

A screening criterion for selection of suitable CO₂ storage sites

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Abstract

Carbon dioxide released into the atmosphere due to anthropogenic activities has raised the alarm of global warming in the near future. CO₂ storage in suitable subsurface geologic media has, therefore, been triggered in recent years. However, identification of suitable sites to store a large quantity of CO₂ for a long period of time is not an easy and straightforward task. Although, a general criterion has already been presented based on local-scale projects in which depth, permeability, porosity, density and containment factors were considered for selection of an appropriate geologic medium, there are many other preliminary factors linked to the storage capacity, injectivity, trapping mechanisms, and containment which should not be neglected during a CO₂ storage site selection. The aim of this paper is to propose a new screening criterion for the CO₂ storage site selection based on a group of key parameters including reservoir and well types, classes of minerals, residual gas saturations, subsurface conditions, rock types, wettability, properties of CO₂, and sealing potentials. These parameters were combined with those factors presented earlier by other scholars to provide a good insight into the suitable selection of storage sites. Although attempts were made to consider the whole parameters linked to a site selection, more studies are still required to get a final conclusion about the effective parameters which should be a part of the analysis.

Keywords: CO₂ storage sites, screening criteria, depleted gas reservoirs, injectivity, trapping mechanisms, containment

1. Introduction

Greenhouse gases are increasingly released into the atmosphere due to anthropogenic activities (Watson et al., 1992). Carbon Dioxide (CO₂) storage and sequestration in suitable geologic sites is a strategy taken in recent years to reduce the quantity of CO₂ released into the atmosphere (Bachu, 2001; Mao et al., 2014). There have, therefore, been many Enhanced Oil recovery (EOR) operations and projects exercised to explore suitable sites for a long-term storage of CO₂. Few of these projects are listed in Table 1.

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Table 1: Database of large-scale CCS projects operated or identified in recent years

Project Name	Location	Project Lifecycle Stage	Operation Date	Primary Storage Type/formation
Commercial CO₂ Storage projects in Depleted Gas Fields, EOR, AND Deep Saline Aquifer (Ukaegbu et al., 2009)				
SLEIPNER (NORWAY)	Norway	Operat	1996	Saline formation/sandstone
WEYBURN	Canada	Operat	2000	EOR /carbonates
ORC (K12-B) PHASE 2	Netherlands	Operat	2004	Depleted gas field Rotliegend (sandstone)
IN SALAH	Algeria	Operat	2004	Producing gas field Krechba (carbonate)
Future Commercial Projects Planning to store CO₂ in Depleted Gas Fields or Deep Saline Aquifers (Institute, 2015)				
SHENHUA NINGXIA CTL PROJECT	China	Identify	2020	Not specified
SHENHUA / DOW CHEMICAL'S YULIN COAL TO CHEMICALS PROJECT	China	Identify	2020	Dedicated Geological Storage
SHANXI INTERNATIONAL ENERGY GROUP CCUS PROJECT	China	Identify	2020	Not specified
DONGGUAN TAIYANGZHOU IGCC WITH CCS PROJECT	China	Identify	2019	Dedicated Geological Storage
CHINA RESOURCES POWER (HAIFENG) INTEGRATED CARBON CAPTURE AND SEQUESTRATION DEMONSTRATION PROJECT	China	Identify	2019	Dedicated Geological Storage

It is estimated that there are more than 800 sedimentary provinces across the continents which are suitable for CO₂ storage practices (Bachu, 2003). However, many factors are often included in the site selection to ensure that selected media are able to hold CO₂ for thousands of years. The basin-scale suitability assessment, for instance, requires considering geological, geothermal, hydrodynamic aspects together with basin maturity, economic, political and societal criteria (Bachu, 2001). There have been studies on the basin analysis in which suitable locations for a storage site were evaluated in terms of geology, capacity and site-source matching (Carneiro and Alberto, 2014; Fang and Li, 2011; Koukouzas et al., 2009; Mao et al., 2014). For instance, according to Metz et al. (2005), cold sedimentary basins (i.e., known for their low temperature gradient) close to the edge of stable continental plates without any fault and fractures are the best places for a long-term CO₂ storage exercise (Metz, 2005). However, selection of a sedimentary basin is the first step which needs to be followed by identifications of geological storage sites based on in-situ characteristics, such as the temperature, pressure, rock-volume, porosity, oil gravity, and in-situ CO₂ properties. (Bachu, 2001). Numbers of these in-situ characteristics with a known impact on the suitability of storage sites have remarkably been increased in the recent years, but there is almost no study considering them in a comprehensive screening criterion for the storage site selection.

The aim of this paper is to present a comprehensive screening criterion for identification of a suitable storage site based on key in-situ properties. Storage in depleted gas reservoirs is mainly discussed in this paper due to their proven storage integrities, relatively well-understood behaviors and availability of infrastructures (Tambach et al., 2015).

2. Different aspects of CO₂ storage sites

In this section, different aspects of CO₂ storages are discussed and major parameters required for a suitable storage site selection are emphasized.

2.1 Storage capacity

Storage capacity is defined as the total volume of a geological medium that can possibly be used for storage purposes. Estimation of storage capacity in gas reservoirs is conventionally done by excluding the formation water during or after the production stage. However, such estimation might be too much conservative when the dissolution of CO₂ in water is neglected (Van der Meer, 2005).

Storage capacity depends mainly on subsurface pressure and temperature conditions at which CO₂ appears at supercritical state (Qi et al., 2010). This is linked to the fact that reaching the supercritical condition is essential for CO₂ to approach a high density and gas-like viscosity, resulting in a complete pore volume utilization and mobility within a reservoir (Ketzer et al., 2012). Figure 1 displays the phase diagram of pure CO₂ indicating the pressure and temperature at which phase changes may take place in subsurface formations (Saeedi, 2012).

