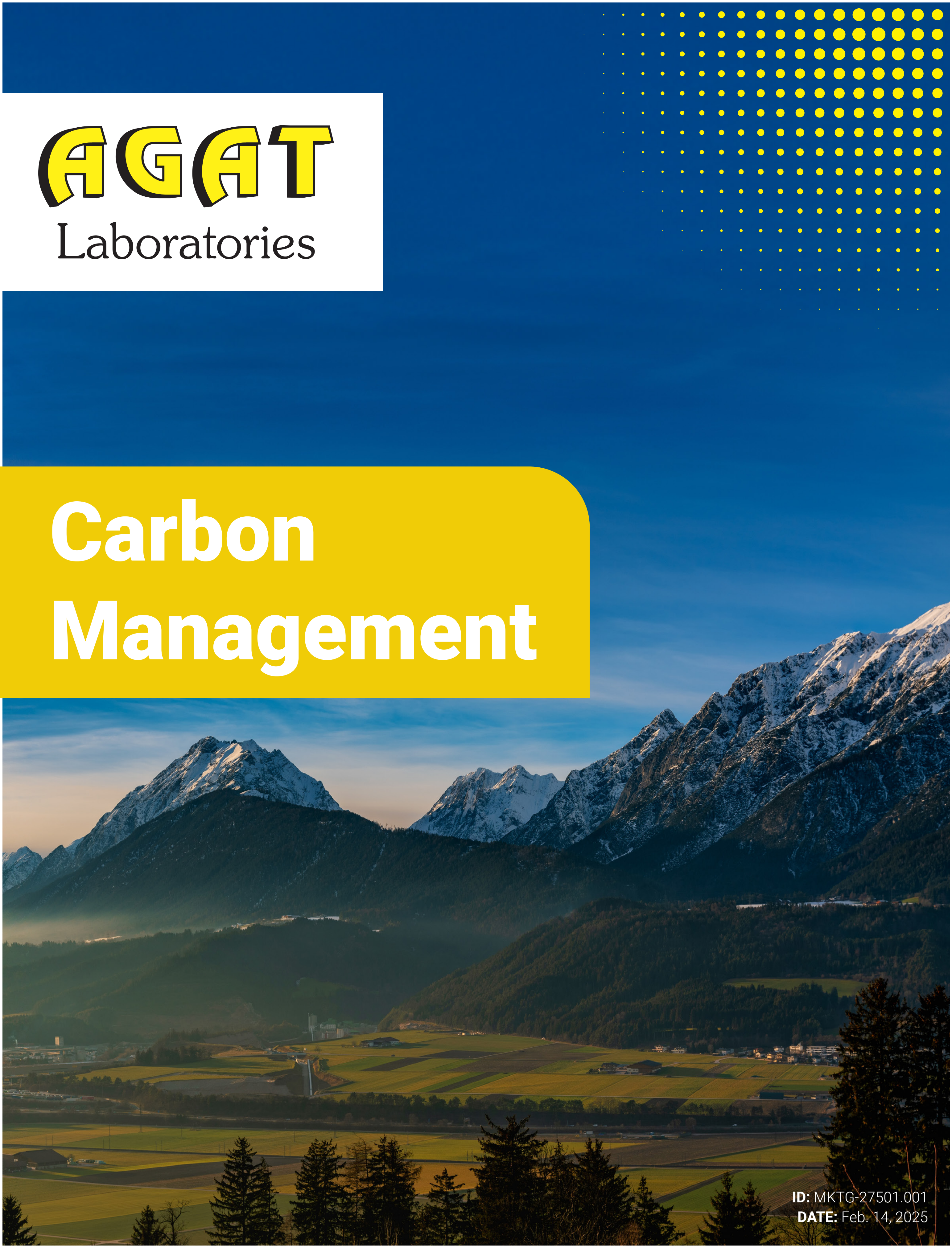
AGAT Laboratories

Carbon Management



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AGAT Laboratories

AGAT Laboratories is a North American leader in analytical services, delivering precise & trustworthy results across the globe. With over four decades of expertise, we've become one of the most geographically diverse and technically advanced laboratory.

Our clients span across diverse sectors, including environmental consulting, energy, mining, food & agriculture, life sciences, and government agencies.

We proudly serve industries across Canada, USA and beyond, delivering accurate and defensible results that drive informed decisions and support public health, safety, and environmental stewardship.

AGAT Laboratories specializes in the following scientific areas:

- Environmental Chemistry
- Ultra-trace and Toxicology
- Agricultural Analysis
- Food Testing
- Geology and Petrology
- Reservoir Characterization
- Air Quality Monitoring
- Petroleum Testing Services
- Oil Sands Analysis
- Advanced Rock Properties
- Core & Materials Testing
- Mining Geochemistry
- Lubricants Testing Services
- Geotechnical Testing Services

Core Values

- **Integrity –** We do the right thing for the right reason, upholding our ethics no matter the outcome, putting quality above all.
- **Accountability –** We admit when we are wrong and take ownership of our actions.
- **Respect –** We value personal diversity while treating all people with dignity.
- **Unity –** We support one another, share a common direction, lift each other up and celebrate our achievements as one.
- **Innovation –** We push the boundaries of science and technology to provide uniqueness in our processes, culture, and scientific advancements.
- **Passion –** We exude enthusiasm in all that we do, valuing the fun and enjoyable environment that we exist in while embracing every challenge along the way.

