2024

# Enhance Origins CCS Project – MMV Plan

**Enhance Energy Inc.**

MEASUREMENT, MONITORING & VERIFICATION PLAN
DECEMBER 2024

enhance

# EXECUTIVE SUMMARY

This document provides the rationale for, and specific details of the Monitoring, Measurement and Verification (MMV) Plan for the Enhance Origins Project in Central Alberta.

The MMV plan guiding principles are:

- Protect the public and other subsurface lessees by ensuring $CO_2$ containment.
- Provide public assurance that $CO_2$ is confined to the storage complex and poses no threat to mineral resources, shallow aquifers hydrosphere, biosphere, and atmosphere.
- Quantify leakage risks and select monitoring techniques to reduce these risks to as low as reasonably practical.
- Tailor monitoring and measurement techniques to the site-specific attributes, including geology and infrastructure.
- Ensure early warning, using proven methods, to provide the opportunity to intervene before potential migration occurs outside of the storage complex.
- Meet or exceed regulatory requirements and provide assurance for the long-term safety and efficacy of the Enhance Origins Project, and
- Be adaptive, ensuring the ability to react to issues appropriately and mitigate them, should they arise.

# ORIGINS MMV PLAN OVERVIEW

| Monitoring Activity | Testing Technique | Frequency of Testing | | |
|---|---|---|---|---|
| | | Baseline | Active injection | Post Injection |
| **Most recent AER D65 CCS Approval** | Meet all clauses and requirements specified within Approval | N/A | As per approval | Refer to Directive 065 |
| **Monitor wells as per the dynamic Offset Wellbore Risk Assessment (OWRA) aligned with the AER Approach to risk management** | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management |
| **Injection Reservoir Pressure** | AER Directive 040 requirements. | Refer to Directive | Refer to Directive | Refer to Directive |

| | | | | |
|---|---|---|---|---|
| **Monitor tubing and annulus pressure on injection wells** | Injection wells | N/A | Continuous tied to SCADA. | N/A |
| **Measure Injected Fluid** | Applicable AER Directives Requirements. Gas Composition Analysis and Volumetric Flow Rate. | Refer to Directive | Monthly | N/A |
| **Induced Seismicity** | Passive monitoring stations | Continuous | Continuous with submissions annually | TBD based on MMV data throughout the project |
| **$CO_2$ Plume** | Seismic monitoring | Once. | Frequency dependent on final technology selection. Evaluate frequency every 3 years. | TBD based on MMV data throughout the project |
| **Dedicated water wells** | Within the Base of Ground Water Protection (BGWP) area. | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, Electrical conductivity, pH, and isotope analysis on all samples. | Twice per year, compositional analysis for the first 3 years of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |
| **Landowner water well surveys** | Selected landowner water wells, where permission is obtained, within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | No monitoring post injection |
| **Shallow Formation Monitoring** | Gas gathering system of producing wells, in cooperation with operators, encompassing well clusters for the MMV Plan Area. | Once. | Twice per year. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |

| | | | | |
|---|---|---|---|---|
| **Soil Gas Surveys** | Appropriately located soil gas locations within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |
| **Atmospheric Gas Sampling** | Appropriate locations within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |
| **Atmospheric monitoring at well pad** | Checks for signs of $CO_2$ leakage | N/A | Continuous | N/A |

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# TABLE OF CONTENTS

# Table of Figures

# INTRODUCTION

Enhance Energy Inc. ("Enhance", "the Operator") is a world-class leader and trusted provider of low-carbon solutions for the transition to a low-carbon economy. Enhance is the founding partner of the Alberta Carbon Trunk Line (ACTL) project, the world's largest capacity dedicated anthropogenic $CO_2$ transportation system. Enhance is also the operator of Alberta's largest carbon utilization and storage initiative located in Clive, Alberta.

Since its first $CO_2$ injection in 2020, the Clive $CO_2$ (Enhanced Oil Recovery) EOR scheme has captured and injected over 5.5 million tonnes of anthropogenic $CO_2$ emissions that would have otherwise been emitted into the atmosphere. The captured $CO_2$ is injected into a deep geological formation that was largely depleted of oil and gas resources decades ago, making it an ideal storage project.

In 2022, Enhance announced the Origins Project ("the Project") in Central Alberta. The project is envisioned as an open access $CO_2$ sequestration hub with the capacity to manage $CO_2$ from hard-to-abate industries, like cement, power generation and petrochemicals that exist along Alberta's Highway 2 Corridor — including the Alberta Industrial Heartland, but also from existing large emissions sources in Central and Southern Alberta, making it one of the largest CCS initiatives worldwide.

Enhance is committed to the safe, efficient, orderly, and environmentally responsible development of the Origins Project to support Alberta's move toward a low-carbon economy. As the owner and operator of a 1.5 MTPA $CO_2$ EOR operation in Clive, Alberta, Enhance has key advantages toward the timely execution of the Origins sequestration hub leveraging operational expertise in local geologies and the utilization of proven MMV techniques and baseline data to demonstrate long-term storage containment.

Enhance is applying for AER Directive 065*, Section 4.1.6 for a $CO_2$ Sequestration Scheme,* Approval to inject commercial volumes of $CO_2$ into the Leduc Formation at the 100/04-36-039-25W4/00 well. The AER D065 application contemplates injection of approximately 28 MT of $CO_2$ into the 100/04-36-039-25W4/00 wellbore with injection targeted to begin in the second half of 2025.

For carbon sequestration projects, the MMV plan sets out the monitoring, measurement, and verification activities for the term of carbon sequestration lease agreement in response to the risks identified in the site-specific risk assessment. The MMV plan contents are developed by the project operator in response to the risks identified and enable regulatory requirements to be met and conditions specified in project approvals to be satisfied. Measurement and monitoring of the injection facilities, geological sequestration site, and surrounding environment provide assurance that $CO_2$ is confined to the storage complex (i.e., containment).

