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Risk Based Approach to Identify the Leakage Potential of Wells in Depleted Oil and Gas Fields for CO_2 Geological Sequestration

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Abstract

The selection of depleted oil and gas fields as potential CO_2 geological storage sites has both positive and negative aspects that need to be considered. The positives are that the storage capacity or pore volume can be reliably estimated from field's production history, and reservoir characterization can be performed with more readily available well, log or seismic data without additional expenses. The main drawback is the presence of wells in the field, as each well may provide a leakage pathway for injected CO_2. The leakage potential of a well is a function of its proximity to injection wells, cement coverage in the potential storage zone, well abandonment conditions including cementing of the annular space, and the nature of any barriers to prevent CO_2 leakage to the surface. Qualitative and quantitative risk-based approaches can be used to identify the wells that have comparatively higher leakage probabilities in comparison to other wells. The objective of this study is to use a risk-based approach to identify and categorize wells based on their leakage potential in depleted oil and gas fields. This will not only help in planning injection strategies but may also help in selection of remediation strategies. The model may be presented well by using the Fault Tree Analysis (FTA) technique. It implements screening criteria and a tier-based approach in which wells are screened and categorized into different tiers based on different well characteristics. The well characteristics include the physical distance from injection wells, the quality and portion of cement coverage of wells in the target zone, the regulations at the time of well completion, the leakage potential of sealing barriers for the targeted zone, the number of overlying shale and sand intervals and leakage of either CO_2 or brine to shallower wells, the nature and quality of permanent or temporary well abandonment procedures, and the quality and length of annular space covered with cement for shallower well casings or sections. Existing models for well leakage are used to quantitatively estimate the leakage rate. The risk of leakage is presented qualitatively and quantitatively in the form of leaked CO_2 volume to shallow aquifers or to the atmosphere. The approach is used for a representative depleted oil and gas field in southern Louisiana to show an example application of the process. The developed model provides a means to systemically identify the wells that are more likely to leak and have high consequences. Due to the reduced order nature of the tool, it should prove to be a useful tool in the planning and execution phase of the CO_2 sequestration process.

Introduction

A fundamental step in the selection of a storage site for CO_2 sequestration is to make sure that the selected site not only meets project economics but also has good storage and long terms retention features. The safety of the storage site becomes the prime importance and dictates the decision of selecting a particular site. The selection of depleted oil and gas fields as a potential CO_2 geological storage site has both positive and negative aspects that need to be considered. The positives are that the storage capacity or pore volume can be reliably estimated from field's production history, and reservoir characterization can be performed with more readily available well, log or seismic data without additional expenses. The main drawback is the presence of wells in the field, as each well may provide a leakage pathway for injected CO_2. In addition to wells, CO_2 may also leak from failure of cap rock and from faults or fractures. Possible CO_2 leakage pathways are depicted in Figure 1.

Depending on the flow area available in a well, the pressure differential, proximity of leaky well to the CO_2 injection well and the nature of the spread of CO_2 (sweep) in the field due to heterogeneity, wells coming into contact with the CO_2 plume may act as possible leakage pathways. For brine leakage only the pressure differential and a wellbore offering the least resistant path to flow may be the only necessary conditions for leakage to occur. The main emphasis in this study is placed on the leakage of CO_2. The information of wellbore flow path available may be estimated from publically available data sources. This work utilizes the Louisiana Department of Natural Resources SONRIS system (SONRIS, 2017). Based on the available data, the wells in a depleted field may be categorized by different features, including drilling date and the nature of cementing regulations at that time, plug and abandonment data and corresponding regulations or procedures adopted to plug a well (Watson and Bachu, 2009).

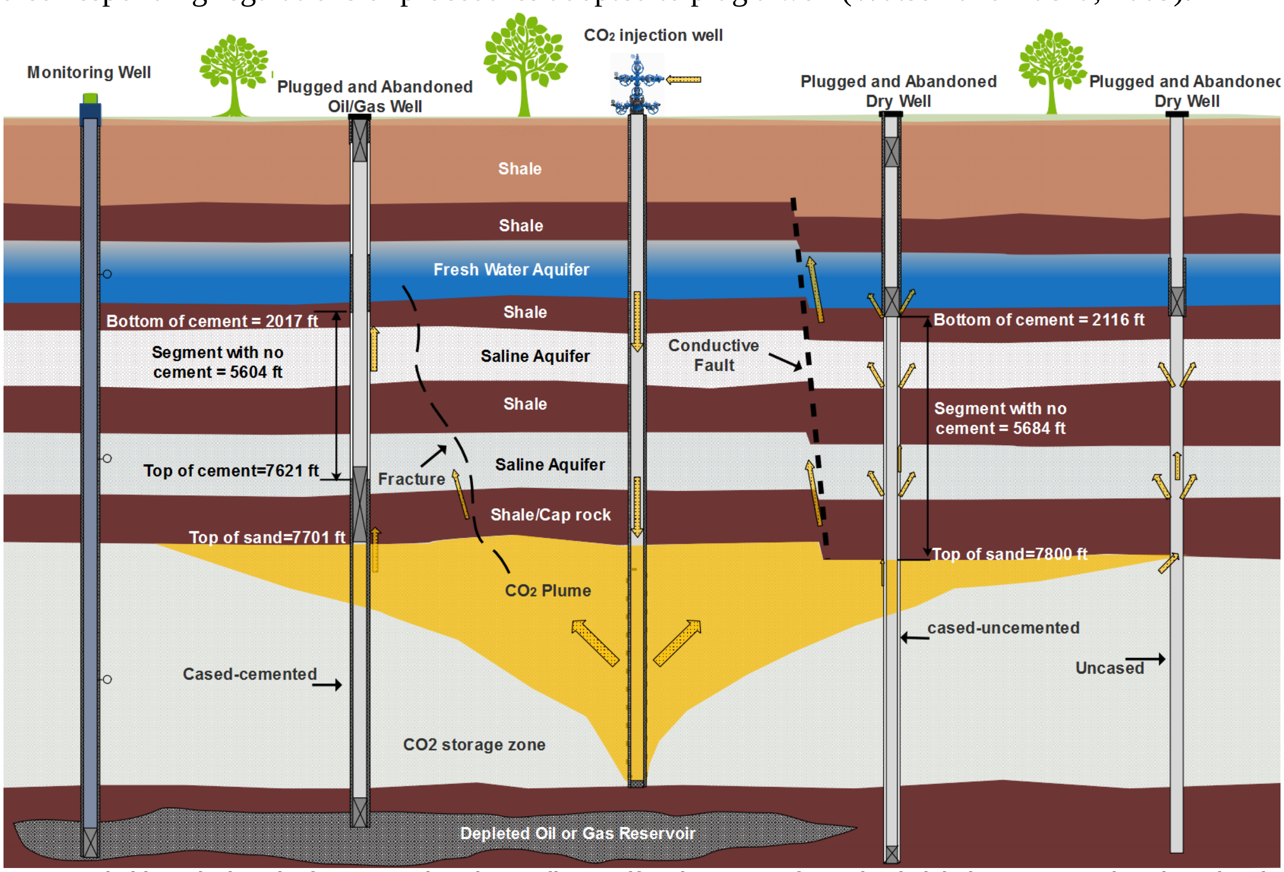


Figure 1: Probable co leak paths for storage in a deep saline aquifer, the storage formation height is exaggerated to show the plume spread, three well types based on the cement coverage in the storage zone are shown

Risk based approaches have been used in the past by researchers to estimate CO_2 leakage risk from storage zones via wellbores. A brief review of some of the most relevant work is presented here. Watson and Bachu (2007) developed a model to identify the wells with higher leakage potential by using the regulatory data. They used a score-based approach to evaluate the deep and shallow leakage potential of a wellbore. They used the spud date, abandonment data and other wellbore information to form the basis of their score system. They pointed out that elastomer bridge material used during the well plugging procedure may be damaged when it comes into contact with CO_2. In another study, Watson and Bachu (2008) used regulatory and wellbore data to evaluate the wells for gas or CO_2 leakage. They noted that majority of the leakage factors depends on the processes adopted during drilling, completion and abandonment phases of a well. Stauffer et al., (2009) used wellbore permeability as a key quantitative measure of a well's leakage potential. They used the amount of CO_2 or brine that could leak along the degraded cement intervals as the basis of their criteria. Celia et al. (2009) studied the effects of depth on the injection rates and showed that the leakage risk decreases for deeper storage zones and for zones with smaller number of wells penetrating the storage zone.

Nogues et al. (2012) proposed a simplified formulation to estimate the leakage along old wells and pointed out that there could be high uncertainties associated with different parameters in estimation of maximum probable leakage. Duguid et al. (2013) analyzed the cementing data of some old wells and concluded that cement for most of the wells was largely intact and was not degraded due to brine exposure. Syed et al. (2014) studied the interaction of CO_2 with well cement and presented a relationship showing the reduction in cement permeability as a result of this interaction. Duguid et al., (2014) studied the cement integrity of an old well for CO_2 injection project and found mixed results for annular cement. They found that, in some well sections the cement had very poor quality, and it will not work as a barrier against leaking fluids; however, in some sections the cement retained its properties and can act as a barrier. Gaurina and Mavar (2017) investigated the CO_2 leakage risk from a storage zone and looked at different leakage sources and categorized the leaks according to their severity. Results of these findings along with additional parameters of prime importance forms the basis of well leakage risk criteria proposed in this study.

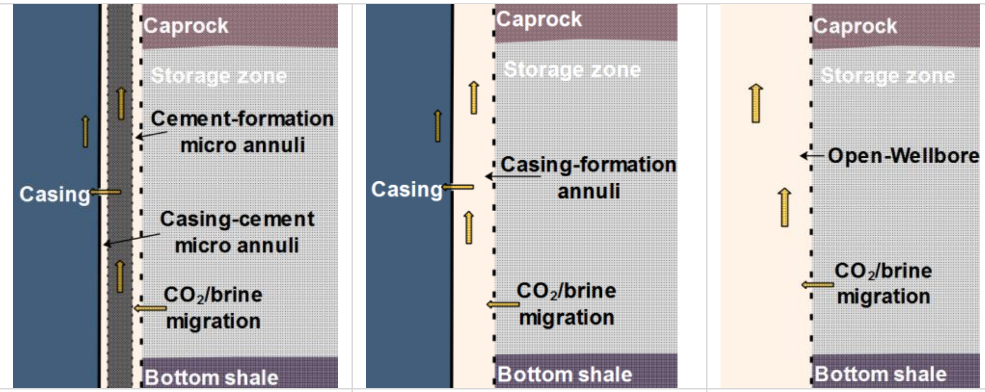
The main objective of the current study is to form a criteria to categorize the leakage potential of plugged and abandoned wells, and identify the wells that are most likely to leak, and suggest the strategies to reduce the leakage risk. According to cement coverage of a well in the storage zone, the wellbore may be categorized as either

- Cased-cemented
- Cased-uncemented
- Uncased

We briefly go over each well category, describing in detail the probable leakage pathways and other important parameters necessary for leakage risk categorization.

Category-1: Wells with complete cement coverage in the storage zone

In these wells, casing in the entire storage zone is cemented. Based on the historical data (Ozyurtkan et al., 2011) and references therein, the fluids from the storage zone may migrate to shallower permeable formations through either cement sheath, casing-cement or cement-formation micro annuli, or may flow inside the casing if casing integrity has been compromised over the years. These possible flow paths have been depicted in Figure 2 (a). These flow path assumptions are valid only if formations have not collapsed in the wellbore. It is highly probable in south Louisiana, that some of wellbores may have collapsed over time. In that case some of the above mentioned flow paths may be unavailable for leaky fluids.



(a) Cased-cemented (b) Cased-uncemented (c) Uncased

Figure 2: Possible fluid migration paths along wellbore inside the storage zone, for (a) a cemented casing, (b) non-cemented casing, (c) no casing, size of the micro annuli has been exaggerated to show details

Category-2: Wells with no cement coverage in storage zone

In these wells the casing in the storage zone is not cemented. Casing was set deeper than the storage zone and cement top is deeper than the storage zone's top. For these wells the casing-formation annular gap is open to flow, unless formation collapses has occurred in the cap rock that might hinder the fluid migration from storage zone. The possible leak flow paths for this wellbore type are depicted Figure 2 (b).

Category-3: Wells with no casing

It is possible that some of the dry wells may only have surface casing for the protection of fresh water aquifer and the rest of the deeper well section may not be cased at all. In a worst case scenario, the entire wellbore area may provide a path for leakage fluids to escape from the storage zone, shown in Figure 2 (c).

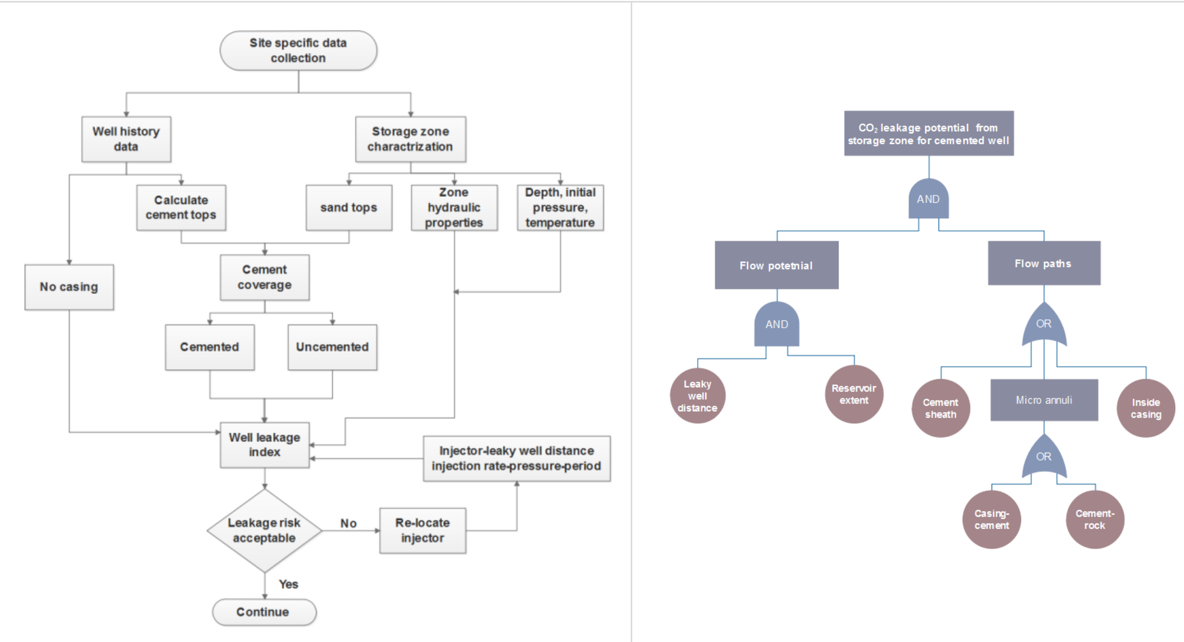
In the next section the rational adopted for estimating the leakage risk potential of these three type of wells is briefly explained.

