leak in a well as part of a remediation plan. A project is recommended to build this type of database that would be accessible to all stakeholders and which could be maintained.

Controversy regarding the sampling, transporting and conducting of isotope analysis on leaking gas should be resolved by continuing to develop methods to winnow out corrupt data from legacy databases.

A training certification or best practice could be developed with experts in the field of isotope analysis. The best practice could include sampling and transporting procedures as well as techniques for conducting the isotope analysis and methods to determine if samples have been compromised.

Legacy wells that have been cut, capped, and abandoned sometimes need to be re-entered because of gas migration or due to surface construction activities. Opening wells with welded caps (vented caps were regulated after 2008 in Alberta) presents a hazard of cutting into high pressure trapped gas under the casing caps. Currently operators may use a welding hot tap procedure to ensure that the casing cap can safely be opened.

A procedure could also be developed to identify the presence of hydrocarbons under welded casing caps without opening the casing. One option may be to adapt cased hole neutron logging devices for application outside of exposed casing tops with a welded cap. This could possibly be done using a transmitter on one side of the exposed casing and a receiver on the opposite side.

Many remote sensing technologies are rapidly evolving, the detection sensitivities are advancing as well as methods to cost effectively identify the gases. It is recommended that some best practices or standards are developed to address these issues.

A possible avenue to resolve some of the subject gaps in best practices and the misunderstandings within industry would be to develop a new Energy Safety Canada (ESC) Industry Recommended Practice (IRP) with the Drilling and Completions Committee (DACC). This work could possibly be an extension of IRP 26 (Well Remediation) or IRP 27 (Well Abandonment) which is close to being published.

3.0 MEASUREMENT OF LEAKS

3.1 LEGACY TECHNOLOGY

A ten-minute SCVF bubble test provides a very rudimentary assessment of a vent flow leak. SCVF can be highly intermittent and this test is considered grossly inadequate for flow quantification. Much more accurate devices have been designed for longer term measurement and monitoring. Many of these systems have data recording and transmission systems that provide the capability to 'monitor from the office'. Industry has reported that there are some inconsistencies between these various automated measurement systems but the reasons for the discrepancies have not been disclosed.

Because low rate SCVF can be highly intermittent it is important to select the appropriate device and to be aware of the minimum testing time that is required to get accurate data.

Some organizations have used PD meters similar to household gas meters. However, these meters are not suitable for very low flow rates.

A common method used on oil and gas wells for measuring SCVF is with a CALSCAN Hawk Vent Gas Meter. CALSCAN meters are used by consultants, service providers and producers.

Several service companies have emerged over the past few decades that specialize in measuring SCVF and detecting GM. Some have developed proprietary technologies and others use devices that are commercially available for sale. Many of the well-known companies and measurement products are listed in Appendix B.

Six common and emerging metering systems that are used to measure or estimate gas flow are as follows:

- Positive displacement (PD) meters
- Differential pressure (DP) meters
- Coriolis meters
- Ultrasonic flow meters
- Vortex flow meters
- FLIR
- Various leak detection and repair (LDAR) imaging systems

3.2 ADVANCED TECHNOLOGIES

There are several companies that have advanced methods of measuring SCVF including very low rate and intermittent flow rates which are sometimes negative when the well anulus is on vacuum for a short time. Many of these systems are designed to remotely take flow measurements over extended periods of time and to transmit data to base stations and to internet websites. Many of these service providers can take fluid samples for chemical analysis and a few can take representative samples for isotope analysis.

Calscan Solutions is an instrumentation and control company that manufactures flow computers, solar powered separator controls and cyclone separators. They provide field services and rentals for measuring SCVF and they sell the metering equipment to other service providers.

A few service companies have developed metering packages to measure steam and other gasses in the vent flow from thermal wells. These systems typically condense steam from the vent flow to measure the water volume (flow rate) as well as metering the vent gas rate. Fluid samples may be taken from some of these devices. Some of these systems can also monitor H_2S levels and casing pressure during testing. One service provider, GCHEM, can also capture samples from thermal wells for chemical and isotopic measurements that are believed to be representative.

Researchers may use a device such as the Full Flow Sampling system (FFS) to quantify a leak. A FFS is a modular and consists of an explosive-proof blower, a mass airflow sensor (MAF), thermocouple, sample probe, constant volume sampling pump, laser-based greenhouse gas sensor, data acquisition device, and analysis software. These systems may be capable of dilution flow rates of 4.25 standard cubic meters per minute.

3.3 EMERGING TECHNOLOGIES

As indicated, instrumentation systems deployed on aircraft and satellite with methane detection methods are evolving to estimate plume volumes and flow rates. GHGSat is a satellite company which is reported to be developing technology to estimate flow rates.

3.4 TECHNOLOGY GAPS

A technology gap exists for methods of accurately quantifying leak rates which are remotely detected or detected by systems that does not include having the leak contained in piping. This is particularly true of close proximity devices like hand-held infrared cameras used to identify low leak rates.

Gas migration through the ground will typically follow a tortuous pathway to surface. Many variables determine where the leak will occur at surface and the number of break-out locations. Methods of accurately measuring GM at the ground surface remains very challenging. Different kinds of flux chambers are being developed for this purpose. Enhanced technologies and practices need continuous advancement for this purpose.

