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Petrophysical Considerations for CO_2 Capture and Storage

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ABSTRACT

Carbon capture, utilization, and storage (CCUS) is a process that involves capturing carbon dioxide (CO_2) emissions and storing them in geological formations. While the challenge of CCUS is one of multiple disciplines, this paper will discuss the key petrophysical considerations worth noting for CCUS projects. As the storage capacity and effectiveness of the storage reservoir depend on the physical and chemical properties of the geological formations that are used for storage, petrophysicists working on CCUS projects must have a good understanding of the subsurface and its limitations. Any CCUS project can be better managed by application and adherence to the CO_2 Storage Resources Management System (SRMS), which aims to develop a consistent approach to estimating storable quantities of CO_2 in the subsurface and evaluating development projects. In this paper, we will also discuss a risk matrix that we have designed as a tool for project petrophysicists to document uncertainties and rank them to enhance communication with team members. We finally share a petrophysical checklist to highlight considerations as the evaluation of prospective, contingent, and (commercial storage) capacity-scale CCUS projects are matured and use a well in the North West Shelf, Australia, as a case study to show how reservoirs can be analyzed for suitability for CO_2 storage.

INTRODUCTION

Carbon capture, utilization, and storage (CCUS) encompasses a range of methods and technologies that involve the capture of carbon dioxide (CO_2) from an emission point source and subsequent sequestration via injection into geological formations. CCUS is commonly viewed as a key technology to assist in reaching global anthropogenic climate change goals.

While the global CCUS project pipeline has been growing since the 2015 Paris Agreement (COP21), the required installed CCUS capacity needs an approximately 100-fold increase by 2050 to achieve net zero targets as defined by the COP21 agreement. Between USD 655 and 1,280 billion in capital investment is required to meet these objectives (Turan et al., 2021). Commercial-scale CCUS requires an accurate understanding of the underlying subsurface for successful implementation of field development plans. The suitability of geological formations for CCUS is essentially an integration of multiple scales (Fig. 1), and a staged process will ensure that the data at the various length scales are properly integrated.

The process starts with the identification and high grading of potential storage sites. Starting with seismic interpretation (Fig. 1a), there is a need to perform depth conversion, interpret key stratigraphic horizons and faults, and evaluate the stratigraphy/facies. Once a suitable site is selected, field-based properties and/or static modeling would need to be populated (Fig. 1b) with evaluations made from petrophysical logs, routine core analysis (RCA), and special core analysis (SCAL) (Figs. 1c to 1e), where the goal would be an estimation of porosity, permeability, mineralogy, relative permeability, and capillary pressure. At this scale, there should be consideration given to the geomechanical aspects of the potential storage sites, with an attempt to understand the stress regime, seal potential, geometry, and integrity. Consideration must also be given to hydrodynamism and trapping mechanisms and whether faults encountered would act as conduits or seals. Reservoir engineering aspects of any CCUS project include

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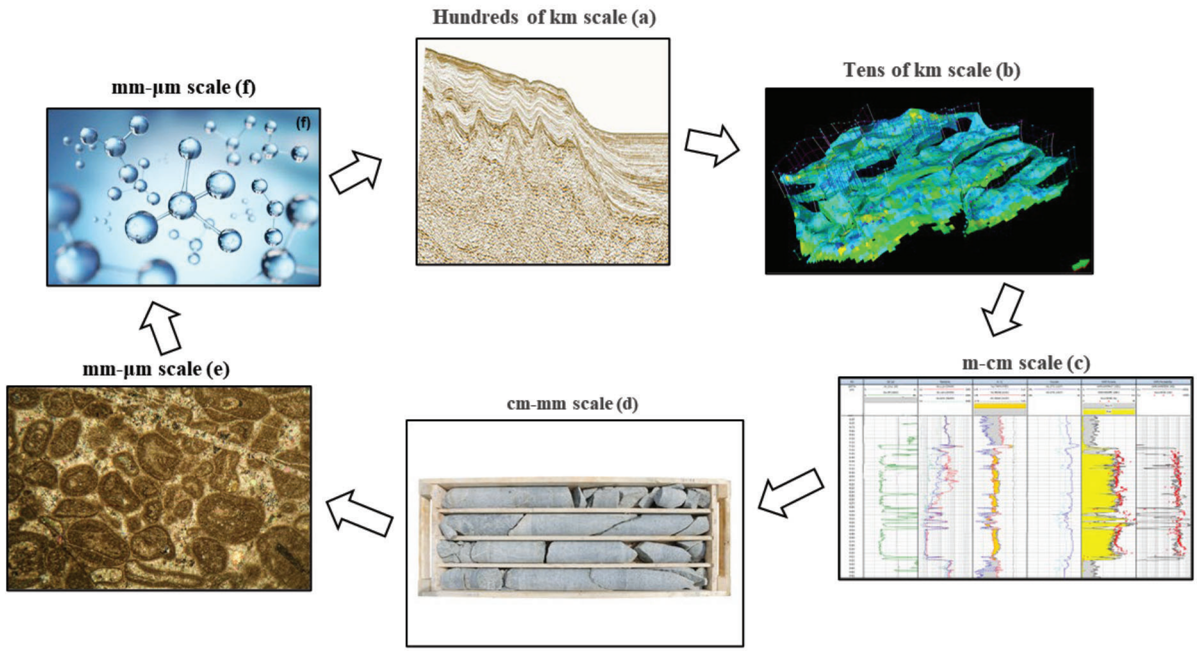

Fig. 1—Schematic illustrating the process of data integration.

an understanding of pressure and temperature, the phase behavior of injected CO_2 fluids, and the integration of data related to well tests that would have been performed in analog or offset wells. Geochemically, aspects related to mineral composition, rock-fluid-CO_2 interactions, and microbial activity should also be considered (Fig. 1f).

The integration of all the above results in the development of static and dynamic models where the volumetric evaluation of the potential storage capacity can be determined (theoretical capacity). When building the dynamic model, the efficiency of CO_2 injectivity into reservoir facies would be accounted for by an "efficiency factor" (E in Eq. 2). E is analogous to a recovery factor in petroleum volumetrics, and there is typically a variety of ways in which it is applied and defined. There are some petrophysical considerations to the value, which results in an estimate of the actual storage capacity (effective capacity), such as the in-situ characteristics of the storage aquifer (e.g., pressure, temperature, salinity, porosity, permeability, heterogeneity), while other components include the CO_2 storage operation potential (e.g., injection rates, duration, and number of wells) and regulatory constraints, such as maximum bottomhole pressures (Bachu, 2015).

The summary above highlights the multidisciplinary challenge associated with CCUS. In this paper, we will focus on just one aspect of this chain, namely the key formation evaluation considerations that need to be accounted for in any CCUS project under the CO_2 Storage Resources Management System (SRMS) (Society of Petroleum Engineers, 2017), shown in Figs. 1c to 1f. This paper will discuss how the SRMS, while similar in some ways to the well-established Petroleum Resource Management System (PRMS), has some fundamental differences that need to be understood. We will also share a "petrophysical checklist," which we apply to a drill well off the North West Shelf in Australia, utilizing it as a case study to explain how assets can be determined as fit for CCUS applications. Finally, we will discuss the importance of data gathering and offer suggestions to help companies as they seek to de-risk future CCUS projects.

PRMS VS. SRMS – SIMILARITIES AND DIFFERENCES

First developed in 1962 by the Society of Petroleum Evaluation Engineers (SPEE), the PRMS provides the framework for the classification and categorization of all petroleum reserves and resources (Society of Petroleum Engineers, 2022). Although the system encompasses the entire in-place petroleum resource and characterizes projects at various levels of technical and commercial maturity, its widest application has been for estimating commercially recoverable quantities using a globally recognized system. In contrast, the SRMS is a relatively new classification framework first developed in 2017 by a subcommittee of the Carbon Dioxide Capture, Utilization, and Storage (CCUS) Technical Section (part of the Society of Petroleum Engineers (SPE)). It aims to provide a consistent approach to estimating storable quantities of CO_2 in the subsurface and evaluating development projects (Bachu, 2015).

The PRMS provided the model for the development of the SRMS, against which CCUS projects can be voluntarily contrasted. While the definitions provided within the SRMS follow standard industrial definitions for most terms and draw parallels from the definitions provided in the PRMS, there are some subtle differences in the frameworks (Fig. 2). Both are similar in that they are project-based, independent of implementation, and detail how resources can be quantified, categorized, and classified (Society of Petroleum Engineers, 2017). In both the PRMS and SRMS, each category (P – reserves or capacity, C – contingent resources, and U – prospective resources) must consider the probability of potential outcomes to capture geological and engineering uncertainties (Society of Petroleum Engineers, 2022). This is usually done in the form of probabilistic resource estimation, representing a P90 (low case referring to 90% of calculated estimates being equal to or exceeding this estimate), P50 (best case – the median), and P10 (high case referring to 10% of calculated estimates being equal to, or exceeding this estimate).

Both the PRMS and SRMS allow the use of volumetric estimations as an analytical procedure for determining the hydrocarbons initially in place (HCIIP, BOE) and theoretical storage resource for CO_2 (mass of CO_2 or M_{CO2} in kilograms) (Eqs. 1 and 2), respectively.

$$\text{PRMS:} \quad HCIIP = GRV \times N{:}G \times \emptyset \times (1 - S_w) \times {}^{1}/_{FVF} \quad (1)$$

$$\text{SRMS:} \quad M_{CO2} = GRV \times N{:}G \times \emptyset \times (1 - S_{wirr}) \times \rho_{CO2} \times E \quad (2)$$

where *GRV* is the gross rock volume (m^3), *N:G* is the net to gross (m/m), *f* is porosity (V/V), S_w is the water saturation (V/V), S_{wirr} is the irreducible water saturation (V/V), ρ_{CO2} is the density of CO_2 (kg/m^3), *FVF* is the formation volume factor (oil – res bbl/STB, gas – scf/bbl), and *E* is the efficiency factor (V/V).

