Title: Petrophysical Considerations for CO_2 capture and storage

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Abstract: Carbon Capture Utilisation 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 depends on the physical and chemical properties of the geological formations that are used for storage, petrophysicists working 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 which 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 analysed for suitability for CO_2 storage.

One-Sentence Summary: This paper aims to discuss the petrophysical considerations that need to be made for compliance with the CO_2 Storage Resources Management System (SRMS), highlight key differences a between the SRMS and the Petroleum Resources Management System (PRMS) and discuss what practicing petrophysicists must consider when undertaking quantification of storage capacity for CO_2 projects.

Keywords (minimum 6): SRMS, PRMS, CCUS, carbon, project management, risk, storage

Introduction

Carbon Capture Utilisation and Storage (CCUS) encompasses a range of methods and technologies that involves 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), required installed CCUS capacity needs an approximate 100-fold increase by 2050 to achieve net zero targets as defined by the COP21 agreement. Between USD $655 billion and USD $1,280 billion in capital investment is required to meet these objectives [1]. 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 (Figure 1), and a staged process will ensure that the data at the various length scales is properly integrated.

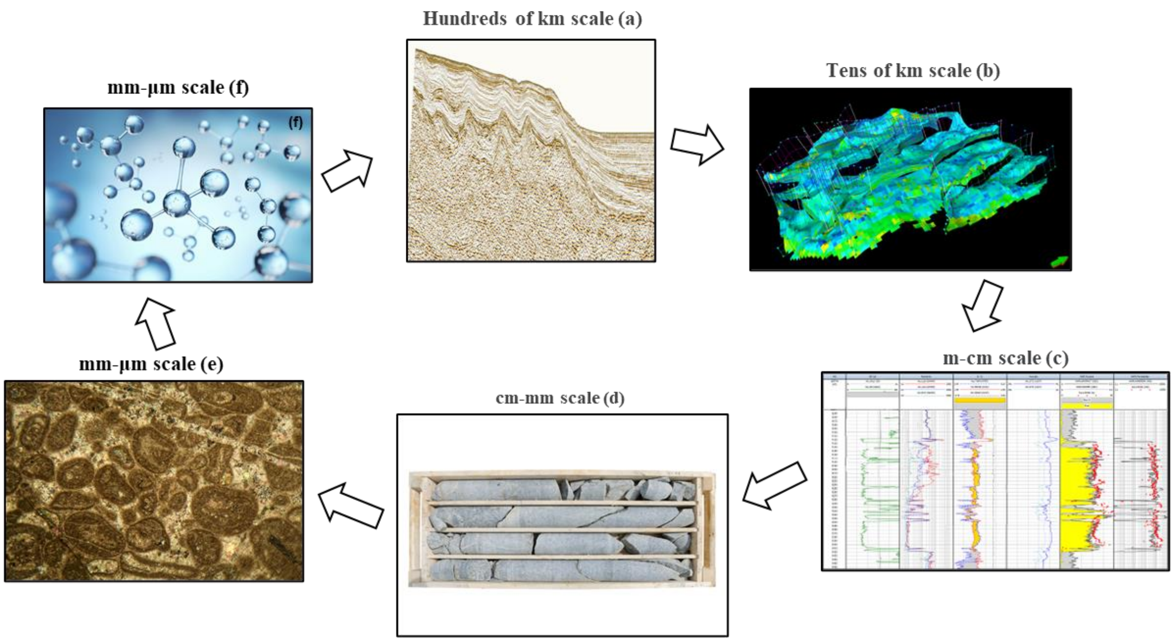

Figure 1: Schematic illustrating the process of Data Integration

The process starts with the identification and high grading of potential storage sites. Starting with seismic interpretation (Figure 1a), there is a need to perform depth conversion, interpret key stratigraphic horizons & faults and evaluate the stratigraphy/facies. Once a suitable site is selected, field based properties and/or a static modelling would need to be populated (Figure 1b) with evaluations made from petrophysical logs, routine and special core analysis (Figure 1c to Figure 1e), where the goal would be estimation of porosity, permeability, minerology, 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 an understanding of pressure and temperature, phase behaviour of injected CO_2 fluids and the integration of data related to well tests that would have been performed in analogue or offset wells. Geochemically, aspects related to mineral composition, rock-fluid-CO_2 interactions and microbial activity should also be considered (Figure 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 Equation 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 bottom-hole pressures [2].

The summary above highlights the multi-disciplinary challenge associated with CCUS. In this paper, we will focus on just one aspect of this chain, namely the key formation evaluation considerations which need to be accounted for in any CCUS project under the CO_2 Storage Resources Management System (SMRS) [3] (Figure 1c to Figure 1f). This paper will discuss how the CO_2 Storage Resources Management System (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, utilising 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 classification and categorization of all petroleum reserves and resources [4]. Although the system encompasses the entire in-place petroleum resource and characterises 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, Utilisation 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 [2].

The PRMS provided the model for the development of the SRMS, by which CCUS projects can be voluntarily contrasted against. 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 (Figure 2). Both are similar in that they are project based, independent of implementation and detail how resources can be quantified, categorised and classified [3] . In both the PRMS and SMRS, 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 [4] . 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).