Our Purpose

To provide "**Service Beyond Analysis**" to three key pillars:

- **Our People**
- **Our Clients**
- **Our Communities**

Carbon Capture, Utilization, & Sequestration

Carbon capture, utilization, and sequestration (CCUS) is rapidly growing in importance as part of the global push to mitigate the impacts of climate change. CCUS is a key carbon management strategy built on interdisciplinary innovation and constructive partnerships between industry, technical specialists, and regulators. CCUS allows the sequestration of greenhouse gases, the storage and distribution of carbon for applications such as enhanced oil recovery, and represents an opportunity for leveraging carbon mitigation incentives. The evaluation of these sequestration and storage projects is complex, requiring a deep understanding of the geological formations involved and the potential interactions that can help or hinder storage capacity, injectivity, sealing efficacy, and mechanical performance margins. AGAT Labs offers a full suite of geological and engineering services to support these projects, in order to help assess project feasibility.

Selection of a reservoir for subsurface CO_2 sequestration requires an assessment of its candidacy based on established screening criteria (Table 1), including formation permeability, porosity, zone thickness, reservoir heterogeneity, reservoir quality, and fluid saturations.[1] Petrophysical and well log analyses, along with any production data if applicable, can help in developing the dataset necessary to conduct this assessment.

Analysis of well log data, such as gamma ray, density, and resistivity logs, is a key initial step in characterizing formation lithology, porosity range, and in situ saturations. This data is critical in the workflow of screening candidate reservoirs and conducting preliminary storage capacity calculations.

This data should be calibrated with measurements on sampled core. The storage capacity calculations can then be further refined through additional laboratory testing and reservoir simulations, to account for dissolution, precipitation, capillary pressure trapping, and potential reactions that would impact injectivity. Geomechanical testing is a critical part of subsurface evaluation for both sequestration formations and their caprock. This testing is used to develop a Mechanical Earth Model (MEM) that will define stress envelopes for safe and optimized short and long-term operation of a sequestration system.

Below we describe a suite of analytical tests and procedures, based on industry best practices, which are recommended to properly evaluate and assess CO_2 sequestration projects.

Parameters	Positive Indicators	Impact
Depth	>800 m	Storage Capacity
CO_2 Density	High	Storage Capacity
Porosity	>0.20	Storage Capacity
Zone thickness	>50m	Injectivity
Permeability	>100 md	Injectivity
Pore throat size distribution	Less heterogeneous	Injectivity
Residual gas /water saturation	Low	Injectivity
Condensate saturation	Low	Injectivity
Lithofacies types	Good Quality	Injectivity

Table 1. Positive indicators for favourable subsurface CO_2 storage[1]

Field Services and Sample Preservation

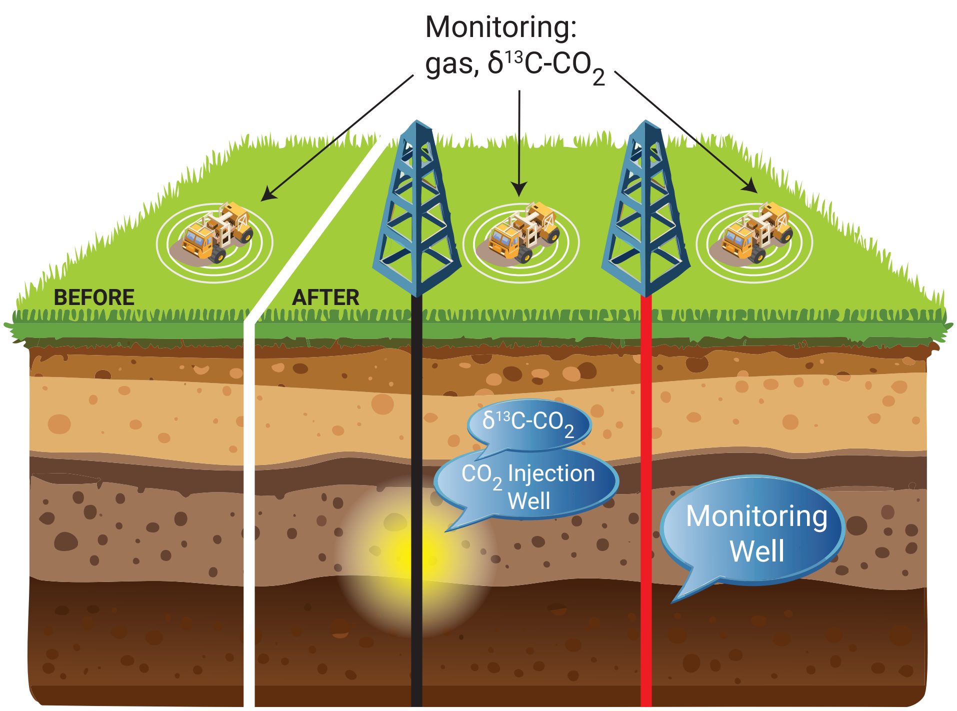
Effective sample handling and preservation are essential in any core analysis program. AGAT Laboratories provides a team of experienced geoscientists and field technicians who can be deployed in the field to oversee coring and preservation activities. Their role is to minimize mechanical disturbance, temperature changes, and dehydration of core samples, all of which could affect the accuracy of subsequent testing. Core preservation is carried out according to protocols agreed upon during pre-spud meetings with the operator's geoscientists and engineers.