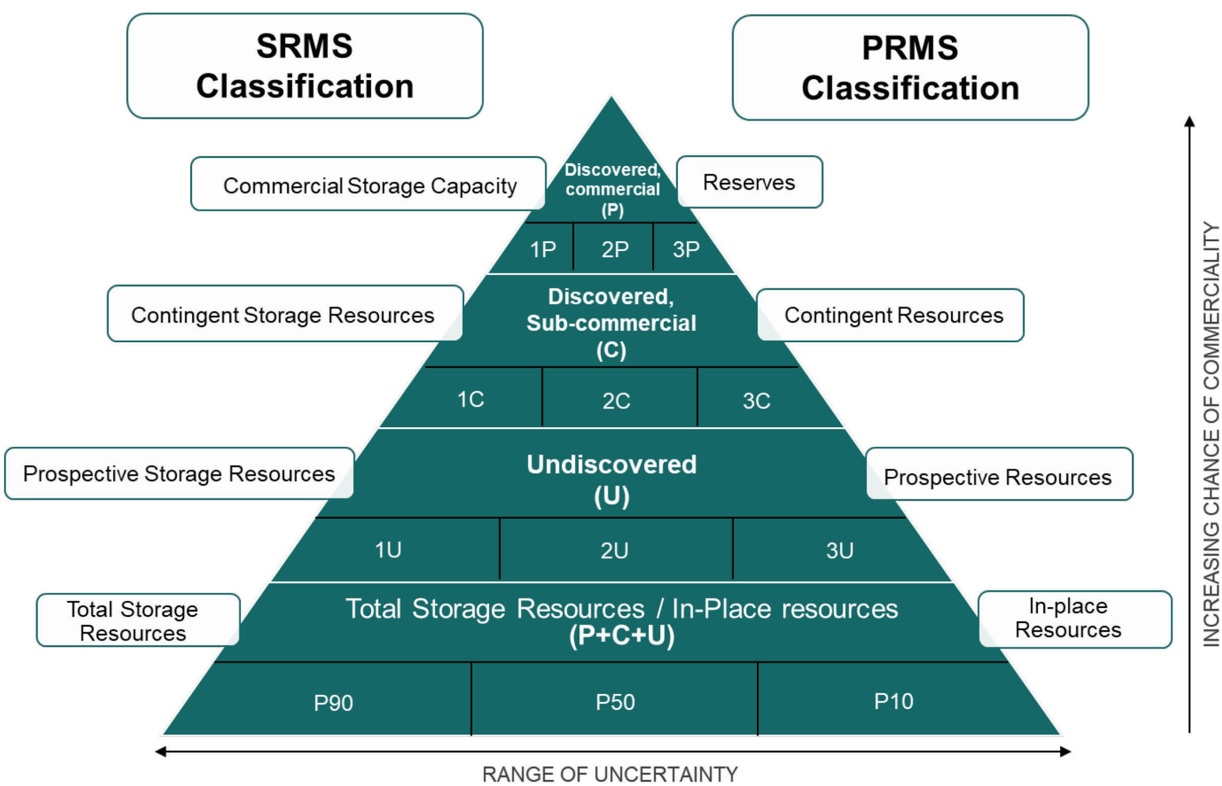

Fig. 2—Comparison of the classification framework for the SRMS and PRMS.

It is important to note that Eq. 2 represents a theoretical maximum storage volume. The actual amount of CO_2 stored in the subsurface will be a function of the dynamic behavior of injected CO_2 into the subsurface and the subsequent displacement of the nonwetting phase fluid. Not every point of the reservoir will be accessible to CO_2 storage or driven to irreducible water saturations. In addition, factors such as reservoir quality (permeability), the presence of faults and fractures, as well as zones of differential pressure (thief zones), can have a significant impact on the CO_2 storage efficiency, in which case, the use of dynamic flow and geomechanical models plays an important role in estimating the bounds of the CO_2 storage capacity.

Unlike the PRMS, which only concerns itself with the commercial production of hydrocarbons (reserves), the SRMS is concerned with the evaluation of accessible pore volumes to store CO_2 (storable quantities) geologically, *with an expectation of permanence.* In other words, (1) the target geologic formation must be discovered and characterized (including containment), (2) injection can occur at commercial rates that will not breach containment, and (3) the storage resource must remain trapped. Both the similarities and differences between the volumetric estimations for storable quantities and reserves are schematically illustrated in Fig. 3.

A challenge in the SRMS framework is the determination of commerciality. Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and injection/cash-flow schedule of storage projects (Society of Petroleum Engineers, 2017). Unlike petroleum, which is a sales product, the CO_2 resource being injected is typically a waste product from other projects or entities; therefore, cash flows should be evaluated for the storage project alone and consider both the (rate of and total) supply as well as negotiated fiscal terms (Society of Petroleum Engineers, 2017). Commerciality can depend on numerous things, including expected quantities of storage projected, estimated costs of injection and revenues from the stored quantities, projected storage, and revenue-related taxes, as well as the application of an appropriate discount rate (Society of Petroleum Engineers, 2017).

Typically, CO_2 storage is carried out in one of three ways: via injection into virgin saline aquifers, into depleted oil and gas fields, or used for enhanced oil recovery (EOR). These methods all have different project drivers, risks, and commercial implications. Economic drivers for CO_2 injection into saline aquifers or depleted fields are usually governed by emissions trading schemes (ETS). These are government frameworks aiming to provide economic incentives for reducing emissions (sequestering CO_2). These projects typically aim for the permanence of CO_2 storage, and the economic considerations typically depend more on the stakeholders involved. For example, if an operator owns two assets outright and is producing from Field A for injection into Field B, there are no associated issues with

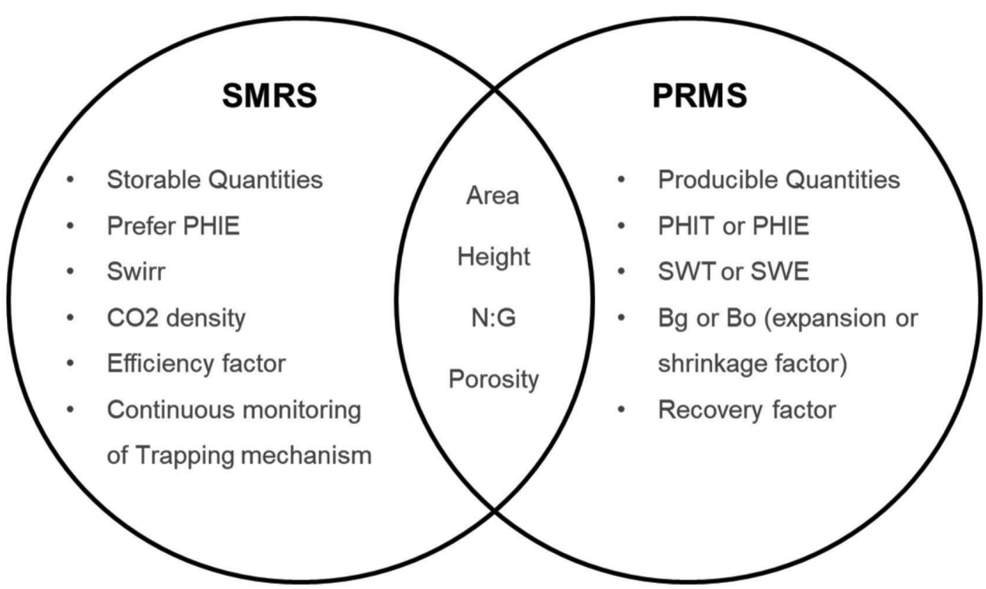

Fig. 3—Venn diagram highlighting similarities and differences for resource evaluation between SRMS and PRMS.

commerciality. However, if Field A (producer) is owned by Company A and Field B is owned by Company B (Storage), then complications arise around tariff payments for acceptance of the CO_2.

On the other hand, utilization projects, such as EOR using CO_2 as a miscible gas, aim to maximize the amount of oil recovered and minimize the amount of CO_2 produced per ton of CO_2 injected. While this may seem counterintuitive for a CCUS project, in principle and depending on the operating conditions, the life cycle of a CO_2 EOR project can have more net CO_2 injected than is produced after final oil production (Hepburn et al., 2019). With such a commercial arrangement, the operator is provided with some economic flexibility, particularly as carbon pricing increases with time. In this case, the operator can shift the emphasis from maximizing oil output to maximizing CO_2 storage. In the United States, assuming an oil price of USD 100/bbl, EOR with CO_2 typically becomes economically viable at CO_2 costs of USD 45 to 60 per ton (Hepburn et al., 2019).

PETROPHYSICAL CONSIDERATIONS FOR CCUS PROJECTS

In this section, and with the SRMS as a guide, the key petrophysical considerations that should be accounted for in a typical CCUS project will be discussed. A caveat is that not all inputs are required all the time; it depends on the type of CO_2 storage project and the stage of project maturity. What we wish to demonstrate, however, is that the petrophysicist can play a critical role in obtaining insight into these properties. Additionally, the practicing petrophysicist is also instrumental in aiding the mitigation of risks associated with these project types through the careful application of evaluation methods.

