# A Portrait of Oil and Gas Wellbore Leakage in Northeastern British Columbia, Canada

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# A Portrait of Oil and Gas Wellbore Leakage in Northeastern British Columbia, Canada

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## ABSTRACT

Northeastern British Columbia (NEBC) in Canada is a zone of conventional oil and gas production since the 1960s. Additionally it contains four shale gas basins that are increasingly being exploited using hydraulic fracturing since the mid-2000s. Based on information that is publicly available through the BC Oil and Gas Commission, it appears that at least 19% of drilled oil and gas wellbores in the province have leakage. However, this incident rate could much higher due to underreporting. There are two major consequences of such wellbore leakage: greenhouse gas emission (GHG) and the possibility of aquifer contamination. This article examines the mechanisms of fluids leakage and estimates the rate of GHG emissions from faulty wellbores.

## RÉSUMÉ

Depuis les années 1960, le nord-est de la Colombie-Britannique au Canada est une zone de production pétrolière et gazière conventionnelle. Cette zone contient également quatre bassins de production de gaz de shale qui, depuis le milieu des années 2000, sont de plus en plus exploités en utilisant la fracturation hydraulique. En se basant sur des données fournies par le « BC Oil and Gas Commission », il apparait qu'environ 19 % des puits de forage dans la province fuient. Cependant, il est possible que cette valeur soit sous-estimée à cause d'une sous-déclaration des incidents. Ces fuites ont deux conséquences majeures : les émissions de gaz à effet de serre (GES) et la possibilité de contamination des aquifères. Cet article examine les mécanismes de fuite de fluides et estime les émissions de GES provenant des puits défectueux.

## 1 INTRODUCTION

Northeastern British Columbia has been the site of conventional oil and gas activity since the 1960s. In the last decade conventional production in the province has declined. However, the overall annual production rate has been steadily increasing due to the exploitation of four shale gas basins starting in 2005 (Figure 1). Shale gas is exploited through the combined techniques of horizontal drilling and multi-stage hydraulic fracturing whereby large volumes of water are injected into the shale in order to enhance permeability and flow. This method used to exploit shale gas, commonly referred to as "fracking", has raised some environmental concerns, particularly the possible cross-contamination of aquifers and the generation of greenhouse gas (GHG) emissions during the process of extraction and production (Vengosh et al. 2014; Rozell 2014; Jackson et al. 2013). Defective sealing in wellbores is considered to be a major factor influencing the potential for leakage (Chesnaux et al 2013; Chesnaux 2013; Jackson et al 2013). This review considers hydraulically fractured wells in the province to be un-conventional and all other well types conventional.

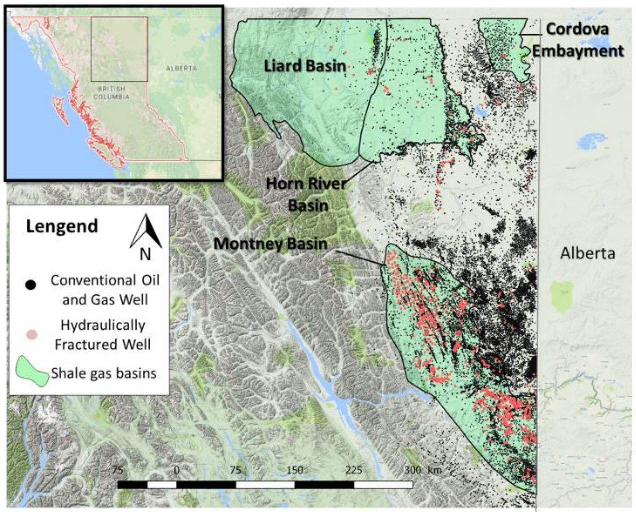

Figure 1: Map of British Columbia showing locations of drilled wells and shale gas basins

All oil and gas wellbores, regardless of type (injection, production or observation) follow a basic design and construction (Figure 2). First, a surface casing is installed below the depth of usable groundwater and cemented to the surface. Second, a production (and sometimes an intermediate) casing is installed with the surface casing to the depth of the target zone. The annular space between the surface and production casing is filled with cement however the height of the top of cement in most cases does not reach the surface. In the majority of wells a replaceable tubing and packer assembly is installed within the production casing in order to convey fluid between the wellhead and the target zone. All wells are installed with a surface casing vent that allows the escape of any gas or fluids in the annular space between the production and surface casing. In British Columbia, like the rest of Canada, the surface casing vent is required to be left open in order to stop the build-up of pressure from leaking gases or fluids (Dusseault et al. 2014).