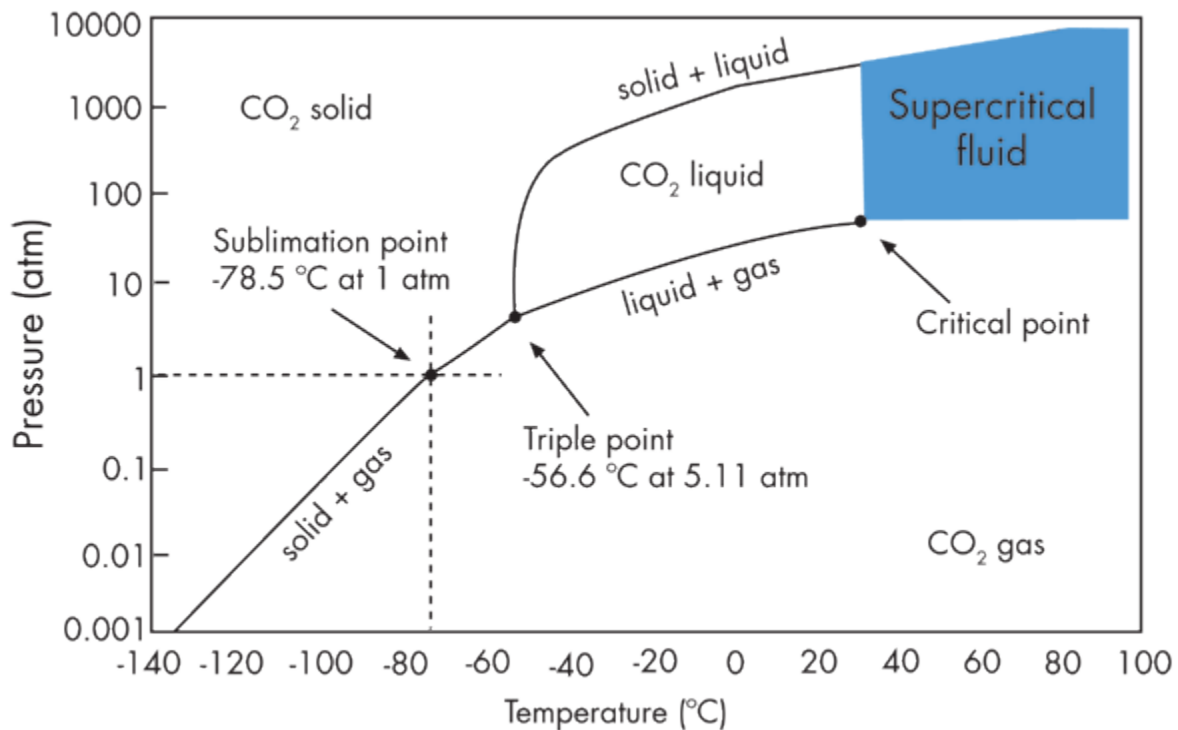


Figure 1: Phase diagram of CO₂ (Saeedi, 2012)

There have been many studies where an efficient storage is reported to be the one taken place in the reservoirs located at the depth of more than 800m (Black et al., 2015; Ketzer et al., 2012; Kimbrel et al., 2015; Metz, 2005; Pentland, 2011; Qi et al., 2010). Pressure, temperature and

density variations are playing important roles in these cases. For instance, the density of CO₂ increases with depth and this enhances the storage capacity (Bachu, 2001; Bachu, 2003; Solomon, 2007) considering the fact that a dense CO₂ occupies smaller pore volumes (Lu et al., 2009; Saeedi, 2012). This density can also be achieved in a low temperature gradient medium where the pressure would be a crucial player to reach the supercritical condition (Bachu, 2003; Qi et al., 2010). Fortunately, up to 80% of hydrocarbon reservoirs in the world, regardless of ages and locations, are located at the depth of 1500m (Van der Meer, 2005). Therefore, dense supercritical CO₂ can be achieved and may not be a concern.

Porosity is another parameter which should be high enough for having a good storage capacity, even though it decreases with depth due to compaction and cementation phenomena (Solomon, 2007). Stratigraphic heterogeneity, referred as the geometry of depositional facies, is also controlling the efficiency of the storage capacity. Hovorka et al. (2004) suggested that a buoyant CO₂ flow avoids a significant portion of the rock volume in a homogeneous rock, resulting in having a low storage capacity. In contrast, a large volume of heterogeneous rocks accepts the injected CO₂ due to disperse flow paths (Ambrose et al., 2008). Other parameters such as the mobility and buoyancy of CO₂, and irreducible water saturations can also reduce the capacity of a storage medium. For instance, Pentland et al. (2011) performed a series of experiments considering a two-phase system by saturating Berea sandstones with CO₂ (90%) and water (10%). They reported that up to 37% of CO₂ was trapped in the pore spaces due to the irreducible water saturation, which was about 10% higher than what was experienced by Suekane et al. (2008).

2.2 Injectivity

Injectivity is the ease with which fluids can flow through stratigraphic intervals (Ambrose et al., 2008). Permeability and thickness of storage sites are directly related to the injectivity (Ambrose et al., 2008; Ghaderi et al., 2009; Qi et al., 2010). For instance, low permeability thin reservoir intervals and complex structures within an injection zone diminish the injectivity. In general, permeability near the well bore must be greater than >100 mD for a favorable injectivity (Watson and Gibson-Poole, 2005). However, the permeability of a medium should be low to ensure that a permanent storage can take place (Shi and Durucan, 2009; Qi et al., 2010). Cinar et al. (2008) stated that a high permeable site is less expensive for CO₂ storage due to lesser number of wells required for the favorable injection. The CO₂ storage modeling of Nisku aquifer in Alberta revealed that a large volume of CO₂ could be injected to avail more storage capacity by controlling the pressure buildup through hydraulic fractures of horizontal wells (Ghaderi et al., 2009). In fact, it would be more economical to consider hydraulic fractured horizontal wells rather than vertical ones in low permeable media, due to lesser number of injection wells required (Cinar et al., 2008).

The reservoir pressure increases during the CO₂ injection and eventually reduces the injectivity to compensate the excessive pressure build-up (Ghaderi et al., 2009; Jalil et al., 2012). This might be a problem for sequestration exercises in an aquifer as the significant pressure build up may not be released due to the resistance of brine in pore spaces (Cinar et al., 2008). It is also reported that the reservoir pressure should not exceed the seal (caprock) fracture pressure in order to mitigate the escape of CO₂ to the atmosphere. Therefore, a comprehensive evaluation of seal integrity is required during the depletion or injection to ensure that fractures will not be initiated within a seal (Raza et al., 2015b).