4.0 LEAK DETECTION ON CLOSED WELLS

4.1 PREVIOUSLY CLOSED / ABANDONED WELLS

Some wells that were drilled and determined to be unproductive at the time of drilling have been plugged with only surface casing set in the wellbore. In this case, cement plugs were set in the open hole part of the wellbore and the surface casing was cut off and capped below ground level. This practice is still occurring.

Wells drilled and cased over the past one hundred years have had production casing cemented in place with varying cement top depths between the casing and the open hole. This occurred as technology and rules changed and as additional shallow gas bearing zones and the base of ground water were identified. Many of these wells have subsequently been abandoned (closed). Consequently, certain hydrocarbon zones were not isolated with cement in abandoned wells and some of these wells may leak.

After 2008, when vented caps were required, a higher frequency of closed wells was observed to be leaking. Many wells abandoned prior to 2008 with welded caps are expected to leak at some point as the casing or the top caps corrode. It has also been determined that leaking wells that were repaired before closure have a high occurrence of leaking again.

As a result of these outdated practices and rules, about 10% or more of closed legacy wells are expected to leak over time. Details of an AER study supporting this assessment were presented at a well integrity conference in Banff in April 2014 (Boyer, Lewis and Cuthill).

4.2 MONITORING HIGH RISK WELLS AFTER CLOSURE

Regulators, producers and other stakeholders may need to accurately monitor wells post-closure, particularly high-risk wells. This may occur on wells inside of urban areas, sour wells, wells that have had previous wellbore remediation or due to a variety of other reasons. A well risk model should be developed for commercial use to help prioritize inspections and closure procedures on wells. A few years ago, the AER developed an operating 'proof of concept' well risk model based on available public data that could be replicated and commercialized.

One of the challenges after a well has been remediated and abandoned is the need for leak monitoring. The current monitoring practice often causes a delay in surface soil reclamation and remediation activity. A simple procedure is illustrated below in Figure 2 in which multiple casing strings on a closed well could be monitored while surface remediation and reclamation work on the soil is progressing toward acquiring a reclamation certificate. This illustration is for surface monitoring of a 'wedding cake' type of subsurface casing cut and cap with a vented production casing and surface casing.

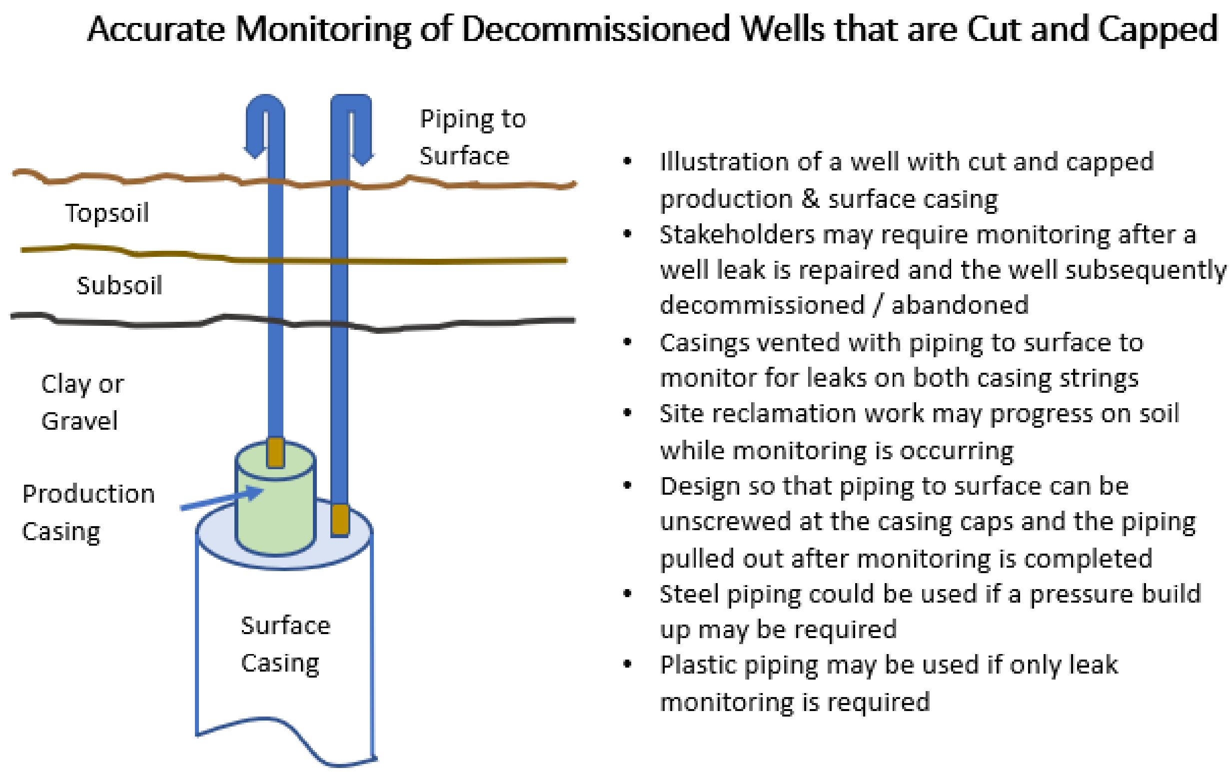

Figure 2: Monitoring a Cut and Capped Well

5.0 ACKNOWLEDGEMENTS

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Thanks also to my career colleagues who have been part of my lifelong learning journey. I appreciate that you have shared your expertise in production operations, reservoir development, drilling, completions, well workover and closure and other operational areas that I have been honored to be employed in. Much of that shared expertise is included in this report in some way.

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