Abandoned wellbores are also a potential source of leakage. It should be noted that in the oil and gas industry the term “abandoned” actually refers to the cement plugging and decommissioning of a well in such a way that it should prevent future leakage. In addition to downhole plugging, abandoned wells are supposed to be cut and capped at least 1 meter below the surface and buried. All details of oil and gas production, including wellbore construction, maintenance and leakage reporting are overseen by the provincial regulatory body the British Columbia Oil and Gas Commission (BC OGC).

There are two primary types of reported wellbore leakage: 1- leakage that exits through the surface casing vent (SCV) and 2- leakage around the wellbore. Leaking fluids can be either gasses or liquids. Leaking gasses are predominantly methane with lesser amounts of heavier hydrocarbons as well as carbon dioxide ($CO_2$) and hydrogen disulfide ($H_2S$) (Dusseault et al. 2014; Vengosh et al. 2014). Leaking liquids include liquid hydrocarbons, brines, and freshwater. In BC freshwater is considered as any water with salinity less than 4000 mg/L (BC OGC 2017). When fluids exit the surface casing vent, this is referred to as surface casing vent flow (SCVF) as represented on figure 2. Gas migration (GM), or stray gas is the term used to describe around the casing leakage of gasses. There is no commonly accepted term for around the casing leakage of liquids.

There are two consequences of oil and gas wellbore leakage: 1- there is risk of aquifer contamination from all liquid leakage (SCVF or around the casing) as well as around the casing gas migration. Ideally, SCVF of gasses will not pose a risk as the gasses are vented to the atmosphere. 2- The release of GHG emissions from both gas SCVF and GM. Although $CO_2$ is more persistent, the short-term effect of methane is 20 times stronger than the latter (Dusseault et al. 2014). With these consequences in mind, the objectives of this study are as follows:

1.) Attempt to determine the incident rate of wellbore leakage in terms of: overall, SCVF gas, liquid (SCVF + around casing), and GM leakage;
2.) Determine the mechanisms of liquid leakage along wellbores;
3.) Estimate the rate of annual GHG emission from leaky wellbores in BC;
4.) Compare leakage rates between conventional and non-conventional wellbores;
5.) Evaluate the future risk of wellbore leakage in BC in terms of GHG emissions and the potential for aquifer contamination.

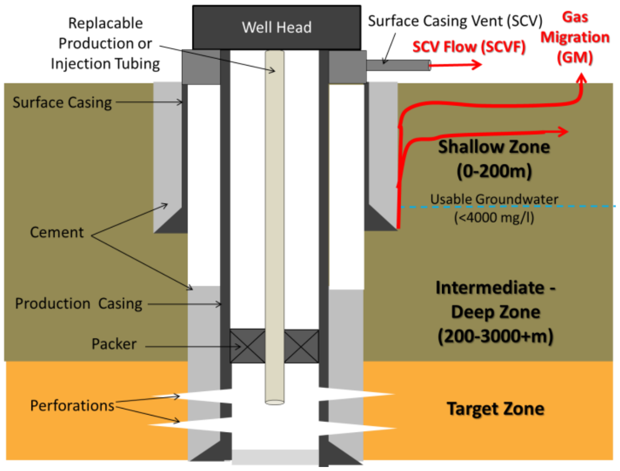

Figure 2: Diagram of basic oil and gas wellbore construction and two primary leakage pathways: surface casing vent flow (SCVF) and gas migration (GM)