Leakage risk classification criteria

A well's leakage potential from a storage zone can be attributed to the following factors

- Wellbore type: Higher leakage rate and high probability of leakage is expected for uncased wellbore sections in comparison to cased-uncemented and cased-cemented wellbores;
- Injector-Leaky well distance: The distance a potential leaky well is from the injection well is another important parameter in CO_2 leakage risk classification. Due to operational conditions and dynamic storage zone variable constraints, the CO_2 plume may not reach every well in the field. Therefore wells in the immediate vicinity of an injector well are more likely to have higher CO_2 leakage than the ones at greater distance;
- Storage zone boundaries: Depending on the storage zone extent, the boundary may behave as a closed, semi-closed or open boundary system. Pressure buildup rate is much higher in bounded storage zones as compared to semi-closed or open boundary zones. Higher pressure buildup may translate to higher leakage rates;
- Overlaying buffer layers (segments): In unconsolidated sands, it is likely that over time some portions of the wellbores may have been blocked by formation collapse. This may greatly influence the leakage rates, especially for uncased wells, as these may greatly alter the permeability of the buffer or collapsed zone.

The proposed leakage risk criteria in the form of a flow chart is shown in Figure 3(a). It starts with site specific data collection, sand and cement top calculations and finally calculating the leakage risk. The corresponding fault tree is shown in Figure 3(b) as well. Fault tree analysis (FTA) is a top-down approach and is a logical representation of the many events and component failures that may combine to cause the system or top event failure (Stamatelatos, 2002 and Zulqarnain, 2015). It uses ‘logic gates’ (mainly AND or OR gates) to show how ‘basic events’ may combine to cause the critical ‘top event’. The top event in the present study is the leakage from the storage zone. One important aspect that is highlighted by the fault tree of a cased-cemented wellbore (Figure 3(b)) is the fact that leakage potential is a combination of flow potential and flow area available. A weakly cemented wellbore segment may not necessarily imply CO_2 leakage, unless other conditions also exist. Therefore flow potential and flow paths are connected by AND gate. An AND gate is activated when all the inputs are available, while an OR gate becomes active if any one of the input is available. For example, when flow potential exists, the fluid may leak through either of the three potential leak paths. Similar well specific fault trees may be constructed for cased-uncemented and uncased wells. Brine leakage FTA will be slightly different than the fault tree for CO_2 leakage as plume extent or sweep are not involved. As pressure builds up the brine may leak, through available flow paths.



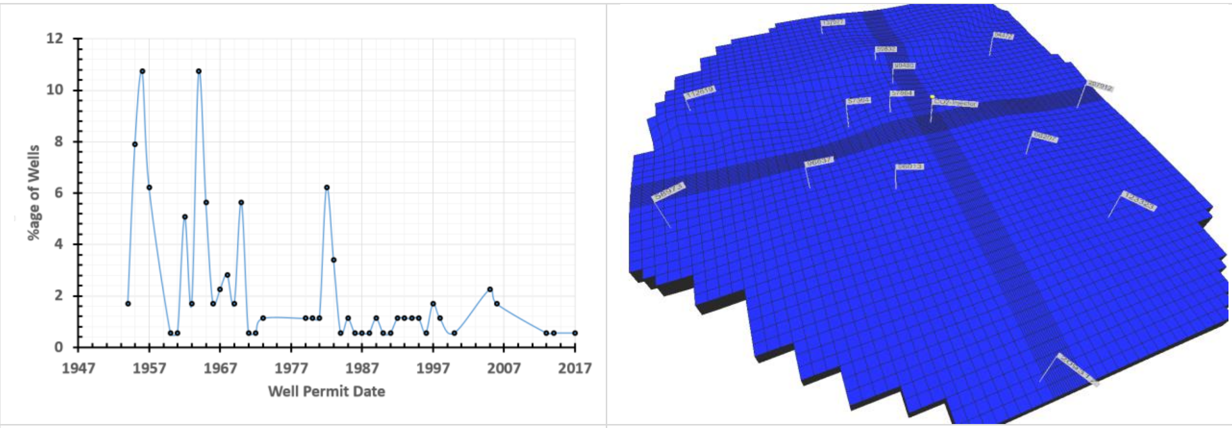
(a) Process flow chart (b) Fault tree of cemented casing section

Figure 3: (a) Flow chart of a well's leakage risk classification, (b) Fault tree of category-1 well section

Next, field specific data to be used for quantitative measurement of the effect of different parameters in defining a well’s leakage potential is examined.

Field Specific data analysis

Bayou Sorrel is a nearly abandoned oil and gas field in southern Louisiana, and is selected as an example case to show the steps necessary to evaluate the leakage potential through wells. In this field, the majority of the wells were drilled in the 1950’s and 60’s, as shown in Figure 4 (a). Here the well permit date is used as approximate proxy for the actual drilling dates, as for some of the wells the actual start of drilling (spud date) was not available. A representative set of 14 wells were randomly selected from the total of 176 wells in the area to assess the leakage risk of each well. The approximate locations of these 14 wells are shown in Figure 4 (b). A majority of the abandoned oil and gas wells are located in the center of the field where the productive sands were located, while wells towards the outer boundary are mostly dry wells and are sparsely located.



(a) well permit date (a) 14 randomly selected wells

Figure 4: (a) well permit dates and (b) 14 selected wells for cement coverage calculation

Well log data is used to identify the top and bottom of the storage zone, with an average depth of 7,900 ft. The injector is initially located in the center of the field to maximize the distance from the zone boundaries. Cement tops are determined by using the well cementing data and by using the following formulation, Bourgoyne et al., (1991).

$$L = \frac{\left(Sacks \times \dfrac{cement\ volume}{sack} - cement\ volume\ left\ in\ casing\right)}{annular\ capacity \times cement\ access\ factor}$$

For wells in which cement access factor was not calculable, a conservative value of 2 was used, as usually an access factor of 1.5 - 1.75 is used, Bourgoyne et al., (1991). The storage zone, cemented intervals, nature of the well (dry plugged or abandoned production well), cement plugs and year in which either the well was plugged or the last workover are given in Figure 5.

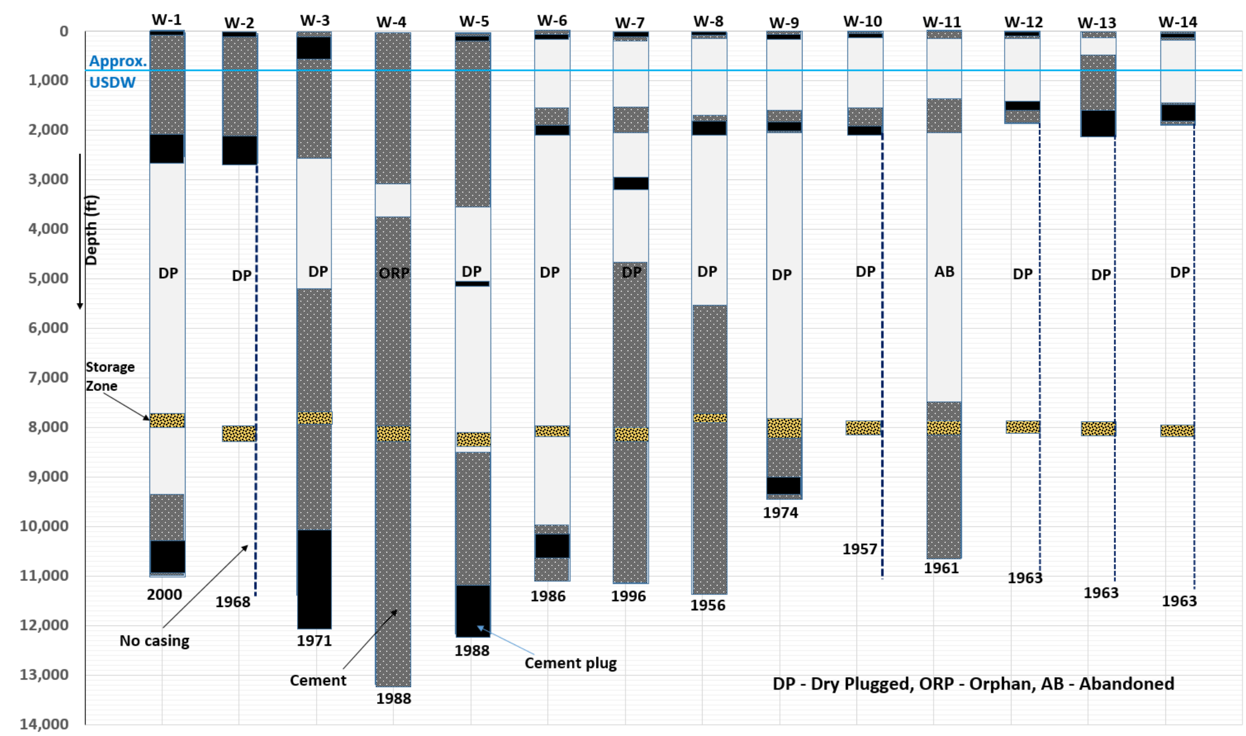


Figure 5: Data of 14 selected wells annuli is shown with storage zone, cemented intervals, nature of well (dry plugged or abandoned oil and gas well), cement plugs and year in which last work was performed on well

The USDW lower depth for this area is in the range of 300-500 ft. A conservative value of 800 ft is selected to allow some margin for depth variations. There are approximately 27 aquifer layers in between the selected storage zone at an average depth 7900 ft and the USDW bottom which is at approximately 800 ft. The average sand and shale thickness of these buffer layers are 131 and 115 ft respectively.

A closer examination of the data shows that dry and plugged wells drilled in 1950's and 60's may only have surface casing installed to protect the fresh water aquifer, with an average casing setting depth of 2,000 ft. These wells may provide the largest leak threat, provided that the wellbore has not collapsed in these wells. These wells need special attention due to the large flow area available to leaking fluids and very high permeabilities in the region. Leakage models used in this study are briefly explained in the next section.

Leakage rate modeling

The amount of CO_2 leakage is the basic element of well leakage risk assessment, consequences can be presented in the form of leaked volume to shallow fresh water aquifers or to the atmosphere. The multi-segment Wellbore Model (MWM) and Cemented Wellbore Model (CWM), available in the NRAP-Well Leakage Assessment (WLA) toolset are used (Huerta and Vasylkivska, 2016). A brief description of the models are provided below.

Cemented wellbore model (CWM)

This model is based on the results of 3-D numerical simulations of injection into a storage zone with an abandoned wellbore (Jordan et al., 2015). Leakage is treated as a flow through porous media by using Darcy's law, (Huerta and Vasylkivska, 2016). In its simplest form the flow rate is estimated from

$$Q = k_{eff} A \frac{\psi_L - \psi_T}{L}$$

where Q is the volumetric flow rate, k_{eff} is the effective permeability, A is the cross sectional area of flow, ψ_L and ψ_T are leakage potential at the leakage source and sink respectively and L is the leak path length. This model can be used to calculate leakage to an overlying shallow aquifer and a thief zone. The thief zone is of fixed thickness and should not be located at a depth less than one third the depth of the storage zone (Huerta and Vasylkivska, 2016). Time varying pressure and CO_2 saturation data from reservoir simulation are used as model inputs. In this study this model is only used to study the effect of storage boundary type on CO_2 leakage rates.

Multi segment wellbore model (MWM)

This model can calculate leakage to multiple overlying aquifers or thief zones and was developed by Nordbotten et al. (2009). This model focuses on modeling flow across large distances and does not take into account the flow in cement fractures and cracks. Flow inside the annulus is modeled and wellbore permeability along each overlying shale zone is prescribed along with the aquifer permeabilities. The model assumes constant density of CO_2 and does not incorporate any geochemical or geomechanical processes taking place inside the wellbore. This model is used to carry out the sensitivity analysis of wellbore type (cased-cemented, cased-uncemented or uncased), distance between the injector and leaky well and number of buffer layers (or barrier zones) between storage zone and leak outlet.

Wellbore permeability calculations

For pure cement, permeability is reported in the range of micro to millidarcy (Ozyurtkan et al., 2013), while the permeability of a cemented wellbore is reported to be in the range of 1.7 mD to 170mD (Gasda et al., 2013). Therefore in this study for a cemented wellbore an average value of this reported range, 86 mD is used. For cased-uncemented annuli and uncased wellbore, we use the following two equations to find the permeability in these cases. Flow rate for a circular porous medium is expressed as by Darcy law

$$q = k\pi r^2 \frac{\Delta P}{\mu L}$$

while the Hagen–Poiseuille's equation is used for flow inside circular pipe

$$q = \frac{\pi r^4}{8} \frac{\Delta P}{\mu L}$$

Comparing these two equations, the equivalent permeability for a circular pipe can be expressed as

$$k = \frac{r^2}{8}$$

The calculated values of the permeabilities for a wellbore with ID = 9.875″, and casing OD = 7″, are shown in Table 1.

Table 1: Permeability of cemented, cased-uncemented and uncased wellbore

Wellbore Type	Cased-cemented (mD)	Cased-uncemented (mD)	Uncased (mD)
Segment Permeability	8.48E+01	7.91E+12	1.59E+13

Now we select the three wells representing the cased-cemented, cased-uncemented and uncased wellbore from 14 well data set and calculate the average wellbore permeabilities for these categories. Well No.4 is selected as a representative example of a cemented wellbore as it has longer segments of cemented annulus. This wellbore has three segments, two cemented and one cased-uncemented segment. We used an average permeability in series to find the average permeability of the wellbore, which is the used in the wellbore leakage model. The average permeability is given by the following expression

$$k_{avg} = \frac{\sum_{i=1}^{n} L_i}{\sum_{i=1}^{n} \left(\frac{L}{k}\right)_i}$$

To represent cased-uncemented and uncased wellbore, well # 6 and 12 are selected, based on their cement coverage. The value of average wellbore permeabilities of these three representative example wells are shown in Table 2.

