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Identification of Wells with High CO_2-Leakage Potential in Mature Oil Fields Developed for CO_2-Enhanced Oil Recovery

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Abstract
Previous work, presented in SPE 106817, "Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores", described a method to predict the potential for wellbore leakage which primarily occurs in the shallow areas of a wellbore.

The work presented here focuses on the potential for leakage to occur from the deep regions of a wellbore, particularly from viable oil reservoirs. The potential for wellbore leakage where CO_2 emhanced oil recovery (EOR) or sequestration is or may be conducted is specifically investigated.

The Alberta Energy Resources Conservation Board collects and maintains data regarding cement types used in primary cementing of casing strings, stimulation information and abandonment data. These data were used to determine the potential for deep wellbore leakage in the presence of CO_2. This deep wellbore leakage potential is then coupled with shallow wellbore leakage potential to predict which wells may leak to other reservoirs, potable groundwater aquifers or to the atmosphere in a CO_2 sequestration or EOR project.

Cements with additives such as bentonite have been shown to be particularly susceptible to CO_2 attack. Wells were screened for cement blends placed in the deeper sections of the wellbore during primary cementing. This information is useful in predicting if a wellbore will remain leak free if CO_2 is placed in the reservoir and the wellbore is contacted.

The stimulation method was evaluated to determine if injected CO_2 may break through to existing wellbores prior to full reservoir sweep, thus decreasing the time that the wellbore could remain leak free. Stimulations such as hydraulic fracture, perforating and acidizing with pressure were deemed to increase the likelihood that wellbores would leak due to cement sheath cracking coupled with CO_2 attack of cement and casing.

The abandonment method was also evaluated. In Alberta the primary form of zonal abandonment utilizes a mechanical bridge plug capped with cement. The bridge plug material is expected to fail in the presence of CO_2 due to CO_2 attack on elastomers and cast iron.

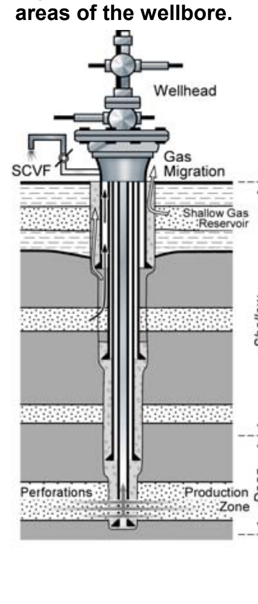
Two large field evaluations are presented as case studies.

Introduction
Several client studies have been conducted to date in Alberta, Canada, to determine factors which may affect wellbore leakage. The findings of these studies were presented previously (Bachu and Watson, 2006; Watson and Bachu, 2007). These papers, particularly SPE 106817, presented an analysis of the factors that affect the leakage potential in the shallow part of a well, and a decision-tree type model which enables ranking of a well's potential to leak based on factors determined in the client studies.

The original ranking system generally focused on leaks from the shallower regions of the well (Figure 1). These leaks typically manifest themselves at surface as annular pressure (surface casing vent flow-SCVF, known also as sustained casing pressure) or soil gas migration. This ranking system did not take into account the potential for a native or injected fluid or gas to create or increase the potential for a well to leak.

In Alberta several reservoirs are currently being evaluated for CO_2 enhanced oil recovery (EOR), while more than 30 depleted oil and gas reservoirs and deep saline aquifers are used for acid gas (CO_2 and H_2S) disposal. In an attempt to determine the potential for a well penetrating one of these reservoirs or aquifers to leak CO_2 or acid gas from the target reservoir, a computer-based tool was developed. This tool uses the data available in electronic form from the Alberta

Figure 1: Shallow and deep areas of the wellbore.



Energy Resources Conservation Board (ERCB) to create a score for each wellbore. This score indicates the leakage potential from both the shallow and deep regions of the wellbore as depicted in Figure 1. Data were also compiled to allow for the future evaluation of possible consequences of a leaking wellbore.

The shallow leakage factors have been determined by analysing known leakage in the field and determining the most prevalent factors that lead to annular pressure and soil gas migration (Bachu and Watson, 2006; Watson and Bachu, 2007). The deep leakage factors, however, have been determined from theoretical deduction and laboratory results.

Shallow Leakage

Factors previously determined to have an effect on shallow wellbore leakage (Bachu and Watson, 2006; Watson and Bachu, 2007) were assigned values which reflected the influence that a particular factor has on shallow wellbore leakage. Table 1 indicates these factors, the criteria and default values assigned based on these criteria. These values are then multiplied to determine a well's Shallow Leakage Potential (SLP) score. Table 2 summarizes scores into general leakage-potential categories.

Table 1: Shallow leakage factors.