Once the core arrives at the lab, it will undergo a spectral core gamma and CT scanning before sampling. This allows for the identification of key testing zones and provides insights into the integrity of the core. Core plugs are then extracted using a variable-speed pneumatic core mill or a high precision CNC milling machine when drilling soft or friable intervals that are often present in cap rock lithotypes. The choice of drilling fluid is made in consultation with the operator, based on the type of testing required and the geological characteristics. Common circulating fluids include liquid nitrogen, air, and brine (KCl solution).

CCUS Monitoring Using Stable Isotopes

Gas samples are regularly collected on the surface to monitor the success of CCUS projects. Fingerprinting this gas is key to determine whether CO_2 is stable in the subsurface or has rather migrated into groundwater, other shallow sections, and/or potentially entered the atmosphere. Stable carbon isotope ratios ($\delta^{13}C$) are a powerful tool to discriminate the injected CO_2 from other sources because the ratios are distinctive for microbial CO_2 versus thermal CO_2 and/or CO_2 associated with hydrocarbon degradation. In some instances, collected samples also contain gas hydrocarbons such as methane and ethane plus components. The origin of these gases (microbial, thermogenic, or mixtures), as well as their potential stratigraphic allocation, can be investigated using stable carbon isotope ratios.

Carbon isotopes fingerprinting would also be conducted in soil gas before a subsurface project begins in order to establish a baseline of carbon isotope ratios in soil/atmosphere and facilitate leakage detection in the future.



Spectral Core Gamma

A spectral core gamma measures the radiation produced by natural radioisotopes within the core, helping to assess lithotypes, as well as providing measurements of potassium, thorium and uranium in the rock. The gamma collected in the laboratory can then be correlated with downhole log gamma readings, enabling the identification and correction of any depth discrepancies.

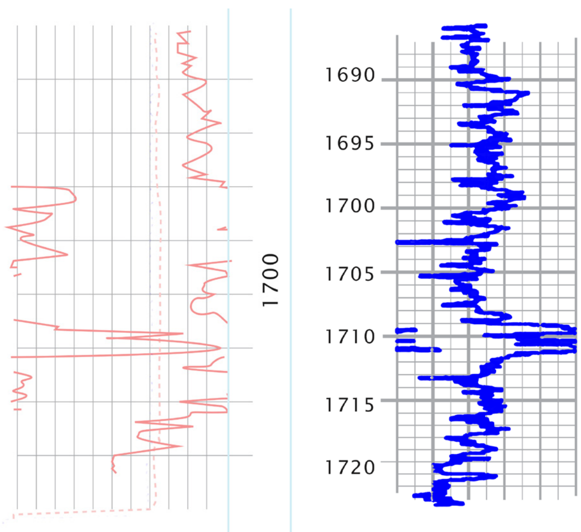


Figure 1. Example of a comparison of total gamma data from a core scan (at left) and from well logs.

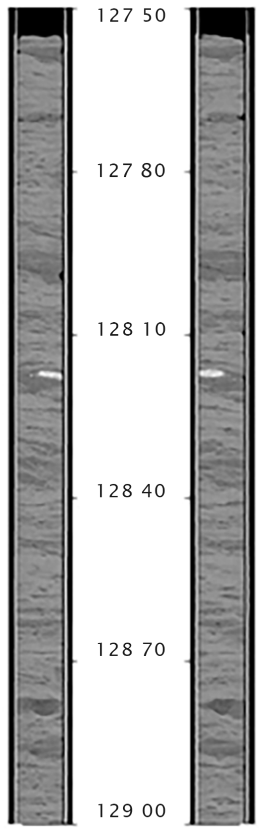


Figure 2. Example of CT scan images of cores in the received core barrels.

Computed Tomography (CT) Scanning

After the core has undergone a spectral gamma scan, it can be further analyzed using CT scanning, which provides valuable insights into density variations and rock integrity that may be difficult or impossible to detect visually. CT scanning is a non-destructive x-ray imaging technique that allows for the pre-screening and identification of specific zones within the core, making it ideal for selecting areas suitable for petrophysical, geomechanical and special core testing that will provide key insights and critical data for carbon storage programs (Figure 2).

Core is stored at refrigerated temperatures (approximately 4°C, 39°F) at all times to minimize evaporative losses. When performing the gamma and CT scans, small core intervals are run at a time to minimize the exposure to ambient room conditions.

Porosity, Permeability and Saturations

Once scans are complete, the core is carefully extracted from the field liners and oriented to indicate the top and bottom directions. It is then placed in designated boxes, with depths measured and marked every half meter. Color photographs are taken of the entire core. At this stage, the core gamma and CT scan results are reviewed to assist in selecting the most suitable sample points for petrophysical, geomechanical and special core testing.

If core or full diameter samples are selected for petrophysical analysis, the core ends will be trimmed and a conformant cylinder will be produced. The cylinder will be used for the porosity, permeability, density and saturation measurements.