CO_2 Migration and Trapping

The behavior of CO_2 in the subsurface is not static, with the CO_2 trapping mechanism evolving with time. Over the short injection timescale, the primary mechanism for trapping will be geological, either under a structural high or in stratigraphic bodies. The risk here is poor knowledge of the subsurface and reservoir, with CO_2 migration via leak pathways to the surface. As part of risk management, a petrophysicist should not only evaluate the subsurface closest to the injection site but also look at wells that can aid in the delineation of the field. It is for the petrophysicist to understand how the petrophysical properties vary in the subsurface, especially the salinity, porosity, and permeability. Mapping out such properties would aid the reservoir geologist in mitigating some of the leakage risks. As much as possible, petrophysical properties should also be used for seismic calibration to determine if amplitude anomalies (e.g., leak pathways and gas chimneys) can potentially be flagged early.

Two short- to medium-term processes (months to years) are capillary trapping within the reservoir pore space as the CO_2 plume migrates updip and CO_2 dissolving in brine, creating carbonic acid (H_2CO_3) (Sulak and Danielsen, 1989). Risks here include seal breach or seal failure from the chemical dissolution of constituent minerals brought about by acidification of the in-situ brine. Another form of failure is also "worm holing," where acidified brine dissolves a mineral, forming a migration pathway. If the field is old with many abandoned legacy wells, acidified brines can interact with cement and steel downhole, increasing corrosion and pitting, and potentially causing CO_2 leakage. Again, a petrophysicist can help to mitigate the risk. First, analysis of the seal properties, including mineral facies and geomechanical properties, should be undertaken. This analysis should also include capillary pressure (P_c) measurements to determine threshold pressures. If there is appetite and budget, a core analysis study on legacy core or cuttings could be undertaken to observe for the interaction of CO_2-brine with any seal rock. In the case of legacy wells, the petrophysicist can aid by reviewing and analyzing the quality of cement bond logs (CBL).

In the long term (decades), CO_2 mineralizes to form cement within the pore space of the rock. Core injection studies have shown that CO_2 interactions between formation water, K-feldspar, plagioclase, and carbonate commonly cause the precipitation of silicate and carbonates. This is perhaps the most effective trapping mechanism but also the slowest occurring. In some instances, the precipitated minerals, in association with released clay particles, will migrate through the pore throat before precipitating and reducing the permeability of the formation (Sadati et al., 2020). This will result in a decrease in the injectivity of CO_2 into the formation and may impact the commerciality of a project. A petrophysicist can aid in the de-risking of such projects by undertaking/reviewing formation damage from previous production data.

Geochemical Alternations and Fines Migration

Fines migration is a phenomenon that occurs in reservoirs when small particles of minerals and other materials present in the formation are mobilized and transported by the flow of fluids through the rock. CO_2 injection into a reservoir can cause fines migration in several ways. First, because CO_2-brine interaction causes a pH reduction with the formation of H_2CO_3 (Zhang et al., 2017), this causes the dissolution of minerals in the formation, including those that bind the fines to the rock matrix, which can lead to their mobilization. In a related manner, pH changes from carbonic acid can cause changes to the surface properties of the rock as well and weaken the bonds to the fine clays, leading to the destabilization and mobilization of such particles. Secondly, CO_2 can cause swelling of clays present in the formation, and dislodge/break fines particles from rock surfaces, mobilizing their movement within the pore space. As pressure gradients are present with CO_2 injection (which is at a higher pressure compared to the formation generally), the dislodged clays/fines move within the pore space towards areas of low pressure, where they can accumulate, reduce overall permeability, and eventually cause a blockage (Pi et al., 2021). As fines migration can have a significant impact on project commerciality, petrophysicists must carefully evaluate the geomechanical properties of the reservoir, including sanding studies, and potentially conduct fines migration studies prior to any injection taking place. Post-injection, petrophysicists must again monitor the efficacy of the injection process using casedhole logging or tracer techniques.

Net Effective Overburden Stress and Impact on Grain Contacts

There are two competing forces in any subsurface reservoir: the downward vertical stress applied by the weight of the overburden counterbalanced by the pore pressure acting outward and radially on the internal pore walls between grains in a fluid-saturated rock (Fig. 4). The difference between the two forces is referred to as the net effective overburden stress (σ'_{NOB}) (Eq. 3).

$$\sigma'_{NOB} = \sigma_v - \propto p_p , \tag{3}$$

where σ_v is the total vertical stress (psi), $\propto$ is the Biot poro-elastic factor, and p_p is the initial reservoir pressure (pore pressure in psi).

σ'_{NOB} has a large impact on the life of a reservoir, with compaction, subsidence, and fracture initiation all intimately tied to this property. In a production environment, p_p typically decreases, and compaction occurs. This can be an effective production mechanism, aiding natural pressure depletion. However, excessive drawdown of the pressure can result in subsidence (e.g., Ekofisk Field) (Sulak and Danielsen, 1989). This is why pressure maintenance and support (via injection of gas or water) is important to increase the pore pressure to as close to virgin reservoir pressure as possible.

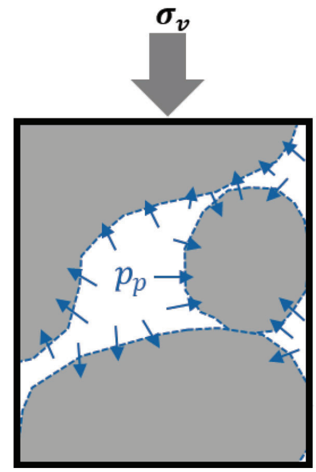

Fig. 4—Schematic of net effective overburden stress at the microscale, with pore pressure acting outwards and total vertical stress acting downwards.

In the case of CO_2 injection, however, where injection sites may be at virgin pressure (e.g., saline aquifer), the risk here is the initiation of new fractures or reactivation of old ones. In addition, CO_2 is not an inert substance. As mentioned earlier, permeance increases over time as the CO_2 undergoes mineralization, but this only occurs after some amount of CO_2 has dissolved in the surrounding brine to form carbonic acid. It is possible that the chemical interaction with the acidified brine can cause a chemical weakening of the intergranular contacts, in turn resulting in a mechanical failure of the formation. A geomechanical study assisted by the analysis of log and core data for wells within the injection site is recommended to de-risk this further.

Fresh Water vs. Saline Aquifer

An understanding of fluid-fluid interactions and the displacement characteristics of CO_2 are critical in CO_2 storage within the subsurface. Salinity, electrical properties, and temperature are all interrelated and can have a major impact on the injectivity of CO_2 into the formation. CO_2 solubility typically decreases with an increase in salinity (Fig. 5); this results in the precipitation of salt and influences near-wellbore porosity and permeability (Sadati et al., 2020). Therefore, a lower salinity aquifer is preferred. However, environmental considerations with potential contamination of water resources can become a constraint when salinities are less than 30,000 ppm. A petrophysicist must, therefore, critically understand the aquifer characteristics and have a regional view of how the salinity varies. In the case of an injection site, salinity calibration is very important. A petrophysicist should insist on a thorough analysis of the ionic components present in the water and, assuming there are conflicts with groundwater requirements, must be ready with secondary or even tertiary injection alternatives.

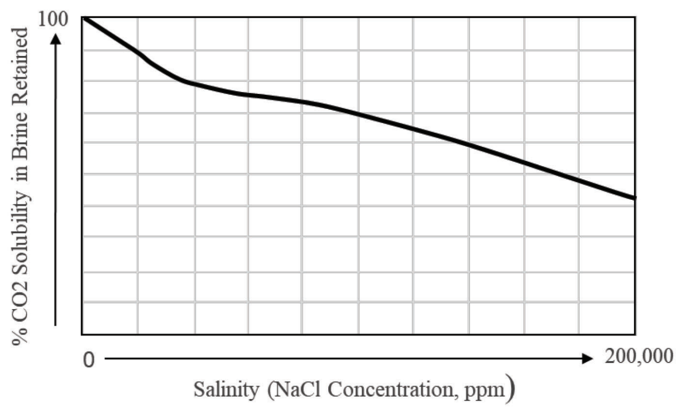

Fig. 5—CO_2 solubility vs. salinity in fresh water (independent of pressure and temperature), adapted from Sadati et al. (2020).

Effective vs. Total Porosity

Porosity is the key petrophysical input for volumetric consideration in estimating the total storage potential of CO_2. In traditional oil and gas exploration/development, the volumetric equation solves for a volume of hydrocarbon in the reservoir. As a result, either effective porosity (PHIE) or total porosity (PHIT) may be used as input into the equation, with the corresponding water saturation (total or effective) being used in accordance to calculate a volume of hydrocarbon (Fig. 6). In CO_2 injection projects, however, the volume of interest is only the amount of free-fluid volume (FFV) that CO_2 may displace after injection. Assuming CO_2 injection occurs in a water-saturated formation, PHIE (not PHIT) should be the input into the theoretical storage resource (Eq. 2).

Wettability

The wettability of a rock refers to the preference of a liquid phase to be attracted to a grain's surface (Glover, 2014). CO_2 is always nonwetting to water (by definition). Therefore, wettability is not an issue in the case of injection into a depleted gas field or a saline aquifer. Wettability only becomes a concern if CO_2 is being injected into a (depleted) oil field. In the case of a water-wet or mixed-wet reservoir, where oil is not predominantly in contact with the grain surfaces, the dissolving of CO_2 in oil or brine causes changes to both oil properties and pH, respectively. In some cases, asphaltene dropout can occur, making the rock more oil-wet. A petrophysicist can assist in de-risking this by conducting SCAL studies with real reservoir fluids to mimic the conditions in the reservoir.