Factor	Criterion	Meets Criterion Value	Default Value
Spud Date	1965-1990	3	1
Abandonment Date	<1995	5	1
Surface Casing Size	≥244.5 mm	1.5	1
Well Type	Cased	8	1
Geographic Location	Special Test Area	3	1
Well Total Depth	>2500 m	1.5	1
Well Deviation	1.2-1.8	1.5	1
Cement to Surface	No	5	1
Cement to Surface	Unknown	4	1
Additional Plug	No	2	1
Additional Plug	Unknown	1.5	1

Table 2: Shallow leak potential.

Shallow Leak Potential (SLP)	Score
Low	<50
Medium	50-200
High	200-400
Extreme	>400

In general the analysis is based on the potential for a well to have a leakage pathway along the wellbore and does not depend on the fluid or gas source that may be leaking.

Deep Wellbore Leakage

Three factors were used to evaluate the Deep Leakage Potential (DLP) for a wellbore in CO_2 sequestration, acid gas disposal and CO_2-EOR. Deep leakage was evaluated based on the presence of CO_2 or acid gas and the impact this acidic environment would have on wellbore construction and abandonment materials such as cement, steel and elastomers. Table 3 indicates the factors, criteria and assigned values used to determine the possibility that deep leakage would occur. These factors are then multiplied to obtain the well's overall DLP. Table 4 summarizes the product score values into general categories.

Table 3: Deep leakage factors.

Factor	Criterion	Meets Criterion Value	Default Value
Fracture	count =1	1.5	1
Fracture	count >1	2	1
Acid	count=1	1.1	1
Acid	count=2	1.2	1
Acid	count>2	1.5	1
Perforations	count>1	2	1
Abandonment type	Bridge Plug	3	1
Abandonment type	Not abandoned	2	1

Table 4: Deep leak potential.

Deep Leak Potential (DLP)	Score
Low	<2
Medium	2-6
High	6-10
Extreme	>10

Cement Type

Several studies have been conducted to determine the effect of CO_2 on the quality of cements used in wellbore construction (Browning, 1984; Onan, 1984; Bruckdorfer, 1986; Krilov et al., 2000; Duguid et al., 2004; Kutchko et al., 2007). Most of these studies indicate that cement will not withstand CO_2 attack and will fail to provide a seal in the casing/hole annulus when CO_2 is introduced (Nelson and Guillot, 2006a). Recent laboratory work suggests, however, that cements with low free water ratios may not be as susceptible to CO_2 attack due to the formation of an impermeable barrier on the cement sheath that halts further deterioration as shown in Figures 2 and 3 (Kutchko et al., 2007a). These studies also suggest that the inclusion of additives, such as bentonite, which increase the free water ratio, increases the potential for cement break down in the presence of CO_2 (Kutchko et al., 2007a). Since no such studies exist for the effect of acid gas on well cements, it is assumed that the conclusions and results for CO_2 would apply to acid gas as well since the reactions are due to the acidic nature of the fluid (Kutchko et al., 2007a).

Figure 2: Kinetic results for the penetration rate of CO_2-saturated brine of the cement. (Kutchko et al., 2007b). (Graph courtesy of B. Kutchko, U.S. Department of Energy.)

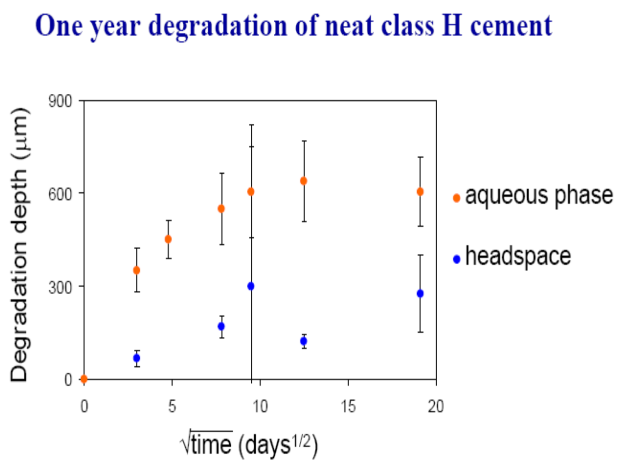
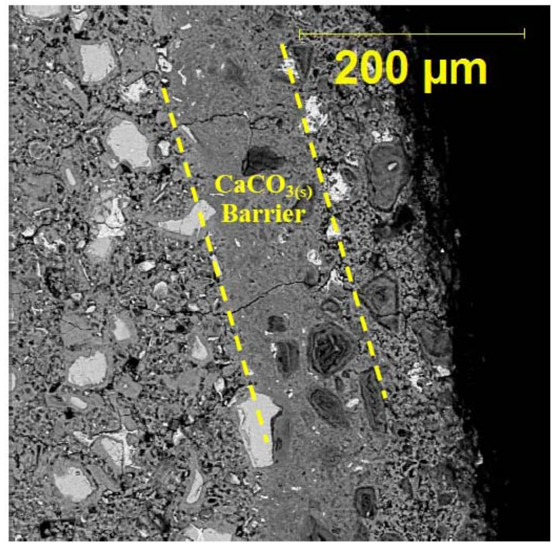


Figure 3: SEM-BSE image of Class H neat cement cured for 28 days. The $CaCO_{3(s)}$ is forming a barrier to further CO_2 infiltration (Kutchko et al., 2007a). (Photo courtesy of B. Kutchko, U.S. Department of Energy).