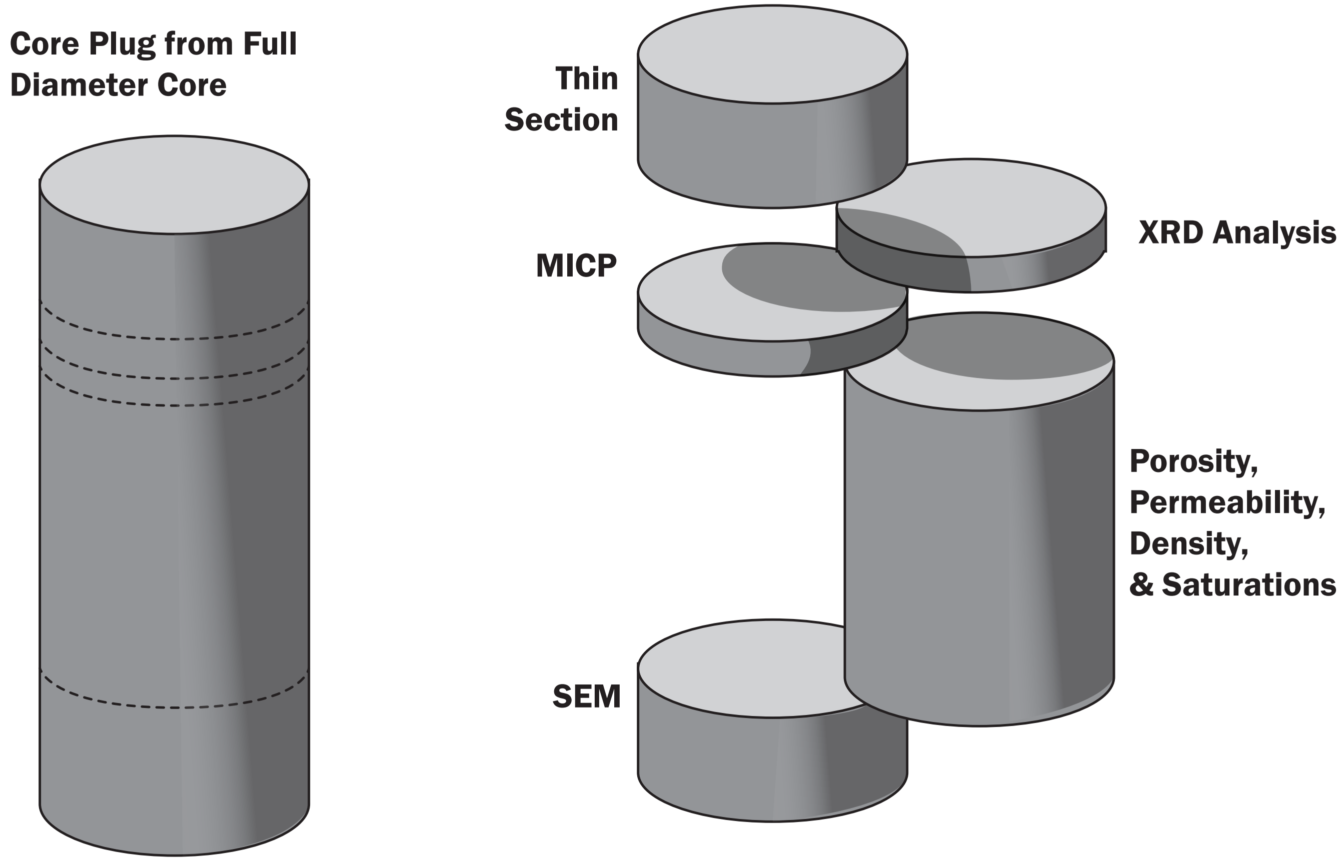


Figure 3. Schematic showing sub-sampling of core plugs for various anaylses.

The end trims can be used for thin sections, SEM, XRD, and MICP analyses.

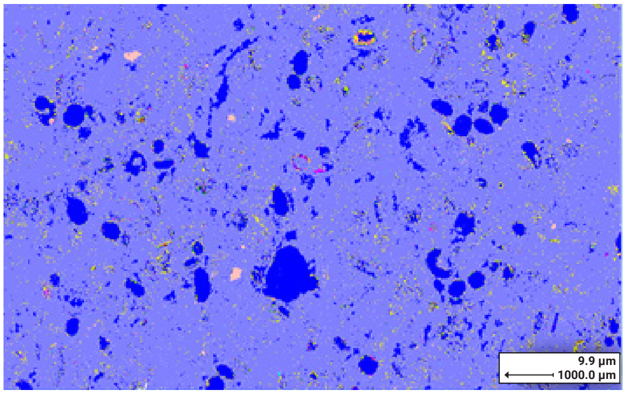
For the porosity measurements, the sample is placed into a Dean Stark extractor to remove free fluids with a methanol extraction to remove any salts in the pores. The samples are then oven dried to remove residual solvent from the cleaning processes. The bulk density is achieved by our ShapeGrabber 3D laser scanning system while the grain density is measured with a helium pycnometer. Bulk density and the grain density is then used to calculate porosity.