## 2 METHODOLOGY

The BC OGC maintains a database of all reported wellbore leakage from oil and gas wells in the province (available upon request). This includes incidences of both SCVF and GM as well as corresponding dates and leakage rates. The BC OGC also maintains the Integrated Resource Information System (IRIS), a database containing information on all drilled oil and gas wells in the province including geological information and wellbore construction and completion details. The IRIS database also contains information on which wells were fracked, so a comparison can be made between conventional and non-conventional wells. Wells in all databases are listed by a Well Application (WA) number. Using the WA number, these databases were combined for statistical analysis. Wells of interest in this study were first flagged in the wellbore leakage database and further investigated in the BC OGC’s ELibrary database. The Elibrary database includes completion workover reports for leaky wellbore that required remedial action. The remedial action taken to stop wellbore leakage that is described in these reports sheds light on the mechanisms of wellbore failure and leakage pathways.

Additionally, field investigations conducted in the Montney Play by the David Suzuki Foundation in 2016 (Werring, 2017, personal communication) were compared to data reported in the BC OGC wellbore leakage database.

This review considers all data from both conventional and unconventional wells up until December 31st 2016.

## 3 RESULTS

### 3.1 Leakage Occurrence Rates

At the end of 2016, 24,599 oil and gas wells had been drilled in BC (Figure 3). Of these, 2,739 have been

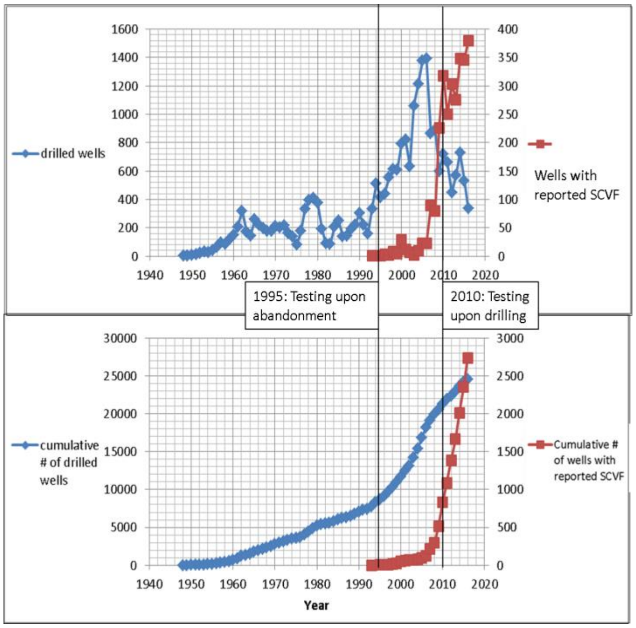

Figure 3: Yearly and cumulative number of reported drilled wells and leaking wells

reported to have wellbore leakage. This equates to 11 % of drilled wells exhibiting wellbore leakage. However, despite the long history of oil and gas development in the province, reporting of wellbore leakage in BC only goes as far back as 1995 (Figure 3). This corresponds to the date at which wells were legally required to be tested for leakage upon abandonment. Another relevant regulatory change that took place in 2010 is the requirement for leakage testing after the drilling and completion of a well as well as during routine maintenance throughout its lifetime, but this was only for wells drilled after 2010. This regulatory change corresponds to a sharp increase in the number of reported incidences (Figure 3). In other words, it is evident that the leakage incident rate is strongly influenced by reporting standards rather than actual well failure rate. To make things more difficult, companies conducting leakage tests are not required to report negative results to the commission (Parsonage BC OGC, personal communication, 2016), and therefore we cannot know with certainty how many wells have actually been tested.

These reporting standards for well leakage make calculating a truly representative incident of leakage rate challenging. One approach we took was to only consider wells drilled after 2010. Because of regulatory requirements these wells are the ones most likely to have been tested for well leakage either following drilling and completion, during routine maintenance, or upon abandonment. According to BC OGC figures, 4,017 wells have been drilled in BC since 2010, of which 761 have been reported to exhibit well leakage. This equates to a well failure rate of 19%. It is possible that wells drilled since 2010 leak less than older wells especially considering that according to the BC OGC, well cementing practices have improved since the mid to late 1990s (Parsonage, BC OGC, personal communication, 2016). However we cannot really say with certainty if this is the case as comparing leakage rates of any wells drilled before 2010 is problematic.