Table 2: Permeability of the representative three wellbore type

Wellbore	Cased-cemented (mD)	Cased-uncemented (mD)	Uncased (mD)
Average wellbore permeability	9.23E+01	8.81E+02	1.02E+03

In the next section we form the basis of the well leakage risk assessment criteria.

Well leakage index (WLI)

Now we form the criteria to define the well leakage index, which can be used to identify the wells that have relatively large leakage risk in comparison to other wells. We assign a range of values from 0 to 1 for each of the four factors of wellbore type, distance of leaky well to injection well, storage zone boundary types and number of buffer layers. Where the value 0 shows no influence and a value of 1 shows maximum influence. These four factors can be used to estimate the leakage potential of the well by calculating the well leakage index

$$WLI = CI \times DI \times LI \times BI$$

where *WLI* is the Well leakage index, *CI* is the cement index, *DI* is the distance index, *LI* is the layer index and *BI* is the boundary type index. Results of the CO_2 leakage models are used to assign values to these indices. Therefore the computed value of the well leakage index will provide a quantitative measure of a well's leakage potential.

Based on the WLI a tier-based approach can be developed, bounded by the limits of WLI from 0 to 1. The assumed well tiers based on the WLI are shown in Table 3.

Table 3: Well tiers for a specific filed based on the WLI

Well Tiers	WLI range (fraction of field's maximum WLI)	Remarks
1	WLI <= 0.25	Wells with minor leakage risk
2	0.25 <= WLI <=0.50	Wells with moderate leakage risk
3	0.50< WLI <=0.75	Wells with high leakage risk
4	0.75 < WLI	Wells with severe leakage risk

Now the results of a sensitivity study of wellbore types, injector to leaky well distance, storage zone boundary type and effect of buffer layers are presented in next section. MWM and CWM leakage models are used to carry out this sensitivity analysis.

Results and discussions

The results of the sensitivity analysis of the different indices are presented in this section. The CO_2 leakage volume to a fresh water aquifer or to the atmosphere is computed and is normalized by the highest leaked volume. For example for wellbore type sensitivity analysis, the leaked volume for uncased or open wellbore is used to normalize the leaked volume of all three well types, as this represents the highest leaked rate. In this way the highest leaked volume has a fraction of 1 and other categories have values that are a fraction of 1. These fractions are than used to define corresponding indices, which are used to calculate the well leakage index.

Sensitivity of wellbore type

The multisegment wellbore model (MWM) is used to carry out this sensitivity analysis. The model allows a maximum of 29 aquifers with 30 shale layers in-between the storage zone and the atmosphere. The Bayou Sorrel field sand data was used to define 29 gross sand intervals between the storage zone at an average depth of 7,900 ft and the atmosphere. A single value of permeability of 500 mD is used for shallow aquifers.

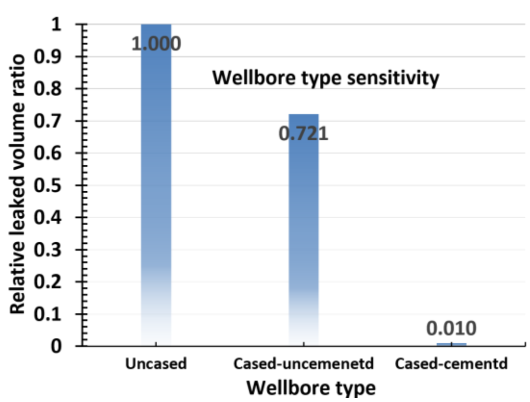


Figure 6: Leakage normalized volume, for three wellbore types for a leaky well at a distance of 328 ft from injector location with a storage zone having open boundaries

The average permeabilities of uncased, cased-uncemented and cased-cemented wellbores shown in Table 2 are used. The normalized leakage volume for the three well types for an active injection period of 30 years is shown in Figure 6. A 30% reduction in the total leaked CO_2 volume is observed when the category shifts from uncased open wellbore to cased-uncemented wellbore and an even more significant reduction is observed for a cased-cemented wellbore. We use this information to define the cement index specified in Table 1.

Sensitivity of injector-leaky well distance

The multisegment wellbore model (MWM) is used to carry out this sensitivity analysis. Due to the nature of the CO_2 displacement in the storage zone, the distance between the injection and the leaky well becomes one of the important parameter for CO_2 leakage risk classification. In this section we examine the results of sensitivity of leaked volume to injector-leaky well distance.

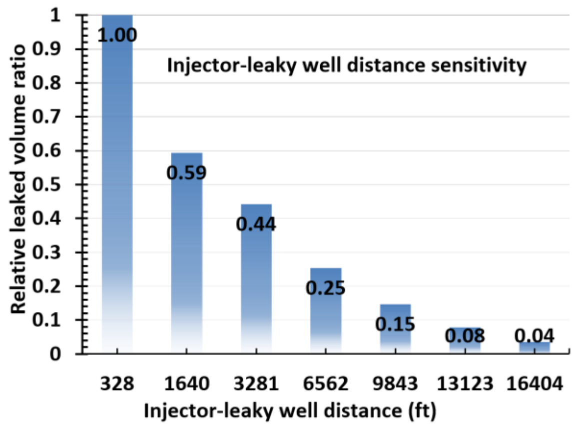


Figure 7: Normalized leaked volume variation with injector to leaky well distance, for a cemented wellbore and with a storage zone having open boundaries

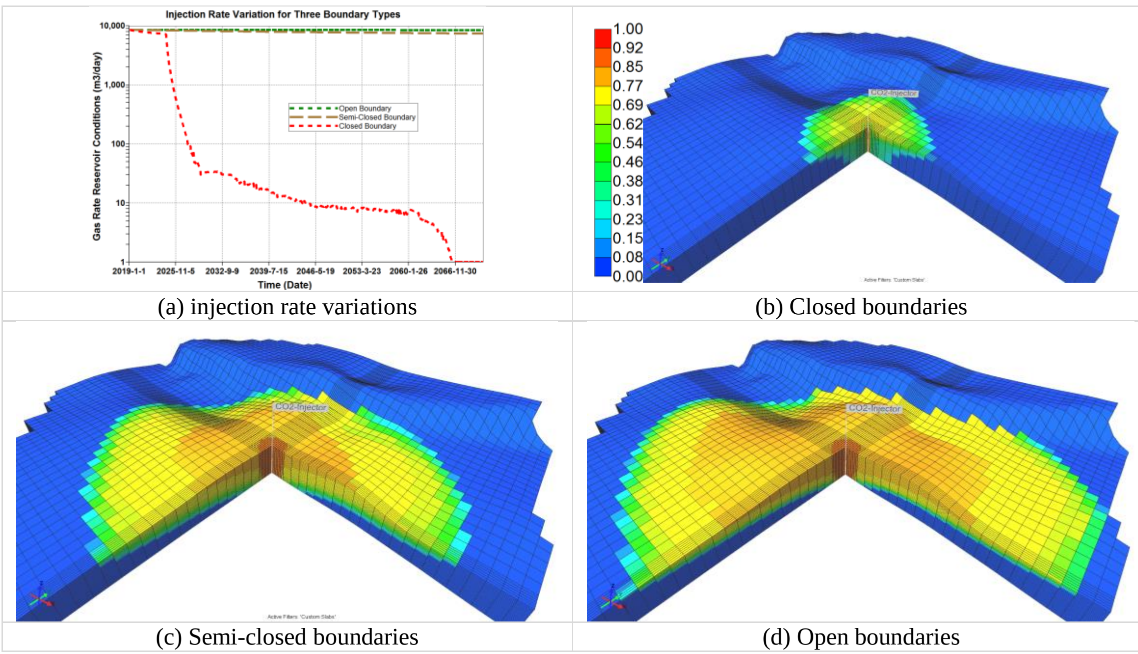
A leaky well at a distance of 328 ft is used to normalize the leaked volume, as it has the highest leaked volume. The results of the leakage model for a cemented wellbore configuration with open zone boundaries scenario for an active injection period of 30 years are shown in Figure 7.A nearly 66% drop can be noticed for the first 3,281 ft and then the cumulative leakage volume decreases slowly. Maximizing the injector-leaky well distance especially the distance from uncased wells will results in substantially reducing the CO_2 leakage volume through wellbore over the course of a projects' life. This parameter can be optimized during the planning phases of a project.

Sensitivity of storage zone boundary type

The storage zone boundary condition dictates the pressure buildup in the zone. Pressure builds rapidly for a closed boundary system, as compared to a semi-closed or an open boundary system. Reservoir simulations are performed to obtain pressure and CO_2 saturation profiles for a cemented wellbore model set of inputs. Three simulation runs were carried out for a closed, semi-closed and open boundary storage zone, at a constant injection rate of 2.46 Mton/year (0.1 m^3/s). A constant rate scenario is assumed to be consistent, as for other wellbore leakage models a constant rate of 0.1 m^3/s was used. For a closed system the injection rate is reduced as the well bottom hole pressures reaches 80% (6267 psi) of the fracture pressure, and injection is continued for a total 52 years, Figure 8 (a). This 52 year time frame is selected due to the fact that in nearly this time, the CO_2 front reaches the storage zone boundary for the more open boundary scenarios, detailed information about problem setup can be found in (Zulqarnain, Zeidouni, & Hughes, 2017). Therefore the same injection period is used for all three boundary types. In order to capture the sensitivity of pressure buildup only, a well located in close proximity (328 ft m) to the injection well is selected, so that the plume extent does not effects the results. The CO_2 plume extent for the three boundary types is shown in Figure 8. Commercially available software Petrel (2014) and CMG-GEM (2017) are used to create 3D geological model and perform reservoir simulations respectively. Plume extent is taken care by the injector-leaky well distance sensitivity analysis.

The smallest spread of the CO_2 plume is seen in the closed system for the studied constant injection rate Figure 8 (b). For this case the bottom hole pressure limit is reached within 5.41 years, with an increase of 2491 psi from initial zone pressure. The CO_2 plume is mainly concentrated around the injection well and a very large portion of the storage zone remain upswept by CO_2. This will have implications for CO_2 and brine leakage rates. For a majority of the wells, CO_2 leakage will not occur during the injection period, but brine may leak excessively to overlaying zones due to high pressure buildup. Since the CO_2 plume is of limited extent, the injection well should be located such that it is away from the leaky well locations towards the edges of the storage zone to further reduce the CO_2 leakage risk. The majority of wells are concentrated in the middle of the field, where the injector is currently located in the simulations.

In the semi-closed system Figure 8 (c), it was assumed that the pressure in the storage zone is supported by a limited extent neighboring aquifer having a size 3 times the size of the storage zone size. Pressure increases with time and an increase of 2184 psi was noted in the well bottom-hole pressure after a period of 52 years. The plume during the injection period does not reach the zone boundary. Also the spread of CO_2 is not homogeneous, therefore some of the wells towards the outer north-west and south-west edges of storage zone do not encounter the CO_2 plume.



(a) injection rate variations | (b) Closed boundaries | (c) Semi-closed boundaries | (d) Open boundaries

Figure 8: CO_2 plume extent for (a) closed boundary, (b) semi-infinite and (c) open boundary storage zone

For the open boundary system, pressure of the storage zone does not increase substantially, with an increase of only 201 psi noted in the injection well's bottomhole pressure over the injection period of 52 years. The extent of the CO_2 plume is largest in open boundary system as can be seen in Figure 8 (d). However, there are still some portions of the storage zone in which the CO_2 plume has not yet reached. The CO_2 plume may keep spreading due to buoyancy even after CO_2 injection has stopped, but at a substantially reduced rate. The results presented here are only for the time interval of active CO_2 injection period.

When we collectively look at the results, we can observe the following trends. In the case of the closed boundary system, the pressure increase is the highest and plume spread is lowest. While in the case of the open boundary system, the pressure increase is the smallest and the plume extent is largest. The storage zone with semi-closed boundary behaves in-between these open and closed systems.

The temporal profile of pressure and CO_2 saturation for leaky wells are extracted from the reservoir simulation data, and are used as inputs to the Cemented Wellbore Model (CWM). The cumulative CO_2 leaked volume is used as an indicator to see the relative difference of different boundary types. The leaked CO_2 volume is normalized using the closed boundary scenario data and results are shown in Figure 9.

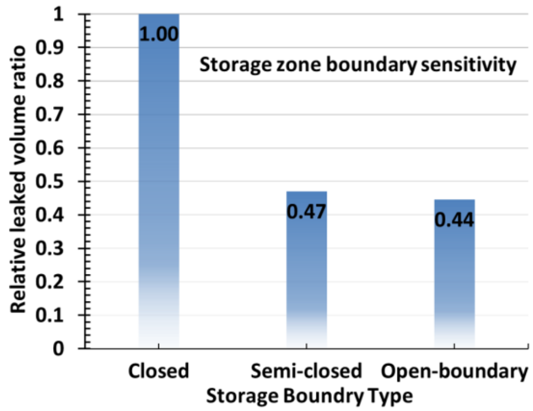


Figure 9: Normalized leaked volume sensitivity to storage zone boundary type, for a cemented wellbore type having a distance of 3oo ft from the injector location

The difference in the leaked volume ratio between the closed and the semi-closed boundary type is substantial and there is only a small change between the semi-closed and the open boundary scenario.

Sensitivity of buffer layers

In south Louisiana with unconsolidated formations, it is possible that over time some of the wellbore sections may have been collapsed. A majority of the drilled formations are made up of shale and therefore shale is the cause of most of the wellbore problems. A collapsed wellbore section may act as a barrier and the wellbore permeability may be altered substantially. This is especially true in the case of an uncased wellbore. This in turn may prevent the migration of leaky fluids through the wellbore. In this section we study the hypothetical but plausible scenario that some wellbore sections may have been collapsed over time and the permeability of these sections is reduced substantially as compared to an open wellbore. A good section of cemented wellbore may also fall under this category.