Bentonite, commonly referred to as gel, is the most common additive to cement. This additive is used as an extender to increase the yield of the cement, decrease the cement density and decrease the fluid loss (Nelson and Guillot, 2006b). The addition of bentonite increases the set cement porosity, increasing the cement susceptibility to corrosion due to acidic formation fluids (Nelson and Guillot, 2006a). Cement blends which include bentonite are often used as "filler" cements to reduce the cost of cementing and the hydrostatic pressure applied to the producing formation or weak formations. Other additives, such as gypsum, which are highly acid-soluble, are also expected to deteriorate rapidly in the presence of CO_2 or acid gas.

Inert additives such as fly ash, silicate (sand) and nitrogen (foamed cement) do not increase the free water ratio and are assumed for this study to have a lesser effect on the deterioration of cement in the presence of CO_2 (Nelson and Guillot, 2006a).

The data, provided by the ERCB, include information regarding the cement types used in the cementing of the production casing. Table 5 itemizes the cement types found in the ERCB electronic database and the values assigned for the purpose of assessing a well's potential to be adversely affected by CO_2 or acid gas and potentially cause leakage. Often, several different types of cement may be used to cement the wellbore. Generally, better quality cement, designed for the well purpose, depth, temperature and reservoir conditions, is run across the zone or completion interval. Filler type cements are often run in the shallower areas of the wellbore. The ERCB data indicate these different cement types in a wellbore, as well as where they are placed by providing the sequence that the cement was

Table 5: Cement types and values.

Cement Type	Assigned Value	Description
1:1 POZ MIX	1	Cement and fly ash
1:1:# POZ	3	Cement, fly ash and various quantities of bentonite
BLACKGOLD	1	Unknown
CAP (NEAT)	1	Cap pumped on top of foam cement, not applicable.
CLASS X NEAT	1	Various neat cements
FILL ECP	1	Cement to fill annular packer, not applicable
FOAMED	1	Cement foamed with nitrogen
G + # PC SALT	1	Cement with various percent salt additive
G + # PC SAND	1	Cement with various percent silica sand additive
GPSL/GPCEM/THX	3	Gypsum and gel additives
LIGHT WEIGHT	3	Assumed gel additive to reduce density
SELF STRESS	3	No cement, hole allowed to slough in on casing
SLAG	1	Blast furnace slag, reduces cement porosity
SLOTTED LINER	3	No cement
SLURRY 6D	1	Unknown
TAPERED CASING	3	No cement
TH CEM/CEM FNDU	1	Thermal cement, usually sand or silica additive
UNCEM CSG/LINER	3	No cement

pumped into the well. Cement data for wells spud prior to 1986 are sparse, however most wells spud after 1986 have detailed information regarding cement type and placement. From this information it is possible to determine which cement type is in the deepest portions of the wellbore. The cement type recorded as being at the bottom of the well is the cement type that this evaluation is based on.

Stimulation and Perforations

The ERCB records information regarding most stimulation treatments to perforations or producing intervals in wellbores, as well as the number of completed intervals in the wellbore. Two types of treatments and perforating are anticipated to have potential effects on long term wellbore integrity due to excessive pressures (Watson et al., 2002), as shown in Figure 4, or chemical reactions. In this study hydraulic fracturing and acidizing with pressure were classified as stimulation methods that could have a negative impact on wellbore integrity. Carbon dioxide or acid gas may migrate through cracks in the cement created by stimulation or perforating. These acidic fluids may increase and hasten the leakage by further deteriorating the cement sheath or corroding the steel casing.

Figure 4: Cement sheath failure and resulting cracks developed from pressure cycling the internal casing (Watson et al., 2002). (Photo courtesy of Halliburton Energy Services).

Hydraulic fracturing breaks the reservoir rock using a viscous fluid, high pump rates and high pressures. The reservoir rock is fractured and the fractures filled with a propping agent, usually sand, that creates a highly porous and permeable flow path to the wellbore. Acidizing dissolves wellbore scales, removes near wellbore damage and dissolves reservoir rock. These stimulations can remove near-wellbore damage caused by drilling activity and increase the flow potential near the wellbore.