However, even when taking such regulatory changes into account, the reliability of the BC OGC's well leakage database is questionable. According to field work undertaken by the David Suzuki Foundation (DSF) in 2016 only about 44% of wells they found to be leaking have entries in the BC OGC well leak database ( Werring, 2017 personal communication) (Figure 4). During their field campaign in the Montney play in 2016 the DSF found 27 wells that exhibited significant surface casing vent flows. Of these 27 only 12 have been entered into the BC OGC database. Additionally, 4 of the 15 wells with SCVF that were not found in the database were drilled during or after 2010. Therefore at least 4 of these wells should theoretically be in the database according to the commission's reporting requirements.

In all, the DSF examined 62 abandoned and suspended wells and found SCVF was detected at 18 or those wells, an SCVF rate of about 29% (Werring 2017, personal communication). He also found that 7 of 25 oil wells were leaking through the SCV, a leak rate of 28%. Four of seven (44%) water disposal wells were also found to exhibit SCVF. Werring determined the presence of methane using a FLIR ThermaCAM GasFindIR HSX infrared camera. Additionally he measured the rate of leakage by attaching a balloon to the vent and allowing it to inflate. The inflated volume attained in a measured time then allowed the calculation of flow rate.

To summarize, it would seem that even 19% could be a very conservative estimation of the number of wellbores that actually leak. It would seem that due to under-reporting this figure could even be much higher. The results of the DSF's field study demonstrate that the reliability of the BC leakage database is questionable.

A requirement for companies to report the results of all wells that have been tested for SCVF or GM regardless of whether or not there are negative test results would help to eliminate this uncertainty.

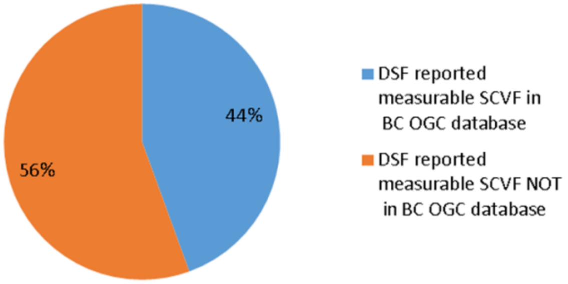

Figure 4: Comparison of reported wells with SCVF in the BC OGC and those identified during a field campaign by the David Suzuki Foundation (Werring, 2017, personal communication).

## 3.2 Type of Leaky Boreholes

Based on the BC OGC data, out of the 2739 reported leaky wells 90.2% uniquely involve gas exiting the surface casing vent (Figure 5). The next most common type of leakage is around the casing gas migration (7.1%). Only 2.2 % of reported leakage involves liquid hydrocarbons or brines. Lastly 0.5% of leakage is in the form of freshwater. This means that about 10% of leaky wellbores have the potential to contaminate aquifers either by around the casing gas migration or liquid leakage. The pathways of liquid leakage (around the casing or through the SCV) are further discussed below.

About 56% of the 137 reported gas migration incidents occur at wells with reported surface casing vent flows (Table 1). Wells having both types of leakage were classified as GM along with those uniquely having gas migration. There are 5 reported cases (3.6% of all GM) where gas migration was reported at wells already cut, capped, and buried underground. According to the Elibrary database, of the 5 reported instances of post cut and cap wellbore leakage, 4 have attempted remedial action (Table 2). This involves digging up the capped well and re-installing a wellhead equipped with a surface casing vent flow. Of these 4, only 2 have attempted to repair the leakage with down-hole methods. Only one of the two repair attempts was successful. As far as we know for the 3 wells that have either not attempted or have failed at repairing the leakage, leakage continues out the surface casing vent of the re-installed wellheads.