This document is designed to outline the MMV plan for the Enhance Origins project during pre-injection, active injection operations and post-injection periods of the project lifecycle. The development of the MMV Plan Area will begin with a single well dedicated to $CO_2$ injection.

Injection pressures will conform to regulatory requirements and be maintained at levels that ensure the injection formation and overlying strata remain unaltered, thus maintaining confidence in the long-term $CO_2$ storage.

The MMV plan relies on a thorough understanding of the reservoir, developed through decades of data gathering from oil and gas operations within the reef complex. Enhance and expert consultants have carefully designed the plan to monitor the $CO_2$ plume development within the storage complex, and to provide safeguards ensuring $CO_2$ storage is secure and effective for the entirety of the injection operations and beyond.

# 1 MMV PLAN DESIGN

The purpose of this document is to outline the approach to public and regulatory assurance of containment through Monitoring, Measurement and Verification (MMV) for the Enhance Origins $CO_2$ Project. The MMV Plan ensures that $CO_2$ injection into the storage complex is contained so that subsurface mineral resources, geosphere, hydrosphere, biosphere, and atmosphere are protected.

Enhance utilizes a risk-based approach to MMV and public protection. The risk-based approach will:

- Identify potential pathways for $CO_2$ migration based on characterization of the storage complex aided by detailed geological and engineering modelling,
- Identify practical, cost-effective, and reliable migration detection strategies and mitigation techniques to address potential migration events, and
- Implement proven and effective monitoring tools, which reduce the risk of migration, by achieving early detection and mitigation strategies.

Enhance is currently operating the Clive $CO_2$ EOR project in Central Alberta. This project has provided valuable learnings and practical experience to aid in the development of the MMV plan for the proposed Enhance Origins Project.

## 1.1 DEFINITIONS

The following definitions are used in several sections of this MMV Plan and are consistent with Appendix C of Alberta Energy's Carbon Capture & Storage: Summary Report of the Regulatory Framework Assessment

Area of review: the surface area within which potential adverse effects may occur due to $CO_2$ plume migration and pressure elevation. The purpose of the area of review is to assist the regulator and all stakeholders in assuring that the sequestration risks are being appropriately managed.

Area of Influence: the spatial footprint of the maximum connected pore volume in the sequestration complex affected by an increase in pore pressure. The area of influence is a useful concept for the regulator to provide assurance for the allocation of pore space within a sequestration complex and on how close other injection activities could be placed.

The MMV Plan is based on the best available guidance and information to date and is in accordance with Appendix P of AER Directive 065: Resources Applications / MMV Principles and Objectives for $CO_2$ Sequestration Projects (July 2023).

The following steps were taken to design the MMV plan:

1. **Assess site-specific storage risks:** Establish definitions for loss of conformance and loss of containment. Identify potential threats and consequences associated with these risk events using a risk assessment method.
2. **Characterize geological safeguards:** Identify and appraise the integrity of each geological seal within and above the storage complex. Identify and appraise potential secondary storage and seal/caprock units.
3. **Select engineered safeguards:** Identify and assess the engineering concept selections that provide preventative safeguards against unexpected loss of containment (e.g., well integrity, geological seal integrity).
4. **Evaluate these geological and engineered safeguards:** Evaluate the expected efficacy of these initial safeguards in relation to the identified conformance, containment and induced seismicity threats, and their potential consequences.
5. **Establish monitoring requirements:** Define monitoring tasks to verify the performance of these initial safeguards and, if necessary, trigger timely corrective measures.

6. **Select monitoring technologies:** Select monitoring technologies considering leak path scenarios, potential induced/triggered seismicity scenarios and confidence for all stakeholders. Incorporate learnings from other projects and apply cost-benefit ranking. Evaluate the expected monitoring capabilities and establish performance targets.
7. **Identify contingency monitoring:** Evaluate alternative monitoring plans to investigate suspected anomalies from baseline. The results of the contingency monitoring inform corrective measures.

## 1.2 TECHNICAL STUDIES AND ASSESSMENTS

Enhance has completed extensive scoping and technical studies for long term $CO_2$ sequestration in the area identifying the following well for the injection of $CO_2$ into the identified pore space in the Leduc storage complex:

- **100/04-36-039-25W4/00**

The identification of the Project Area (Figure 1) was based on the following technical programs and assessments (listed below in Table 1) to support the area definition by in-house as well as third-party experts. These are discussed in detail later in the document.

Table 1: List of Technical Studies and Assessments

| Technical Study or Assessment | Last Updated | Conducted By |
|---|---|---|
| **Geological, Hydrogeological and Mineralogical Characterization of the Sedimentary Succession Overlying the Leduc (D3-A) and Nisku (D-2) Oil Reservoirs in the Clive Oil Field in Alberta** | December 2011 | Alberta Innovated Technology Futures |
| **Geochemical Effects on Deep Strata in Case of $CO_2$ Leakage from the Leduc D3-A and Nisku D2 Oil Reservoirs in the Clive Oil Field in Alberta** | March 2012 | Alberta Innovated Technology Futures |
| **Geochemical Analysis of the Effects of $CO_2$ Injection in the Clive Leduc and Clive Nisku Reservoirs in the Clive Field** | March 2012 | Alberta Innovated Technology Futures |
| **Assessment and Interpretation of Data Collected in Phase 11 of the Alberta Carbon Trunk Line Project: Development of a Site Conceptual Model and Risk Considerations** | March 2013 | Alberta Innovated Technology Futures |
| **Baseline Shallow (Non-Saline) Groundwater Monitoring (Clive)** | April 2019 | Golder & Associates |
| **Induced Seismicity Risk Assessment** | 2023 | Dr. Mark Zoback – Stanford University |
| **$CO_2$ Storage Efficiency for Capacity Estimation – Integrating Geological and Engineering Risks in a Clastic Saline Aquifer in Central Alberta, Canada** | 2023 | GLJ Ltd. |