Trapped Residual Phase Saturation

When CO_2 is injected into a depleted oil field, residual hydrocarbon saturation (S_{hr}) becomes an important parameter to evaluate. S_{hr} is the fraction of hydrocarbons trapped in the reservoir that has experienced water encroachment (Holtz, 2002). This residual saturation occupies effective pore space, which would otherwise be able to host CO_2 being injected. Studies have suggested that a reduction in brine mobility,

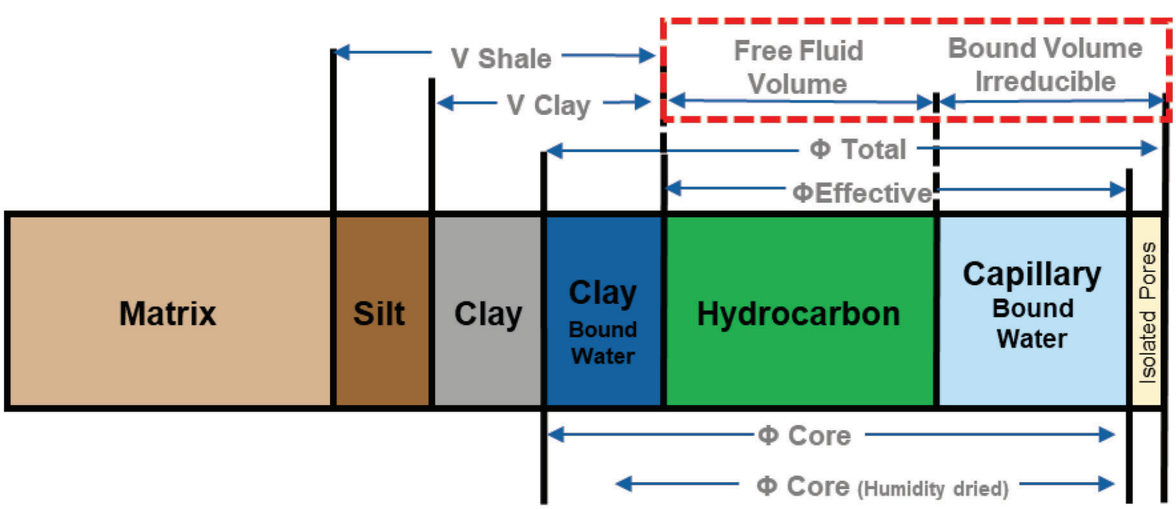

Fig. 6—Summary of bulk rock volume and the various definitions of porosity.

density, and viscosity of gas mixtures when dissolved into supercritical CO_2 can cause a decrease in storage capacity. Additionally, multiphase depleted gas reservoirs may also experience lower CO_2 injectivity at early stages, although this may improve over time (Raza et al., 2018).

In such cases, studies into trapped residual phase saturations are valuable pieces of information. If a petrophysicist understands the fundamental reservoir properties like porosity or clay types present within the injection reservoir, then through the choice of appropriate analogs, one could obtain an early estimate of S_{hr} (Fig. 7). If there is higher confidence data like core measurements, petrophysicists (working cooperatively with reservoir engineers and geomodelers) can help to design pre-injection dynamic models which can properly capture the phase behavior of such reservoirs.

Capillary Pressure and Irreducible Saturation (S_{wirr}) Ranges

When injecting into saline aquifers, the reservoirs of interest are typically at 100% S_w. For injection into depleted oil or gas fields, the goal is to displace any wetting phase such that all the effective pore space is filled with the nonwetting CO_2. In all these cases, the focus of the evaluation is S_{wirr}, which reflects the minimum amount of water that will not be displaced by any amount of injected CO_2 volume. The assumption here is that S_{wirr} is associated with clay- and capillary-bound water only. Typically, S_{wirr} values are determined from capillary pressure (P_c) data. The P_c data can be from conventional core or mercury injection capillary porosimetry (MICP) measurements.

$$P_c = \frac{2\gamma cos\theta}{r} \tag{4}$$

$$(P_c)_{lab} = (P_c)_{lab}\frac{(\gamma\cos\theta)_{lab}}{(\gamma\cos\theta)_{res}} \tag{5}$$

$$(P_c)_{res} = HAFWL \times (x - y) \tag{6}$$

where γ is interfacial tension (dyne/cm), θ is the contact angle (degrees), subscript (*lab*) are measurements made at lab conditions, subscript (*res*) are measurements at reservoir conditions, and x and y are the wetting and nonwetting phase gradient in psi/m, respectively.

A practicing petrophysicist must note a few things when evaluating S_{wirr}. First, as P_c is converted to the height above the free-water level (HAFWL or column height) using fluid parameters or an analog (Eq. 6), and as these values are hard to measure experimentally, a petrophysicist might consider a range of values and adopt a "low-best-high" solution for S_{wirr} estimates. Secondly, there should be a full range of rock types available to ensure a complete characterization of the reservoir.

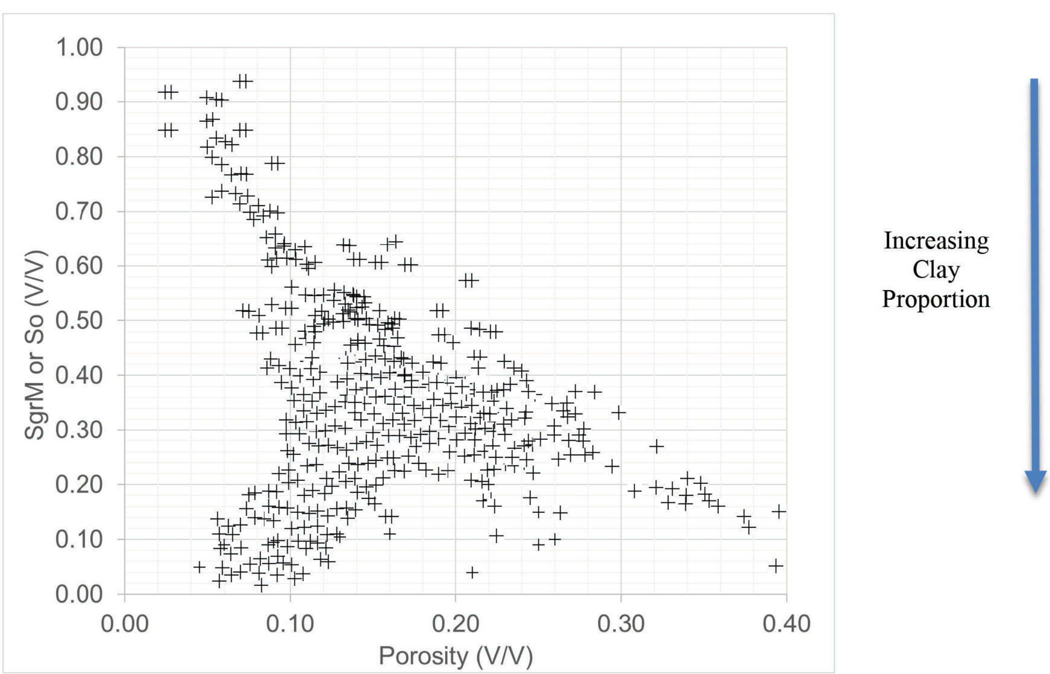

Fig. 7—Plot of maximum residual phase saturation (SgrM) as a function of porosity and increasing clay proportion, modified from Hamon et al. (2001).

P_c measurements should also be done on seal rock, if available. In the scenario where there are no data available or no reasonable analogs available nearby, an estimation of capillary seal characteristics can be made by converting preproduction hydrocarbon column heights to equivalent CO_2 column heights (Naylor et al., 2011). Again, a petrophysicist should look into the sensitivities of the x or y values (Eq. 6) by assuming that the density of the wetting and nonwetting phases is changing as a function of temperature and pressure (Fig. 8). It is worth noting that if the structural trap is capillary limited, then the sensitivities can determine the theoretical maximum CO_2 column height.

Joule-Thomson Cooling and Geomechanics

The injection of high-pressure CO_2 into low pore pressure, depleted oil and gas reservoirs can lead to significant Joule-Thomson cooling (JTC). JTC is a thermodynamic process that occurs when a high-pressure fluid is allowed to expand rapidly in the reservoir, causing its temperature to decrease. JTC is particularly relevant in the context of CCUS. During injection and subsequent depressurization, JTC can cause significant changes in the geomechanical properties of the rock, which must be carefully monitored to ensure the integrity and safety of the storage reservoir.

Upon first being injected into the formation at a high pressure, the rock would become saturated with the supercritical CO_2. The significant pressure gradients that develop between the underpressured reservoir and the overpressured CO_2 could result in an adiabatic expansion of the CO_2 in the pore space, causing the temperature of the fluid and the surrounding rock to decrease, potentially freezing the in-situ pore fluids as well as causing the generation of hydrates, thus severely limiting the overall injectivity of the reservoir (Maloney and Briceno, 2009). The rapid freezing also causes microstresses to develop at the grain-to-grain contact, brought about by the rapid freezing of the interstitial water (Maloney and Briceno, 2009).

At later timescales, as injection slows or stops, and as the CO_2 fluid migrates into the reservoir, it starts to undergo expansion. In this case, Joule-Thomson expansion (JTE) can also add mechanical stress to the rock formation via the propagation of fractures or deformation of the rock. In some instances, the risk brought about by potentially increasing porosity and permeability are changes in the strength and stiffness of the rock. The degree of change in these properties will depend on the rock type, the magnitude of the pressure reduction, and the speed of the JTC/JTE process.

For practicing petrophysicists, data are key here. Part of the risk mitigation is to perform geomechanical studies on different states of stressed rock and, if possible, simulate rapid freezing or cooling of rock samples before subjecting them to geomechanical testing. This should be done in collaboration with a core lab or geomechanics expert. Additionally, log data should be calibrated to these studies, and "what-if" scenarios should be modeled prior to sanctioning any form of injection process in a field to further de-risk the potential for failure.