Permeability measurements in carbon capture programs are performed by steady-state methods in the reservoir zones and unsteady-state methods in the caprock sections. The steady-state permeability can be performed on a plug or full diameter core while the unsteady state permeability is typically performed on a plug.

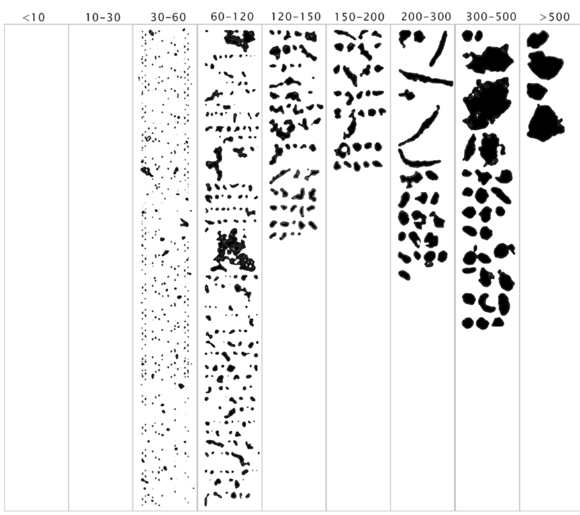
Geological Analysis

Mineralogy and Petrology testing can provide fundamental data for understanding both storage and cap rock for a CCUS reservoir. In particular a strong understanding of the mineralogy and mineral deportment (particularly for clay minerals), the porosity architecture, rock fabric and microtexture, can provide insights into potential formation damage. In addition, geological testing can be done after special core analysis tests, such as core floods, permeability regains, and compatibility studies, to investigate the impacts of these simulations on the rock fabric, mineralogy, and rock sensitivity.

Pores Scanned



Pore Distribution



Pore Size (µm)

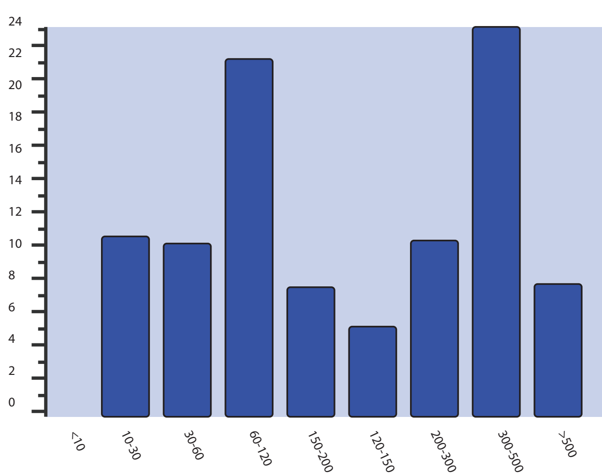


Figure 4. Example of QEMSCAN images with detailed information on the sample pore system.

Microscopy

Microscopic imaging provides detailed information on the mineralogy, rock fabric and porosity systems. Used in conjunction with other analytical techniques, microscopic imaging allows for stronger understanding of the capacity for a formation to store CO2 or have adverse effects when interacting with injection fluids. QEMScan (figure 4), thin section petrology (figure 5) and scanning electron microscopy (figure 6) can be used to evaluate the microscopic characteristics of a target formation.

Rock fabric and microtexture define the petrophysical properties that exert control on fluid flow and the surfaces available for adsorption, ion exchange, or chemical reaction. For example, while a rock may have a certain overall bulk mineralogy, the critical mineralogy for formation performance as a CO2 reservoir is that directly associated with the porosity spaces. By analyzing the rock using thin sections, SEM, and/or QEMSCAN, the type, structure, and extent of minerals present within and adjacent to pores and pore throats can be investigated. QEMSCAN in particular can do so quantitatively for many rock types, producing detailed information on the pore system and its mineral associations from a polished section scan of a rock sample.

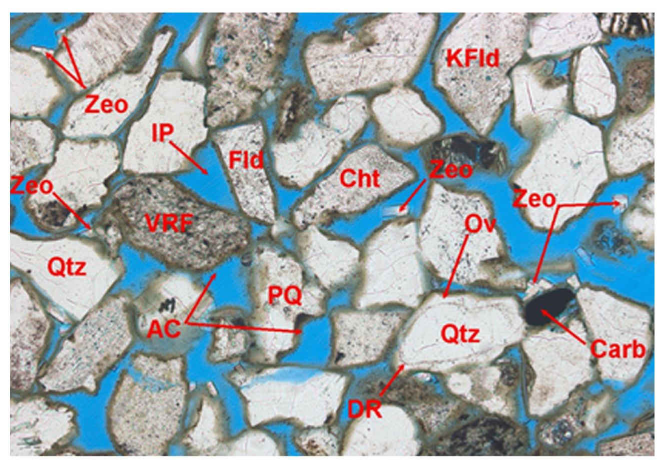


Figure 5. A thin section photomicrograph of clastic reservoir showing porosity (blue) and mineralogy