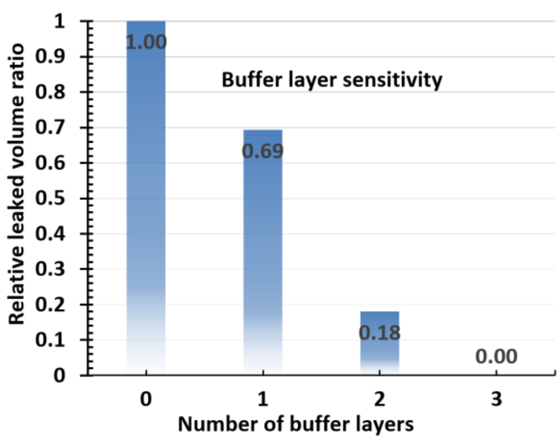


Figure 10: Normalized leaked volume sensitivity to buffer or barrier layers, for an open wellbore configuration at a distance of 300 ft from injector location for a storage zone with open boundaries

An uncased wellbore configuration is used to study the buffer layer effects. We assume the thickness of each buffer layer is approximately 100 ft (30 m) and select shale layers having nearly the same thickness in the upper portions of the well with less than 4,000 ft depth and carry out the sensitivity analysis. A permeability value of 0.01 mD is assumed for these buffer layers. The results of the leakage rate to fresh water aquifers are reported in Figure 10. A nearly 30% reduction in leakage volume is noted if one such buffer layer or segment exists and a higher reduction of nearly 82% is noticed if two buffer or collapsed zones are present each of which has 100 ft length and 0.01 mD permeability.

Calculation of the wellbore leakage index

Based on the results of the sensitivity of four wellbore parameters, we now formulate the criteria to assign the indices to different parameters. The suggested values based on the modeling results are shown in Table 4.

Table 4: Assign indices to different variable categories

Variables	Category-1	Category-2	Category-3
Wellbore Type	**Cased-cemented**	**Cased-uncemented**	**Uncased**
Cement Index (CI)	0.01	0.72	1
Injector-leaky well distance (m)	**5000**	**1000**	**100**
Distance index (DI)	0.04	0.44	1
Boundary Type	**Open boundary**	**Semi-closed**	**Closed**
Boundary Index	0.44	0.47	1
No. of Buffer Layers	**2**	**1**	**0**
Layer Index (LI)	0.18	0.69	1

Now we apply this criteria to the sample of 14 selected wells. The field is bounded by a fault to the north, so most probably it will behave like a semi-closed system. The well information and assigned indices are shown in Table 5. After calculation of the well leakage index for each of the wells, we use the criteria specified in Table 3, to assign the well tiers, in order to identify the wells that have relatively higher leakage potential. Initially we use the WLI value for no buffer layers as a conservative approach to assign the well tiers.

Table 5: Assigned variable indices for the 14 selected wells for well types 1-cased-cemenetd, 2-cased-uncemented, 3-uncased

Well Sr. No.	Wellbore Type	Cement Index	Injector-leaky well distance (ft)	Distance Index	Storage zone boundary type	Well leakage index when number of buffer layers		
					Semi-Closed	0	1	2
1	2	0.72	984	0.73	0.47	2.4602E-01	1.6975E-01	2.3180E-02
2	3	1.00	2297	0.52	0.47	2.4272E-01	1.6748E-01	2.2563E-02
3	1	0.01	4921	0.33	0.47	1.5370E-03	1.0605E-03	9.0477E-07
4	1	0.01	1640	0.60	0.47	2.8203E-03	1.9460E-03	3.0462E-06
5	2	0.72	9843	0.15	0.47	5.2372E-02	3.6137E-02	1.0505E-03
6	2	0.72	5906	0.28	0.47	9.5333E-02	6.5780E-02	3.4806E-03
7	1	0.01	6890	0.24	0.47	1.1440E-03	7.8937E-04	5.0123E-07
8	1	0.01	984	0.73	0.47	3.4169E-03	2.3577E-03	4.4715E-06
9	2	0.72	16404	0.03	0.47	9.4121E-03	6.4943E-03	3.3927E-05
10	3	1.00	11483	0.12	0.47	5.4734E-02	3.7766E-02	1.1473E-03
11	1	0.01	328	1.00	0.47	4.7002E-03	3.2431E-03	8.4606E-06
12	3	1.00	4921	0.33	0.47	1.5370E-01	1.0605E-01	9.0477E-03
13	3	1.00	2625	0.48	0.47	2.2713E-01	1.5672E-01	1.9757E-02
14	3	1.00	9843	0.15	0.47	7.2739E-02	5.0190E-02	2.0264E-03

The results of the assigned well tiers are shown in Figure 11. From this distribution it is easy to identify the wells with the highest leakage potential. Wells assigned to tier-4 need special attention, as these have the highest leakage potential.

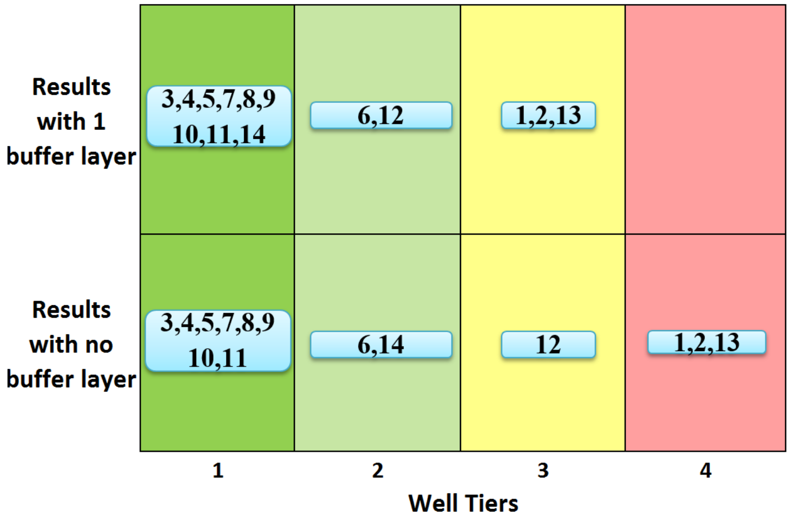


Figure 11: Well tiers assigned to 14 selected wells, based on their well leakage index value

Well 1 falls in tier-4 primarily due to its close proximity to the injection well and its wellbore category of cased-uncemented, which have relatively higher permeability values than cased-cemented wellbores. Similar arguments are true for other wells as well. Now we examine the effect of buffer layers. As can be seen in Figure 11, the presence of only one buffer segment or layer reduces the leakage risk of some of the wells, visible by their well tier shift to lower values. The presence of more buffer layers or well segments that may act as barriers will further reduce the leakage risk of wells.

The criteria used to define indices have a range from 0 to 1. These ranges may be revised and may be calibrated to account for the relative effect of different indices. In that case the ranges may not necessary be restricted between 0 and 1 and relatively higher values of such an index would be the indicators for concern.

Conclusions

A risk based approach is presented that can be used to identify wells that have relatively higher leakage potential as compared to other wells penetrating a storage zone. The method uses qualitative and quantitative measures of assessing a well's leakage potential. The approach uses well leakage index as the primary variable to categorize the wells into four tiers, with tier-1 having lowest and tier-4 having highest leakage potential. The cement data of a representative sample of 14 wells from a Louisiana oil field is used to categorize the wellbore types into cased-cemented, cased-uncemented or uncased wellbores to calculate their respective leak permeabilities. The results of well cement data show that dry and plugged wells drilled in the 1950's and 60's need special attention. These wells may only have surface casing installed to protect fresh water aquifers and well segments passing through the deeper storage zones may not be cased. These wells may provide the largest flow area to leaking fluids provided that the wellbore has not collapsed. It was also observed that all wells had some sort of protection for the fresh water aquifers, either cemented surface casing or cement plugs installed at an average depth of 2,000 ft. Well leakage index is based on the cement coverage of the well section passing through the storage zone, the well's proximity to the injection well, the nature of the storage zone boundaries and the number of buffer barrier layers or zones between the storage zone and the base of the USDW. The CO_2 leakage to the USDW is calculated for a period of 30 years and average leaked volume is estimated for a constant storage zone injection rate of 2.46 Mt/year. The leaked volume is normalized for each variable category and a well leakage index is calculated based on these normalized values. The well leakage index provides a quantitative measure of a well's leakage risk. It is also noted that optimization of injector location is of prime importance for well leakage risk assessment. If possible it should be located in the field where wells are sparsely located. The proposed risk based model to categorize the wells based on the well leakage index should facilitate in the planning and execution stages of a project.

Nomenclature

FTA	Fault tree analysis
CMW	Cemented wellbore model
MWM	Multisegment wellbore model
WLI	Wellbore leakage index
CI	Cement-index
DI	Distance index
BI	Boundary index
LI	layer index
k_{eff}	Effective permeability (mD)
k_{avg}	Average permeability (mD)
ψ	Leakage potential

Acknowledgements

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Risk Based Approach to Identify the Leakage Potential of Wells in Depleted Oil and Gas Fields for CO_2 Geological Sequestration

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Mehdi Zeidouni, Richard G. Hughes

CMTC-2017

LSU

07/19/2017

Presentation Outline

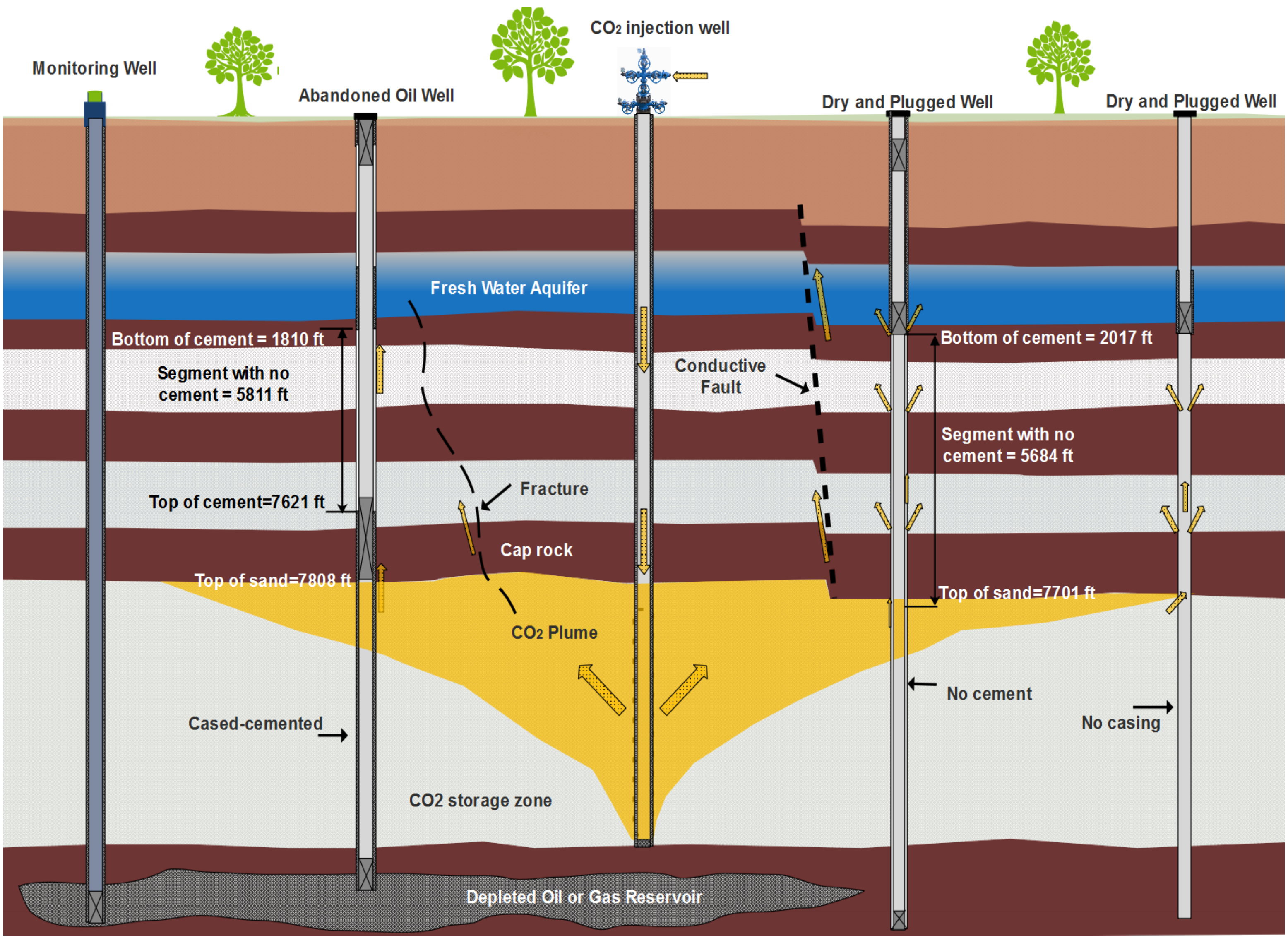
- **Background leakage and wellbore types**
- **2- Methodology**
- **3- Results and conclusions**

Depleted oil and gas fields for Sequestration

- **Positive aspects**
  - the storage capacity or pore volume can be reliably estimated
  - reservoir characterization can be performed with more readily available well, log or seismic data

- **Negative aspects**
  - presence of wells in the field, as each well may provide a leakage pathway for injected CO_2

Leakage from storage zone



Wellbore Leakage-Important Parameters

- **Wellbore type (Cement Index)**
- **Injector-Leaky well distance**
- **Storage zone boundaries**
- **Overlaying buffer layers (segments)**