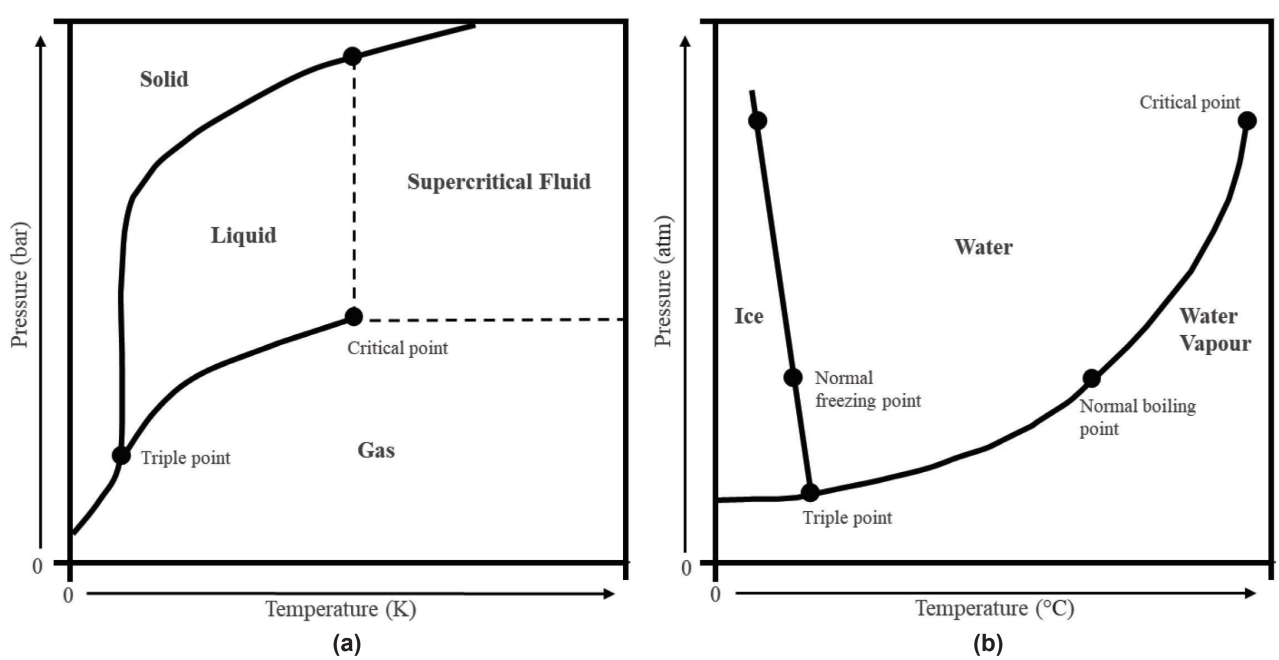

Fig. 8—Generic pressure-temperature phase diagram (a) CO_2 and (b) water.

Casedhole and Production Logging

Casedhole logging is a method used to evaluate the wellbore and the surrounding formation behind the casing of a well, while its complementary technique, production logging, is a method used to evaluate the flow of fluids through a cased, perforated wellbore. In CO_2 injection operations, monitoring for long-term effects is key to determining formation properties over time or to determining the effectiveness of CO_2 injection and storage operations (Odom et al., 2000; Müller et al., 2007).

Starting at the wellbore scale, production logging tools (PLT) may prove useful to determine if fluid is entering the zones as per design, reaching target zones, or (in EOR operations) displacing oil and gas effectively. Fluid density, temperature, and pressure measurements are useful measures as well for the efficiency of the injection and storage processes, particularly when it comes to optimizing injection rates to achieve the desired level of CO_2 storage. These tools are passive and are not impacted by deleterious effects from CO_2 injection. Caliper tools and magnetic casing collar locators (CCL) should be interpreted for corrosion or scale formation, which can affect the integrity of the well and the surrounding formation. In the case of the remediation of wells, PLT tools can be used to determine if these have been adequately addressed.

For behind casing, CBLs should be used to evaluate the integrity of the cement that surrounds the casing of the well. This is important for CO_2 storage operations, as any leaks in the wellbore can cause CO_2 to escape into the surrounding formation. Using pulsed-neutron or carbon-oxygen logging, the petrophysicist can determine how the CO_2 is moving in the formation via observations of fluid contact. A casedhole resistivity tool (CHRT) can serve a similar function, particularly if CO_2 is being injected into a saline aquifer. The displacement of brine would cause a resistivity change, which can be used to evaluate saturation. For plume detection, CHRT applied across a series of wells in the field can be used to map resistivity changes in the field and, therefore, create a “pseudo-map” of CO_2 movement.

RISK MATRIX

Having now discussed the degree of risk and uncertainty in CO_2 storage projects, it is therefore only prudent that a project risk matrix be first developed before embarking on any such injection projects. In this paper, given that we are focusing primarily on the petrophysical considerations for storage projects, the risk matrix we have designed is a tool for project petrophysicists to document risks/uncertainties and how these rank relative to each other (in terms of impact on the project) for the purpose of better communication with project managers or subsurface members. This means any risk that cannot be mitigated primarily through petrophysical evaluation is not included in Table 1.

The risk matrix can also be used as a way of developing fit-for-purpose data acquisition programs. When data acquisition is tied to a project-level risk or uncertainty, the purpose of data collection becomes a lot clearer. The value of information associated with acquiring the data set may also be assessed—relating the likelihood of reducing key risks and uncertainties to the financial impact that would be associated with the risk occurring. This allows the data sets that reduce the most amount of risk to a project for the least cost to be prioritized.

As opinions of risk can be subjective, we have designed the matrix with “generality” in mind. We do this using categorical “Low, Medium, and High” descriptors. As illustrated by Table 1, and from left to right, our matrix outlines (a) key risk events that may occur, (b) impact rating, defined as how the identified risk can potentially affect the material success of the project, (c) data acquisition priority, defined as the timeliness of data collection for project de-risking, (d) the impact on the project, and (e) what data should be acquired.

SRMS PETROPHYSICAL CHECKLIST

Utilizing our discussion of the petrophysical considerations and our generated risk table, we next developed a simplified checklist that can be used when conducting a petrophysical evaluation of CO_2 storage potential. This checklist is not designed to be an all-inclusive, exhaustive list of petrophysical “must-dos” in a CO_2 sequestration project. Rather, it aims to provide a relatively simple guideline to follow in terms of best practices to produce a technically sound and easily auditable interpretation. The checklist is developed with consideration for the SRMS and is given in Fig. 9.

How much detail is required for each stage of the evaluation will depend on the geological uncertainty, the data available, as well as the timeline and scope of the project. For example, a project in a depleted gas field is likely to have a lot more data available that can be integrated into petrophysical evaluation, whereas injection into a saline aquifer is likely to carry a larger uncertainty with less data available. We first start at the prospective storage resources, or the theoretical capacity, as defined by SRMS (Fig. 9). The evaluation required at this stage is similar to any oil and gas

Table 1—Generic Risk Matrix for CCUS Project

Risk Event	Impact Rating	Data Acquisition Priority	Impact on Project	Recommended Data Acquisition
Leakage up legacy wells	High	High	Possible migration of CO_2 from the primary storage site	Continued monitoring of production wells via casedhole logging and/or pressure monitors Monitoring of seabed for surface expressions of gas expulsion Drop core monitoring
Contamination of freshwater aquifer	High	Medium	Breaching environmental considerations of the project	Formation water samples
Inaccurate storage capacity estimates	High	Medium	Not able to inject a sufficient volume of CO_2 per design	Additional well and core data to de-risk volumetric inputs for site-specific reservoir parameters, e.g., core, NMR
Geomechanical alterations in the reservoir	High	Medium	Thermal cooling of reservoir or localized pressure buildup at legacy well locations. Wellbore collapse, subsidence	Lab tests on reservoir core data, where available, or preliminary geomechanical study based on existing data such as logs
Top seal failure	Medium	High	CO_2 mobility and migration are different from expectations impacting capacity and containment	Core and SWC collection on top and intraformational seals for geomechanics study Capillary pressure measurements
Migration of CO_2 beyond storage complex	Medium	High	CO_2 mobility and migration are different from expectations impacting capacity and containment	Tracer tests, detailed static and dynamic modeling of reservoirs
Insufficient injection rates	Medium	Medium	Lack of storage capacity and incorrect well count due to uncertainty in injectivity	Core data are taken across key injection complex to calibrate to modeling inputs RCA / SCAL
Geochemical alterations in the reservoir	Medium	Medium	Impaired injectivity and reduced final storage capacities Formation of chemical compounds not anticipated impacting material selections and threatening injectivity	RCA/SCAL, XRD, petrography, lab tests on core, and fluid data input into geochemistry study
Limited ability to monitor plume through passive methods	Medium	Low	Various monitoring technologies will have to be deployed to infer CO_2 remains in storage site	Installation of downhole gauges for pressure monitoring in offset wells

petrophysical evaluation. Key differences are an assessment of PHIE and the estimation of S_{wirr}.

As the project is matured to a Contingent Storage Resource stage, consideration must be given to formation mineralogy, permeability, core-derived S_{wirr} and residual hydrocarbon saturation (in depleted fields), and formation temperature and pressure. This accounts for the more detailed dynamic observations and rock-fluid and fluid-fluid interactions. This provides a more detailed understanding of the formation's storage potential before final investment decisions.

Because the density of CO_2 is important in volumetric calculations for total storage capacity, as well as the phase of the fluid being critical for the project's success, the petrophysicist may be required to consider other factors or parameters that may typically fall under petroleum or reservoir engineering disciplines at both the Contingent Storage Resources and Commercial Storage Capacity phases. These include CO_2 chemical composition, pore pressure, and fracture gradient analysis, in addition to geomechanical studies on grain-grain and fluid-grain impacts, as well as casedhole monitoring to evaluate injection rates and potential fines migration.