| | | |
|---|---|---|
| **Preliminary Origins Reservoir Simulation Model** | 2023 | Enhance Energy Inc. |
| **Quest Past and Forecast Performance** | 2023 | GLJ Ltd. |
| **Capacity Estimate** | February 2024 | GLJ Ltd. |
| **Origins Hydrogeology Study** | August 2024 | Integrated Sustainability Consultants |
| **Clive Field and Bashaw Regional Characterization and Geocellular Modeling** | September 2024 | Petrel Robertson Consulting Ltd. |
| **Origins Carbon Sequestration Hub Project Geological Documentation** | September 2024 | Petrel Robertson Consulting Ltd. |
| **Offset Wellbore Risk Assessment (OWRA) (ongoing)** | 2024 | Enhance Energy Inc and Noble Ventures Inc. |
| **Containment Risk Assessment** | 2024 | Carbon Management Canada |
| **Reservoir Simulation Modeling** | 2024 | Enhance Energy Inc. |
| **Geomechanical Study** | 2024 | RESPEC Company LLC |

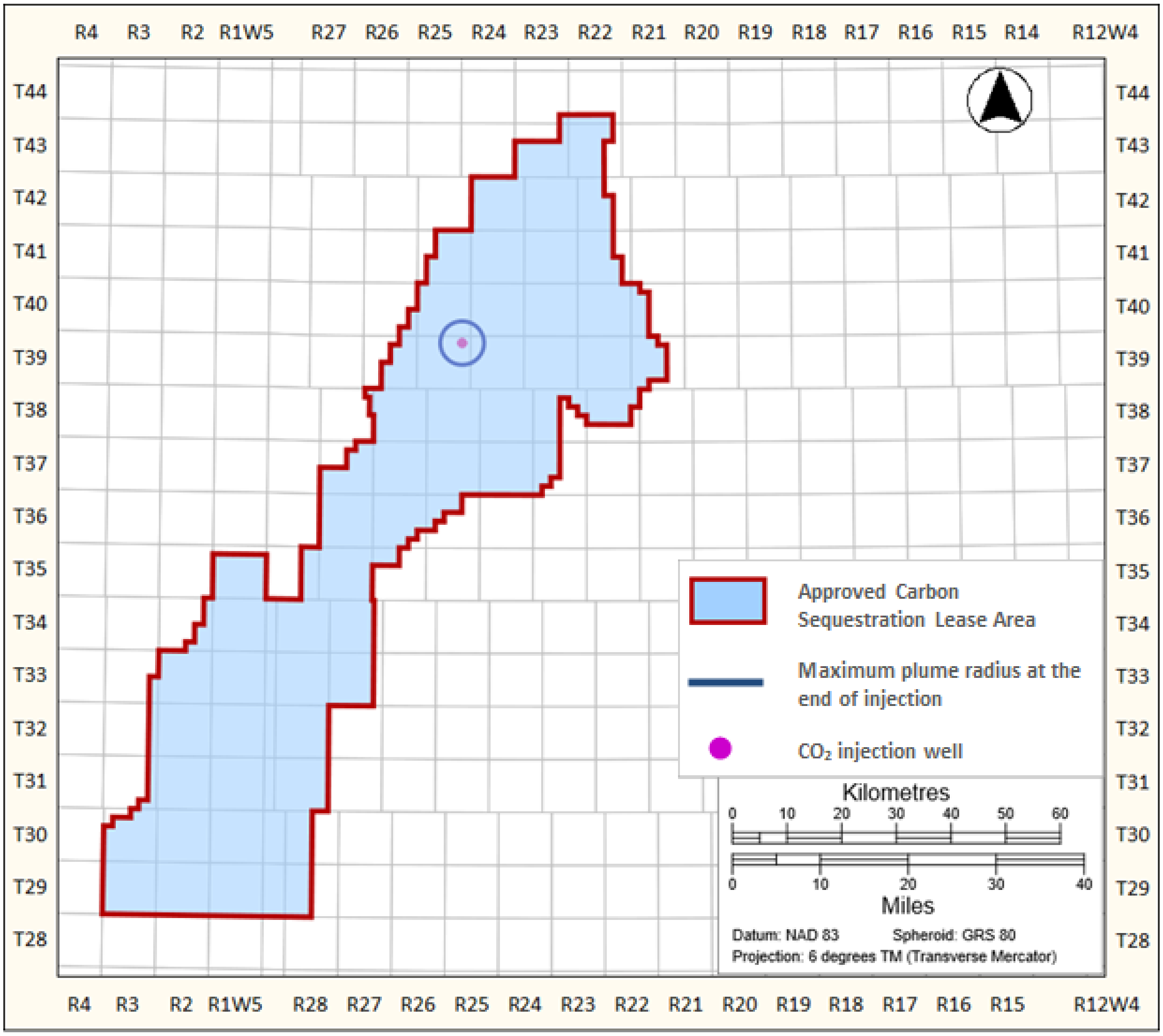


**Figure 1: Sequestration lease boundary and the calculated maximum fluid injection area for the injector well.**

## 1.3 MMV Stages

The MMV plan is designed to remain an active and a live document that follows the lifecycle of the carbon sequestration project. In accordance with Figure 7 of the Alberta CCS Summary Report of the Regulatory Framework Assessment, Enhance has defined the following key stages for the storage hub which define the evolution of the MMV as the Project progresses through the various stages as listed and illustrated in Figure 2 below:

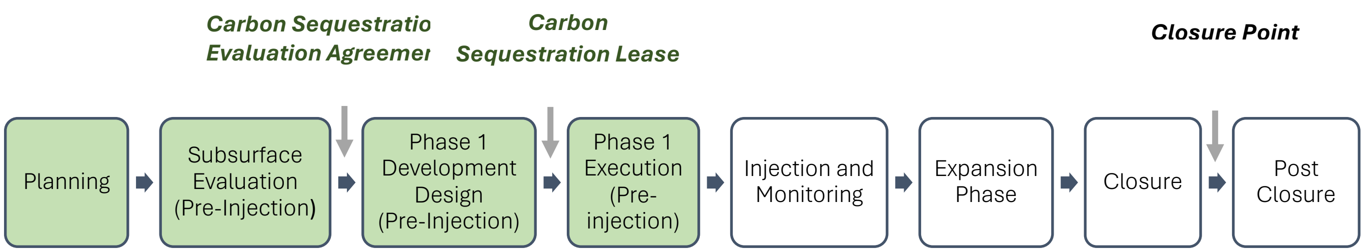


**Figure 2: Hub Project Development Phases (Adapted from Figure 7 of the Alberta Energy Regulatory Framework Assessment, 2013).**

## 1.4 Assumptions, Constraints and Limitations

There are significant constraints and limitations that influence the Project. Some of the known constraints and limitations are identified below and shall be updated as the Project progresses through the project development stages.

1. **Publicly available data** – Carbon sequestration is relatively new in the province and most projects are in pilot status. Not all information from pilots is within the public domain making it challenging to identify technologies and/or previous or best practices.

2. The current Project design is based on sound science and engineering and uses the **Best Available Technology Economically Achievable (BATEA)** at the time of this document. However, the project is in the very early stages from a long-term storage perspective. Monitorability of all aspects remains a critical factor in the success of this Project.

3. **New Technologies** –New and existing technologies, whether repurposed or cutting-edge, often lack a proven track record that aligns with the economic constraints of technology selection and implementation.

4. **Offset Wellbore Risk Assessment (OWRA) Approach Under Development** – Enhance is currently collaborating with the AER in developing a standardized approach for OWRA. The well specific OWRA cannot be finalized to define the Origins monitoring program as it relates to offset wellbores until a formalized OWRA approach is defined.

5. **Seismic Data** – Acquired seismic data is utilized for assessing characteristics of the subsurface and evaluating the need for additional acquisition on a project need basis.

# 2 SITE SUITABILITY ASSESSMENT THROUGH SITE CHARACTERIZATION AND RISK ASSESSMENT PROCESS PER CSA Z741-12

## 2.1 EVALUATION PLAN AND EXECUTION

The concept of the Origins Project was initiated well before Alberta Energy's industry wide requests for proposals to develop CCUS hubs in Alberta. Enhance Energy has been operating the Clive $CO_2$ EOR project since 2020 and has developed significant baseline data and monitoring learnings from that project. Origins is the next natural step in creating world-class, efficient, and trusted CCUS capability in Central Alberta, by providing commercial-scale open-access sequestration capacity, leveraging the Alberta Carbon Trunk Line (ACTL) to meet large emitter sequestration demand in the Edmonton-Calgary corridor. Carbon Sequestration Tenure has been granted by Alberta Energy for injection into the Woodbend Group within the Leduc Formation. Enhance has extensive operational experience and a large amount of data from the Clive $CO_2$ EOR project within analogous reservoir geology to Origins. Origins initial site selection prior to applying for pore space tenure evaluated injectivity, storage capacity, containment and the potential for induced seismicity with $CO_2$ injection. In addition to these four major characteristics, geographic location and proximity to the ACTL were considered.

Site selection for the Origins CCS project was largely based on experience and data collected from the Clive $CO_2$ EOR Project.

- **Injectivity** observed at Clive informed the selection of the Origins hub location and injection zone.
- **Storage Capacity** of the Leduc Formation was assessed based on historic oil and gas production along with the associated history of the Bashaw reef complex and verified by an independent third-party.
- Initial **Containment** was assessed based on the work in the Clive oil field and validated by site-specific technical, site characterization. The Clive $CO_2$ EOR Project has demonstrated a competent primary seal in the Ireton and secondary seals in the Calmar and Wabamun anhydrites.
- **Induced seismicity** was considered when determining the location for the Origins Project. The Bashaw reef complex mitigates induced seismicity risk by having considerable amounts of under burden, preventing the transfer of pressure to the basement. The low risk of induced seismicity was verified by independent third-party expertise.

The specific well location of 04-36 was later chosen based on geographic proximity to the ACTL and the ability to utilize existing infrastructure and accommodate for future development and scale up. Seismic data was acquired and analyzed prior to finalizing the injection location. A review of the offset wellbores was completed to ensure the chosen location of the well was not in direct proximity to existing wellbores. In addition, the well location was selected away from existing oil and gas accumulations such that no impact on existing resources would be introduced.

In February 2024, the 04-36 well was drilled and 89.5 m of core was retrieved. The core was processed, cleaned, and slabbed. Routine core analysis was completed including saturation, porosity, CT imaging, gamma logs, pressure decay profiles and imaging. This data further informed the site characterization, risk assessment and MMV Plan.

## 2.2 GEOLOGY

### 2.2.1 REGIONAL SETTING – DISPOSAL ZONE AND CAPROCK (CONFINEMENT STRATA)

Upper Devonian strata in the Western Canadian Sedimentary Basin include (from youngest to oldest): Wabamun Group; Winterburn Group, which includes the Graminia, Calmar and Nisku Formations; and the Woodbend Group, which includes the Cooking Lake, Leduc and Ireton Formations.

Figure 3 illustrates reservoir and caprock components of the Origins Project overlain on the Upper Devonian stratigraphic succession. The Leduc disposal reservoir is capped by Ireton shale, which is designated as the primary caprock; the Ireton includes in places carbonate-rich strata of the Camrose Member. Regional secondary seals for the Project occur in thin continuous shales of the Calmar Formation, and in evaporitic strata of the overlying Stettler Formation. The Graminia and Blue Ridge members cannot be mapped with confidence in the study area.