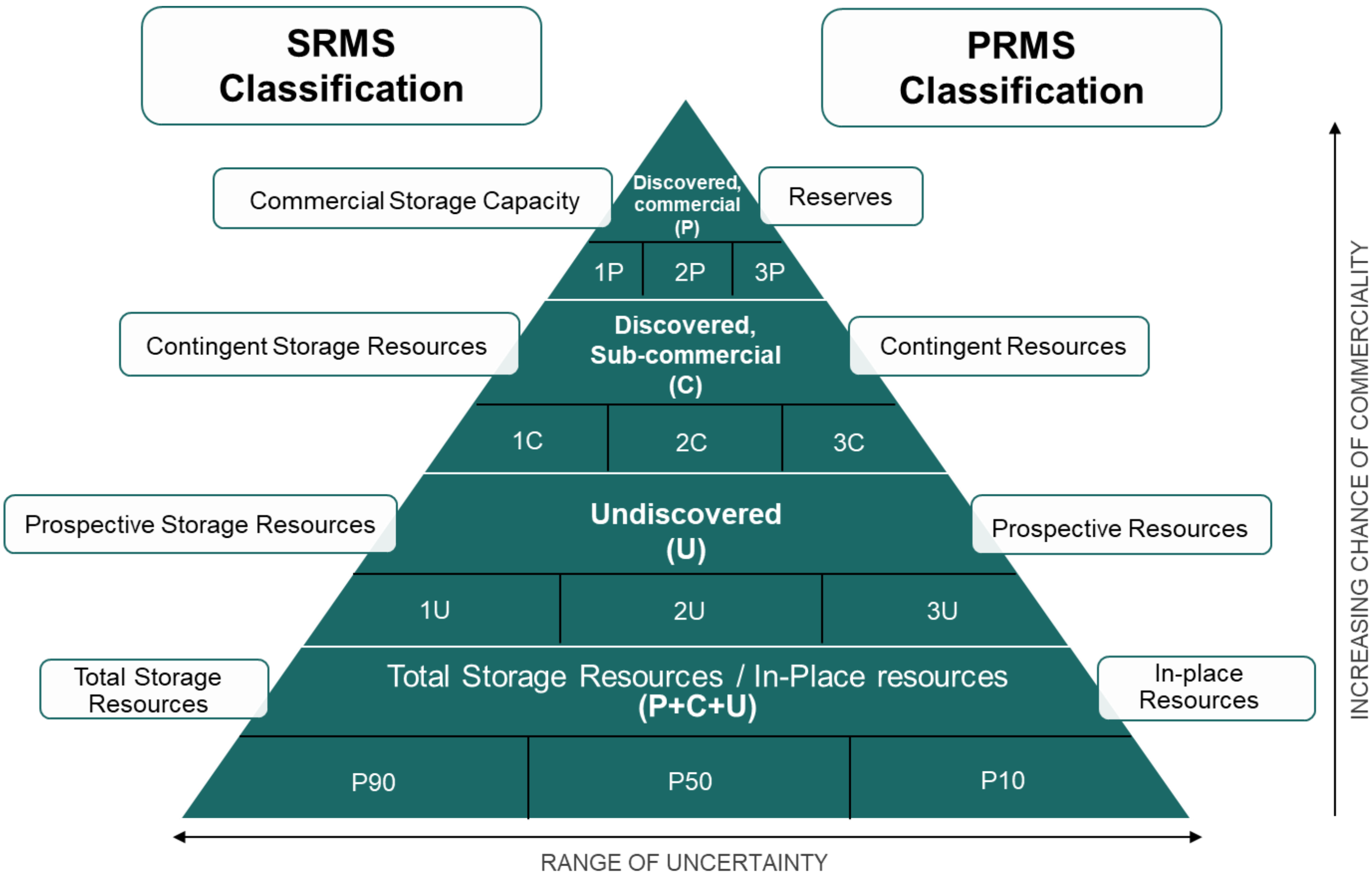

Figure 2: Comparison of the Classification framework for the SRMS and PRMS.

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) (Equation 1 and Equation 2) respectively.

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

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

where GRV is the Gross Rock Volume (m^3); N:G is the Net to Gross (m/m); ϕ is porosity (V/V), Sw is the water saturation (V/V), SW_{irr} 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 - rbbl/stb, gas – bbl/scf) and E is the Efficiency Factor (V/V).

It is important to note that Equation 2 represents a theoretical maximum storage volume. The actual amount of CO_2 stored in the subsurface will be a function of the dynamic behaviour of injected CO_2 into the subsurface, and the subsequent displacement of the non-wetting 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 characterised (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 is schematically illustrated in Figure 3.