CASE STUDY – CLOVERHILL-1

In this section, we will use a generic gas well (Cloverhill-1) (Geoscience Australia, 2023) as a case study to outline the practical application of the petrophysical workflow presented in Fig. 9. Cloverhill-1 is a wildcat exploration well drilled in 2014 and is located southwest of exploration permit WA-268-P in the North West Shelf off the coast of Western Australia (Fig. 10). The well targeted the Top Mungaroo "AA" sands and the intra-Mungaroo "A-Lower" sands. The well was selected because it encountered both gas and water and has a modern and complete log suite, which makes it a good analog example to show a hypothetical CO_2 sequestration storage project, either into the brine aquifer or into a (depleted) hydrocarbon-bearing zone.

The Triassic Mungaroo Formation is characterized by upper and lower delta plain channel sandstones, swamps, and restricted embayments. The system is dominantly

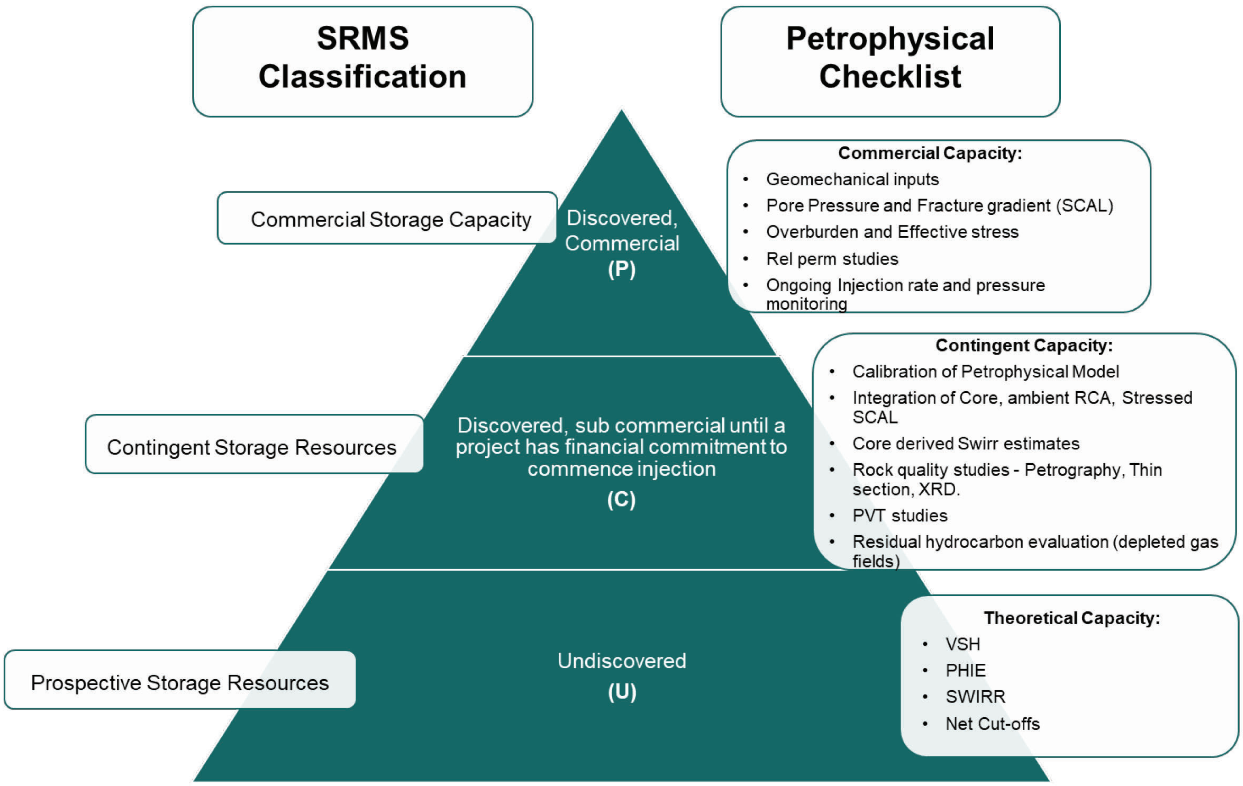

Fig. 9—Generic petrophysical checklist for evaluating the CO_2 storage potential in line with the SRMS workflow.

comprised of sand and shale of variable thickness, occasionally interbedded with thin coals and pyritic nodules. The reservoirs are predominantly quartz, along with some dispersed glauconite grains. The reservoir section is divided into two main intervals, the A and AA sands. In general, the A sand has poorer sand development than the overlying AA sand and is a more coal-prone interval. This is reflected in a lower net-to-gross compared to the overlying AA sand (20% in the A sand and approximately 60% in the AA sand). The sand quality is also poorer in the underlying A sand, with average effective porosities of 20% compared to 25% in the AA sands (see Table 2). At Cloverhill-1, the A sand and the lower portion of the AA sand are water-bearing, while the upper part of the AA sand is gas-bearing (Fig. 11).

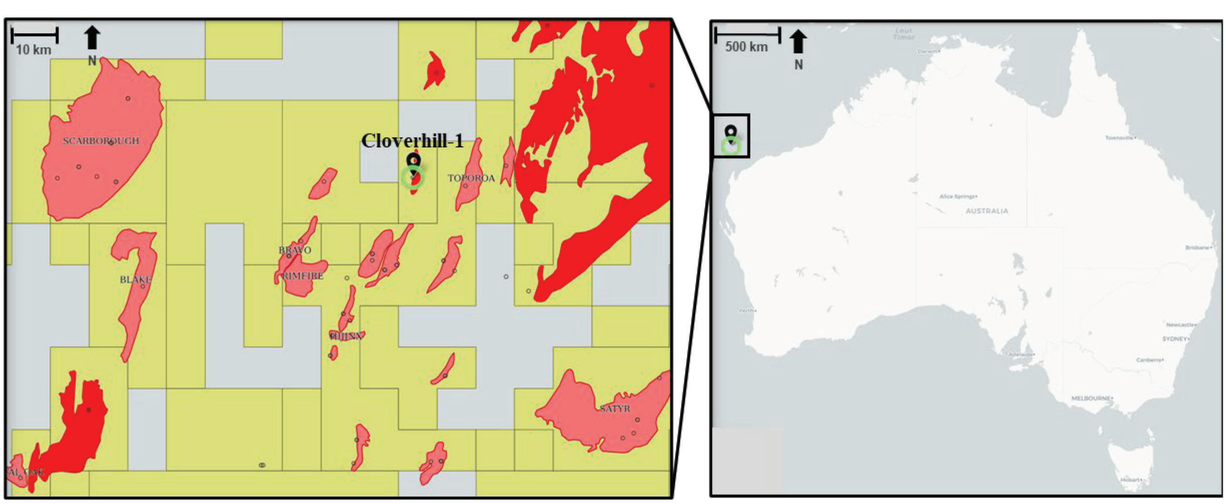

Fig. 10—Location map of the Cloverhill-1 well, modified from MapStand (2023).

The initial steps in the generalized petrophysical workflow (Fig. 9) are consistent between both hydrocarbon exploration and CO_2 storage projects. Both require standard formation evaluation procedures, with an integration of wireline (WL), logging-while-drilling (LWD), and mud logs, formation pressures, cuttings, and knowledge of the depositional system. The initial evaluation covers the key inputs into the theoretical storage capacity at the prospective resources stage in Fig. 9. For the petrophysicist, that means determining volume of shale (VSH), PHIE, S_{wirr}, and applicable net cutoffs.

Both total and effective properties were calculated in this case. From the logs and available core data, the *N*:*G*, porosity (both total and effective), and S_{wirr} can be determined quite readily. The evaluation uses a deterministic approach for determining the VSH, porosity, and water saturation. Both VSH_{GR} and VSH_{ND} were calculated, with the lowest of the two being carried through the evaluation. This acted as input into the *N*:*G* calculations through the use of a VSH cutoff of less than 0.5.

From here, porosity was interpreted using straight density (D) porosity (PHID) or in combination with neutron (N) to give total porosity (PHIT). PHIT was corrected for hydrocarbon effects and invasion. For quality control (QC) purposes, porosity is also evaluated using the nuclear magnetic resonance (NMR) porosity with D logs (density magnetic resonance porosity or DMRP). For application to CO_2 injection into a saline aquifer, however, effective porosity (PHIE) must be evaluated. To do this, we calculate the porosity of shale and remove its porosity component to determine the final PHIE value.

The water salinity was derived in the water leg penetrated in Cloverhill-1 using a Pickett plot technique. This provided an output salinity of 25,000 ppm NaCl, which is relatively fresh, thus making it a viable CO_2 injection reservoir at first glance. The cementation exponent (*m*) and saturation exponent (*n*) were derived from a nearby analog; the final values used for this interpretation are $m = 1.92$ and $n = 2.15$. The resultant resistivity-derived water saturation (SWT_{RES}), NMR-derived water saturation (SWT_{DMRP}), and capillary-pressure-derived saturation from core (SW_{PC}) show a good match. S_{wirr} was confirmed by observing the matches between SW_{PC}, SWT_{RES}, and saturation estimated by the array dielectric tool ($SWXO_{ADT}$). NMR also provides an independent measure of S_{wirr} by summing the clay-bound water and capillary-bound water (BVW + BVI). The S_{wirr} is equivalent to the minimum water saturation from capillary pressure curves. The storage capacity of CO_2 is determined by evaluating Eq. 2. The integration of variable methods of evaluating porosity, and water saturation gives confidence in the evaluation and the inputs into Eq. 2.