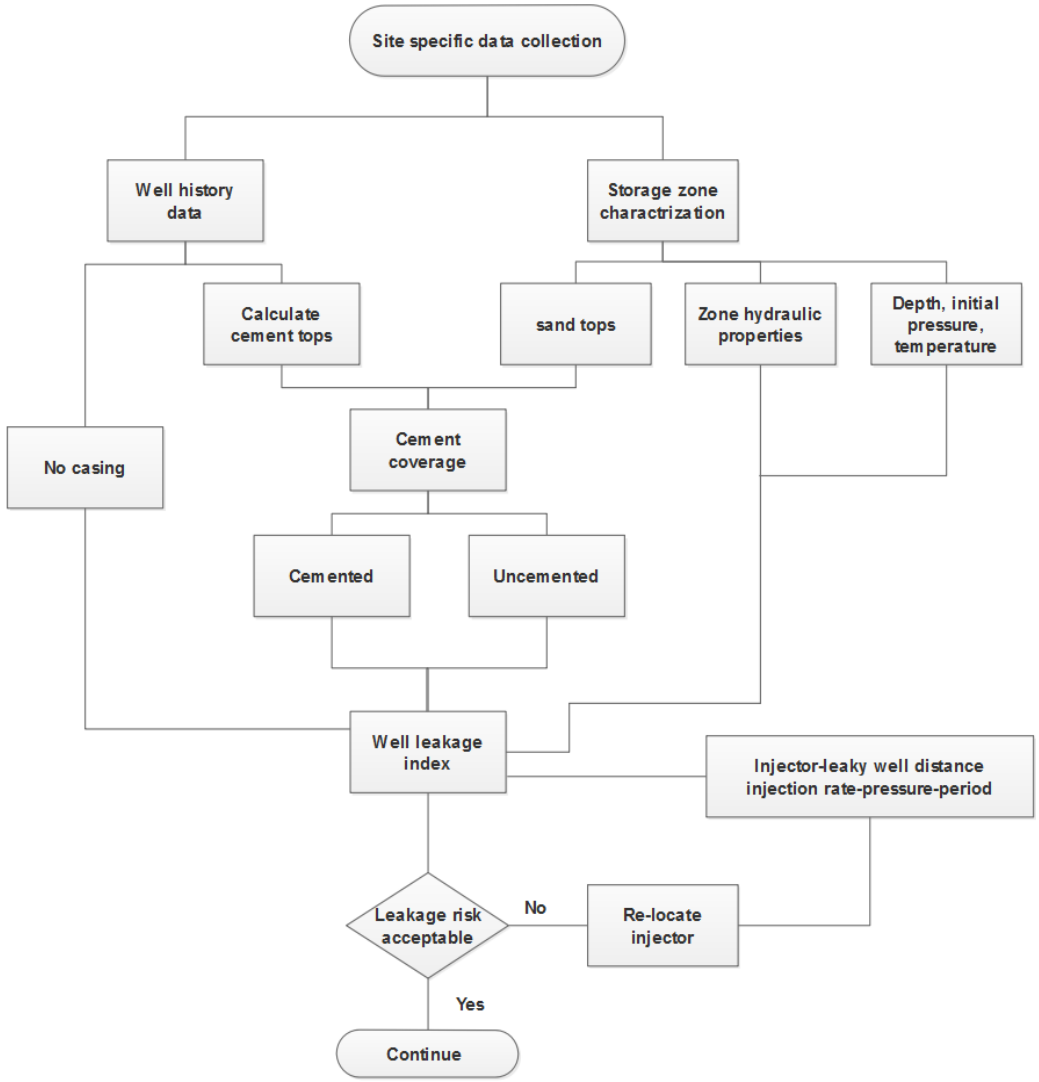
Well Leakage Index and Well Tiers

		Assumed ranges	
Variable category	Symbols	Min	Max
Wellbore type (cased-cemented, cased-uncemented, uncased)	cement index (CI)	0	1
Injector-leaky well distance	distance index (DI)	0	1
Buffer layers	Layer index (LI)	0	1
Boundary type (open, semi-closed, closed)	Boundary index (BI)	0	1

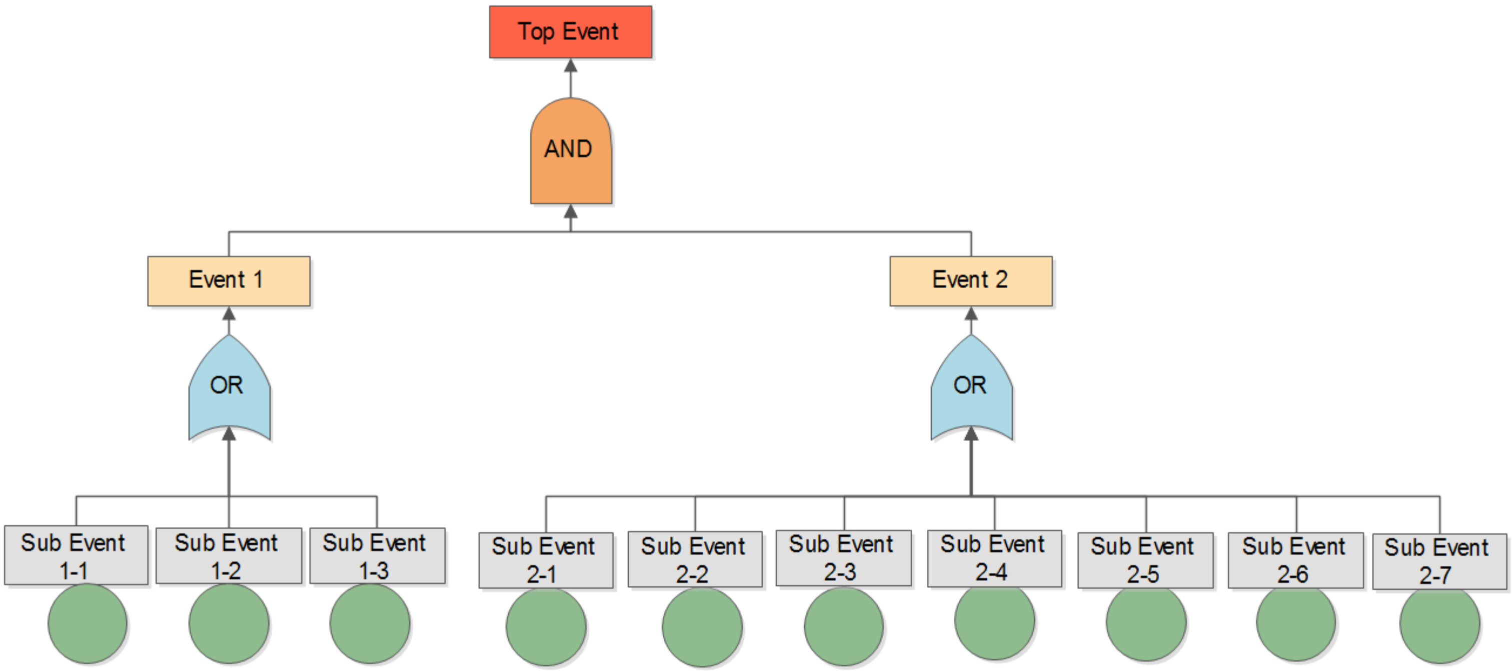
$$WLI = CI \times DI \times LI \times BI$$

Well Tiers	WLI range	Remarks
1	<=0.03	Wells with minor leakage risk
2	0.03-0.05	Wells with moderate leakage risk
3	>0.05<0.1	Wells with high leakage risk
4	>0.1	Wells with severe leakage risk

Workflow Diagram

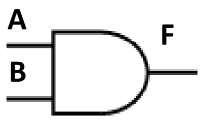


Fault Tree



- A Fault Tree is a graphical representation of events in a hierarchical, tree-like structure
- Create the logical process of event occurrence by using gates and represent failures using a few basic events
- Requires information on quantitative system reliability and maintainability data, such as failure probability, failure rate, expected failure, down time, repair rate, etc.

Gates and Probabilities



AND

Inputs		Output
A	B	F
0	0	0
1	0	0
0	1	0
1	1	1

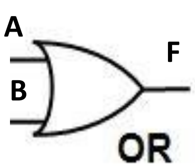
$$P(A \; and \; B) = P(A)P(B|A) = P(B)P(A|B)$$

Assumption: Mutually Independent

$$P(A|B) = P(A)$$

$$P(B|A) = P(B)$$

$$P(A \; and \; B) = P(A)P(B)$$



Inputs		Output
A	B	F
0	0	0
1	0	1
0	1	1
1	1	1

$$P(A \; orB) = P(A) + P(B) - P(A \; and \; B)$$

Assumption: Mutually Independent

$$P(A \; orB) = P(A) + P(B) - P(A)(B)$$

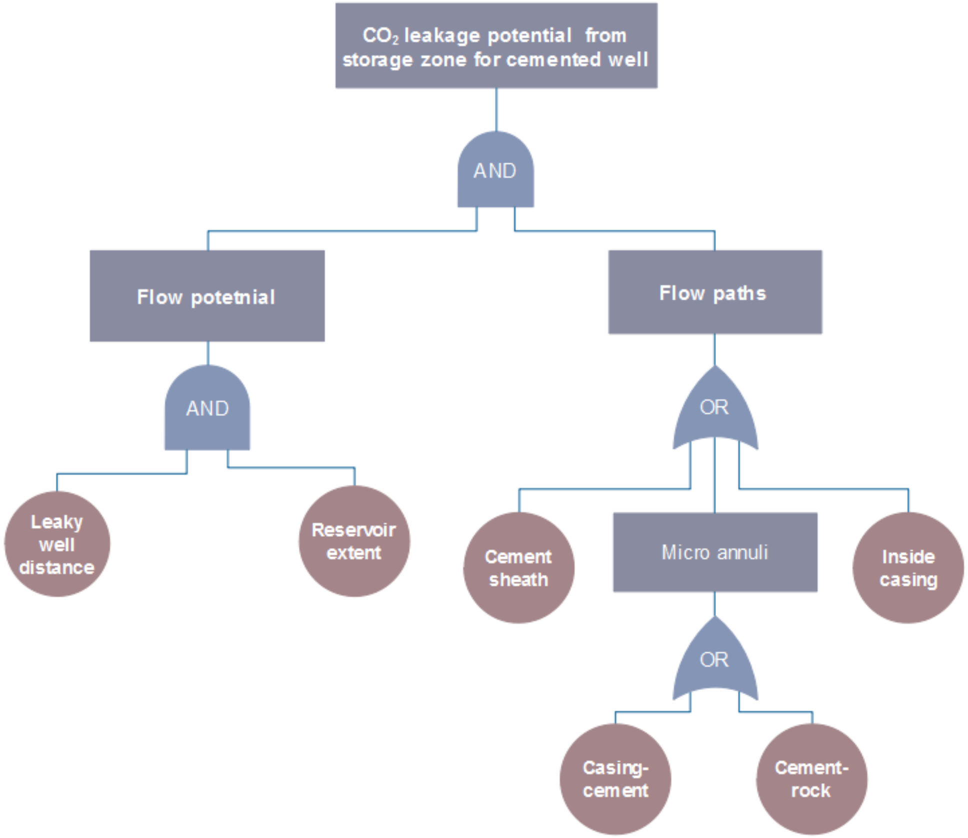
Assumption: Rare Events

If the $P_{A\&B}$ is small ≤ 0.2 than

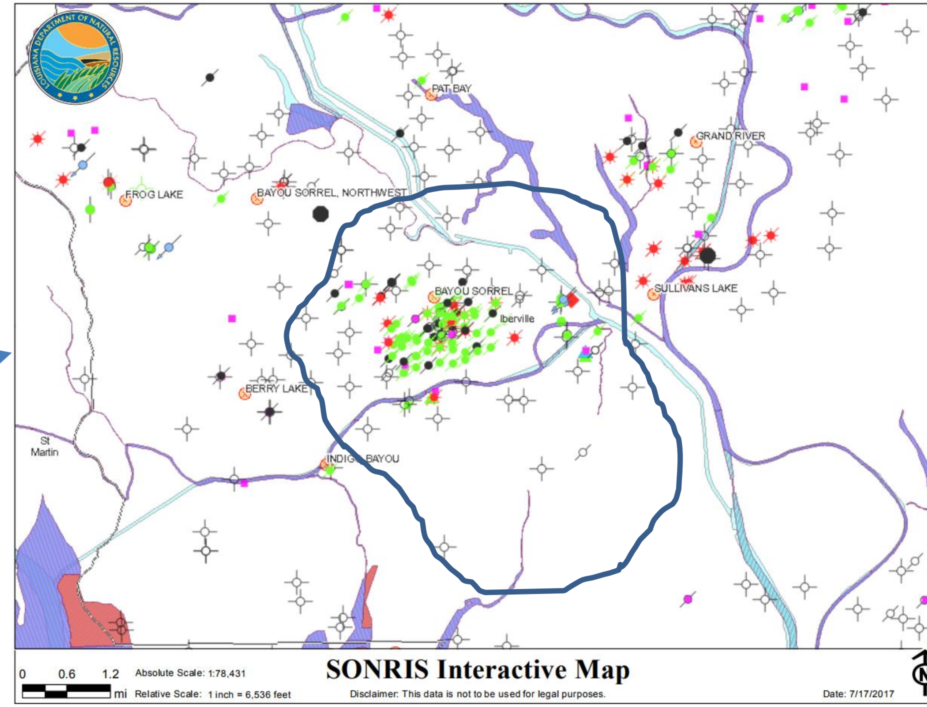
$$P(A \; orB) = P(A) + P(B)$$

with error ≤ 11%. Then this approximation is called “rare event approximation”.