In the situation where CO_2, acid gas and/or water is used for reservoir EOR, it is anticipated that CO_2 or the acid gas may break through to these reservoir fractures preferentially, bypassing unaltered reservoir rock due to the higher permeability of the fracture (Marsters, 2007). As well, where wells have been abandoned due to depletion or produced for long periods of time, the localized reservoir pressure around these wells may facilitate the flow of flood fluids to migrate towards these low pressure areas. Multiple completions or perforated intervals provide a higher potential for cross flow between discrete geologic zones within the wellbore itself.

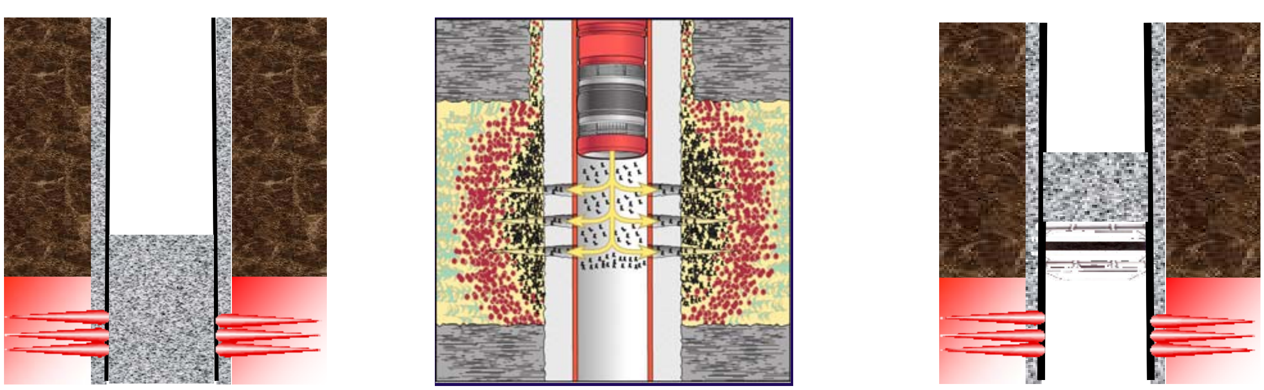
The data were analysed to determine if a particular well was stimulated by fracturing, acidizing or if it had multiple completions. Fracturing has been given a higher risk score due to higher treatment pressures and deeper penetration into the reservoir, typically achieved by fracturing. In comparison, acidizing and perforating are usually near-wellbore treatments. Both fracturing and acid treatments were counted for the individual wellbores. This count information is used based on the assumption that the more times a well is stimulated, the higher the chance that casing, cement and/or cap rock systems may be damaged. The number of completions is also counted and any well that has multiple completed intervals was assigned a higher value due to the increased potential of crossflow.

Zonal Abandonment Method

In Alberta the ERCB allows three options for zonal abandonment of cased wells. The methods, as depicted in Figure 5 are: a cement plug that extends a minimum of 15 meters above and below the perforated interval, a cement squeeze through the perforations with or without a retainer, or, the most commonly used method, a mechanical bridge plug capped with 8 meters of cement (ERCB 2007).

Figure 5: Regulatory approved zonal abandonment methods in Alberta, Canada.

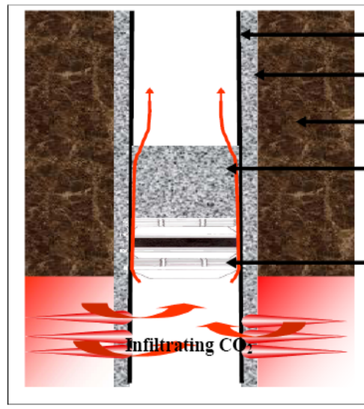
Cement plug set across perforations. **Cement squeeze with retainer to perforations.** **Bridge plug capped with 8 meters of cement.**



This factor identifies the abandonment method for a particular well and assigns a value based on these criteria. It is anticipated that the bridge plug abandonment method will have a shorter life than other methods due to mechanical failure, change of reservoir pressure due to the injection of CO_2, acid gas and/or water, or a change in the gas/fluid chemistry below the bridge plug (Schremp and Roberson, 1975). Bridge plugs are typically made of cast iron and an elastomer sealing unit as shown in Figure 6. Both iron and the typical nitrile elastomers used are subject to CO_2 or acid gas attack that can lead to seal failure (Schremp and Roberson, 1975).

Cement caps placed above bridge plugs are typically dump-bailed into place. Cement caps evaluated in an earlier client study were found intact in only 50% of the wells investigated. This corresponds to laboratory findings that indicate dump-bailing of cement may be ineffective in providing adequate seals (White et al., 1992). Based on these findings, the ability of dump-bailed cement plugs to maintain an effective seal above the bridge plug is considered negligible for this study.