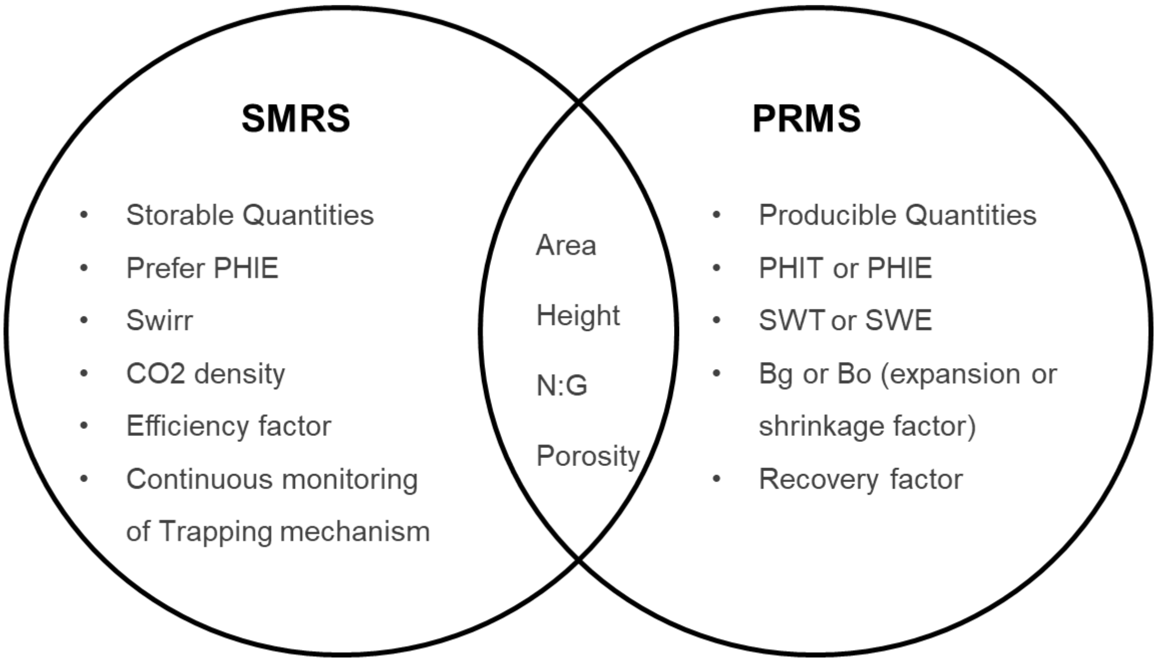

Figure 3: Venn diagram highlighting similarities and differences for resource evaluation between SMRS and PRMS.

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 [3]. Unlike petroleum, which is a sales product, the CO_2 resource being injected is typically a waste product from another projects or entities; therefore, cashflows should be evaluated for the storage project alone and consider both the (rate of and total) supply as well as negotiated fiscal terms [3]. 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 [3].

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 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 is no associated issues with 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, utilisation projects such as enhanced oil recovery using CO_2 as a miscible gas, aims to maximise the amount of oil recovered and minimise the amount of CO_2 produced per tonne of CO_2 injected.

While this may seem counter intuitive for a CCUS project, in principle and depending on the operating conditions, the lifecycle of a CO_2 EOR project can have more net CO_2 injected than is produced after final oil production [5]. 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 maximising CO_2 storage. In the United States, assuming an oil price of $100/bbl, EOR with CO_2 typically becomes economically viable at CO_2 costs of $45-$60 per tonne [5].

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 careful application of evaluation methods.

A. CO_2 migration and Trapping

The behaviour 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 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, 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) [6]. Risks here include seal breach or seal failure, from 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 interaction of CO_2-brine with any seal rock. In the case of legacy wells, the petrophysicist can aid by reviewing and analysing the quality of cement bond logs (CBL).

In the long term (decades), CO_2 mineralises to form cements 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 [7]. This will result in a decrease in 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.

B. 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, this causes dissolution of minerals in the formation, including those that bind the fines to the rock matrix, leading 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. As fines migration can have 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 cased hole logging or tracer techniques.

C. 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 (Figure 4). The difference between the two forces is referred to as the net effective overburden stress (σ'_{NOB}) (Equation 3).

$$\sigma'_{NOB} = \sigma_v - \propto p_p \qquad \text{Equation 3}$$

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).

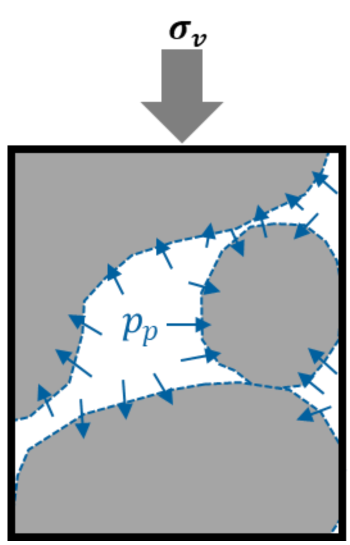

Figure 4: Schematic of Net effective overburden stress at the micro scale, with pore pressure acting outwards and total vertical stress acting downwards.

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) [6]. 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.

In the case of CO_2 injection, however, where injections sites may be at virgin pressure (e.g. saline aquifer), the risk here is 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 weaking 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.

D. 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 inter-related, 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 (Figure 5); this results in the precipitation of salt and influences near well bore porosity and permeability [5]. 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.

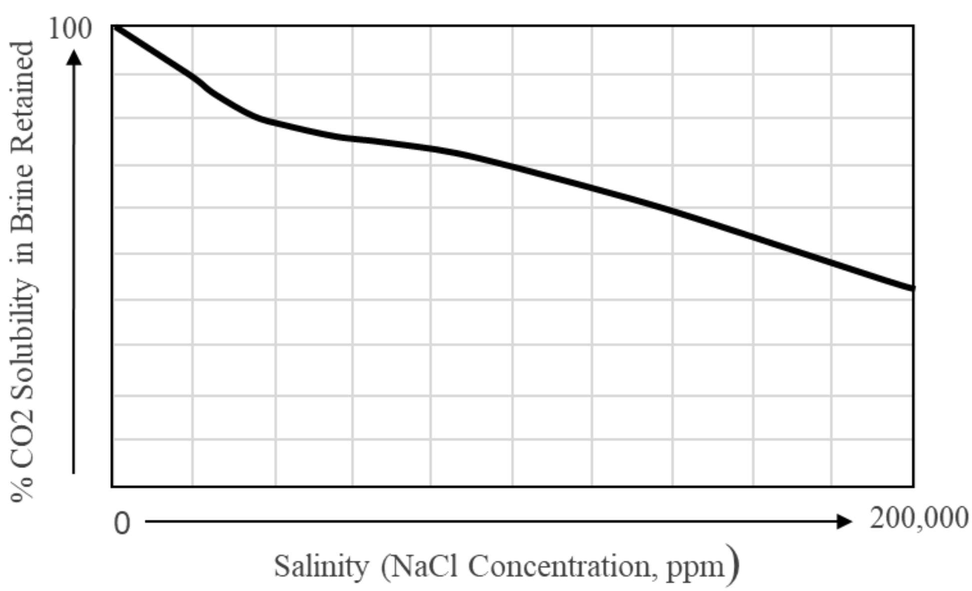

Figure 5: CO2 solubility vs. salinity in freshwater (independent of pressure and temperature). Adapted from [7].