Gates and Probabilities

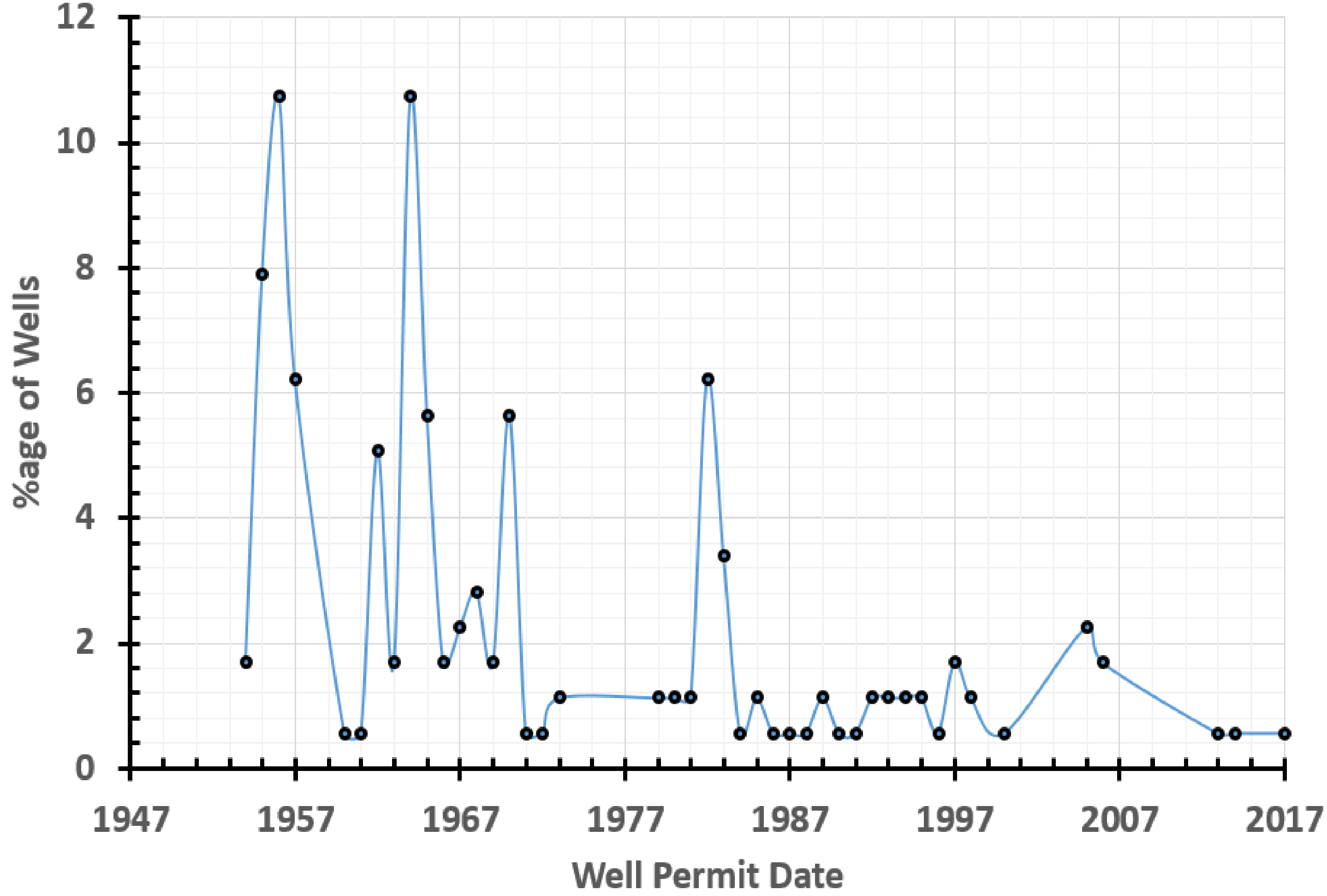


Bayou Sorrel-Well Data



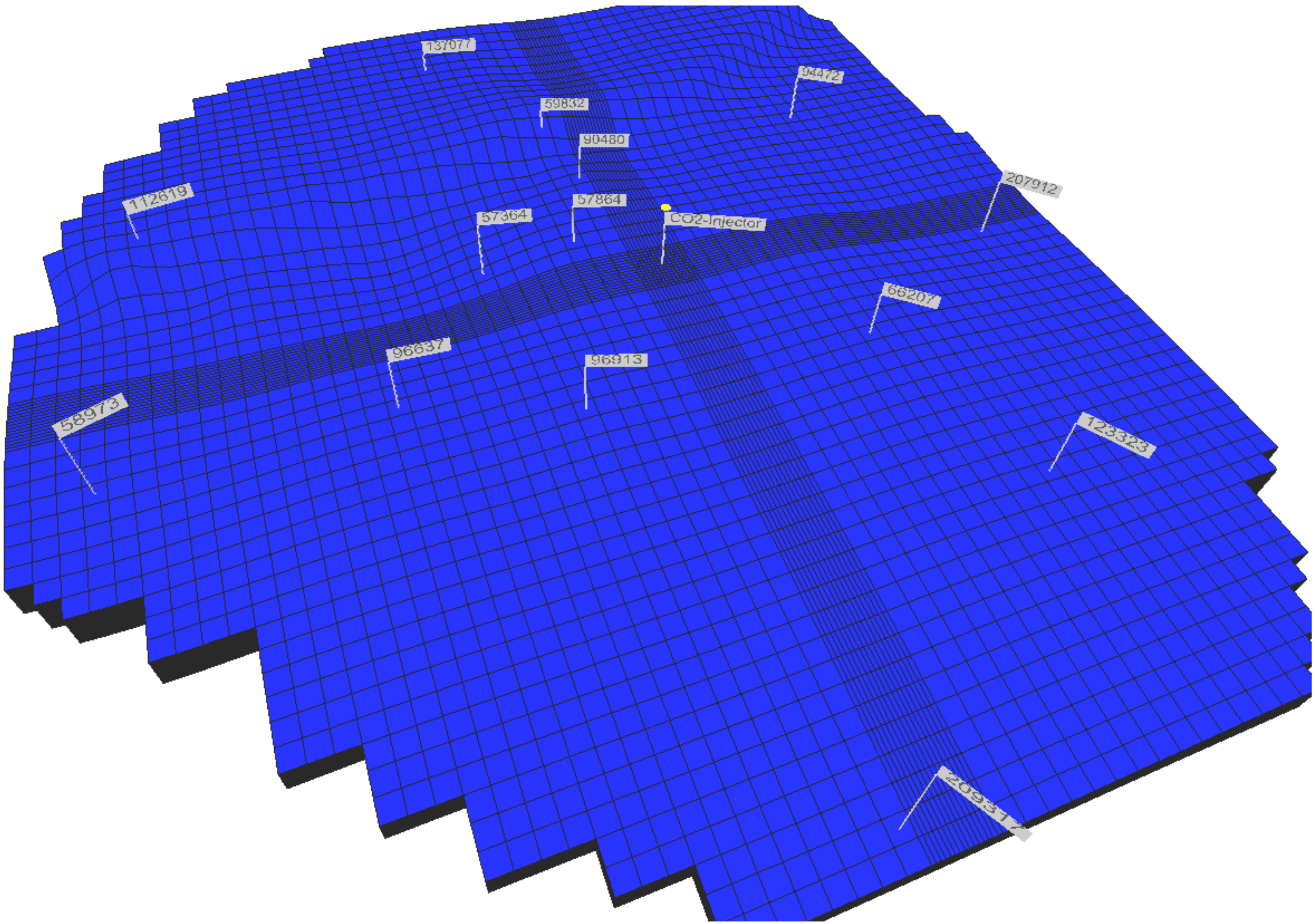
Field Name	Well Status Code	Well Status Code Description	Number of Wells
BAYOU SORREL	03	PERMIT EXPIRED	17
	09	ACTIVE- INJECTION	2
	10	ACTIVE - PRODUCING	3
	20	PA-35 TEMPORARY INACTIVE WELL TO BE OMITTED FROM PROD.REPORT	1
	23	ACT 404 ORPHAN WELL-ENG	3
	26	ACT 404 ORPHAN WELL-INJECTION AND MINING	1
	29	DRY AND PLUGGED	36
	30	PLUGGED AND ABANDONED	111
	33	SHUT-IN PRODUCTIVE -FUTURE UTILITY	1
	36	SHUT-IN WAITING ON PIPELINE	1
			Field Total: 176

Well Permit Data

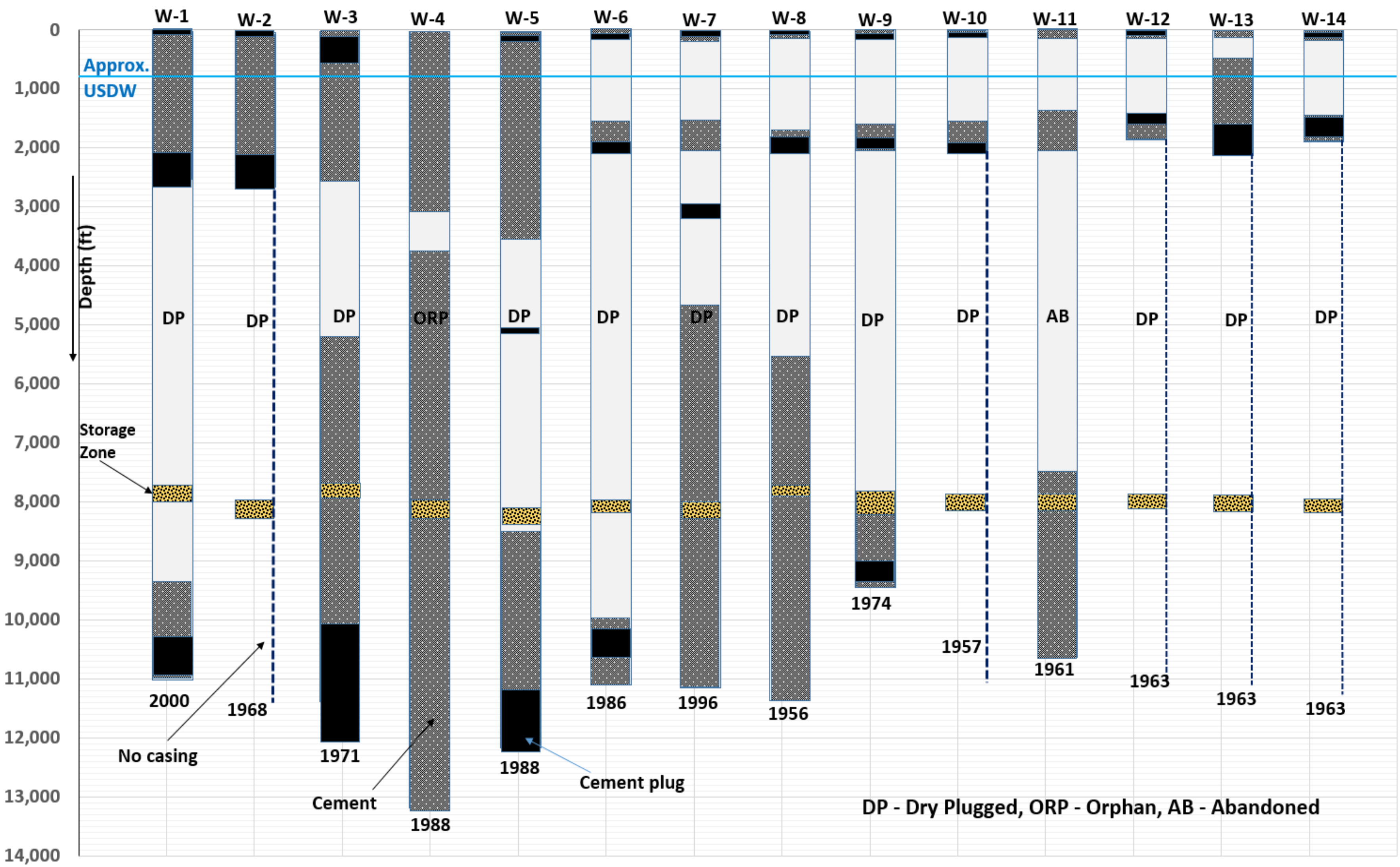


Ref: SONRIS

Selected Wells for Detailed Analysis



14 Sample Well Data

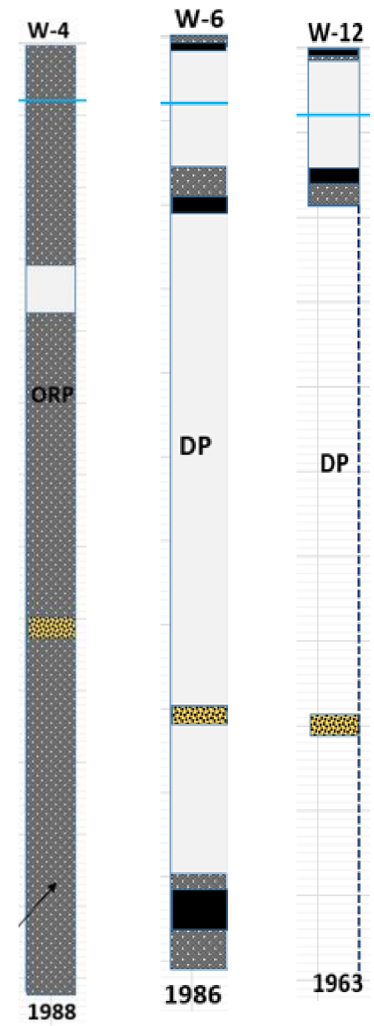


Permeability Calculations

Wellbore Type	Cased-cemented (m²)	Cased-uncemented (m²)	Uncased (m²)
Segment Permeability	8.40E-14	7.83E-03	1.57E-02

$$k_{avg} = \frac{\sum_{i=1}^{n} L_i}{\sum_{i=1}^{n} \left(\frac{L}{k}\right)_i}$$

Wellbore	Cased-cemented (m²)	Cased-uncemented (m²)	Uncased (m²)
Average wellbore permeability	9.14E-14	8.72E-13	1.01E-12