The evaluation of *N*:*G* was via cutoffs for the volume of clay (VCL, assuming 60% of VSH) at ≤ 0.5, along with a PHIE cutoff of ≥ 10%. An effective water saturation (SWE) cutoff of ≤ 50% was also used to highlight the hydrocarbon-bearing AA sands, as shown in Table *2*. We also ran scenarios with alternative cutoffs (VCL ≤ 0.5, PHIE ≥ 4%, and SWE ≤ 75%) and utilized the NMR outputs to determine a range of porosity and saturations, particularly in the water-bearing sands.

Post-initial evaluation of the theoretical capacity, the saline aquifer in both the A and lower AA sands is a good contender for CO_2 storage. The AA sand may also be of interest for storage once the hydrocarbon column has been produced. The analysis would need to be undertaken on estimating column heights of CO_2 that could be supported (in the absence of capillary seal characteristics of the caprock). Currently, the saturation height function used to generate SW_{PC} in Cloverhill-1 is based on analog fields nearby. MICP analysis should be conducted as part of the SCAL program on a range of plugs that represent the variety of rock types encountered in the reservoir. This will provide better estimates to S_{wirr} for input into Eq. 2. The pressure data also confirms the free-water level (FWL), which will be important to update any assumptions made around this for saturation height modeling. Having a good understanding of S_{wirr} will be critical in the case of application to depleted field CO_2 injection, as it will also aid in future modeling of any S_{hr} post-production to better understand fluid-fluid interactions after the onset of injection.

For completeness, we performed a Monte Carlo simulation to evaluate the prospective storage capacity of the Cloverhill-1 well location. Input parameters are given in Tables 2 and 4. The scenarios we have modeled are (1) injection into a depleted hydrocarbon zone (AA sand), (2) injection into a high-quality, water-bearing sand (i.e., high NTG AA Sand – Fluvial), and (3) injection into a lower quality water-bearing sand (i.e., lower NTG A Lower Sand), which has more heterogeneity and potential intraformational seals in the form of interbedded coals. We utilized reported values of GRV for the Cloverhill-1 well (with a ±20% range taken for low and high cases) as well as assuming values for both density of the CO_2 (±25 kg/m^3 for the low and high) and efficiency factors (*E*) ranging between 2 to 10%. These values have been assumed to remain identical for all three zones for this example.

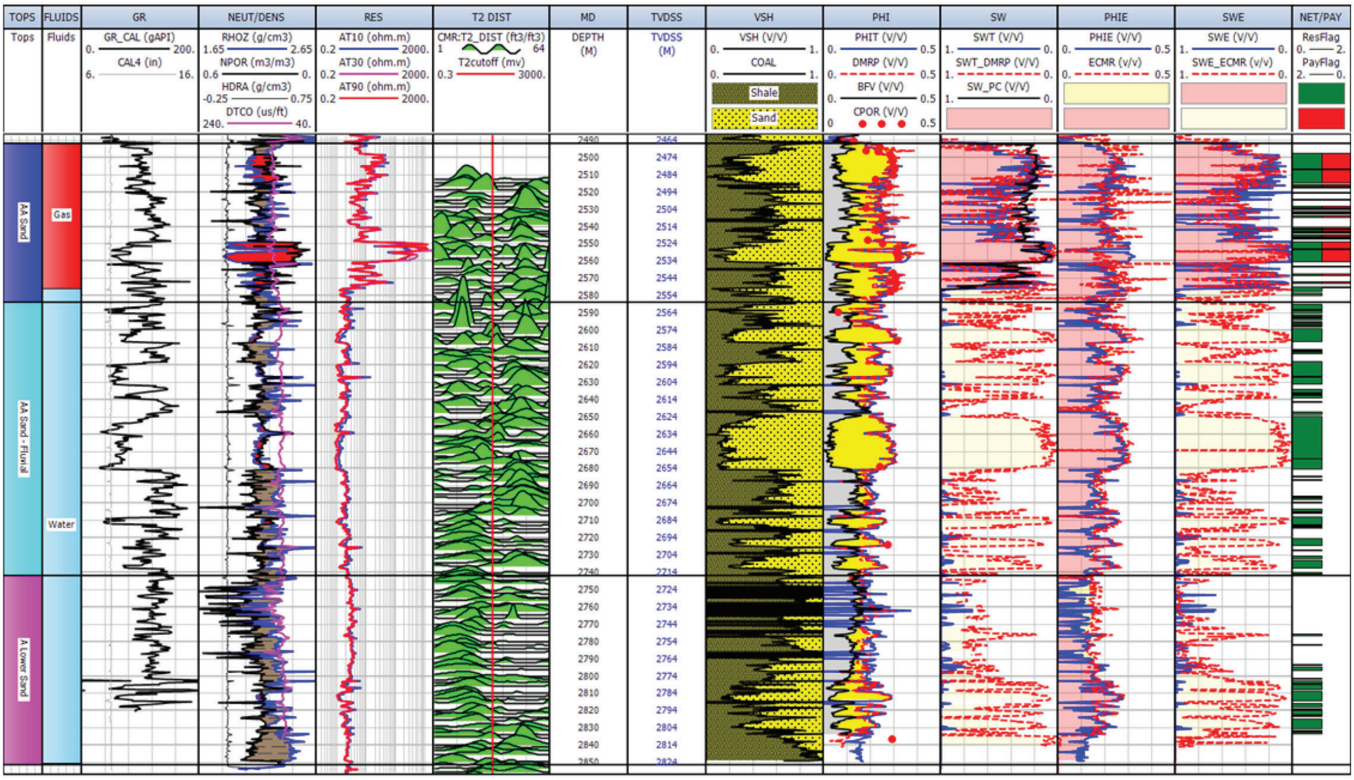

Fig. 11—Cloverhill-1 log data and petrophysical interpretation – 1:1,800 scale.

Table 2—Petrophysical Sums and Averages by Zone Over for the Cloverhill-1 Well*

		Net			Pay			
Zone	Gross	Net	N:G	Av PHIE	Pay	N:G	Av PHIE	Av SWE
	(m TVDSS)	(m TVDSS)	(v/v)	(v/v)	(m TVDSS)	(v/v)	(v/v)	(v/v)
AA Sand	92	45.57 – 46.33	0.49 – 0.52	0.24 – 0.25	39.4 – 42.5	0.42 – 0.46	0.24 – 0.26	0.16 – 0.26
AA Sand – Fluvial	158	88.9 – 92.35	0.56 – 0.59	0.23 – 0.25	77.0 – 79.1	0.48 – 0.52	0.25 – 0.26	0.18 – 0.25
A Lower Sand	109	24.08 – 38.56	0.22 – 0.35	0.20 – 0.21	19.0 – 21.1	0.17 – 0.21	0.21 – 0.22	0.21 – 0.25

*Note: Values are displayed as ranges, given that multiple scenarios were run for property estimation. Note that SWE is equivalent to S_{wirr}.

Table 3—Probabilistic Inputs Into Theoretical Storage Volume

Area (km^2)			Density CO_2 (kg/m^3)			Efficiency Factor (*E*)		
P90	P50	P10	P90	P50	P10	P90	P50	P10
11.2	14	16.8	650	675	700	0.02	0.04	0.10

Integration with geophysicists and reservoir engineers would be required to narrow uncertainty in GRV and CO_2 density for specific pressure-volume-temperature (PVT) conditions. The reported values of GRV are likely overly pessimistic in this scenario, as GRV here is for the Cloverhill-1 well and would benefit from a field-scale structural/seismic interpretation by a geophysicist. The value of *E* would also need to be reviewed for different modeled scenarios, particularly in saline aquifers versus depleted hydrocarbon zones, where you would expect these to vary due to the differing host fluid that supercritical CO_2 is being injected into. From our preliminary evaluation, we note that the AA Sand-Fluvial has the largest storage capacity, which is no surprise given that it has the largest gross thickness and best petrophysical properties, as shown in Table 4.

Table 4—Potential CO_2 Storage Capacity at the Cloverhill-1 Well Location

Reservoir	Mass CO_2 (MM Ton)			
	Low	Best	High	Mean
AA Sand	0.4	1.0	2.4	1.3
AA Sand – Fluvial	0.8	1.9	4.6	2.4
A Lower Sand	0.3	0.6	1.4	0.8

To continue maturing storage resources through to a contingent classification (C – discovered and subcommercial), we will need to start increasing our degree of confidence by integrating more detailed data sets. This includes data as it relates to (stressed and ambient) RCA and SCAL, along with thin sections, scanning electron microscope (SEM) and X-ray diffraction (XRD) thin sections, PVT, and hydrocarbon evaluation from CO_2-brine studies (Fig. 9). RCA and SCAL experiments should include permeability and trapped residual phase experiments as well as fines migration. Rock quality studies through petrography, thin sections, and XRD will also be needed to better understand mineralogy and pore structure.

The maturation to commercial storage capacity (P) requires even more detailed studies to be undertaken, with the integration of geomechanical and dynamic simulation. Relative permeability for CO_2 to brine will be of interest to gauge how the CO_2 plume will behave after the onset of CO_2 injection. As the project is driven towards commerciality, there is naturally less involvement from the petrophysicist, and integration with other subsurface disciplines becomes key. Other subsurface experts may require petrophysical inputs and "what-if" scenario modeling as optimal injection rates are modeled, either via dynamic modeling or material balance.

DATA ACQUISITION

Data gathering and acquisition are critical in properly evaluating key parameters for CO_2 sequestration projects.