Figure 6: Bridge plug capped with 8 meters of cement with infiltrating CO_2.



Zonal abandonment type had originally been included in the potential for shallow wellbore leakage. For this study the zonal abandonment method has been evaluated as deep potential for leakage, because it has a direct effect on the potential for wells to leak from the CO_2 sequestration or acid gas disposal formation up the inside of the production casing where it may impact all horizons in the wellbore.

Wells that have not been cased are called drilled and abandoned. These wells have been left out of the analysis since records in Alberta indicate that the leakage occurrence rate is 0.5% of drilled and abandoned wells compared to 13% of cased abandoned wells (Bachu and Watson, 2006). Additionally, no data exist to determine the cement type in the cement plugs used to abandon uncased wells. It is assumed, based on field knowledge, that cement plugs typically consist of neat type cements, and these wells will therefore have a lower DLP.

Case Studies

The Pembina and Zama oil fields in Alberta (Figure 7) were evaluated using the previously described method. These fields are being considered for CO_2 or acid-gas EOR, and pilots are currently being run in both. The results of the evaluation can be used to determine the overall leakage potential for existing wells in oil fields where CO_2 or acid gas injection may be used for EOR and/or future sequestration. The information provided by this analysis can be used to target particular wells for further evaluation based on their individual DLP and SLP scores. Table 4 provides general information for comparison between the two oil fields and the potential for well leakage based on the predetermined factors.

Figure 7: Map of Alberta, Canada, showing the location of the Pembina and Zama Fields in red.

Table 4: Field data and results summary.

	Pembina	Zama
Number of cased wells	9860	607
Number of wells drilled and abandoned	1050	106
% of wells with cement data	40%	64%
% of wells with high DLP cement score	28%	20%
% of wells fractured	75%	2%
% of wells acidized	47%	80%
% of wells abandoned	12%	13%
% of wells with multiple completions	11%	55%
% of wells with extreme DLP	14%	28%
% of wells with extreme SLP	7%	18%
% of wells with extreme SLP and DLP	1.6%	4.3%

Pembina Field Wellbore Leakage Potential

The Pembina Field, the largest oil field in Canada, was discovered in the early 1950's with drilling continuing on until today. Wells in the field typically are drilled to a depth of approximately 1600-1800 m. The wells are generally completed and produced from the Cardium Formation which is a sandstone with an overlaying conglomerate and a thick shale caprock. In recent years some uphole potential has been realized. The wells are generally vertical with single completions. Wells that have been cased and completed are typically abandoned with a bridge plug set within 15 m of the perforated interval with 8 m of cement dump-bailed on top. Generally, wells in the Pembina Field were stimulated by hydraulic fracturing and to a lesser extent by acidizing the completed interval.

Historically, the primary cementing requirements have been 100 m above the Cardium Formation at 1400 m or the overlying Belly River Formation at an average depth of about 800 m (ERCB, 1990). Surface casing setting depth is at approximately 180 m. The base of groundwater protection varies between 200 and 600 m, with typical Base of Ground Water Protection (BGWP) at 470 m (Alberta Environment, 1995). Although there are wells with potentially 1200 m of uncemented casing in the Pembina Field, there are very few gas or oil bearing zones within the overlying horizons to leak to surface. External casing corrosion does not seem to be problematic in the area, with 1.3% of Pembina wells reporting casing failure compared to 1.1% province wide.

The distribution of wells, by either DLP or SLP scores, for the Pembina Field is presented in Figures 8 and 9, respectively. This analysis gives an overall picture of the potential for well leakage and which area of the wellbores is most prone to leakage. Figures 10 and 11 indicate the geographic location of wells with extreme deep and shallow leakage potential in the Pembina Field, respectively. This information would be useful when determining the areas of an oil field that would be most desirable for CO_2 EOR or sequestration, and gives some indication of the potential economic impact of wellbore remediation prior to injection of CO_2 at the scoping stage. The well locations of a particular DLP or SLP score or range of score may be used to determine potential consequences by overlaying population density, ground water, surface water or other potential leak receptors. Individual factors, such as which wells are abandoned or have at risk cement types can also be analysed based on the nature of the proposed project.

Figure 8: Pembina Field DLP Score distribution.