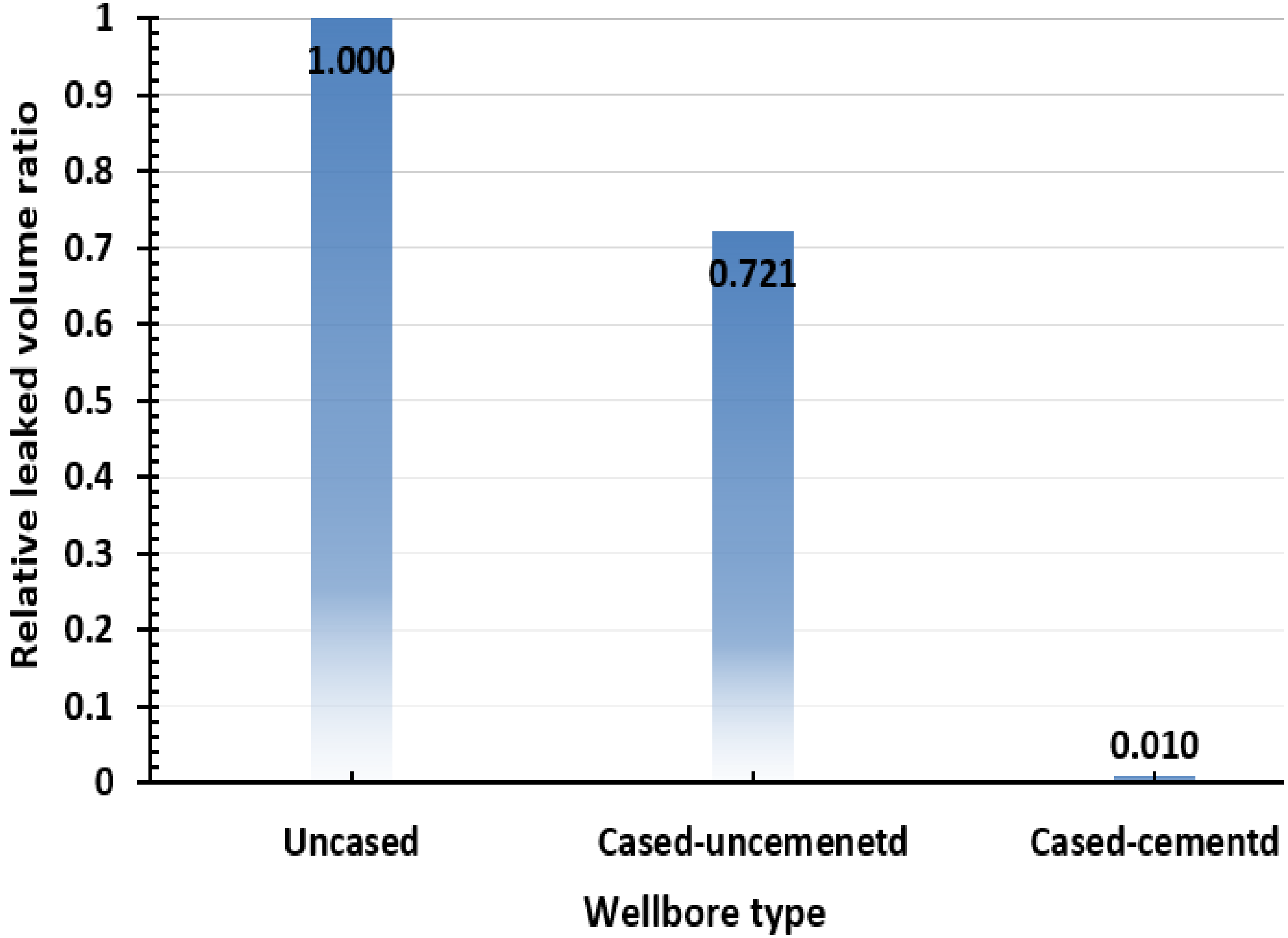


Wellbore Leakage Models Used

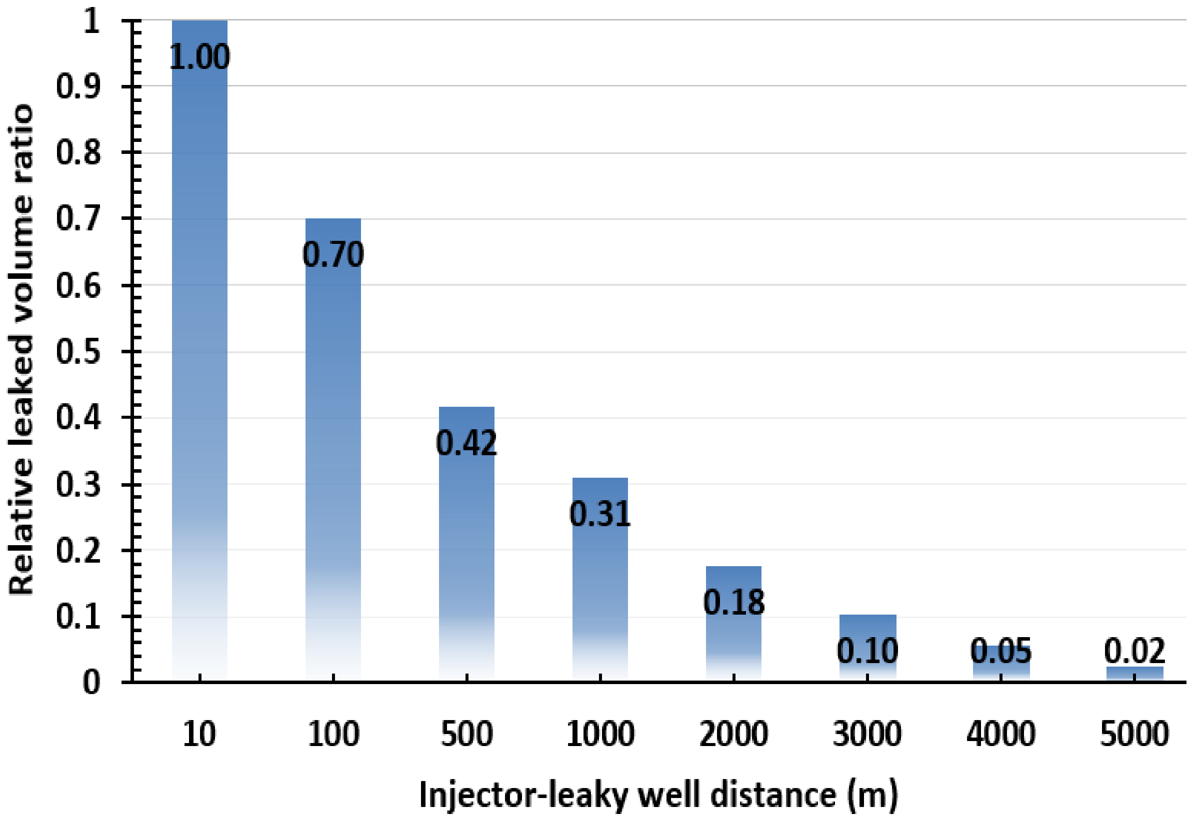
- **Cemented wellbore model (CWM)**
  - This model is based on the results of 3-D numerical simulations of injection into a storage zone with abandoned wellbore (Jordan et al., 2015). Leakage is treated as a flow through porous media by using Darcy's law, (Huerta, N. J.; Vasylkivska, 2016)
  - **Used for storage zone boundary sensitivity analysis**

- **Multi segment wellbore model (MWM)**
  - This model can calculate leakage to multiple overlying aquifers or thief zones and was developed by (Nordbotten et al., 2009). This model focuses on modeling flow across large distances and does not take into account the flow in cement fractures and cracks
  - **Used for wellbore type, injector-leaky well distance and buffer layer sensitivity analysis**

Results Wellbore Type for Cement Index

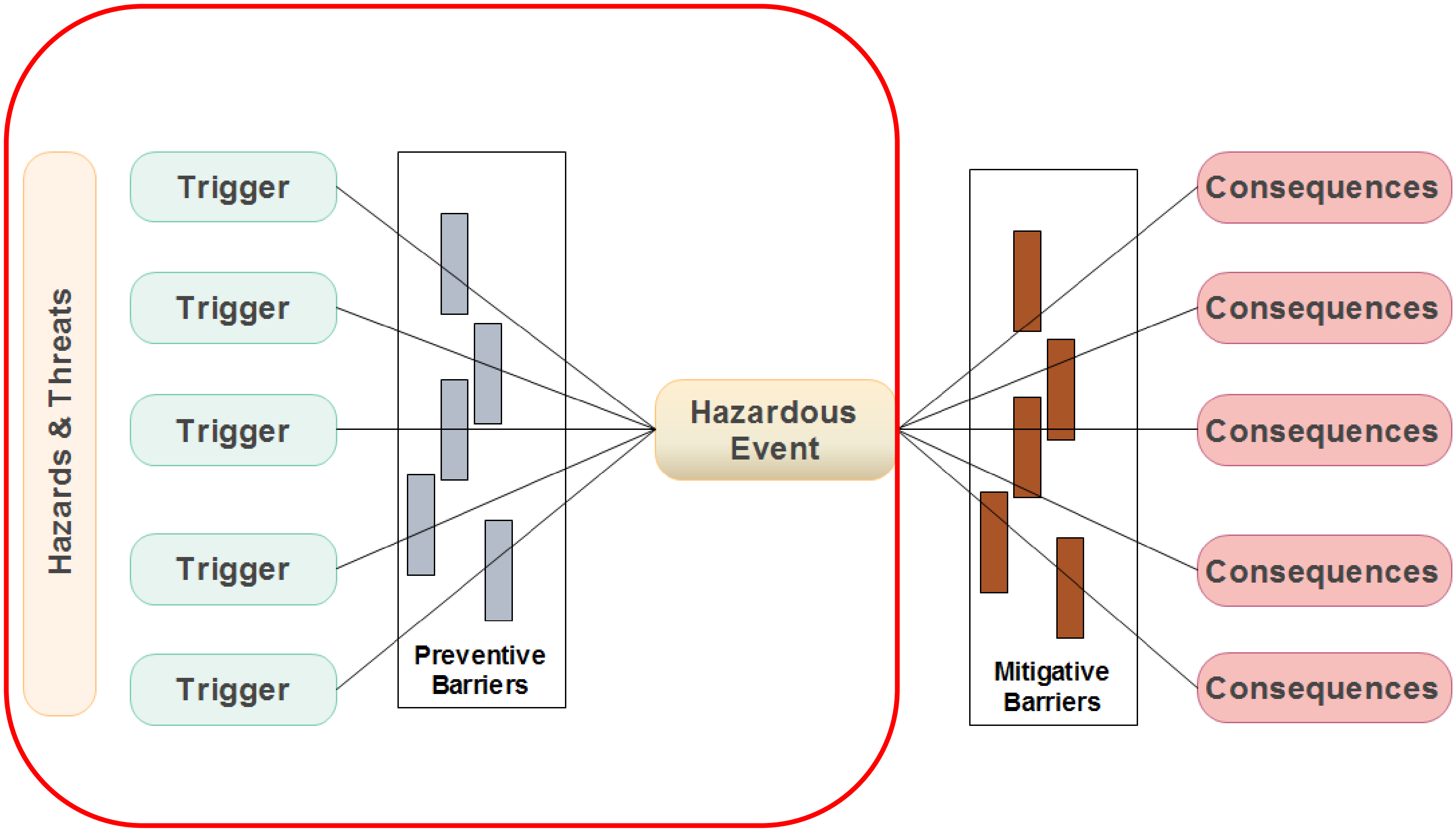


Results-Well Distance

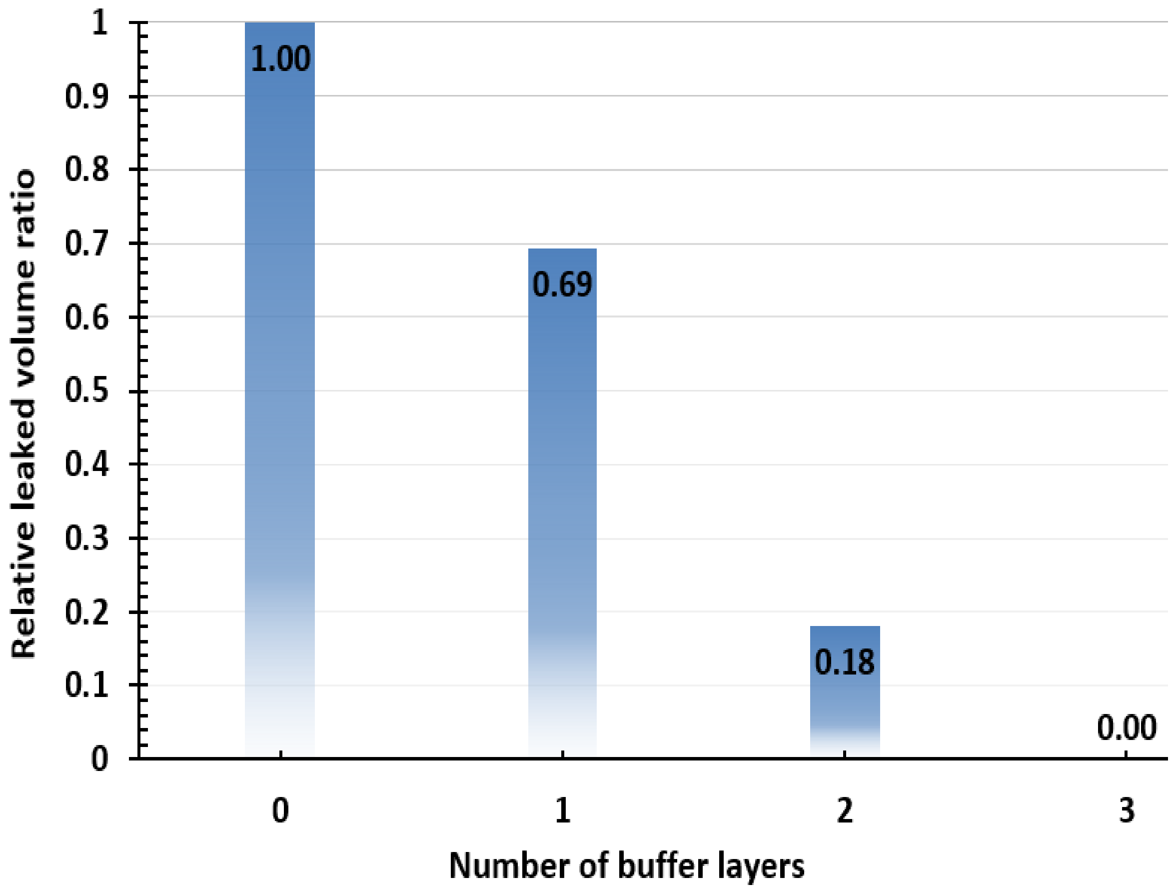


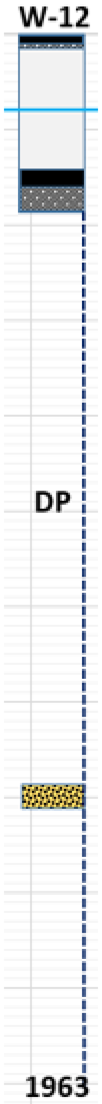
Results-Buffer Segments (layers)

- Multiple layers of Barriers

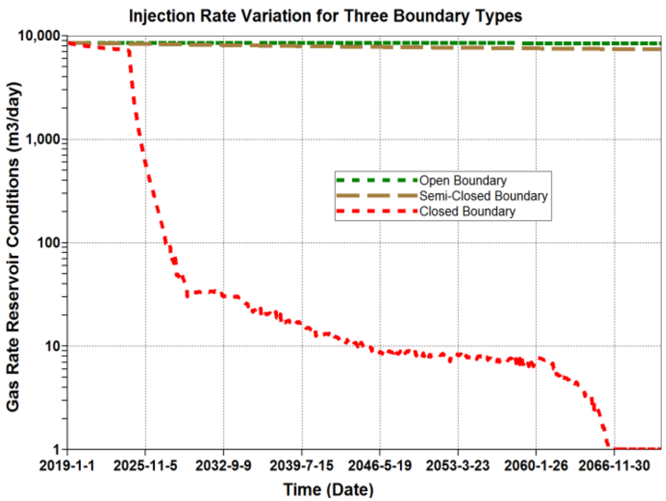


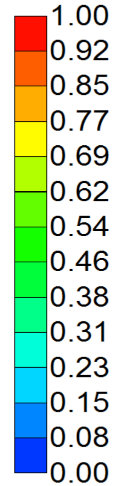
Results-Buffer Segments (layers)