It seems that there is an inevitable link between the injectivity and drive systems of gas storage reservoirs. Such link has also been observed in abandoned water flooded (externally supported) reservoirs and natural water drive (internally support) reservoirs, but the remarkable pressure increase, due to external water support, makes it hard to have an efficient injectivity and storage capacity in these kinds of reservoirs (Bachu, 2004; Van der Meer, 2005). It is, therefore, assumed that the theoretical CO₂ storage capacity in oil and gas reservoirs with a weak natural water drive support is decreased by 3% (Bachu, 2004). Compacted reservoirs may also not be a very wise choice for the CO₂ storage due to pore volume collapses under a significant reduction of initial pressure (Van der Meer, 2005).

There have been many studies attempting to estimate the injectivity either in labs (Ott et al., 2015; Peysson et al., 2014; Saeedi and Rezaee, 2012) or through numerical simulations (Ganesh et al., 2014; Giorgis et al., 2007; Jalil et al., 2012; Oldenburg and Doughty, 2011; Oruganti and Bryant, 2009). According to these studies, mineral dissolutions/precipitations near a wellbore have a significant impact on rock properties and the injectivity (Raza et al., 2015b). Geochemical reactions, resulting in the dissolution and precipitation of minerals, depend mainly on subsurface thermodynamic conditions, fluid and rock compositions in a CO₂-brine system. These interactions often occur in a shorter period of time in carbonates compared to siliclastic rocks (Raza et al., 2015b). In fact, sandstone as a siliclastic rock does not show any significant geochemical reactions (De Silva et al., 2015). The mobilization of detrital or diagenetic clays can also clog pore throats, and decrease the injection rates (Ambrose et al., 2008). The CO₂-brine-rock chemical reactions based study carried out on the Goldeneye depleted gas reservoir located at offshore of North Sea indicated that the mechanical parameters (i.e., Young's modulus, Poisson's ratio) of sandstone reservoirs, consisting mainly of quartz (~80%) and feldspars (~10%) with small amounts of authigenic clays and intergranular cements, had not yet gone through any significant changes during the injection (Hangx et al., 2013).

Capillary trapping is probably one of the trapping mechanisms with known impacts on the injectivity (Kimbrel et al., 2015). The entrapment of injected CO₂ in the pore space of rocks surrounded by water develops what is known as the residual CO₂ saturation during the capillary trapping (Iglauer et al., 2011; Lamy et al., 2010). This residual saturation is impacted by rock properties and can be measured experimentally in a lab (Suzanne et al., 2001; Suzanne et al.,

2003). The residual gas in depleted reservoirs may significantly increase or decrease the storage capacity (Saeedi, 2012). It also reduces the brine mobility and decreases the density and viscosity of gas mixtures when it dissolves into the supercritical CO₂ (Oldenburg and Doughty, 2011). Saeedi and Rezaee (2012) experimental investigation showed that the saturation of residual gas in sandstone decreases the CO₂ injectivity at early stages but this injectivity improves as the injection progresses. This would be mainly due to the permeability dependent rate of replacing CO₂ with residual gases (Saeedi and Rezaee, 2012).

2.3 Trapping mechanisms

As the pressure builds up due to the injections, the trapping of CO₂ in a geological medium is taken place. The efficiency of the trapping mechanism, however, depends mainly on reservoir characteristics and in-situ parameters (Bachu, 2001). For instance, a structural/stratigraphic trapping occurs when CO₂ stops to be a free gas and traps under the supercritical condition as a residual gas. A solubility trapping, on the other hand, is a long-term process taken place when CO₂ dissolves into subsurface fluids and chemically reacts with the rock matrix (Bachu et al., 2007; Iglauer et al., 2011; Zhang and Song, 2014). Generally speaking, site selections based on dominant trapping mechanisms are essential to prevent any leakage to surface or subsurface resources.

In the context of a structural trapping, CO₂ flows vertically upon the injection in the absence of prominent barriers and accumulates below any seals due to the gravity force. Although, this accumulation is immobilized by capillary or dissolution trappings (Riaz and Cinar, 2014), depending on the degree of seal integrity, reactivated faults or poorly completed wells can potentially result in leakage of CO₂ into other permeable formations (Saeedi, 2012).

The geometry of pore spaces, rock–fluid interactions and fluid–fluid interactions play vital roles when it comes to the CO₂ storage in a geological medium (Chalbaud et al., 2010). The Laplace model represents these interactions (Eq. (1)), which affect the flow process and in the long-term, control the capillary-sealing efficiency (Chalbaud et al., 2010):

$$P_c = P_{CO_2} - P_{Brine} = \frac{2 \cdot \gamma_{b,CO_2} \cdot \cos \theta}{R} \quad (1)$$

In the above equation, P_c is the capillary pressure, γ_{b,CO_2} is the interfacial tension between brine and CO₂, R is the largest connected pore throat and θ is the contact angle representing the medium wettability.

There are numerous parameters which can control the capillary trapping, including vertical permeability, thermodynamic properties of a CO₂-H₂O phase, heterogeneity, etc. (Raza et al., 2015a). For instance, brine viscosity reduces the chance of having a good capillary trapping mechanism (Bandara et al., 2011; Taku Ide et al., 2007). Interfacial tension is another parameter which is linked to the residual CO₂ saturation (Wildenschild et al., 2011), particularly

in consolidated sandstone reservoirs (Raza et al. 2015a). However, the CO₂-brine interfacial tension is less than that of a hydrocarbon-brine and thus, a lower residual gas saturation is usually observed in a CO₂-brine system (Saeedi and Rezaee, 2012; Raza et al. 2015a). The Interfacial tension decreases with increasing the pressure and is impacted by the temperature to a great extent (Sarmadivaleh et al., 2015).