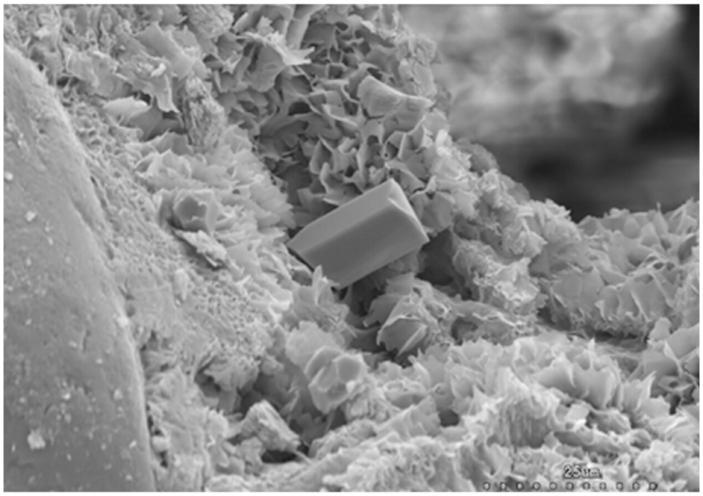


Figure 6. SEM high magnification image of a grain-mount preparation of the same rock shown in Figure 5

Cap Rock Integrity

The candidacy of a reservoir for subsurface CO_2 storage and sequestration is also dependent on the ability of the cap rock to seal in the injected gas. We also provide measurements of permeability and threshold pressure on cap rock samples at various in situ stresses to evaluate the sealing capacity of the cap rock to CO_2 migration. Furthermore, the water-rock compatibility tests should be properly designed and conducted to evaluate the detrimental effects of CO_2 or dissolved CO_2 on the permeability and mechanical integrity of the cap rock through long-term CO_2/water-rock interactions.

Geomechanics

AGAT Labs offers a full suite of geomechanical testing on samples ranging in size from cuttings to full diameter core. Triaxial testing can be completed on mechanically intact samples having a diameter of 2.5-10cm (1”-4”) and a length that is twice the diameter. Special conditions on triaxial testing, such as high temperature (up to 200°C, 392°F), pore pressure control (client specified fluid), and confining pressure cycles can be accommodated using a state of the art servo controlled apparatus to ensure that project specifications are met. Other geomechanical testing includes Direct shear, Brazilian tensile, point load, Schmidt hammar and Micro-indentation.

The data collected may include Poisson’s ratio, Young’s modulus (figure 7a), poroelasticity, strength parameters, Mohr-Coulomb failure envelopes (figure 7b), friction characteristics, ultrasonic velocity, acoustic emission and more. This data is key to building a Mechanical Earth Model that will provide a safe operational envelope for any injection project, in accordance with regulation.

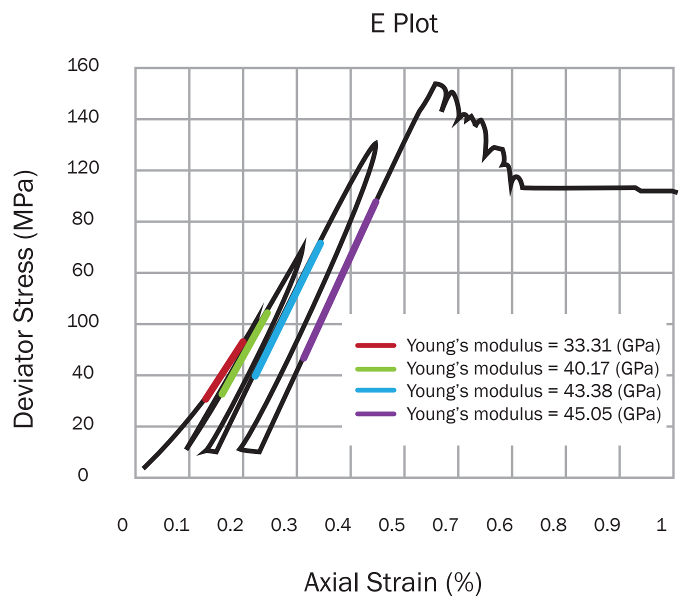


Figure 7a. Example of geomechanical test data.

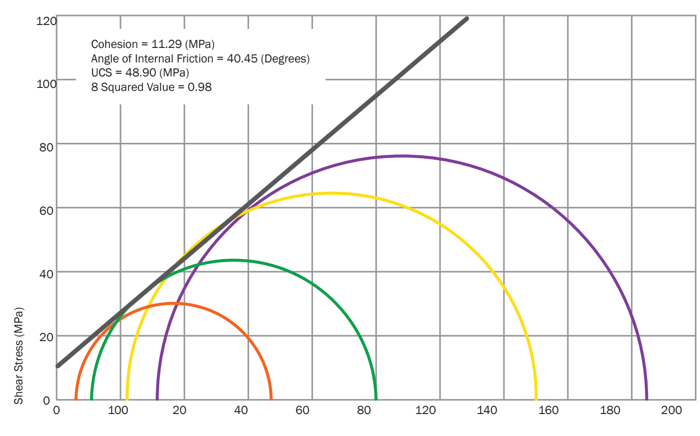


Figure 7b. Example of Mohr Coulomb plot.