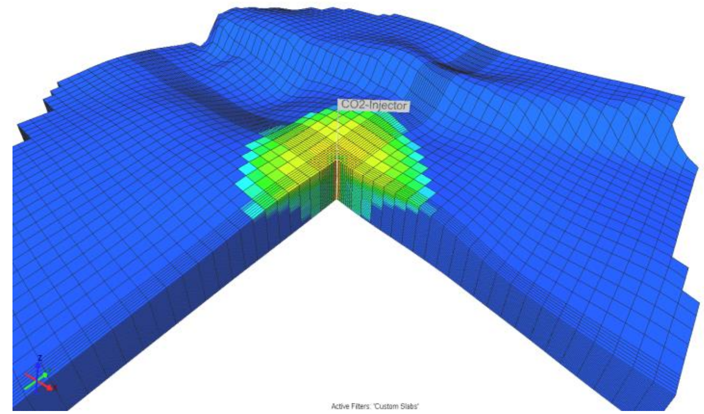




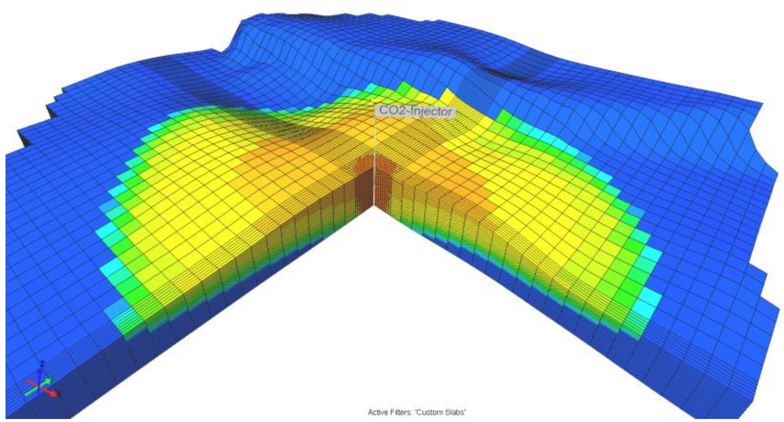
Results-Store Zone Boundary (Simulation Results)



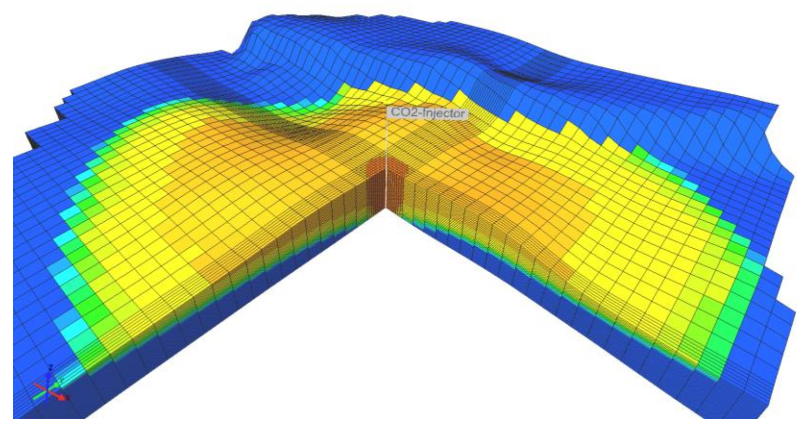




(a) Storage zone with closed boundaries, rate=2.64 Mt/y

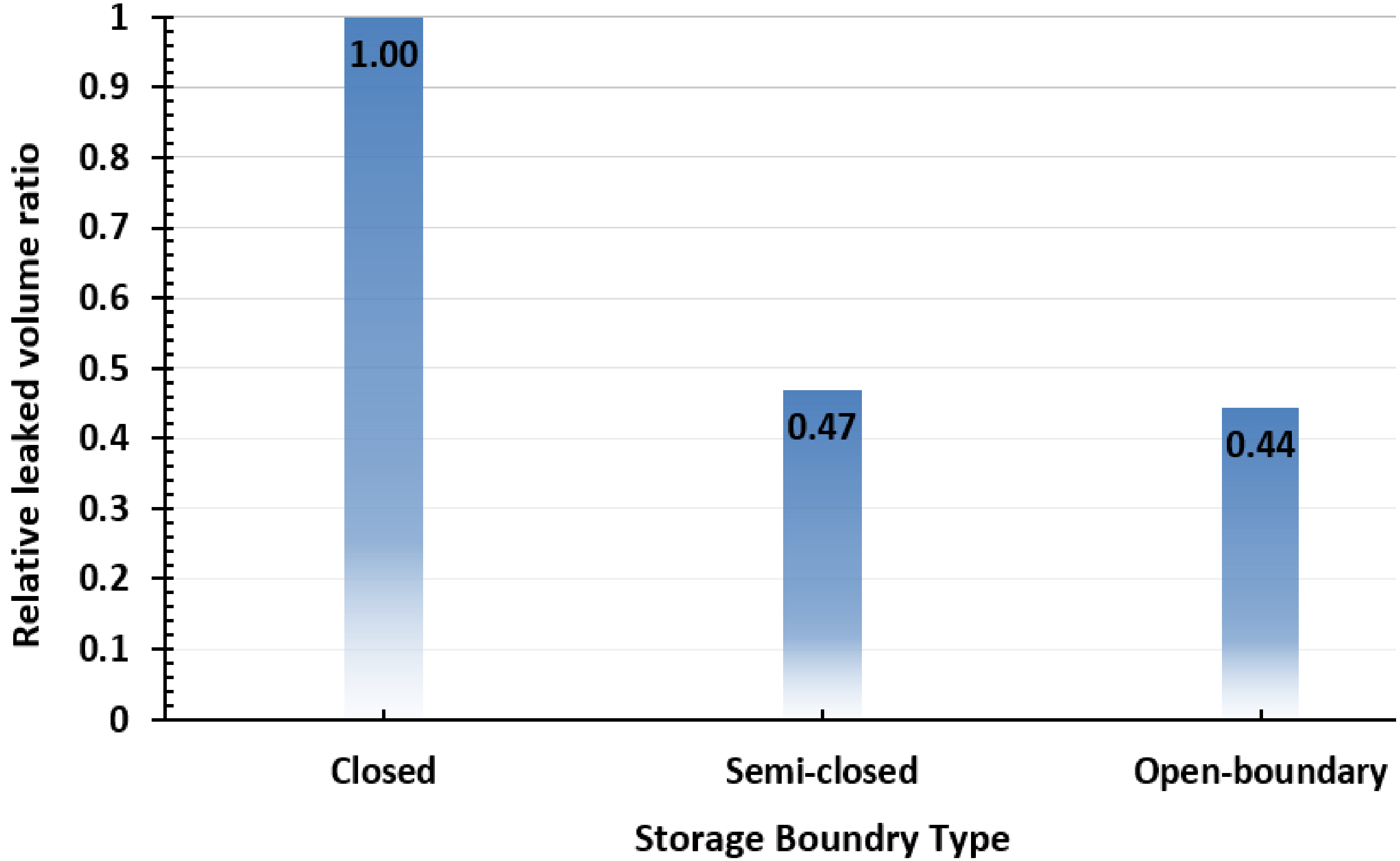


(b) Storage zone with semi-closed boundaries, rate=2.64 Mt/y



(c) Storage zone with open boundaries, rate=2.64 Mt/y

Results-Store Zone Boundary



Well Leakage Index

Variables	Category-1	Category-2	Category-3
Wellbore Type	**Cased-cemented**	**Cased-uncemented**	**Uncased**
Cement Index (CI)	0.01	0.72	1
Injector-leaky well distance (m)	**5000**	**1000**	**10**
Distance index (DI)	0.02	0.31	1
Boundary Type	**Open boundary**	**Semi-closed**	**Closed**
Boundary Index	0.44	0.47	1
No. of Buffer Layers	**2**	**1**	**0**
Layer Index (LI)	0.18	0.69	1

Well Leakage Index-14 Wells

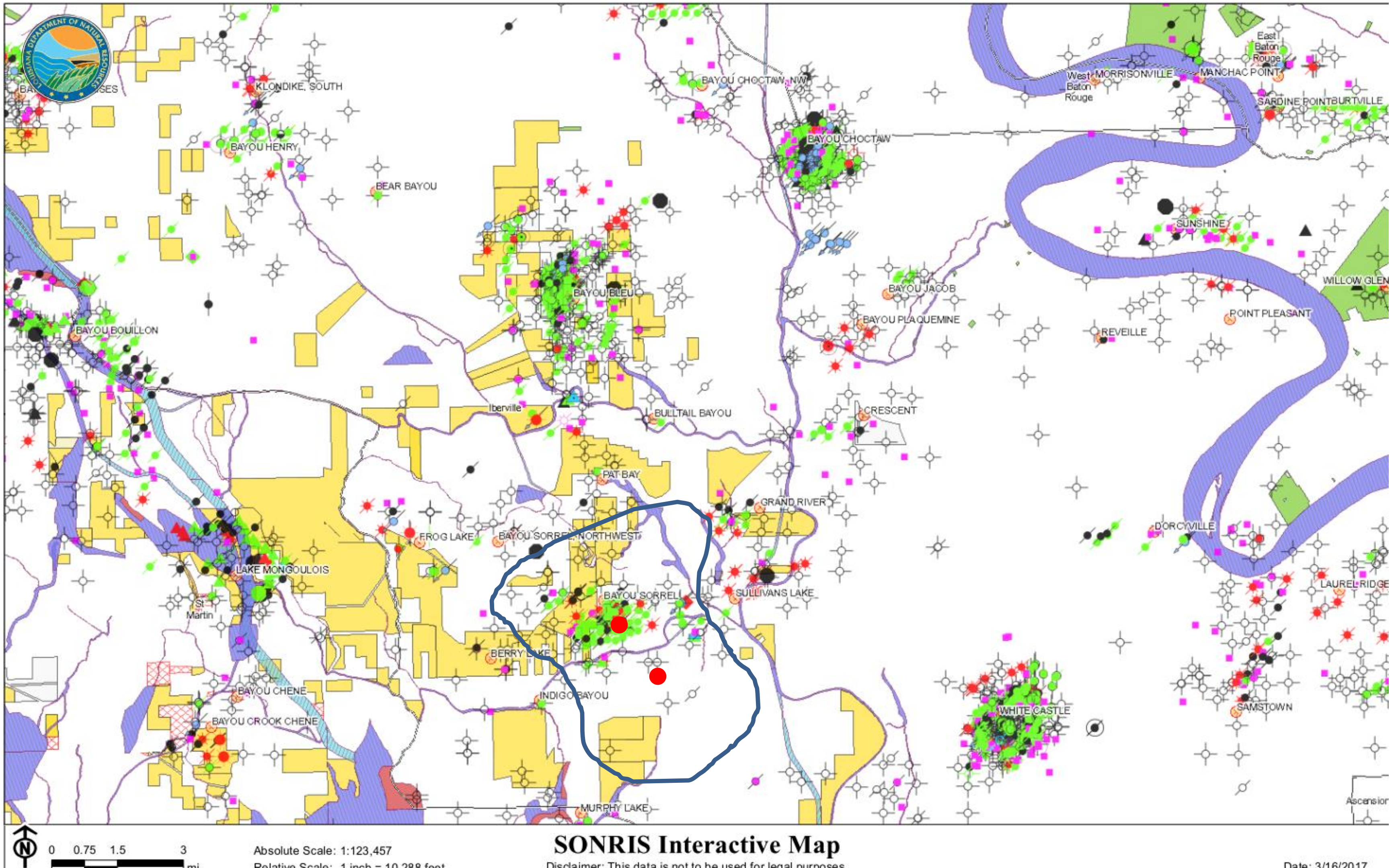
Well Sr. No.	Well Type	Cement Index	Injector-leaky well distance (m)	Distance Index	Storage zone boundary type	Well leakage index when number of buffer layers		
						0	1	2
1	2	0.72	300	0.49	0.47	1.6548E-01	1.1418E-01	1.0487E-02
2	3	1.00	700	0.35	0.47	1.6611E-01	1.1462E-01	1.0567E-02
3	1	0.01	1500	0.23	0.47	1.0880E-03	7.5071E-04	4.5333E-07
4	1	0.01	500	0.41	0.47	1.9141E-03	1.3208E-03	1.4032E-06
5	2	0.72	3000	0.12	0.47	4.0805E-02	2.8155E-02	6.3767E-04
6	2	0.72	1800	0.20	0.47	6.8463E-02	4.7239E-02	1.7951E-03
7	1	0.01	2100	0.18	0.47	8.3495E-04	5.7612E-04	2.6699E-07
8	1	0.01	300	0.49	0.47	2.2983E-03	1.5858E-03	2.0229E-06
9	2	0.72	5000	0.04	0.47	1.3147E-02	9.0711E-03	6.6191E-05
10	3	1.00	3500	0.10	0.47	4.5081E-02	3.1106E-02	7.7833E-04
11	1	0.01	80	0.70	0.47	3.2922E-03	2.2716E-03	4.1510E-06
12	3	1.00	1500	0.23	0.47	1.0880E-01	7.5071E-02	4.5333E-03
13	3	1.00	800	0.33	0.47	1.5607E-01	1.0769E-01	9.3284E-03
14	3	1.00	3000	0.12	0.47	5.6673E-02	3.9104E-02	1.2301E-03

Impact of Buffer Layers

	1	2	3	4
Results with 1 buffer layer	3,4,5,7,8,9, 11	6,10,14	12	1,2,13
Results with no buffer layer	3,4,7,8,9,11	5,10	6,14	1,2,12,13

Well Tiers

Wellbore Leakage Risk Reduction



Conclusions

- A risk based approach is developed to find a well's CO_2 leakage potential
- The approach uses the wellbore leakage index as the primary variable to identify the leakage potential
- Wellbore leakage index is based on a well's cement coverage of the storage zone, proximity to injection well, storage zone boundary type and number of buffer zone with low permeability values
- Quantitative measure of these four parameters is obtained by using the well leakage models
- The criteria is applied to a representative set of 14 wells from a depleted oil and gas field in South of Louisiana to show an example application
- The criteria is presented in a tabular form for easy applications

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Questions/Feedback