E. Effective vs Total Porosity

Porosity is the key petrophysical input for volumetric consideration in estimating 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 (Figure 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 into a water saturated formation, PHIE (not PHIT) should be the input into the theoretical storage resource (Equation 2).

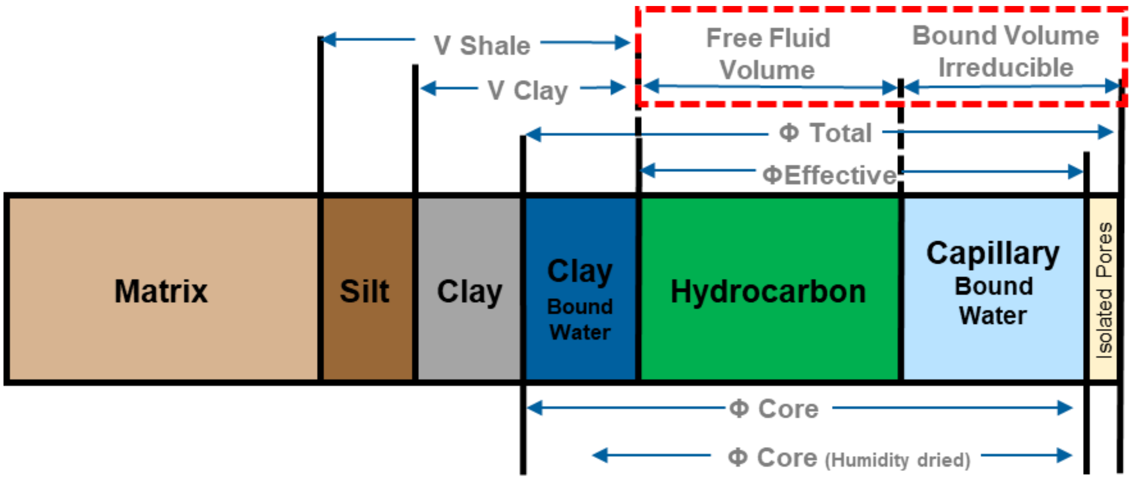

Figure 6: Summary of Bulk rock volume, and the various definitions of porosity.

F. Wettability

The wettability of a rock refers to the preference of a liquid phase to be attracted to a grain's surface. CO_2 is always non-wetting 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 drop out can occur, making the rock more oil-wet. A petrophysicist can assist in de-risking this by conducting special core analysis studies (SCAL) with real reservoir fluids to mimic the conditions in the reservoir.

G. 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 [10]. This residual saturation occupies effective pore space which would otherwise be able to host CO_2 being injected. Studies have suggested that reduction in brine mobility, density and viscosity of gas mixtures when dissolved into supercritical CO_2 can cause the 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 [11].

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} (Figure 7). If there is higher confidence data like core measurements, petrophysicists (working cooperatively with reservoir engineers and geomodellers) can help to design pre-injection dynamic models which can properly capture the phase behaviour of such reservoirs.

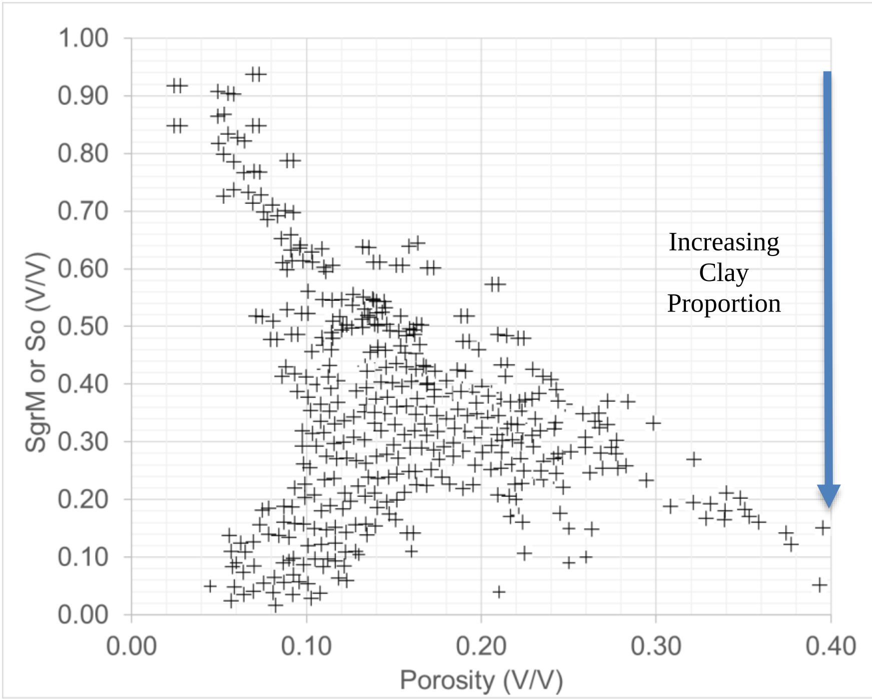

Figure 7: Plot of Maximum Residual Phase Saturation (SgrM) as a function of Porosity and increasing Clay Proportion. Modified from [8]

H. Capillary Pressure & Irreducible Saturation (SW_{irr}) Ranges:

In injection into saline aquifers, the reservoirs of interest are typically at 100% Sw. 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 non-wetting CO_2. In all these cases, the focus of the evaluation is SW_{irr}, 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 SW_{irr} is associated with clay and capillary bound water only. Typically, SW_{irr} values are determined from capillary pressure (Pc) data. The Pc data can be from conventional core or mercury injection capillary porosimetry (MICP) measurements.

$$P_c = \frac{2\gamma cos\theta}{r} \quad \text{Equation 4}$$

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

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

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 are reservoir conditions, x and y is the wetting and non-wetting phase gradient in psi/m respectively.