Pore Throat Size Distribution & Capillary Pressure (MICP)

Pore throat size distribution is analyzed in a Micromeritics Autopore Porosimeter, where cleaned and dried samples are evacuated of air, then injected with mercury at increasing pressures. Volume of mercury injected is recorded at each pressure stage, up to a maximum injection pressure of 60,000 psi to ensure intrusion into all pore spaces in the sample. The capillary pressure data generated in this experiment can be converted to pore throat size distribution. Analysis of this data can aid with the interpretation of rock typing, reservoir quality, and reservoir heterogeneity (Figures 8 and 9), and capillary characteristics of the in situ fluid-rock system.

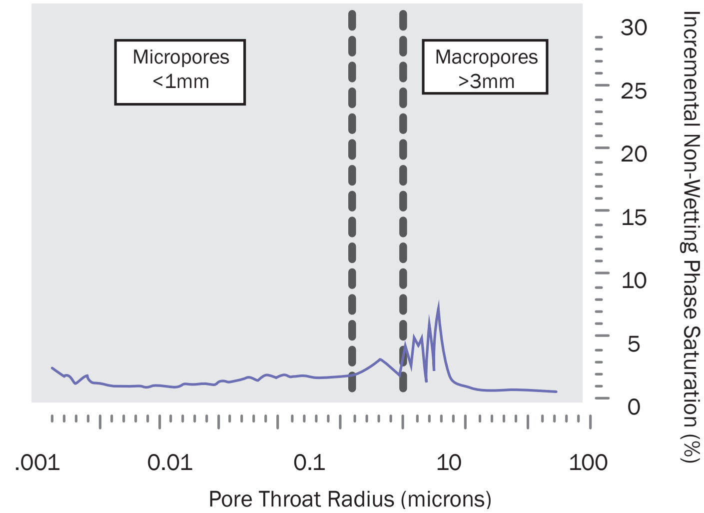


Figure 9. Example of Pore Throat Size Distribution data plotted against saturation.

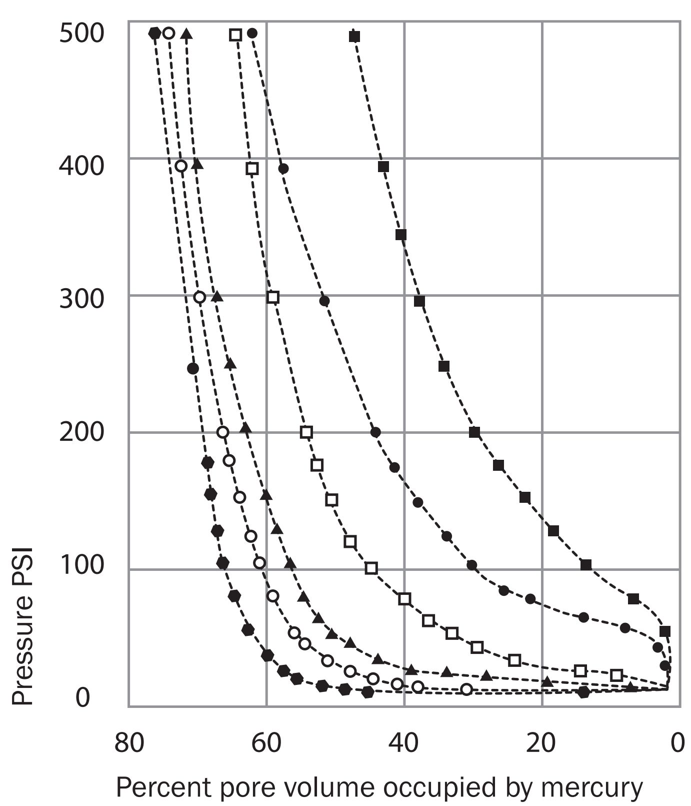
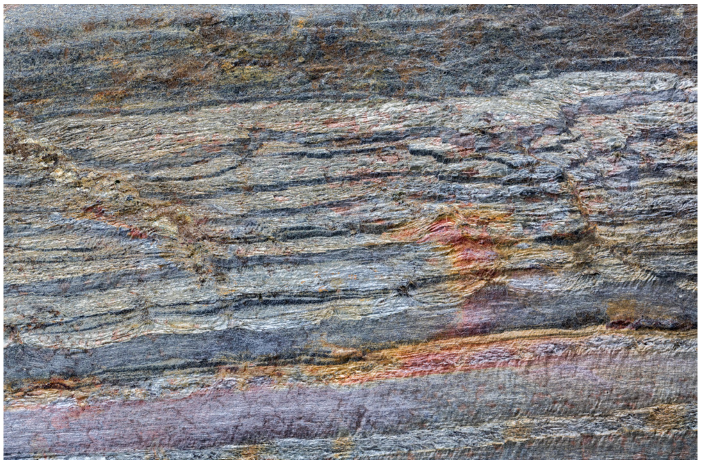


Figure 8. Example of capillary pressure data showing interpretations of reservoir quality.