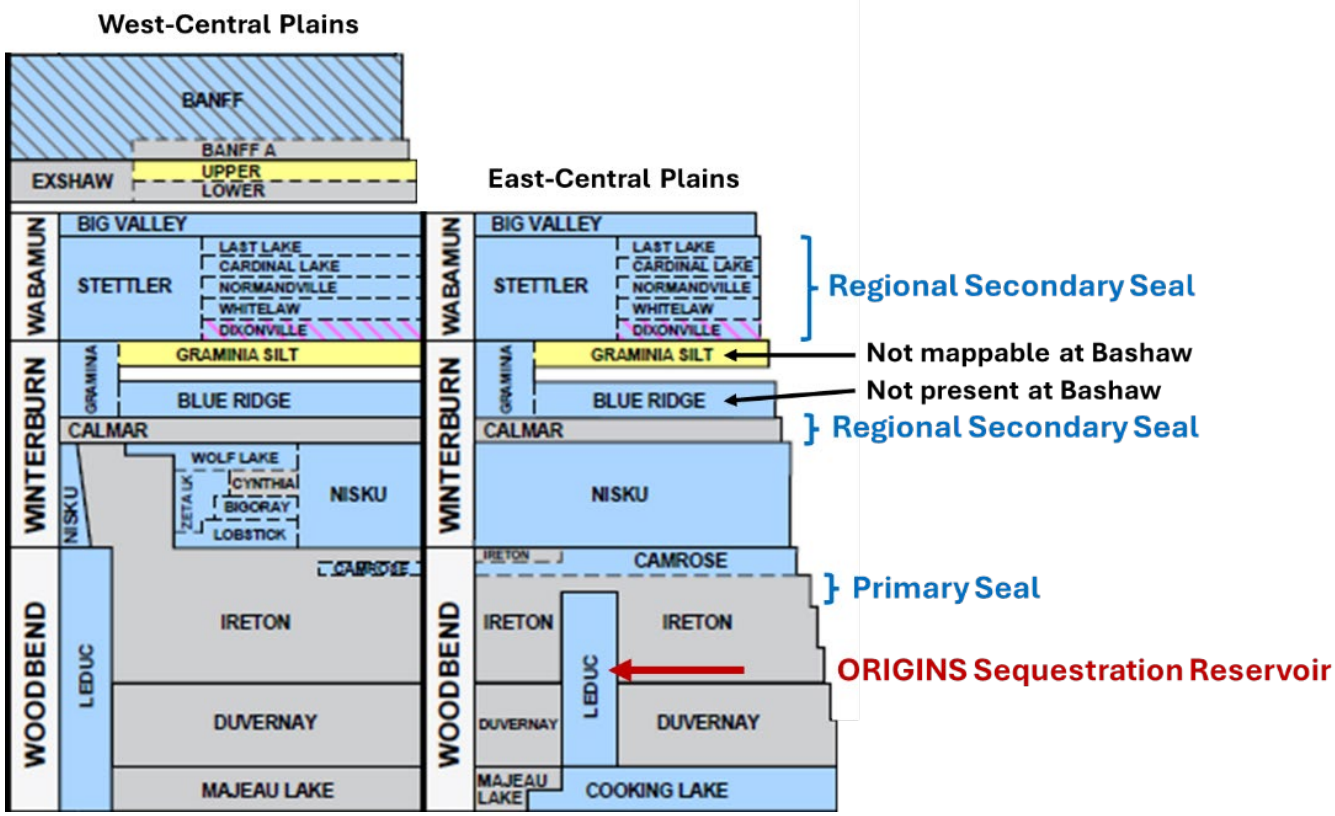


**Figure 3: Stratigraphic column, Upper Devonian strata of central Alberta. The east-central Plains column best represents the Bashaw area, but Mississippian Exshaw and Banff Formations occur over part of the study area (after Alberta Geological Survey, 2019).**

#### DEPOSITIONAL SETTING

During Late Devonian time, Western Canada lay in tropical waters on the western flank of the North American craton. Switzer et al (1994) summarized Woodbend and Winterburn depositional settings:

> "During early phases of Woodbend Group deposition the WCSB underwent gradual deepening. This resulted in the development of a thick aggradational succession of carbonates with substantial topographic relief between shelf and basinal areas [Leduc and Duvernay Formations]. By the end of Woodbend deposition, during a period of reduced rate of subsidence and / or sea level fall, most of the basin was filled by shales [Ireton Formation]. Winterburn Group deposition was characterized by overall shallowing and filling of the basin."

Thick and extensive reef complexes of the Leduc Formation (Leduc) created a distinctive paleogeography in the southwestern WCSB (Figure 4). As many of these reefs contain oil and gas, they have been delineated in detail by exploration and development drilling. The Bashaw reef complex grew on the Cooking Lake Platform within the East Shale Basin province, southeast of the Rimbey-Meadowbrook reef chain, and northwest of the southern Alberta Leduc shelf. At Bashaw, the Woodbend section is on the order of 300 meters thick.

Following the Ireton basin-filling event, rapid sea level rise cut off terrigenous clastic supply and allowed Nisku shelfal carbonates to prograde toward a shelf edge just northwest of Edmonton (Figure 6). Transgressive and regressive phases are best developed in the West Pembina Basin to the northwest but are more difficult to distinguish on the regional southeastern shelf. At Bashaw, Potma et al (2001) identified initial ramp and shoal facies succeeded by shallow subtidal ramp facies containing a higher proportion of evaporites.