A practicing petrophysicist must note a few things when evaluating SW_{irr}. First, as Pc is converted to height above free water level (HAFWL or column height) using fluid parameters or an analogue (Equation 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 SW_{irr} estimates. Secondly, there should be a full range of rock types available to ensure a complete characterisation of the reservoir.

Pc measurements should also be done on seal rock, if available. In the scenario where there are no data available or no reasonable analogues available nearby, an estimation of capillary seal characteristics can be made from converting pre-production hydrocarbon column heights to equivalent CO_2 column heights [12]. Again, a petrophysicist should look into the sensitivities of the x or y values (Equation 6) by assuming that the density of the wetting and non-wetting phase is changing, as a function of temperature and pressure (Figure 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.

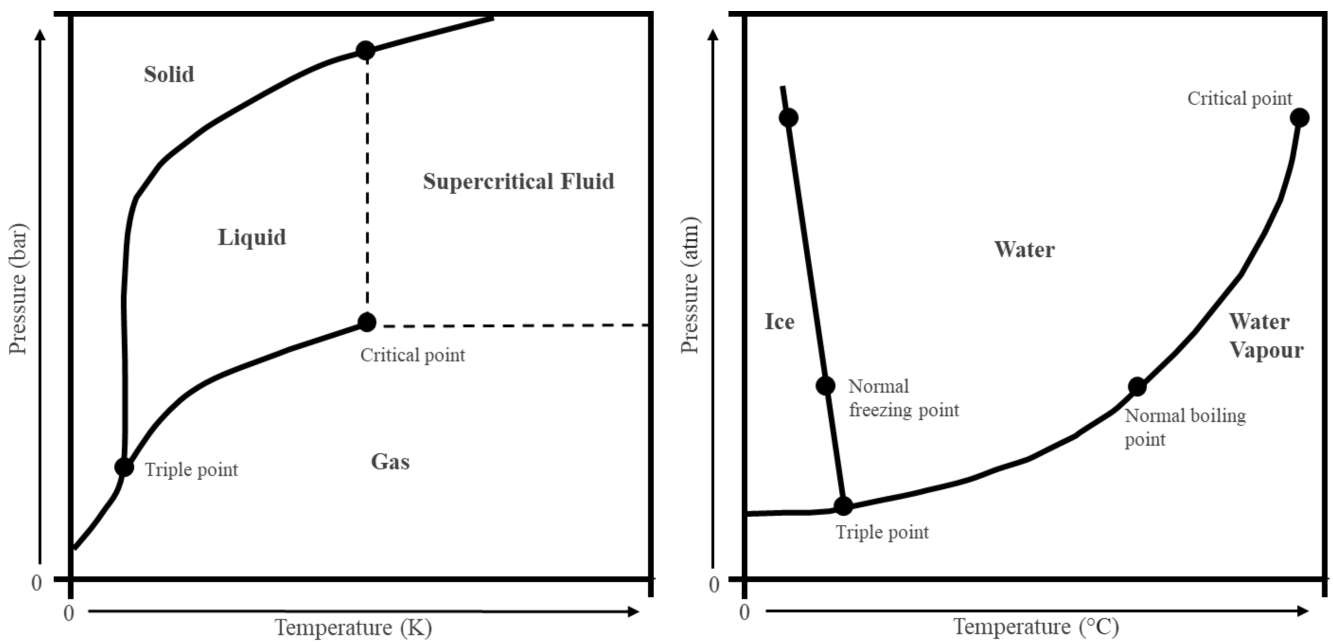

Figure 8: Generic pressure-temperature phase diagram (L) CO_2 and (R) Water

I. 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 the 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 under-pressured reservoir and the over-pressured 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 [9]. The rapid freezing also causes micro stresses to develop at the grain-to-grain contact, brought about by the rapid freezing of the interstitial water [9].

At later timescales, as injection slows or stops, and as the CO_2 fluid migrates in the reservoir, it starts to undergo expansion. In this case, Joule–Thomson expansion (JTE) can also add mechanical stress to the rock formation, via 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 is 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 modelled prior to sanctioning any form of injection process in a field, to further de-risk the potential for failure.

J. Cased Hole & Production Logging

Cased hole 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 determine formation properties over time, or to determine effectiveness of CO_2 injection and storage operations [10, 11].

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 efficiency of the injection and storage processes, particularly when it comes to optimising 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 case of remediation of wells, PLT tools can be used to determine if these have been adequately addressed.

For behind casing, cement bond logs (CBL) 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 cased hole 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 become a lot clearer. The value of information associated with acquiring the dataset 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 datasets which reduces 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 which 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.

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 cased hole 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 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 localised pressure build up 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 different from expectation 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 different from expectation impacting capacity and containment	Tracer tests, detailed static and dynamic modelling of reservoirs
Insufficient injection rates	Medium	Medium	Lack of storage capacity and incorrect well count due to uncertainty in injectivity	Core data taken across key injection complex to calibrate to modelling 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

SRMS Petrophysical checklist

Utilising our discussion into the petrophysical considerations and our generated risk table, we next developed a simplified checklist that can be used when conducting 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 Figure 9.