Data types used in CO_2 injection projects can be broken into three broad categories: seismic, logs (LWD and WL), and core. To ensure the data gathering is fit for purpose and within the project scope and budget, key project risks and uncertainties should be identified early in the project definition phase, and the various phases of the data gathering and analysis should be outlined and understood with key stakeholders and service companies.

Typically, seismic two-dimensional (2D) or three-dimensional (3D) data sets are acquired early in the project define phase for regional interpretation, identification of traps, and determining gross rock volume, which typically has the largest impact on any volumetric analysis. While the petrophysicist may be involved in providing inputs for seismic to well ties, depth conversion, or fluid substitution studies, this is out of scope for the discussions of this paper.

Petrophysicists are most concerned with well-based data, either from LWD or WL logging. Given the necessity to acquire core and aquifer fluid samples, oil-based muds (OBM) should be used as a preference where possible. If there is an appetite for the acquisition of both LWD and WL data, this should be encouraged, as there is natural lapsed time between an LWD and WL operation, which can be used as a mini downhole "injectivity" and capillary trapping test. As an example, if OBM filtrate has invaded a depleted reservoir or saline aquifer, and an LWD pass shows a light hydrocarbon effect (LHC) in the permeable sand, then the WL pass should show a similar LHC, illustrating that capillary trapping and injectivity have taken place. In fact, the longer the time between the LWD and WL passes, the better. This is a qualitative test, of course, but it adds confidence that the CO_2 injection operation may be possible.

Depending on the maturity of the evaluation required for the CO_2 injection study, some specific log measurements may also be necessary to reduce evaluation uncertainty. This may include (but is not limited to) NMR logs, which can provide an independent measure of PHIE, FFV, and S_{wirr}, which can be compared with traditional evaluation methodologies outlined earlier. Elemental capture spectroscopy tools would be useful to map mineral presence, and dielectric logging would be helpful in salinity and porosity evaluation. Image logs that can capture fractures at various length scales would also be useful in understanding fracture potential and distribution. Formation pressure and temperature are key in predicting the phase and resulting density of CO_2 on injection for input into theoretical storage volume estimates.

Core observations are also important to calibrate log-based petrophysical models. As early to medium timescale CO_2 trapping is very much dependent on a good understanding of pore structure, conducting experiments at the microscale can allow some insight into how the system may behave at the macroscale. Table 5 highlights some of the key core analysis experiments that would be useful for CCUS evaluation depending on subsurface uncertainties in each field. The table excludes basic measurements (i.e., porosity, permeability, grain density, etc.) and only focuses on CO_2-specific measurements based on objectives (i.e., which uncertainties are the focus), experiment type, and the outputs, as well as what sized samples are appropriate for testing.

This table does not consider quality assurance (QA)/QC checks that should be conducted on the core lab facility to determine the adequacy of facilities or core preparation, which should be done by default (e.g., core gamma log, photography, whole core CT, etc.). It is also critical, as part of the update, to ask the core laboratory for data showing samples have equilibrated when measurements are made. A last point to note is on time-lapse monitoring. CO_2 is a "live" fluid that changes with time and exposure to subsurface conditions. Therefore, as much as possible, these experiments should be repeated, and results should be compared to previous measured values. In this way, this "time-lapse" series of experiments will show how the trapped/injected CO_2 is causing/undergoing change with time.

CONCLUSION

We have attempted to provide our view into the best practices associated with the petrophysical evaluation of CCUS projects. We adhered to the SRMS framework and illustrated the key role a petrophysicist plays when it comes to understanding total storable resources, especially given how formation evaluation is directly responsible for at least three out of the six volumetric inputs in the theoretical storage resource for CO_2 (Eq. 2), and how the involvement of the petrophysicist throughout can aid in maturation of the project from the prospective storage resources stage through to the commercial storage capacity stage, including the monitoring phase. We also discussed the key petrophysical considerations for a typical CCUS project, with the caveat that not all considerations are relevant all the time. Instead, these are dependent on the geologic uncertainty, data availability, type of CO_2 storage project, as well as the stage of project maturity. We provided a generic risk matrix template and SRMS "petrophysical checklist" to act as a framework for petrophysicists to communicate key project risks associated with petrophysical uncertainties and how these can best be mitigated, as well as a generic guide through best practice interpretation and application to a case study from a well

Table 5—Core-Based Experiments for De-Risking CCUS Project

Objectives	Experiment	Outputs	Sample Size				Sample Type			Notes
			< 1 in. (e.g., cuttings)	1–1.5 in.	4 in. (Full Dia.)	Comp	CCA	SWC	Perc	
Fluid Displacement, Diffusion Processes	• X-ray CT and mCT • Imbibition and drainage capillary pressure • Counter current imbibition/Spontaneous Imbibition	• Irreducible water saturation • Trapped gas saturation (Sgt)		✓			✓	✓		Both porous plate and centrifuge can be run. Use CT to perform time-lapse monitoring of CO_2 migration as well as trapping mechanism. Also, perform a series of capillary hysteresis experiments (scanning curves). Run experiments at S_{wi} (as an analog for gas cap behavior).
Fines Migration	• NMR • Flow through experiments • X-ray mCT	Change in: • Porosity • Permeability • Saturation • Fines produced in effluent • Injectability	✓	✓			✓	✓	✓	Recommended to confirm salinity before these experiments are done. These experiments are to be done via "time lapse."
Mechanical Properties	• Triaxial compression test • Uniaxial compression test	• Strength and elastic properties (Young's modulus and Poisson's ratio) • Pore volume Compressibility • Bulk volume Compressibility		✓	✓		✓	✓		Samples are required to have a 2:1 length: diameter ratio (this prevents interference between the end platens and the sample as it fails). Vertical samples are preferred. Experiments should be designed to answer questions related to wellbore stability, solids production, subsidence, well operability limits, thermal fracturing, and seal integrity. Also, hysteresis studies are recommended.
Seal Capacity/Integrity	• Mercury injection	• Threshold pressure • (Distribution of) pore sizes	✓	✓			✓	✓		Recommended to run on multiple samples of the same rock type.
Salinity	• Dean-Stark • Standard water analysis (acetate water analysis)	• Ions present in water		✓			✓	✓		Tested on either water obtained on E-line or water from Dean-Stark.
Others	• Interfacial tension, • Geochemical interactions • CO_2 properties, CO_2-HC blend for injection, salt precipitation		✓						✓	Experiments should be done on both caprock as well as on reservoir rock. Fluid samples will be required as well.

drilled off the North West Shelf in Australia, where both injection into a brine aquifer or depleted gas field may be applicable. The importance of data acquisition at various stages of a CCUS project is covered, with an emphasis on log application and core-based experiments. It is important to note that ongoing time-lapse reservoir surveillance and monitoring is critical for the success of any CCUS project due to the varying nature of CO_2 plume migration and subsurface conditions over time. While the motivation for the SRMS framework and this paper is for CO_2 storage, this workflow may prove helpful for other applications of gas storage projects, too. Throughout this work, we hope that we have outlined key criteria for petrophysical considerations necessary for fit-for-purpose interpretations and auditing of CCUS projects to achieve the goal of de-risking and maturing more of these projects through the execution stage in a lower carbon economy. We wish to finally conclude by saying that while the paper is petrophysically focused, the challenge of CO_2 storage is a truly multidisciplinary exercise that requires integration from all subsurface disciplines.

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NOMENCLATURE

Abbreviations

2D = two-dimensional
3D = three-dimensional
Bg = gas formation volume factor, in rb/STB
Bo = oil formation volume factor, in rb/STB
BVI = bound volume irreducible
BVW = bound volume water
C = contingent storage resources
CBL = cement bond log
CCL = casing collar locators
CCUS = carbon capture, utilization, and storage
CHRT = casedhole resistivity tool
CO_2 = carbon dioxide
COP21 = 2015 Paris Agreement
CT = computed tomography
DMRP = density magnetic resonance porosity
EOR = enhanced oil recovery
ETS = emissions trading scheme
FFV = free-fluid volume
FVF = formation volume factor
FWL = free-water level
GRV = gross rock volume
H_2CO_3 = carbonic acid
HCIIP = hydrocarbons initially in place
JTC = Joule-Thomson cooling
JTE = Joule-Thomson expansion
LHC = light hydrocarbon correction
LWD = logging while drilling
MICP = mercury injection capillary pressure
NaCl = sodium chloride
NMR = nuclear magnetic resonance
NTG = net-to-gross ratio
OBM = oil-based mud
P = commercial storage capacity
P90 = low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
P50 = mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
P10 = high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)
PHID = density porosity
PHIE = effective porosity
PHIT = total porosity
PLT = production logging tools
PRMS = Petroleum Resource Management System
PVT = pressure, volume, temperature experiment
QA = quality assurance
QC = quality control
RCA = routine core analysis
RF = recovery factor
SCAL = special core analysis
SEM = scanning electron microscope
SgrM = maximum residual phase gas saturation
SPEE = Society of Petroleum Evaluation Engineers
SRMS = CO_2 Storage Resources Management System
SWC = sidewall core
$SWXO_{ADT}$ = saturation derived from array dielectric tool
TD = total depth
TVD = true vertical depth
TVDSS = true vertical depth sub-sea
U = prospective storage resources
WL = wireline
XRD = X-ray diffraction

Symbols

- m = cementation exponent
- n = saturation exponent
- P_c = capillary pressure
- S_{hr} = residual hydrocarbon saturation
- S_w = water saturation
- SWE = effective water saturation
- S_{wirr} = irreducible saturation
- SWT = total water saturation
- SWT_{RES} = total water saturation derived from resistivity
- SW_{PC} = total water saturation derived from core
- VSH_{GR} = volume of shale derived from gamma ray log
- VSH_{ND} = volume of shale derived from neutron and density logs
- ρ_{CO2} = the density of CO_2

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