Potma et al (2001) assigned the post-Nisku Graminia-Blue Ridge interval to a third Winterburn depositional sequence. While well developed in west-central Alberta, it is represented only by the distinctive Calmar Shale lying unconformably on the Nisku at Bashaw; any Blue Ridge carbonates or Graminia silts deposited subsequently cannot be distinguished with confidence on well logs. Following a brief post-Nisku lowstand, Calmar strata accumulated as sea level rose and reworked siliciclastics, dispersing silts and clays across the basin. At Bashaw, the Calmar is a highly distinctive and continuous shale and serves as a regional secondary seal to the Origins sequestration complex.

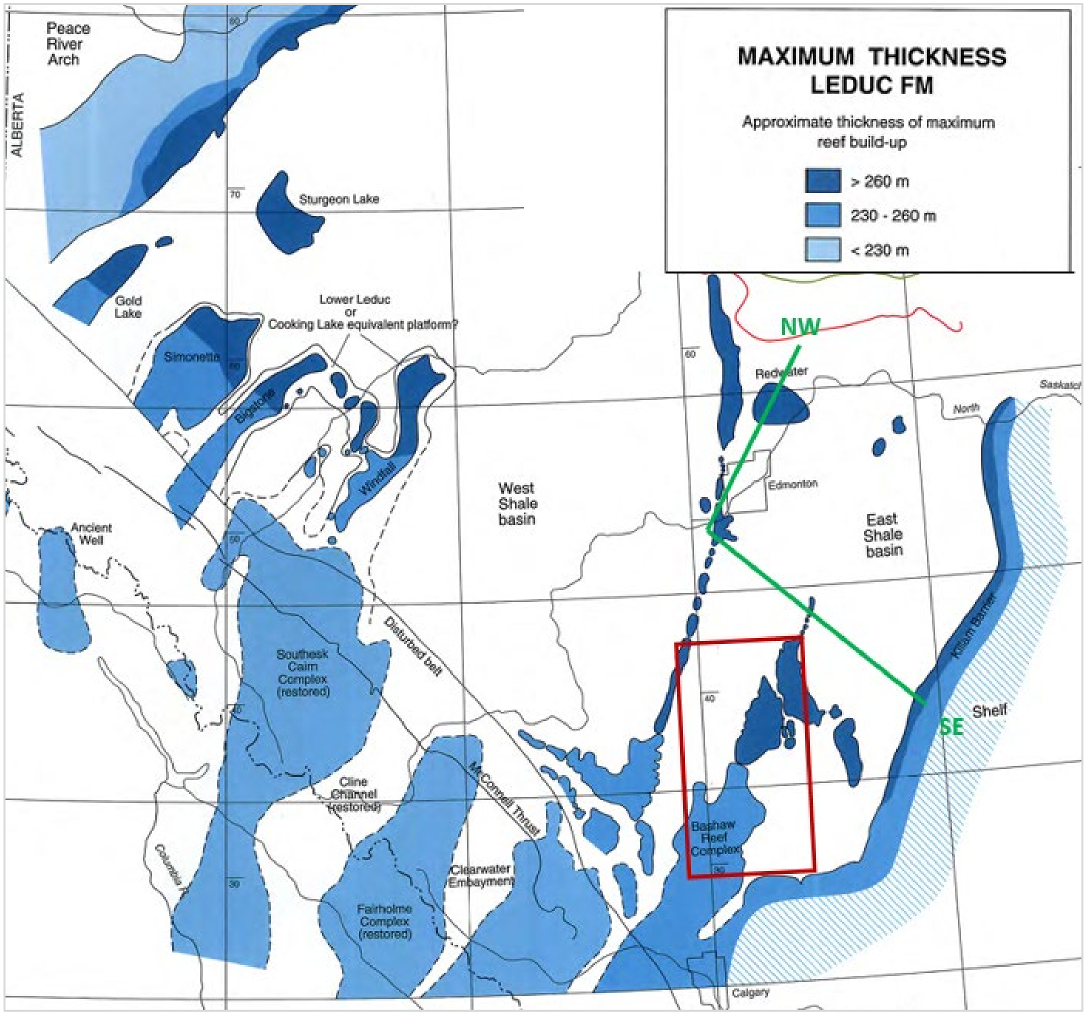


**Figure 4: Leduc paleogeography of the southwestern Western Canada Sedimentary Basin. The Bashaw Reef complex study area is outlined in red. Line of cross-section is shown in green (see Figure 5 for details). From Switzer et al (1994).**