How much detail 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 firstly start at the prospective storage resources, or the theoretical capacity as defined by SRMS (Figure 9). The evaluation required at this stage is similar to any oil and gas petrophysical evaluation. Key differences are an assessment of PHIE and the estimation of SW_{irr}.

As the project is matured to a Contingent Storage Resource stage, consideration must be given to formation mineralogy, permeability, core derived SW_{irr} and residual hydrocarbon saturation (in depleted fields), 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 density of CO_2 is important in volumetric calculations for total storage capacity, as well as phase of the fluid being critical for the project success, the petrophysicist may be required to consider other factors or parameters which 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 as well as geomechanical studies on grain-grain, fluid-grain impacts as well as cased hole monitoring to evaluate injection rates and potential fines migration.

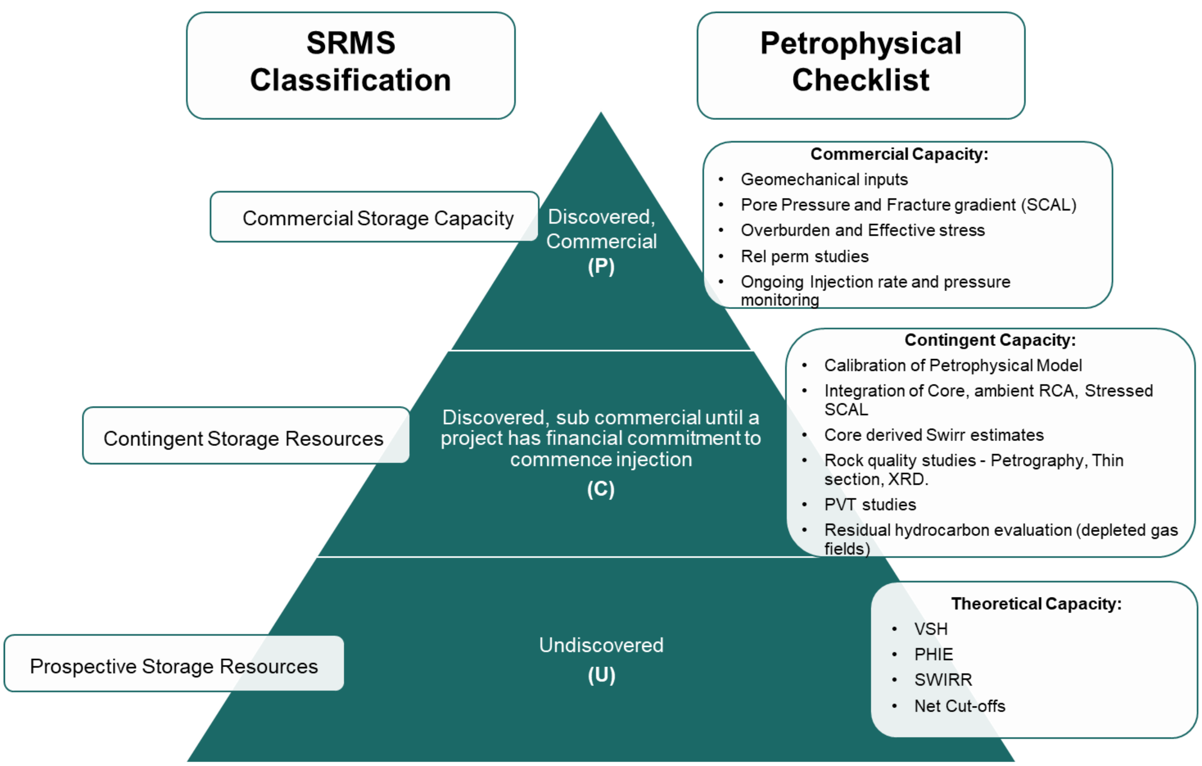

Figure 9: Generic petrophysical checklist for evaluating the CO2 storage potential in line with SMRS workflow

Case Study - Cloverhill-1

In this section, we will use a generic gas well (Cloverhill 1) [12] as a case study to outline the practical application of the petrophysical workflow presented in Figure 9. Cloverhill 1 is a wildcat exploration well drilled in 2014 and is located in the southwest of exploration permit WA-268-P, in the Northwest Shelf off the cost of Western Australia (Figure 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 analogue 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 characterised by upper and lower delta plain channel sandstones, swamps and restricted embayments. The system is dominantly 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 with 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 Table 2. At Cloverhill-1 the A sand and lower portion of the AA sand is water bearing, while the upper part of the AA sand is gas bearing (Figure 11).