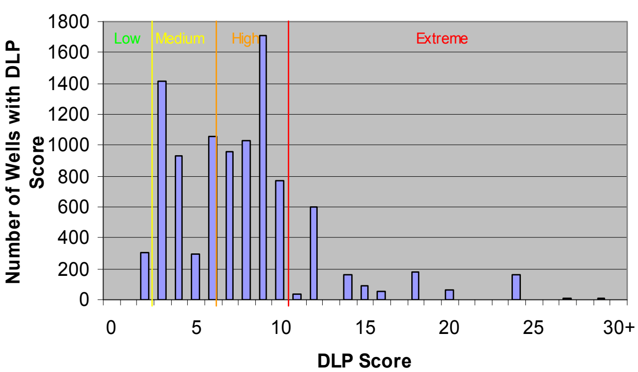


Figure 9: Pembina Field SLP Score distribution.

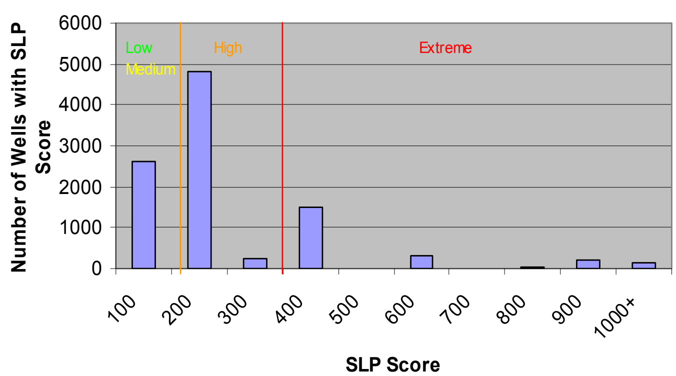


Figure 10: Location of Pembina wells with extreme DLP shown in red against all field wells in black. The green grid indicates 6x6 miles/square.

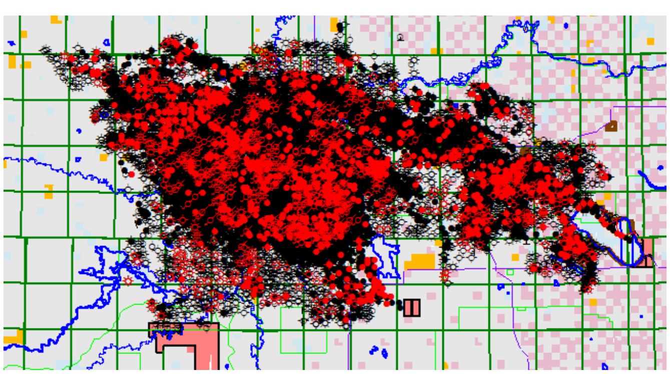
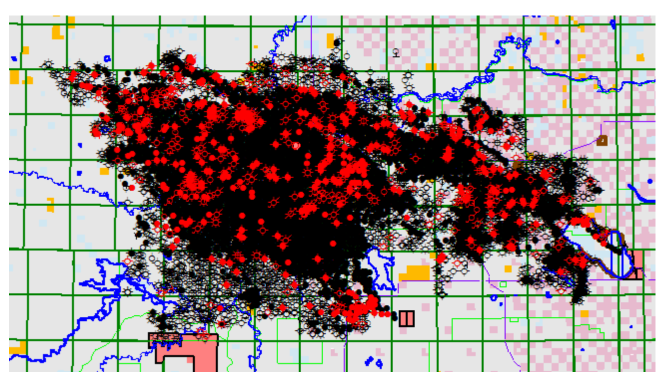


Figure 11: Location of Pembina wells with extreme SLP shown in red against all field wells in black. The green grid indicates 6x6 miles/square.



The analysis of shallow leakage potential in the Pembina Field indicates leakage potential similar to the reported provincial average of 6.1% (Bachu and Watson 2006), with only 7% of wells falling in the extreme categories. The analysis of the deep leakage potential indicates that wells are predominantly cemented with neat cements that pose the lowest risk for deterioration when in contact with CO_2 compared to other common wellbore cements. The deep leakage analysis also indicates that fracture stimulation may create leakage pathways in the deep regions of the wellbore and that fracture stimulation is the main factor in DLP for the Pembina Field. Figures 10 and 11 also indicate that the potential for shallow well leakage (SLP) in the field may be of lesser concern and is not as widely distributed as the potential for deep well leakage (DLP).

The low potential for leakage scores, however, may be underestimated if wellbore abandonment procedures do not change in the future. With only 12% of cased wells currently abandoned in the Pembina Field, the leakage scores may not reflect future leakage potential due to abandonment method.

Cement type data are electronically available only for 40% of the wells. It was assumed that the unknown well cement types would be type neat and would, therefore, have a lower potential for deterioration due to CO_2 attack. This assumption may underestimate the potential for deep well leakage.

Based on the available information it appears as though wells in the Pembina Field could withstand project implementation of CO_2 EOR or CO_2 sequestration if wells abandoned in the future use a more robust downhole abandonment method than bridge plug capped with cement. Investigation to determine zonal isolation after stimulation in wells indicated as having extreme DLP would be beneficial in determining the actual effect of the stimulation on zonal isolation. More study is required to determine the durability of neat cement and bridge plugs to improve the confidence of these findings.