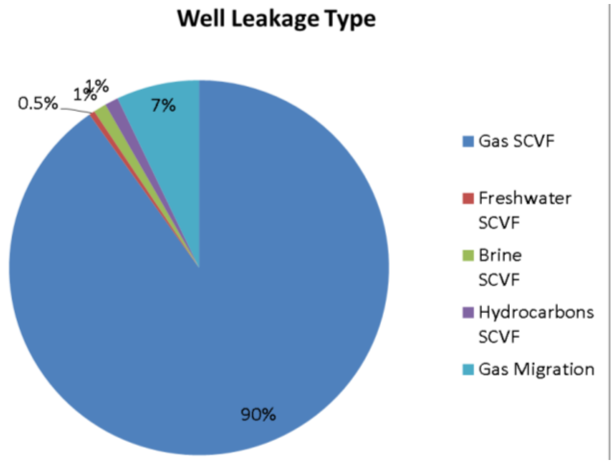

Figure 5: Main types of reported wellbore leakage in the BC OGC well leakage database

Table 1: Types of gas migration occurrences

| Type of Gas Migration | reported incidences | % of total reported incidences |
|---|---|---|
| Gas migration with surface casing vent flow | 55 | 40.1 |
| Uniquely Gas Migration | 77 | 56.2 |
| Gas migration after wellhead cut and capped | 5 | 3.6 |

Table 2: Well operator response to gas migration detected after well surface abandonment

| Well # | Year of Cut and Cap | Year of Reported Gas Migration | Prior reported leakage?[1] | Action Taken by Well Operator |
|---|---|---|---|---|
| 1403 | 2012 | 2016 | Y | Wellhead re-installed with surface casing vent |
| 6747 | 1988 | 2016 | N | Successful remedial action (squeeze cementing) |
| 8619 | 2015 | 2016 | N | Wellhead re-installed with surface casing vent |
| 8818 | 1996 | 2015 | N | Multiple attempts at remedial action. (without success). Well-head re-installed with surface casing vent |
| 14605 | 2014 | 2015 | N | No reported action to date |

[1] That is to say during the operation lifetime of the well (i.e. before abandonment)

### 3.3 Causes of liquid leakage from wellbores

In total there are just 50 wells in BC that have reported liquid leakage (brine and/or liquid hydrocarbons). We found just 27 completion workover reports for these wells. We define 6 main leakage pathways (Figure 6).

1) Leakage of cement through the cemented outer annular space of the production casing. This includes leakage along the contact between casing and cement, between cement and bedrock, as well as through the cement itself;
2) Entry of fluids into the annular space through un-cemented zones;
3) Leakage through the production casing into the surface casing;
4) Leakage of production fluids into the surface casing along the wellhead;
5) Leakage along the outside of the surface casing;
6) Leakage out the vented cap of a cut, capped, and buried wellbore.

As figure 7 indicates the first four types of leakage should either exhibit build-up pressure in the wellbore or have fluids exiting out the surface casing vent. Leakage types 5 and 6 on the other hand will enter directly into the soil either around (5) or through the top (6) of the wellbore.

The most common pathway of leakage is through the production casing due to corrosion or other defects (Figure 7). Half of the time this type of casing leakage occurs below the base of the surface casing and the other half, above. Two of these incidences involve salt water disposal wells (WA # 3996 and 12654). In addition to transporting injected brines back up the surface casing vent, at least one of these leaky disposal wells (WA # 12654) contaminated an aquifer after pressurized brine travelled up along the outside of the cemented surface casing. This apparently allowed as much as 6000 cubic meters of brine to enter the aquifer before the leakage was discovered. There were also another two incidents of production casing failure leakage that were related to hydraulic fracturing activities. WA # 29691 had SCVF of brine 5 minutes after initiating its first hydraulic fracture stage. Another well (WA # 24546) is reported to have SCVF of brines following communication with an offset fracked well.

The next most common pathway is from un-cemented zones that allow an unimpeded flow of fluids directly into the annular space between the production and surface casings (23%). Another 11% of leakage is due to failure of “primary seals” at the wellhead itself. Lastly, about 4% of leakage comes from zones above the surface casing. In these instances leaking fluids travel up along failed surface casing cement and exit in the soil surrounding the wellbore much in the same way as gas migration. It should be noted that 4% represents only a single reported incident. However, we did not include the case of disposal well WA 12654 as we consider the primary mechanisms of wellbore leakage for this well to be production casing failure. There were no reported incidences of liquid leakage through failed production cement nor out the top of cut and capped wellbores. Besides wellhead seal, in most cases squeeze cementing was the method used to repair leaky wellbores. This involves perforating the production casing below a leakage pathway and circulating cement up the surface casing.