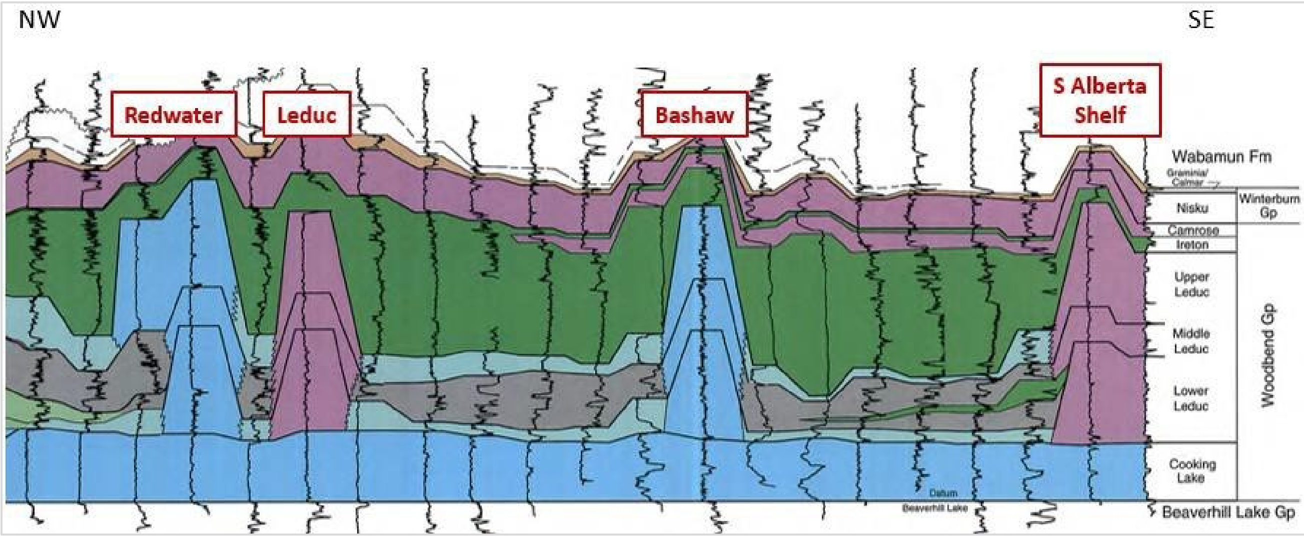


**Figure 5: NW-SE stratigraphic cross-section illustrating Bashaw reef complex in the context of regional Woodbend-Winterburn deposition. Well representing Bashaw is at Duhamel just to the northeast, and unlike the Bashaw complex has not been dolomitized. After Switzer et al (1994).**

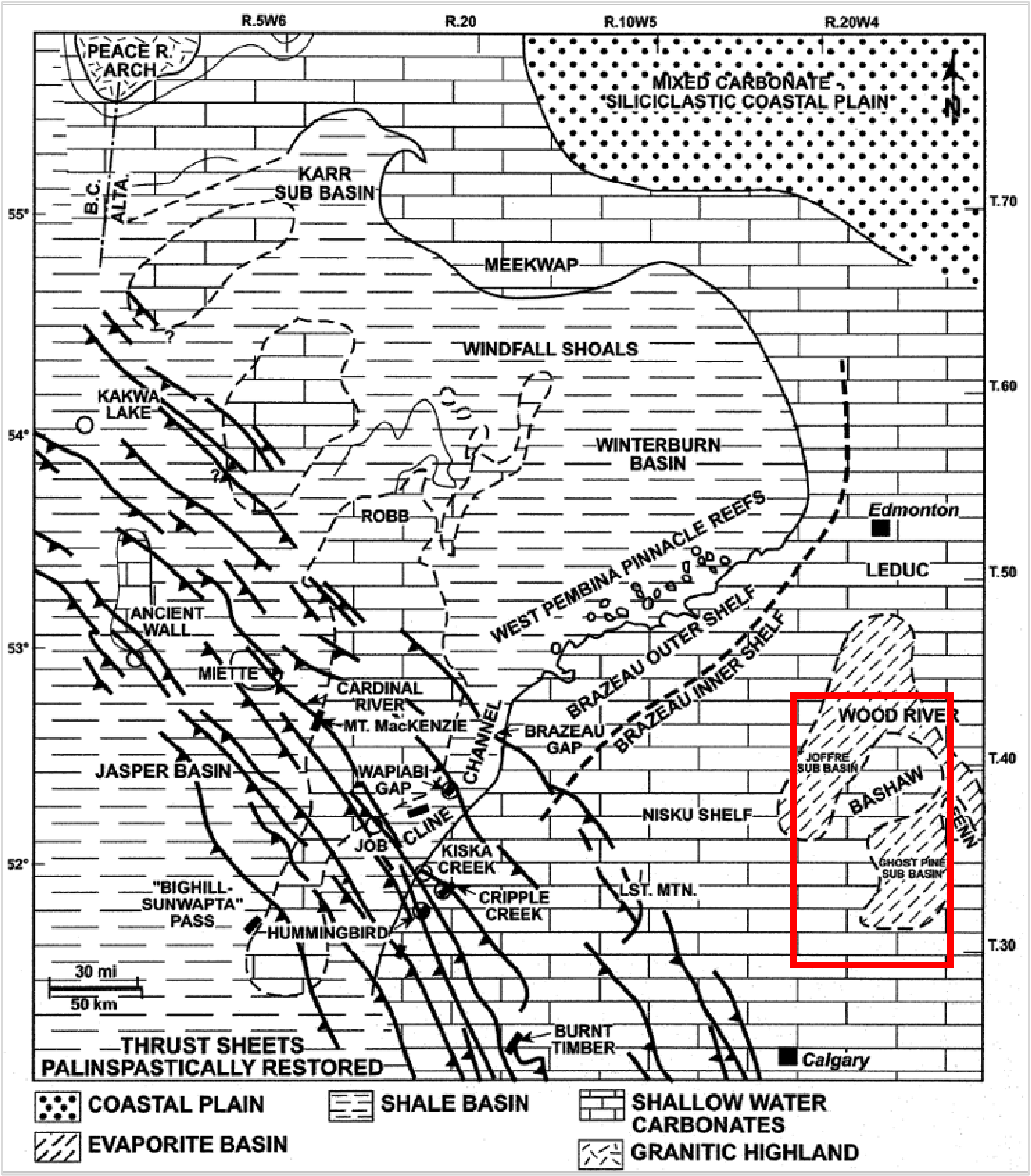


**Figure 6: Nisku paleogeography in central Alberta. The Bashaw Reef complex study area is outlined in red. From Potma et al. (2001).**

Wabamun sedimentation took place across the WCSB in an overall regressive sequence following the early Famennian transgression associated with the Calmar – Graminia. Halbertsma (1994) documented a broad shelfal setting ranging from open marine carbonates in the far northwest (northern British Columbia) to restricted, dominantly evaporitic settings in southern Alberta and adjacent Saskatchewan. At Bashaw, more than 200 meters of finely crystalline dolomites with some limestone in the west transition to stacked supratidal evaporitic facies southeastward (Figure 7).