Zama Field Wellbore Leakage Potential

The Zama Field was discovered in the mid 1960's. The productive zone is the carbonate reef Keg River Formation at an average depth of 1600 m. The wells are generally vertical with multiple completions. On average, each well has two completions, or perforated intervals, with several wells having five or more completions. Wells that have been cased and completed are typically abandoned with a bridge plug set within 15 m of the perforated interval and with 8 m of cement dump-bailed on top. Wells in the Zama Field were stimulated by acidizing the completed interval. Very few wells are hydraulically fractured.

Historically, the cementing requirements have been 100 m above the Slave Point Formation, which overlays the Keg River formation, at an average depth of about 1200 m (ERCB, 1990). Surface casing setting depth is at approximately 275 m, however older wells have setting depths less than 200 m. The Base of Ground Water Protection varies between 75 and 400 m, with the average BGWP at 250 m (Alberta Environment, 1995). Within the uncemented depths of the wellbores several productive intervals have been discovered since many of the wells were drilled. Overlying gas-bearing formations such as the Jean Marie and the Beaverhill Lake, may contribute to gas leaking to surface. The reported casing failures for the Zama Field are 6% of all wells compared to failures of 1.1% of wells in Alberta. These high numbers of casing failures may be explained by the exposure of casing to the Wabamum Group and Banff Formation which are limestones within the exposed casing depths. The presence of $CaCO_3$ has an adverse effect on external casing corrosion and ultimately casing failure (Caswell, 1988).

The distribution of wells, by either DLP or SLP scores, for the Zama Field is presented in Figures 12 and 13, respectively. These score distributions indicate that deep leakage potential is quite prevalent within the Zama Field. Figure 14 and 15 indicate the geographical location of wells with extreme leakage potential in the field. Because the Zama Field is made up of several hundred reefs, this information would be useful when determining which pool would be most desirable for CO_2 EOR or sequestration and gives some indication of the potential economic impact of wellbore remediation prior to injection of CO_2 or acid gas at the scoping stage. Both deep and shallow leakage potentials are broadly distributed throughout the field. The deep leakage potential appears to have a denser distribution across the field. Although Figures 14 and 15 focus on extreme DLP and SLP scores, the distribution charts indicate that there are large numbers of wells in the high categories for both DLP and SLP. The well locations of a particular DLP or SLP score or range of score may be used to determine potential consequences by overlaying population density, ground water, surface water or other potential leak receptors.

Figure 12: Zama Field DLP Score distribution.

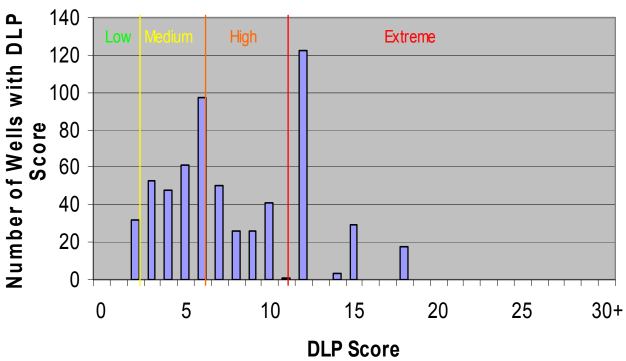


Figure 13: Zama Field SLP Score distribution.

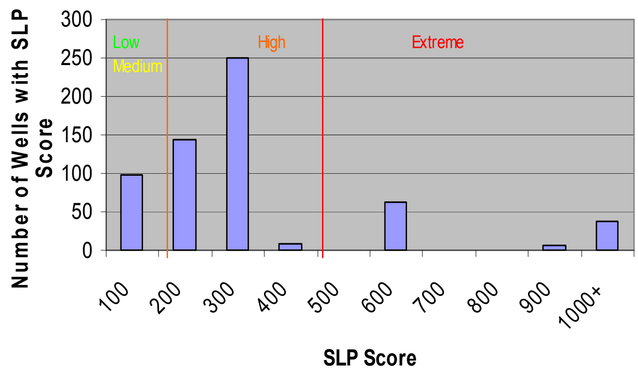


Figure 14: Location of Zama wells with extreme DLP shown in red against all field wells in black. The bold green grid indicates 6x6 miles/square.