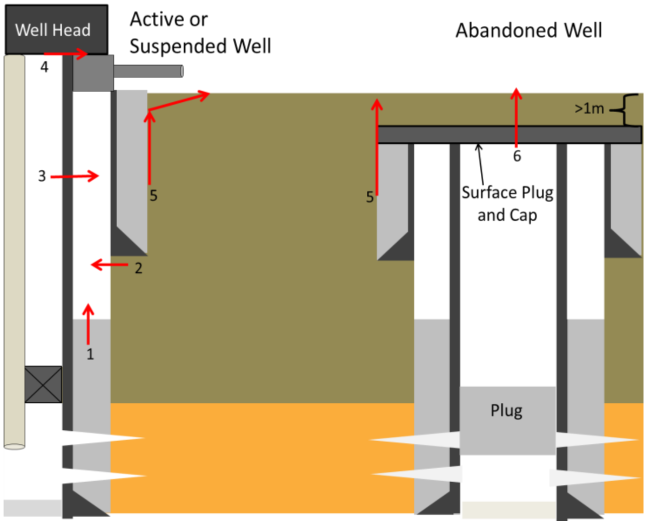

Figure 6: Reported leakage pathways along wellbores. 1) through the cemented annulus between the surface and production casing. 2) from un-cemented zone 3) through production casing into un-cemented surface casing 4) wellhead seal failure 5) around the surface casing leakage 6) out the top of cut and capped wellbore

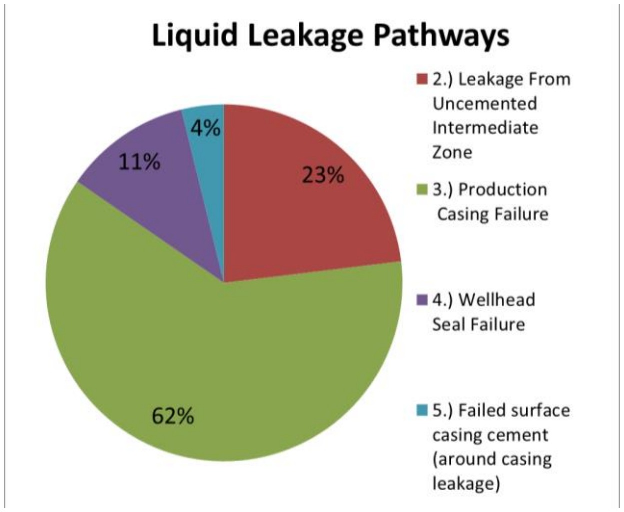

Figure 7: Reported liquid leakage pathways. Only 27 out of 50 wells with liquid leakage have workover reports.

## 3.4 Estimation of annual GHG emissions

The other consequence of wellbore leakage is the release of methane, a greenhouse gas, into the atmosphere. The most direct method for calculating the total rate of methane leakage is by adding the daily rates of all leaky wellbores in the BC OGC database. Leakage rates in the reported database are not actually continuous daily measurement but rather discrete measurements extrapolated over larger time periods. The database does not define the exact method of measurement that was used to determine flow rate, but presumably it is similar to that described in Section 3.1. Our calculation excludes wells that have been remediated or abandoned, assuming that they have successfully been repaired to stop leakage as required (BC OGC 2017). According to the database there are then 1,493 wells that are currently leaking gas in the province either through the vent or around the casing. In cases where multiple vent flow measurements were reported, the most recent measurement was used. The total leakage rate of these 1,493 wells is 7,070 $m^3$/day or 2.5 million $m^3$/year in total.