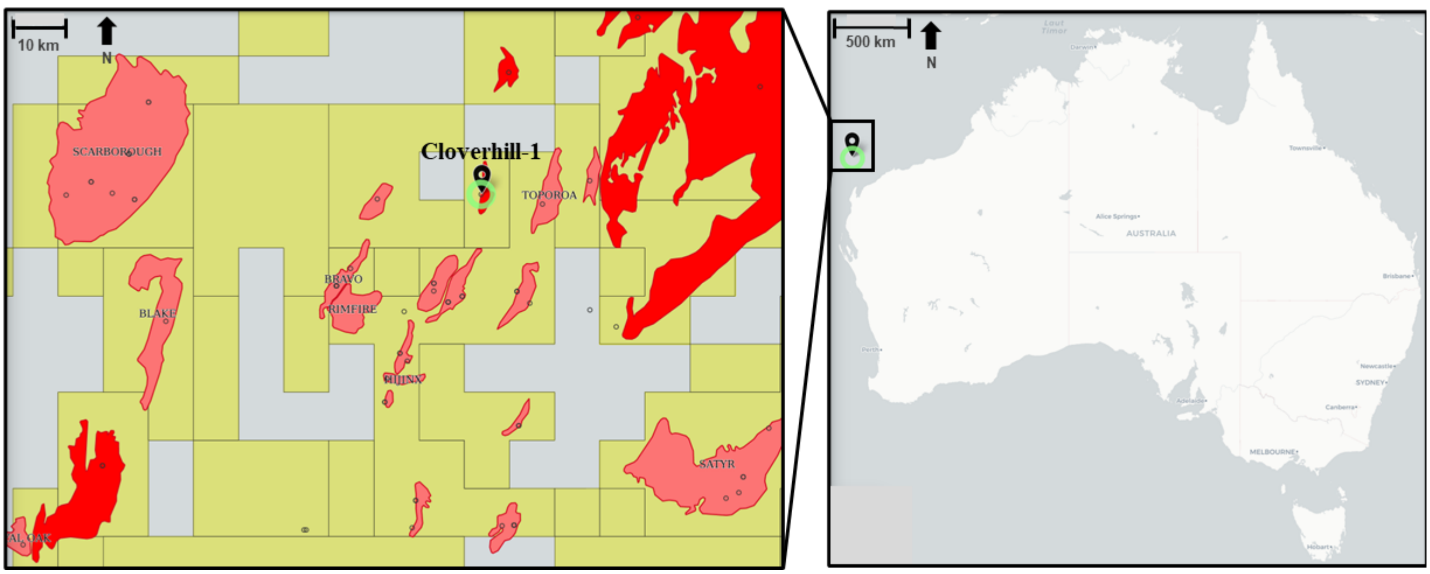

Figure 10: Location map of the Cloverhill-1 well. Modified from Mapstand [13]

The initial steps in the generalised petrophysical workflow (Figure 9) are consistent between both hydrocarbon exploration and CO_2 storage projects. Both require standard formation evaluation procedures, with an integration of wireline, LWD, mudlogs, 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 Figure 9. For the petrophysicist, that means determining VSH, PHIE, SW_{irr} 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 SW_{irr} can be determined quite readily. The evaluation uses a deterministic approach for determining volume of shale, 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 less than 0.5.

From here, porosity was interpreted using straight Density (D) porosity (PHID), or else in combination with neutron (N) to give total porosity (PHIT). PHIT was corrected for hydrocarbon effects and invasion. For QC purposes, porosity is also evaluated using the 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.

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 analogue; 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. SW_{irr} 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 SW_{irr} by summing the Clay bound water and Capillary bound water (BVW + BVI). The SW_{irr} is equivalent to the minimum water saturation from capillary pressure curves. The storage capacity of CO_2 is determined by evaluating Equation 2. The integration of variable methods of evaluating porosity and water saturation gives confidence in the evaluation and the inputs into equation 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%. A 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 utilising the NMR outputs to determine a range of porosity and saturations, particularly in the water bearing sands.