There have been many studies indicating the importance of wettability during the CO₂ storage practice. Contact angle is the parameter quantifying the wettability in a CO₂-brine system and is sensitive to the variation of pressure and temperature (Iglauer et al., 2015; Sarmadivaleh et al., 2015). According to the recent studies, this contact angle has a great impact on the injectivity, containment security, structural, residual, dissolution and mineral trapping capacities (Iglauer et al., 2015). According to Raza et al. (2015a), the contact angle has a great impact on the capillary trapping in a water-wet system because CO₂ appears occasionally in a non-wetting phase (Raza et al., 2015a). In a non water-wet system, therefore, the pressure on the seal is increased by the CO₂ plume resulting in fracture initiations and leakages through the site. Sandstone and limestone plus pure minerals such as quartz, calcite, feldspars, and mica are strongly water wet in a CO₂-water system (Iglauer et al., 2015). Pentland et al. (2011) highlighted that the residual CO₂ saturation may not be high if CO₂ acts as a wetting phase.

The pore throat size and its distribution are important in the fluid transportation processes due to their effects on reservoir properties (i.e., fluid saturation, porosity, permeability and, to some extent, wettability) (Lake, 1989). In the context of CO₂ storages, having a narrow pore throat size is more beneficial than a wider pore one because the high aspect ratio (i.e., pore-body radius to pore throat radius) affects the fluid interface and causes the flow of the wetting phase to go into the pore throats offering a high non-wetting phase saturation (Grobe et al., 2009; Pentland et al., 2012). Although, a large volume of heterogeneous rocks accepts the injected CO₂ due to disperse flow paths (Ambrose et al., 2008), high heterogeneity in the pore-throat size distribution affects the CO₂ distribution and flooding processes (Wei et al., 2014). Therefore, slow and lateral movements of CO₂ in the storage medium is crucial to enhance the chance of immobilization in a low permeability medium (Shi and Durucan, 2009; Teletzke and Lu, 2013). On the other hand, a fast movement of CO₂ plum in the absence of any barriers in the storage medium can alter the wettability due to the pressure build up, and reduces the breakthrough capillary efficiency of the seal during a long-term contact (Chalbaud et al., 2010).

A favorable capillary trapping is often achieved in quartz-rich sandstones and carbonates which are strongly water-wet (Raza et al., 2015a). Carbonates are mostly composed of calcite and dolomite while sandstone comprises quartz and feldspar (Iglauer et al., 2015). The solubility rate (solubility trapping) in the pore water is linked to the composition of formation fluids and rocks. For instance, if a rock is composed mainly of carbonates, the chemical reactions of brine with the rock increase the solubility (De Silva et al., 2015). However, carbonates are more stress sensitive than sandstones and this may cause complexities during the storage (Lamy et al.,

2010). When it comes to the solubility trapping, the temperature, the pressure, salinity ranges, and type/composition of rocks play crucial roles (De Silva et al., 2015). For instance, high temperature and low pressure conditions result in having a low density CO₂, which in turn causes the CO₂ plume to flow at a higher rate and makes the monitoring far more complicated (Lu et al., 2009). The increase of CO₂ pressure, on the other hand, increases the CO₂ dissolution and the brine density (De Silva et al., 2015). This increase in the density may result in gravitational instabilities in which denser brine moves downward away from the flowing CO₂ plume, promoting the solubility trapping (Elenius et al., 2015; Iglauer et al., 2015). According to Chevalier et al., (2010), the CO₂ solubility is favorable in the low temperature and low saline areas.

Mineral trappings often occur after the CO₂ dissolution when bicarbonate ions such as calcium, magnesium and iron reacts with silicate minerals, including clays, micas, chlorites and feldspars (Solomon, 2007). During the mineral trapping, the dissolved CO₂ changes the geochemical conditions of the medium, mostly by increasing the pore water acidity, causing the dissolution of minerals included in a reservoir or seal (Ketzer et al., 2012). The experimental study revealed that the usage of sea water having sulfates enhances the permeability damage induced during the injection due to precipitations of calcium sulfates (Mohamed and Nasr-El-Din, 2013). The mineral trapping is generally controlled by the temperature, pressure and salinity of the formation water as highlighted in Table 2 (De Silva et al., 2015).

Table 2: The effect of pressure, temperature and salinity on the mineral trapping (De Silva et al., 2015)

Rock Type/Basin	Major Minerals	Water type/ionic strength	T (°C)	P (MPa)	Outcome
Glauconitic sandstone, Alberta Basin	Quartz (87%), K-feldspar (2%), plagioclase (1%), glauconite (5%), kaolinite (2%), calcite (1%), dolomite (1%), siderite (1%)	Saline water with high salinity	105	9	Very little reaction observed in fast-reacting carbonate mineral due to high salinity
Sandstone from Rio-Bonito Formation, Brazil	Quartz, albite, arnorthite, calcite, dolomite, illite, kaolinite/chlorite and illite-smectatite mixed layer	0.1 M NaCl solution	80	0-12	No reaction after 3 months Part of illite-smectatite mixed layer turned into illite
Navajo sandstone, Colorado, USA	Quartz (90%), feldspar (2%), smectatite, kaolinite	0.2 mol/kg KCL	200	30	Dissolution of feldspar and conversion of smectatite to illite are the main reactions observed. Chemical reaction induced by CO ₂ injection cause pore throat clogging by moving the smectatite
A number of sandstone types from North German Basin	Quartz, feldspar, calcite, illite, barite, chlorite kaolinite	Formation brine	100	10	Development of micro-fractures in detrital minerals Initial dissolution of calcite

2.4. Containment

Containments of a storage site depend mainly on the characteristics of caprocks, faults and fracture surrounding a reservoir. Caprock is not usually a concern when the integrity of a storage site is evaluated, but the sealing ability of faults has often raised an alarm. A fault must have a permeability of less than 0.1mD (Ketzer et al., 2012) and should be surrounded by clays and evaporites or other impervious rocks in order to be counted as a reliable seal (Van der

Meer, 2005). Seals capacity, their geometry and integrity are the most important aspects of containment when it comes to the storage site reliability analysis (Ambrose et al., 2008).