However this value of 2.5 million $m^3$/day is a conservative estimate. Most importantly it assumes that all leaky wellbores in the province have been flagged and entered in the database. As previously explained this seems unlikely as many older wells have probably not been tested for leakage. This is supported by the fact that the majority of the wells that tested positive for leakage during the David Suzuki Foundation’s field survey do not appear in the BC OGC database.

In order to correct for this under-reporting we can consider that 19% of wells leak as previously estimated. If we eliminate the 2,246 wellbores that have been abandoned after 1995, assuming they have been tested and repaired for gas leakage, this leave 22,353 wells that could be leaking. If 19% of these wells leak this equates to 4,247 leaky wellbores. Because many wells have more than one reported leakage rate throughout time an average leakage rate was calculated for each well. Based on this, the average leakage rate between wells is about 10 m$^3$/day per leaky well (Figure 8). 4,247 wells leaking at an average rate of 10 m$^3$/day equates to a total rate of 42,470 m$^3$/day or 15.5 million m$^3$/year. Note that this estimation considers that some cut and capped abandoned wells leak methane to the atmosphere. As other authors have noted (Watson and Bachu 2009) it seems plausible that wellbores abandoned before 1995 could be leaking gas or other fluids. This is supported by our observations. At least 5 wells in BC were found to be leaking after being cut and capped (Table 1) and only in one case has leakage been successfully repaired. As Dusseault et al. (2014) point out there is no program in place for examining abandoned wellbores for leakage. It is unclear why or how these cut and capped wellbores were identified for leakage.

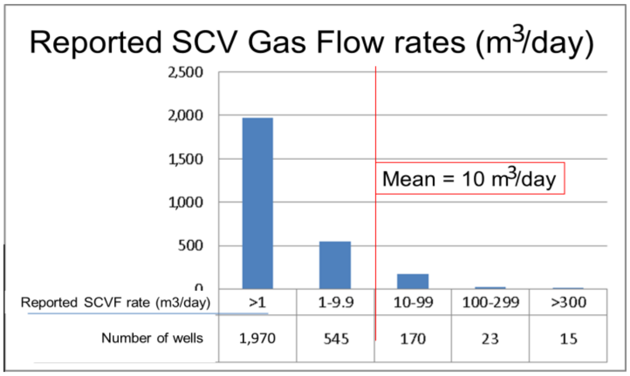

Figure 8: Histogram of gas SCVF leakage rates. For wells with multiple entries from different dates the average between all entries was used

### 3.5 Leakage Occurrence rates for conventional vs. non-conventional wellbores

According to the IRIS database from the year 2011 to 2016 there were 2016 hydraulically fractured wells drilled and 498 conventional wells. It appears that hydraulically fractured wells are about 5% more likely to leak than conventional wells (Table 3). This is mostly due to a higher occurrence rate of gas SCVF for hydraulically fractured wells. However, this difference is not very large and unfortunately the mechanisms of gas SCVF were not investigated in this review so it is difficult to explain why this is the case.

Table 3: Percent of wells of convention (non-fracked) and non-conventional wells drilled that have wellbore leakage of a given type (2011-2016)

| Well Type | Gas surface Casing vent flow (SCVF) | Liquid SCVF | Gas Migration | Any Leakage |
|---|---|---|---|---|
| Non-fracked | 12.0% | 0.4% | 1.6% | 14.1% |
| Fracked | 19.5% | 0.1% | 0.5% | 20.1% |

## 4 DISCUSSION

As conventional production continued to decline, the vast majority of new wells in BC will be hydraulically fractured in order to access unconventional resources. Hydraulically fractured wells do not have a significantly higher leakage occurrence rate compared to conventional wellbores. However, wellbore leakage appears to be nevertheless an issue in terms of both GHG emissions as well as the possibility of aquifer contamination. For instance, for every 200 new wellbores that are drilled we should expect at least 40 of them to leak. 36 of these leaky wellbores uniquely involve the release of gases from the surface casing vent which does not pose a risk of aquifer contamination. On the other hand 3 of these wells will have around casing gas migration and 1 will have liquid leakage. Aquifer contamination could occur in both cases, however, it is important to note that liquid leakage through the casing does not necessarily mean that these fluids enter the groundwater zone. Once the liquid leak is identified, operators can either shut-off the vent or capture the fluids. Additionally, given that there were no reported instance of leakage through a cement annulus between the production and surface casing, it seems that fully cementing the production casing to the surface would greatly reduce the risk of liquid surface casing vent flow. This would also mitigate failure of production casing by providing a second barrier. On the other hand, it seems unlikely that operators could find a way to effectively manage around the casing leakage without wellbore remediation.