CO_2 PVT Properties & Solubility

The critical point of CO_2 is at 31.1°C (87.8°F) and approximately 7,377 kPa (1,070 psi), most in situ sequestration projects will inject CO_2 in its supercritical state. Sequestration fluids may include CO_2-saturated brines, or CO_2 with associated impurities, often in a supercritical state. These injection fluids must be characterized for their phase behaviour under changing Pressure Volume and Temperature (PVT) conditions.[2] AGAT's PVT lab and team are well equipped and prepared to carry out these investigations. Supercritical CO_2 can dissolve in formation water and contribute to the overall storage capacity of a reservoir, but dissolution is dependent on a number of factors, such as pressure, temperature, salinity and gas impurity. To quantify this for a specific formation, sampled or synthetic formation water is charged to a high pressure high temperature (HPHT) PVT cell at reservoir temperature. The PVT cell is equipped with a sight glass to visualize the pressurized fluid with a camera connected to phase behavior visualization software. Sampled or supplied CO_2 is then charged to the cell at the maximum injection pressure of the reservoir. The cell is agitated to promote mixing until a saturated fluid is achieved. The pressure is then reduced in the cell, leading to phase separation.

This process is repeated for a series of pressure depletion stages, from maximum reservoir pressure to current in situ pressure. At each stage, the volumes of CO_2 and water, interfacial tension and solids precipitation are measured to determine CO_2 solubility in water, which can be used in storage capacity calculations.



Fluid-Rock Compatibility

Another consideration in storage capacity assessments is the compatibility of the injected fluid with in situ fluids and formation rock. Injected CO_2 will lower the pH of formation water and can dissolve minerals and cements in the formation, leading to unpredictable permeability changes.[3,4] Formation dissolution can lead to stimulated flow through the reservoir, but can also lead to formation damage from mineral precipitation or grain shifting from dissolution of cements.

This compatibility can be evaluated in a core flooding experiment. There are various ways of designing these experiments, but a general workflow would be to load a core plug saturated with formation water into a core holder for pressurization and heating to reservoir conditions. The sample would then be flooded with formation water to establish baseline permeability for future comparisons. The core stack would be flooded with a CO_2 and formation brine mixture for a set number of pore volumes before shutting in the cell for a set period of time.

Further, moisture-equilibrated CO_2 and dry CO_2 are subsequently flooded through core for extended pore volume to investigate potential formation damage or enhancement of the reservoir in front and behind CO_2 migration plume and near wellbore area due to mineral dissolution and precipitation, salt precipitation due to dry-out, and potential fines migrations. The sample can then be unloaded for geological analysis to assess mineral dissolution and any impact to the integrity of the rock matrix. Water analyses can also be conducted with mineral modeling to assess potential long term scaling tendencies given the potential compositional changes over the duration of the experiment.

Multiphase Fluid Transport

Beyond storage capacity, successful carbon sequestration projects require an understanding of fluid flow properties through various lithofacies and channels in the reservoir. Hysteresis of relative permeability, wettability, and drainage (CO_2 injection) and imbibition (post injection) processes affect the saturation and distribution of mobile and immobile CO_2 and formation water during injection and long term storage [8,9,10,11].

AGAT recommends relative permeability and relevant special core analysis measurements on core samples representing all facies present in the reservoir to help engineering models predict fluid flow and distribution throughout the lifetime of the project. Deliverables of these tests will also include residual water saturations that further aid in storage capacity determination and estimation of free gas saturations. Relative permeability measurements are conducted on stacks of core plugs or on full diameter samples. Core samples will be restored to in situ reservoir conditions. Samples are saturated with formation water and are brought to reservoir conditions, and are flooded with formation water to establish baseline permeability. The samples are then flooded with moisture-equilibrated CO_2 (in the supercritical state) and the produced fluids are collected downstream to monitor in situ saturation changes and CO_2 breakthrough. The results are used to derive relative permeability curves with core flood history match. A schematic our the experimental set up is shown in Figure 11.

A recommended additional step to this experiment would be to flood the sample with supercritical dry CO_2 after residual water saturation is reached. It has been shown that flooding with dry CO_2 can lead to permeability change from vaporization of formation water and subsequent salt precipitation.[5] This additional step or dedicated separate test would help quantify the extent of permeability change from salt deposition in the near wellbore area, which is strongly related to CO_2 injectivity.

Enhanced Oil Recovery

Subsurface CO_2 injection can have the added benefit of Enhancing Oil Recovery (EOR) prior to becoming a long term sequestration field, given the appropriate reservoir geology, minimum miscibility pressure (MMP), oil gravity, viscosity and pressure and temperature conditions.[6]

MMP for a CO_2 injection program is the minimum pressure in which CO_2 is miscible in formation oil at a given temperature (typically reservoir temperature). If the MMP is determined to be lower than reservoir pressure, CO_2 will be miscible and may lead to an enhanced recovery of oil from oil swelling and viscosity reduction. MMP can be determined in the lab through a variety of PVT experiments, with the slim tube method being the most commonly accepted method.[7, 11]

EOR can then be further probed in a coreflooding experiment to determine oil recovery factors. Core samples representing the various lithofacies throughout the reservoir zone can be mounted in a coreflood apparatus. Samples are flooded with formation oil to establish baseline permeability, before flooding with CO_2 until no more oil is produced. After a Dean Stark analysis to determine residual saturations, the oil recovery from flooding with CO_2 can be determined to understand the incremental oil recovery with CO_2 over primary or secondary recovery. Other valuable parameters, such as CO_2-oil relative permeability and end point saturations, are also determined in this experiment.

A series of phase behavior tests are performed to assess swelling of the in-situ fluids with CO_2 as well a the fluid characteristics near wellbore and at the flood front.

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