The sealing capacity of a fault, however, is affected by the pore-throat size, contact angle (wettability) and interfacial tension of rock forming minerals (Daniel and Kaldi, 2008). These minerals, including mica, muscovite and phlogopite, are strongly water-wet and favor the sealing ability of caprocks or faults against the leakage of the CO₂ plume (Iglauer et al., 2015). The upper limit of the breakthrough pressure of a seal, on the other hand, is linked to the interfacial tension of the CO₂/water system and is often less than that of the Oil-water system. Thus, detailed analysis of the pressure sustained by seals is crucial before and during the injection (Li et al., 2006). For example, a study on the faults surrounding the Gippsland Basin in Australia indicated that the sealing capacity would not be the same at different locations, depending on the interfacial tension of CO₂-water systems (Divko et al., 2010).

Thickness of a seal is another aspect of integrity analysis which should not be neglected (Kaldi et al., 2013). According to Chadwick et al. (2008), Chevalier et al. (2010) and Ramirez et al. (2010), a seal must have a thickness of at least 10m to provide resistance against the CO₂ plume pressure.

A seal integrity changes by the increase of the pore pressure and stress variations induced due to the injection (Kaldi et al., 2013; Ouellet et al., 2011). A significant increase of the pressure during the injection decreases the normal stress on a fault surface and causes the mechanical break-down (reactivation) (Olden et al., 2012; Raza et al., 2015b). Therefore, hydraulic integrity analysis of storage sites is essential before starting or even during the storage.

Compressibility of geologic media is another vital piece of information which should be a part of the analysis. If a reservoir is highly compressible, changes of pore pressure reactivate the faults during the compaction, causing a significant leakage to surrounding formations. Geomechanical evaluation has then become inevitable for those hydrocarbon fields suffering from a severe compaction effect, such as the Wilmington oilfield in California and Ekofisk field in the North Sea (Olden et al., 2012).

Last but not least is the borehole condition which is linked to the cement placement and near-field stress conditions before the injection (Hawkes et al., 2004). Analysis of seismic and well data, especially Cement Bond Logs (CBL) during the production stage, would be required to ensure that the wellbore condition may not become a serious issue during the injection.

2.5 Cost

There are many economic aspects included in the site selection which should not be neglected. Transportation of large quantities of CO₂ from a source to storage sites can be done through pipelines in a cost effective way. The cost of this transportation, however, depends mainly on locations (e.g. Onshore or offshore), the size and composition of pipelines and operating

conditions (Bennaceur et al., 2008). According to Metz et al. (2005), transportation cost from a source to a site is estimated to be around 1-8 USD/tCO₂ per 250 km pipeline. The report released in the recent years indicated that as long as the distance between major sources and prospective sedimentary basins is less than 300 Km, transportation may not induce excessive costs on storage projects (Metz, 2005). Non-condensable impurities such as N₂, O₂ and Ar which are often mixed with CO₂ during the capturing practice may also pose extra costs on storage projects. These impurities are required to be separated before the injection as they may reduce the storage capacity of a site (Wang et al., 2011). Furthermore, moisture of CO₂ needs to be removed to avoid corrosions and hydration, which can induce extra costs (Ghg, 2004). Thus, careful considerations of costs included in a storage project is an essential step at early stages before the injection begins.

3. A New Screening Criterion

There are few studies presenting a screening criterion for depleted reservoirs by referring to different aspects of a storage site selection. For instance, Kovscek (2002) presented a screening criterion for the CO₂ storage in depleted oil reservoirs. Key parameters such as reservoir depth, storage capacity, water and oil volumes in place, formation thickness, and permeability were considered in his criterion. He indicated the density of CO₂ as one of the important parameters which should be included as a part of site selection. There was also an emphasis on the relationship between the production and fault and fractures reactivations (Kovscek, 2002). Solomon (2006) proposed a criterion in which the depth of injections, the density of CO₂ and brine, reservoir properties, impurities and durations of storages for an EOR practice were taken into consideration. Chadwick et al. (2008) presented a local scale criterion based on the integrated experiences of five CO₂ injection projects in Europe (See Table 3). Ramirez et al. (2010) used a Multi-Criteria Analysis (MCA) method to develop a screening criterion which could be used to rank the suitability of Netherlands reservoirs (e.g., aquifer, gas and oil) for a long-term CO₂ storage. They considered three parameters: 1) storage capacity, 2) storage costs and 3) locations as the threshold screening factors. Table 4 gives the threshold of screen parameters used by Ramirez et al. (2010).

There have not yet been any screen criteria proposed to select a suitable depleted gas reservoir for the purpose of CO₂ storages. In fact, reservoir/well types, mineralogy, the residual gas saturation, subsurface conditions, rock types, wettability, properties of CO₂, and sealing potential factors appear to be very important in a site selection, but they have not yet been included in any screening criteria. Thus, for the purpose of this study, the technical discussion and parameters presented by Chadwick et al. (2008) were combined with other critical factors in order to present a new and more comprehensive screening criterion for depleted gas reservoirs. This criterion can be a very good asset in evaluation of worldwide gas reservoirs

which are at identification stages for CO₂ storage purposes. Table 5 gives the screen criterion proposed by this study.

Table 3: The screening criterion proposed for the CO₂ storage by [Chadwick et al. \(2008\)](#)

Parameters	Positive Indicators	Cautionary Indicators
Total Storage Capacity	Total Capacity of reservoir estimated to be much larger than the total amount produced from the CO ₂ source	Total capacity of reservoir estimated to be similar or less than the total amount produced from the CO ₂ source
Depth	1000-2500 meter	<800m or >2500m
Thickness (net)	>>50m	<20m
Porosity	>20%	<10%
Permeability	>300mD	10-100mD
Salinity	>100 g/L	<30 g/L
Seal Properties		
Lateral Continuity	Un-faulted	Laterally Variable Faults
Thickness	>100 m	<20 m
Capillary Entry Pressure	Much greater than buoyancy force of maximum produced CO ₂ column high	Similar to buoyancy force of maximum produced CO ₂ column height

Table 4: Thresholds used for the pre-screening of CO₂ storages in Netherland ([Ramírez et al., 2010](#))