Although the problem of liquid leakage and gas migration may seem small in this particular example, in reality the problem could be amplified by the sheer magnitude of the number of new wells drilled. Anywhere from 20 to 40,000 new wells could be drilled in BC by 2040 in order to exploit the provinces shale gas resources (Hughes 2015). With so many new wells it seems that it would be difficult for operators to be aware of all leakage incidents at all times, especially if leakage occurs sometime after initial well completion and testing. Dusseault et al. 2014 defines two main mechanisms of wellbore leakage; short-term and long-long term mechanisms. Short-term mechanisms describe deficiencies in the primary construction and completion of the wellbore and ideally any leakage of this type should be noticed during testing following well completion. However, as they point out, there are also long-term mechanisms such as operation stresses and long-term cement and casing degradation which could take many years to develop. According to Dusseault et al. (2014) even the most adequately constructed wellbores can degrade over time and the long-term integrity of wellbores is questionable after 100 years.

Additionally there are also instances of induced wellbore damage whereby leakage along a wellbore is caused by external factors. Wellbore damage can be induced by either communication with offset injected wells (injection, disposal or hydraulically fractured wells) or by seismic activity. One of the incidences of brine leakage from the surface casing vent occurred at a well (WA 24546) that communicated with at offset frack well. Wellbore leakage due to communication with offset fracked wells has been documented in Alberta (Watson 2013). Similarly, there is at least one disposal well in BC that communicated with the surface casing of an offset disposal well (BC OGC 2009). This incident is not reported in the BC OGC SCVF database however.

Both hydraulic fracturing and associated waste disposal wells have been linked to induced seismic events in British Columbia (Atkinson et al. 2016). There are at least two confirmed instances where such seismic activity damaged nearby wellbores (BC OGC 2014; 2016). Although neither of the two incidences was linked to wellbore leakage, it seems plausible that it could occur under the right circumstances. This is a concern raised by the BC OGC itself (Stefik 2014)

If either induced wellbore damage long-term degradation occurs on wells that are already abandoned, some time could pass before leakage is detected and repaired. For example some of the wells were found to be leaking more than 20 years after their abandonment (Table 2). This begs the question: how many other abandoned wells are also unknowingly leaking?

The other important issue is the release of GHG emission from all these newly drilled wells. Assuming the previously calculated failure rate of 19% and leakage rate of 10 $m^3$/day we can conclude that, on average, every newly drilled well will leak 2 $m^3$/day of methane. This equates to 730 $m^3$/year for every newly drilled well. If 30,000 new wells are drilled then we expect the overall leakage rate to be around 21 million $m^3$/year, not counting previously drilled leaky wells.

The current GHG emissions volume is difficult to assess due to an apparent lack of reporting. By the most conservative estimates (directly calculated from the BC OGC SCVF database itself) total leakage is about 2.5 million $m^3$/year. However, based on field observations by the DSF it appears that many leaky wells are not appearing in the database. A more realistic estimate is around 15.5 million $m^3$/year. This uncertainty could be cleared up with better reporting standards, specifically the reporting of negative results. That way we could confirm which wells are actually being tested for leakage. In other jurisdictions such as the province of Québec, both negative and positive test results are reported (*Bureau d'audiences publiques sur l'environnement*, 2011) although it appears that not all wells in the province have been tested.

Lastly, it should be noted that wellbore leakage is not the only source of upstream GHG emissions. Flaring and leakage from equipment such as pneumatic devices also contribute to the total GHG emission footprint. An estimation of the current GHG emissions footprint from all upstream oil and gas activities in BC is dscribed by Atherthon et al. (2017).

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