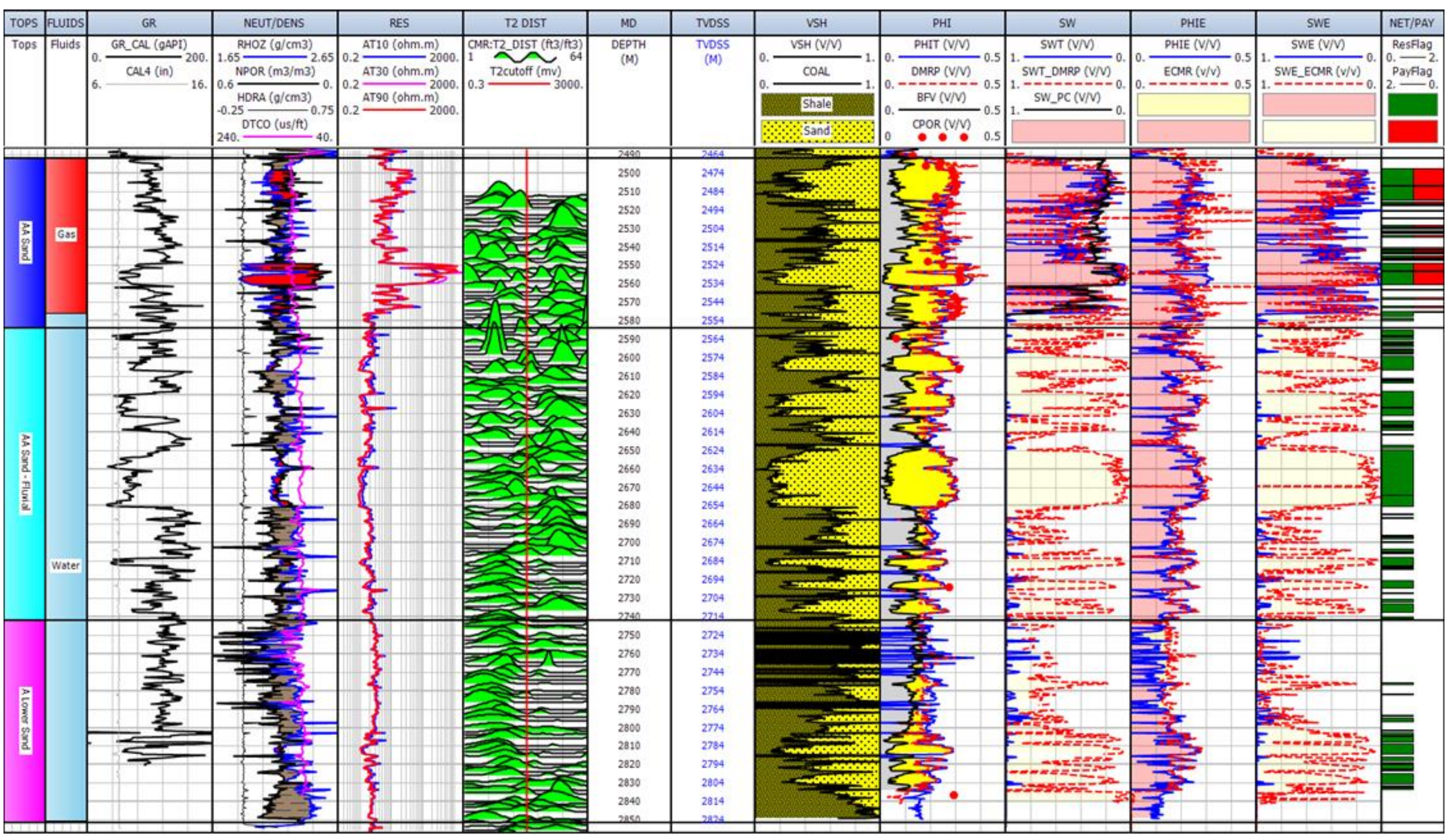

Figure 11: Cloverhill 1 Log Data & Petrophysical Interpretation – 1: 1800 scale

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 SW_{irr}.

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. Analysis would need to be undertaken on estimating column heights of CO_2 that could be supported (in absence of capillary seal characteristics of the cap rock). Currently the saturation height function used to generate SW_{PC} in Cloverhill-1 is based on analogue fields nearby. MICP analysis should be conducted as part of the SCAL program on a range of plugs which represent the variety of rock types encountered in the reservoir. This will provide better estimates to SW_{irr} for input into Equation 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 modelling. Having a good understanding of Sw_{irr} will be critical in the case of application to depleted field CO_2 injection, as it will also aid in future modelling 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 Table 2 and Table 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 utilised 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 CO_2 (± 25 kg/m3 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.

Table 3: Probabilistic inputs into Theoretical storage volume

Area (km2)			Density CO2 (kg/m3)			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 at for specific 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 modelled scenarios, particularly in saline aquifers vs 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 CO2 (MM Tonnes)			
	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 sub-commercial), we will need to start increasing our degree of confidence by integrating more detailed datasets. This includes data as it relates to (stressed and ambient) RCA and SCAL, along with thin sections, SEM and XRD thin sections, PVT and hydrocarbon evaluation from CO_2-Brine studies (Figure 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 be undertaken, with 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 modelling as optimal injection rates are modelled, either via dynamic modelling or via 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 Wireline, WL) and core. To ensure the data gathering is fit for purpose and within project scope and budget, key project risks and uncertainties should be identified early in 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 2D or 3D datasets 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 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 a 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 adds confidence that the CO_2 injection operation may be possible.

Depending on the maturity of 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 SW_{irr} 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 which can capture fractures at the various length scales would also be useful in understanding fracture potential and distribution. Formation pressure and temperature are key in predicting 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 time scale 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 which 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 QA/QC checks that should be conducted on the core lab facility to determine 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 which 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.

Table 5: Core based experiments for de-risking CCUS projects.

Objectives	Experiment	Outputs	Sample Size				Sample Type			Notes
			< 1" (e.g. cuttings)	1-1.5"	4" (Full Dia.)	Comp	CCA	SWC	Perc	
Fluid Displacement, Diffusion Processes	• X-Ray CT and µCT • 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 Swi (as an analog for gas cap behaviour)
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 & 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 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	• Ions present in water		✓			✓	✓		Tested on either water obtained on E-line or else water from Dean-Stark

	(Acetate Water Analysis)									
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

Conclusion

We have attempted to provide our view into the best practice 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 into the theoretical storage resource for CO_2 (Equation 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 a 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 SMRS '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 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 emphasis on log application and core-based experiments. It is important to note that ongoing time lapse reservoir surveillance and monitoring is critical in 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 SMRS 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 to execution stage in a lower carbon economy. We wish to finally conclude by saying that while the paper is petrophysically focused, the challenge of CO2 storage is a truly multidisciplinary exercise that requires integration from all subsurface disciplines.

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Appendix 1: Nomenclature

Bo	Oil formation volume factor, in rb/stb
Bg	Gas 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
CHRT	Cased hole resistivity tool
CO_2	Carbon dioxide
CCUS	Carbon Capture Utilisation and Storage
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
LWD	Logging while drilling
LHC	Light hydrocarbon correction
m	Metre
m	Cementation exponent
MICP	Mercury injection capillary pressure
n	Saturation exponent
NaCl	Sodium chloride
NTG	Net to gross ratio
NMR	Nuclear magnetic resonance
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)
Pc	Capillary pressure
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
SMRS	CO_2 Storage Resources Management System
SPEE	Society of Petroleum Evaluation Engineers
S_W	Water saturation
SWC	Sidewall core
SgrM	Maximum Residual Phase Gas Saturation
S_{hr}	Residual hydrocarbon saturation
SWE	Effective water saturation
SWT	Total water saturation
SWT_{RES}	Total water Saturation derived from resistivity
SW_{irr}	Irreducible saturation
SW_{PC}	Total water saturation derived from 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
VSH_{GR}	Volume of shale derived from gamma ray log
VSH_{ND}	Volume of shale derived from Neutron and Density logs
WL	Wireline
XRD	X-ray diffraction