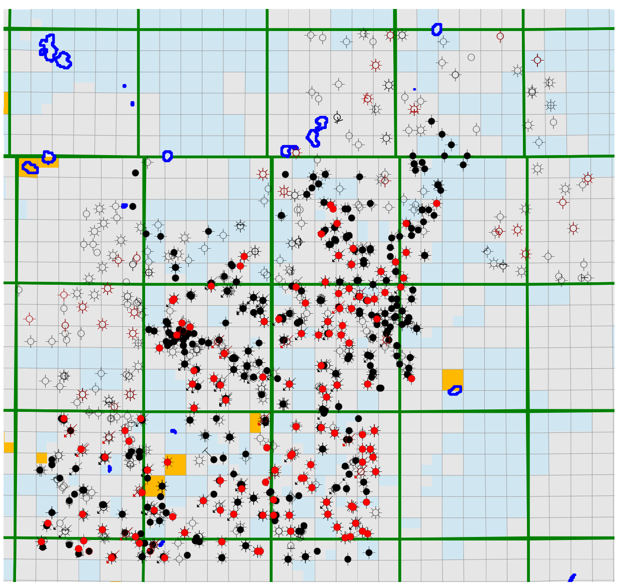
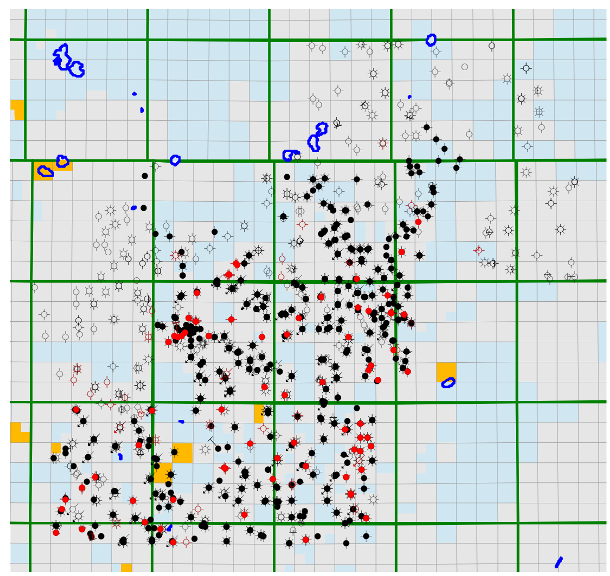


Figure 15: Location of Zama wells with extreme SLP shown in red against all field wells in black. The bold green grid indicates 6x6 miles/square.



Within this analysis the wells in the Zama Field show significant potential for leakage, both shallow, which is independent of fluid type, and deep, which may occur in the event that CO_2 or acid gas is introduced to the historical producing formations.

Previous work identified that approximately 6.1% of all cased wells in the province had shallow leakage in the form of surface casing vent flow (annular pressure) reported (Bachu and Watson 2006). Based on the analysis of the Zama Field, 18% of the wells have extreme potential of shallow leakage. This result is expected since the reported incidence of surface casing vent flow, determined from ERCB data, within the Zama Field is 30% of cased wells, well above the provincial average.

The potential for deep leakage shows that 28% of the wells in the Zama Field have an extreme deep leakage potential. This assessment for deep leakage potential is based on:

1. Approximately 30% (based on known and extrapolated data) of the wells have cement in the deeper regions of the wellbore that may be susceptible to CO_2 or acid gas attack because of the additives used.
2. Eighty percent of wells are stimulated by acidizing, with 60% of the wells having multiple acid stimulations. These stimulations may reduce the near wellbore seal, thus affecting isolation, and may reduce the time for CO_2 or acid gas breakthrough to the wellbore.
3. Fifty-five percent of the wells have multiple completions, increasing the potential for leakage between zones.
4. Thirteen percent of wells have been abandoned with a bridge plug. The remainder of the wells have not yet been abandoned. The assigned zonal abandonment value of two for wells that have not yet been abandoned may be too high. In the future, if zonal abandonment practices change to some other, more robust system the assigned value for zonal abandonment could be reduced to one.

Conclusion

The development of a computer-based tool to compile and mine available regulatory data to determine the potential of a well to leak has created the ability to conduct a first-pass evaluation of large numbers of wellbores to determine their relative potential for leakage, both shallow and deep. The use of this tool will speed up the wellbore assessment process by zeroing in on potential problem wells which may require closer scrutiny prior to the implementation of a CO_2 EOR, acid gas disposal or CO_2 sequestration scheme. The tool can also be used in risk assessment analysis if potential consequences of leakage are overlain, such as population density, ground water information or the presence of H_2S along the wellbore. The tool need not be specifically used to determine leakage in the presence of acid gas or CO_2, but can also be used to evaluate the potential for other types of leakage such as annular pressure (surface casing vent flow, aka sustained casing pressure) or gas migration.

Based on the findings of this study, careful well evaluation should be conducted to determine if wells in a particular CO_2 EOR or sequestration scheme are at risk for leakage. More study is required to determine the durability of cement and bridge plugs to improve the confidence of this evaluation.

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