Parameter	Threshold
Capacity	≥4 Mt for gas/oil and ≥2 Mt for aquifer
Thickness reservoir	>10m
Depth top reservoir	≥800m
Reservoir porosity	Aquifers: >10%
Reservoir Permeability	Aquifers: an expected permeability of 200 mD or more
Thickness seal	≥10m. Both simple seals as well as complex seal have been taken into account.
Seal composition	Salt, anhydrite, shale or claystones
Reservoir composition	Aquifers: sandstone, hydrocarbon fields: limestone, sandstone, siltstone, carbonates
Initial pressure	Overpressure excluded
Salt domes	Relevant for aquifers. Traps located alongside/ near salt domes/walls have been excluded because there is a high risk of salt cementation

Table 5: A new screening criterion for selection of global depleted gas reservoirs

Parameters	Positive Indicators	Cautionary Indicators	Indication of Aspect	
CO₂ source and total Storage Capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO ₂ source	Total capacity of reservoir estimated to be similar or less than the total amount produced from the CO ₂ source	Storage Potential	
Depth	>800m	800m>depth>2000m	Storage Capacity	
CO₂ density	high	low	Storage Capacity	
Porosity	>20%	<10%	Storage Capacity Capillary trapping	
Thickness (net)	>>50m	<20m	Storage Capacity Injectivity	
Permeability (near-wellbore)	>100mD	10-100mD	Injectivity	
Well type	horizontal well with or without hydraulic fracture/vertical well with hydraulic fracture	vertical well without hydraulic fracture	Injectivity	
Type of minerals	Ca-, Mg-, or Fe-rich framework minerals such as feldspars, clays, micas, and Fe-oxides	fast reacting carbonates minerals	Injectivity/mineral trapping	
Residual gas /water saturation	less	high	Injectivity	
Pore throat size distribution	less heterogeneous	high heterogeneous	Injectivity and Trapping	
Salinity	low	high	Solubility trapping	
Temperature	low temperature gradient	High temperature gradient	Solubility trapping	
Pressure	under pressure	overpressure	Solubility trapping	
Gravity number	less	high	Capillary trapping	
Rock type	quartz rich sandstones and carbonates	highly stress sensitive carbonates	Capillary trapping	
Rock wettability	strong water wet	less water wet or oil-wet	Capillary trapping	
Interfacial tension	high	low	Capillary trapping	
Hydraulic integrity	Reservoir type	reservoir without compaction/ aquifer support	reservoir with compaction/aquifer support	Containment
		have not experienced any injection in past	have experienced any injection in past	
	Well location & condition	less faults and fractures	more faults and fractures	
Seal capacity – CO₂ column height	capillary entry pressure much greater than buoyancy force of maximum produced CO ₂ column high	capillary entry pressure similar to buoyancy force of maximum produced CO ₂ column height	Containment	
Seal geometry - Lateral continuity	un-faulted	laterally variable faults	Containment	
Seal geometry –Thickness	>100 m	<20 m	Containment	
Hydraulic integrity: Seal	presence of mineral and stress characterization data of seal	absence of mineral and stress characterization data of seal	Containment	
Distance between CO₂ emissions source and target medium	<300km	>300km	Transportation Cost	

4. Parameter Estimations

In this section, different approaches developed to estimate the density, viscosity and interfacial tension of CO₂ together with the storage capacity, permeability, residual gas saturation and wettability of depleted gas reservoirs are presented. A method recently proposed to determine the CO₂ emission from different sources is also highlighted.

4.1 CO₂ emission point source

Large fossil fuel and synthetic fuel plants along with natural gas production sites and fossil-based hydrogen production plants are among the major sources of CO₂ emissions. Mao et al. (2014) presented a methodology to estimate the amount of carbon emission released from different sources as given in Table 6.

Table 6: Methodologies proposed to estimate CO₂ emissions from stationary sources (Mao et al., 2014)

Methodology	Description
CO₂ emission from cement plant: $C_{CO_2} = 0.9 \times E_{cp}$	CO ₂ emission is estimated based on the cement production and combustion, where: C _{CO₂} = tons per year E _{cp} = Cement production rate (tons per year)
CO₂ emissions from coal fired power plant: $CF_{CO_2} = 3.664 \times C_{\%} \times F_r$	CO ₂ emission is estimated through combustion, where CF _{CO₂} = tons per year C _% = carbon in coal (weigh fraction: %) F _r =coal usage rate (tons per year)
CO₂ emissions from natural gas power plant: $NG_{CO_2} = (1100 \times P) / 2000$	where NG _{CO₂} =tons per year P= annual plant generation (MWh)
CO₂ emissions from oil power plant: $H_{CO_2} = (3.664 \times F_r \times C_{\%} \times D_r) / (2000)$	CO ₂ emission is estimated by combustion, where H _{CO₂} = tons per year D _r = oil density (lb per gallon) C _% =Percentage of carbon in the oil F _r = oil usage rate (gallons per year)
CO₂ emissions from refinery plant: $R_{CO_2} = 11 \times E_p$	CO ₂ emission is estimated based on emission factor for petroleum refinery production, where: R _{CO₂} (tons per year) E _p = Petroleum plant production rate (barrel per day)
CO₂ emissions from fertilizer production: $NH_{3CO_2} = E_{NH_3} \times (\theta_{NH_3} + \theta_{fuel})$	where NH _{3CO₂} = tons per year θ _{NH₃} =CO ₂ process emission factor for NH ₃ production (12 tons CO ₂ per ton of NH ₃) θ _{fuel} = CO ₂ combustion emission factor (0.5 tons CO ₂ per ton NH ₃) E _{NH₃} = Production rate (tons per year)
CO₂ produced from natural gas reservoir: $V_{CO_2} = R_f \times \text{volume of OGIP}$	where V _{CO₂} =volume of CO ₂ produced (cubic meter) R _f = CO ₂ recovery factor OGIP= original gas in place

4.2 Density of CO₂ at reservoir conditions

There are a number of correlations developed for estimating the density of CO₂. One of the most successful approaches conventionally used for estimation of the density is the one proposed by Bahadori et al., (2009). It should be noticed that this approach (Eq. (2)) can only be used for the temperature between 293 K to 433 K and the pressure of 25 bar to 700 bar.

$$\rho = \alpha + \beta T + \gamma T^2 + \theta T^3 \quad (2)$$

$$\alpha = (A_1 + B_1 P + C_1 P^2 + D_1 P^3) \quad (3)$$

$$\beta = (A_2 + B_2 P + C_2 P^2 + D_2 P^3) \quad (4)$$

$$\gamma = (A_3 + B_3 P + C_3 P^2 + D_3 P^3) \quad (5)$$

$$\theta = (A_4 + B_4 P + C_4 P^2 + D_4 P^3) \quad (6)$$

In the above equations, P is the pressure in bar, ρ is the density in kg/m³, T is the temperature in Kelvin, α , β and γ are the temperature coefficients estimated by Eqs. (3)–(6) and Table 7.

Table 7: Variations of temperature coefficients included in Eq. (3-6) (Bahadori et al., 2009)

Coefficient	25 bar<P<100 bar	100 bar<P<700 bar
A1	2.09E+05	1.05E+05
B1	-1.46E+04	-9.40E+02
C1	2.89E+02	2.40E+00
D1	-1.60E+00	-1.82E-03
A2	-1.68E+03	-8.25E+02
B2	1.17E+02	7.62E+00
C2	-2.32E+00	-1.96E-02
D2	1.28E-02	1.50E-05
A3	4.45E+00	2.14E+00
B3	-3.10E-01	-2.02E-02
C3	6.16E-03	5.27E-05
D3	-3.42E-05	-4.04E-08
A4	-3.92E-03	-1.83E-03
B4	2.73E-04	1.77E-05
C4	-5.43E-06	-4.65E-08
D4	3.02E-08	3.59E-11

4.3. Interfacial tension

The aqueous solution (saline water) density can be quantified using the approach presented by [Ji and Zhu \(2013\)](#). In this case, Interfacial tension between CO₂ and brine can be estimated using Chalbaud's approach which gives an appropriate estimation when pressures and temperatures are in the range of 45 to 255 bars, and 71 to 100°C respectively ([Chalbaud et al., 2009](#)). In fact, Chalbaud's approach links the interfacial tension to the differential density and is expressed as:

$$\gamma_{b,CO_2} = \gamma_{Wplateau} + \lambda^* X_{NaCl} + \left[\frac{P}{M} (\Delta\rho) \right]^\eta \times T_r^\beta \quad (7)$$

where γ_{b,CO_2} is the interfacial tension of CO₂ in mN/m, T_r is the reservoir temperature in °C, P is the pressure in bar, λ , η and β are the regression coefficients obtained from fitting a least-squares curve to experimental data, M is the CO₂ molar mass, $\Delta\rho$ is the differential density of supercritical CO₂ and saline water. The values of λ , η and β coefficients together with P , M and $\gamma_{Wplateau}$ parameters used to estimate the interfacial tension are summarized in Table 8.

Table 8: Regression coefficients and parameters used to model the interfacial tension ([Chalbaud et al., 2009](#))

REGRESSION COEFFICIENTS OF EQ. (11)		CONSTANT VALUES OF EQ. (11)	
λ	1.255	P	82
η	4.7180	M (g/mol)	44.01
β	1.0243	$\gamma_{Wplateau}$	26

The density of supercritical CO₂ required in the above equation can be estimated using the approach proposed by [Bahadori et al., \(2009\)](#) while water density accounting the dissolved NaCl/CO₂ effect is determined through employing the Rowe and Soreidi approach ([Rowe Jr and Chou, 1970](#); [Soreide and Whitson, 1992](#)).

4.4 Oil and gas capacity estimations

Estimating the storage capacity of CO₂ in oil and gas reservoirs is much easier compared to other geological media considered for a sequestration practice. This is mainly due to large amounts of data acquired during the production stage of oil and gas reservoirs. The effective storage capacity of these reservoirs is calculated from the original gas in place using the following equation: ([Bachu et al., 2007](#); [Di Zhou, 2013](#)).

$$M_{CO_2} = \rho_{CO_2r} \times R_f \times (1 - FIG) \times OGIP \times \left\{ \frac{(P_s \times Z_r \times T_r)}{(P_r \times Z_s \times T_s)} \right\} \times C_e \quad (8)$$

where, M_{CO_2} is the storage capacity, OGIP is the volume of original gas in place, R_f is the recovery factor, FIG is the fraction of injected gas, P , T and Z are, respectively, the pressure, the temperature and the gas compressibility factor. The subscripts "r" and "s" in the above

equation indicate the reservoir and surface conditions respectively. The term $(P_s \times Z_r \times T_r) / (P_r \times Z_s \times T_s)$ is the reservoir volume factor, B_g .

The above equation is simplified into Eq. (9) when there are no gas injections.

$$M_{CO_2} = \rho_{CO_2r} \times R_f \times OGIP \times B_g \times C_e \quad (9)$$

According to [Bachu and Shaw \(2005\)](#), $C_e = C_{eff} \cdot C_{aq}$, where C_{eff} is the effective storage coefficient, representing the CO_2 mobility and density, while C_{aq} represents the reduction in the storage capacity as a result of water invasion during the production. These coefficients are defined based on the study performed in one of the fields of Western Canada.

There is another way to estimate the CO_2 storage capacity which is mainly based on the areal extent and thickness of reservoirs as formulated below ([Bachu et al., 2007](#)):

$$M_{CO_2t} = \rho_{CO_2r} [R_f A h \phi (1 - S_w) - V_{iw} + V_{pw}] \quad (10)$$

In the above equation, M_{CO_2} is the mass theoretical storage capacity R_f is the recovery factor, ρ_{CO_2r} , is the density of CO_2 at reservoir condition, A , h , ϕ and S_w are reservoir area, thickness, porosity and water saturation, respectively. V_{iw} and V_{pw} are the volumes of injected and produced water, respectively.

4.5 Permeability

Drill stem testing results can be used to determine the vertical and horizontal permeability of reservoirs. Transient analysis of radial flows at perforations recorded during a well testing is used to calculate the horizontal permeability, k_h . The spherical flow taken place away from a wellbore can, on the other hand, be used to estimate the slope of a pressure-time curve which gives the spherical permeability, k_s . The spherical permeability is linked to the horizontal and vertical permeability (k_v) using the following equation:

$$k_s = \sqrt[3]{k_h^2 k_v} \quad (11)$$

It should be noticed that the vertical and horizontal permeability are similar when anisotropic permeability does not exist ([Ayan and Mongini, 1994](#)). Permeability can also be estimated from a core sample data analysis and interpretations of wireline log data ([Cooper, 2009](#); [Ketzer et al., 2012](#)). In fact, the results of the well logs such as Neutral Magnetic Resonance (NMR) and acoustic logs can be used to predict the permeability ([Anderson, 2011](#)).

4.6 Residual gas saturation

Generally, the capillary trapping in terms of residual gas saturation is quantitatively measured through either core flooding tests ([El-maghraby et al., 2011](#); [M.Krevor et al., 2011](#)) or trend line analysis of the residual to maximum gas saturations at flow reversals ([Pentland et al., 2010](#)).

There are numerous approaches used to determine the oil and gas residuals including electrical resistivity or thermal decay time logs based analysis (Ransom and Holm, 1978). Archie equation (Eq. (12)) can also be used to determine the water saturation, which in turn gives the oil or gas saturation.

$$S_w^{1/n} = (R_o / R_t) \quad (12)$$

$$1 - S_w = S_h \quad (13)$$

$$S_g = S_h - S_o \quad (14)$$

where S_w is the water saturation, R_o is the resistivity of pore volumes filled with water, R_t is the true resistivity, n is the saturation exponent, S_h is the hydrocarbon saturation, S_g is the gas saturation and S_o is the oil saturation (Ransom and Holm, 1978).

4.7 Wettability

The contact angle varies between 0° to 180° based on the intermolecular force balance. The measuring techniques used for the contact angle determination consist mainly of direct observations during the sessile drop, tilting plate, Wilhelmy balance and capillary bridge methods (Iglauer et al., 2015).

Wettability of depleted zones can also be determined if the pressure profile is acquired covering the region of oil/water or gas/water contacts. This pressure profile can be developed using wireline formation testers at short-depth intervals and employed to predict formation fluids which are directly linked to the free-fluid density within the pore system. Having the vertical distance between the free water and movable-fluid levels estimated using the pressure profile, porosity and permeability data can be applied to determine the average wettability through the following equation:

$$J(P_{ct}) = P_{ct} (k / \phi)^2 / \sigma_{nw/w} \cos \theta_c \quad (15)$$

where P_{ct} is the capillary rise or fall expressing as below:

$$P_{ct} = hg(\rho_w - \rho_{nw}) \quad (16)$$

The slopes of the pressure profile curve estimated from moveable hydrocarbon or water levels are used to get the non-wetting and wetting phases densities in kg/m^3 as formulated below: (Desbrandes et al., 1990)

$$\rho = \frac{G}{g} \quad (17)$$

where P_{ct} is the minimum threshold pressure when a non-wetting phase (oil or gas) enters into a porous medium.

The $J(P_{ct})$ is often between 0.1 to 0.17 for consolidated formations and varies from 0.35 to 0.447 for unconsolidated intervals. It is estimated using the capillary pressure curve. The contact angle can then be determined using the permeability and porosity data obtained from the wireline logs data analysis while $\sigma_{nw/w}$ is estimated from correlations or fluid sample data analysis (Desbrandes and Bassiouni, 1990).

4.8 Containment

The seal capacity is initially evaluated by the mercury injection test. This assessment can also be made through empirical analysis where the physical properties of CO₂ (i.e., density, temperature, pressure) are estimated for a depleted reservoir (Kaldi et al., 2013). For the seal geometry though, well and field data including, stratigraphic, sedimentological, wireline log and seismic data analysis can be used. To find rock mechanical properties, and fracture pressures for analysis of a seal integrity, data and approaches presented in Table 9 can be used.

Table 9: Methods used for in-situ stresses and pore pressure estimations (Aadnoy and Looyeh, 2011; Raza et al. 2015b)

Measurement Parameter	Types of Stress	Measurement Approach	Estimation Approach
Reservoir Pressure	P_{res}	▪ Drillstem Test (DST)	▪ Density Log
		▪ Repeat Formation	▪ Sonic Log
		▪ Modular Formation Dynamics Test	▪ Seismic Velocity
		▪ Logging While Drilling (LWD)	▪ Mud Weight Used
		▪ Measured Direct Tests (MDT)	
Stress Magnitude	σ_v	▪ Density Log	
	σ_H		▪ Breakout
			▪ Mud Weight
			▪ Observations of Well Failure
σ_h	▪ Hydraulic Fracturing	▪ Leak-off (LOT) Test	
		▪ Formation Integrity Test	
		▪ Lost Circulation	
Stress Orientation	$\sigma_h \text{ or } \sigma_H$	▪ Cross Dipole	▪ Drilling Induced Fracs
		▪ Mini-frac	▪ Fault Direction
		▪ Hydraulic Fracture Test	▪ Natural Frac Direction
		▪ Drilling Induced Fracs	
		▪ Breakout	

5. Conclusion

There have been few screening criteria proposed for the storage site selection in which parameters such as depth, density, permeability and sealing properties were considered. However, there are few other important parameters which may increase the confidence of

selecting a suitable geologic medium for CO₂ sequestration purposes. In this paper, attempts were made to cover the most important parameters related to key aspects of suitable storage site selections, including injectivity, trapping mechanisms and strength of containments. Depleted gas reservoirs were taken into consideration exclusively in this research due to their large storage potentials. A screening criterion was proposed through a comprehensive review of the recent findings linked to the current status of CO₂ storage sites. The results obtained indicated that compactions and water supports increase the risk of having an effective storage capacity due to dispersed flow paths which can be created in a storage site. Although, a reasonable permeability and thickness should be present for a successful injection operation, the presence of horizontal or vertical wells with hydraulic fractures and good completions enhance the ability of a site to accept more CO₂ during the injection. The status of faults and fractures, subsurface conditions, rocks and fluid properties should not also be neglected for having a safe storage medium.

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