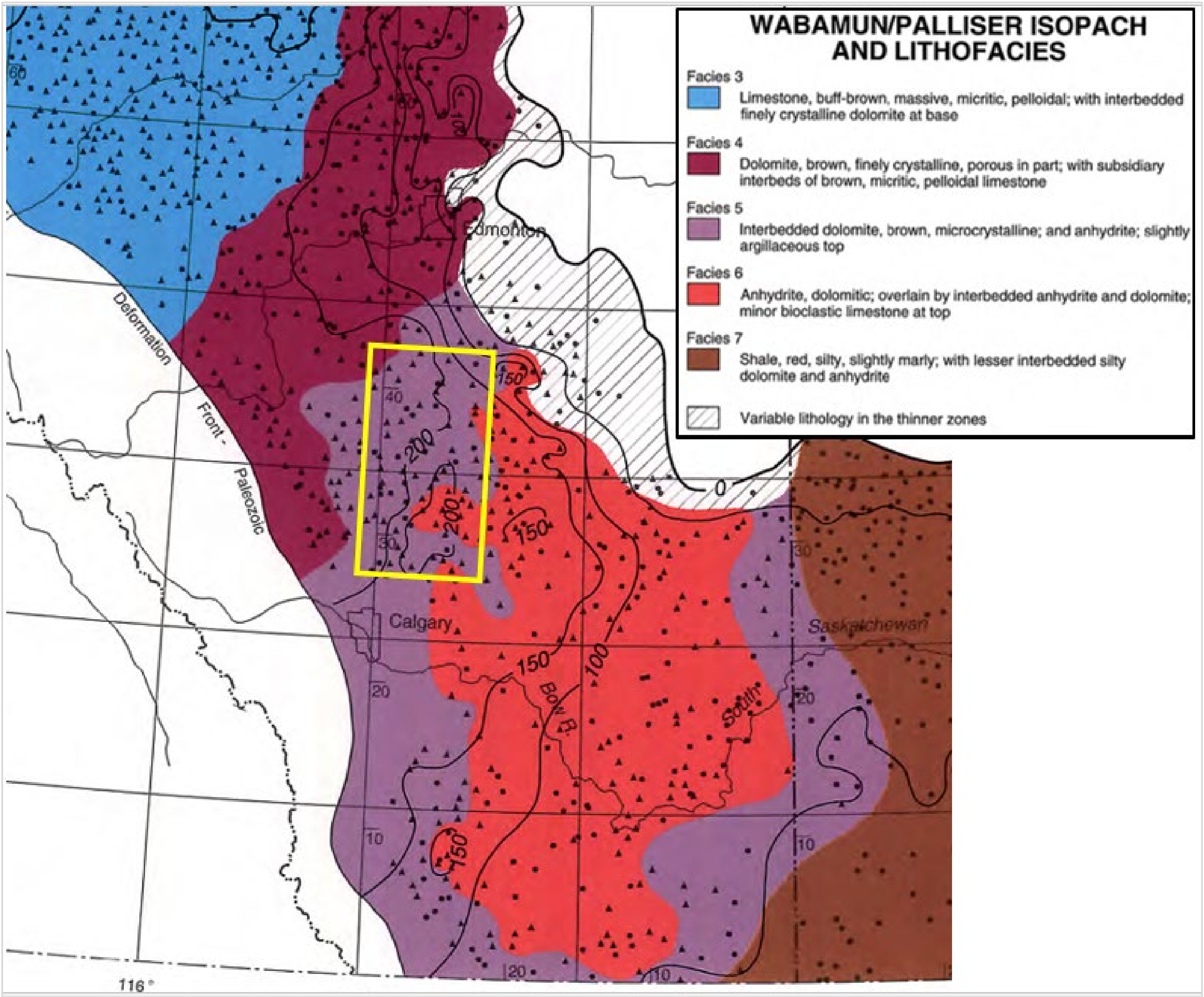


Figure 7: Wabamun lithofacies of the southwestern Western Canada Sedimentary Basin. The Bashaw Reef complex study area is outlined in yellow. From Halbertsma (1994).

### 2.2.2 Stratigraphic Analysis – Leduc Formation Reservoir

Historic studies of Leduc Formation reservoir facies have focused on discrete limestone buildups, such as Golden Spike in the Rimbey-Meadowbrook trend or the Redwater buildup northeast of Edmonton (Potma et al., 2001). Both Golden Spike and Redwater have been extensively drilled and cored, supporting detailed facies analysis throughout the Leduc section. The much larger Bashaw carbonate reef complex (Bashaw Platform) is a regional feature defined by relatively sparse well control (<1 well per township) except in local field developments such as Clive and hence has not been subjected to rigorous regional facies analysis.

The Leduc Formation was mapped using all available penetrations (~1400) across the Bashaw reef complex. Tops were correlated based on a grid of regional stratigraphic cross-sections, which included as many deep (Cooking Lake Formation) penetrations as possible. However, approximately 65 wells fully penetrate the Leduc allowing the underlying Cooking Lake to be picked, with many of these near the platform edges where the lateral extent of the buildup was tested in exploration wells.

Most Leduc wells penetrate only the upper 25-50 meters of the Leduc to evaluate for oil pay, limiting understanding of Leduc thickness and facies architecture below this level. The upper 25-50 meters of the Leduc has been cored extensively across the Bashaw reef complex, although almost all cores are concentrated within producing oil pools, particularly at Clive. Total Leduc thickness ranges up to about 230 meters across the Bashaw reef complex.

#### Clive Field Leduc Reservoir Facies

Enhance engaged carbonate geologist expert Murray Gilhooly to describe Leduc Formation cores in the Clive Field (Township 39 & 40, Range 24W4), which is the closest and most extensive dataset in proximity to 04-36, to better understand lateral and vertical distribution of reservoir facies. Attention was paid to depositional facies, stratigraphy, diagenesis and fracturing as they relate to reservoir quality. Core-based stratigraphic cross-sections were constructed to aid in understanding the nature of layering, facies, and resultant reservoir / non-reservoir distribution.

Summarizing findings:

- Clive Leduc facies fall almost entirely within the restricted lagoon, semi-restricted lagoon and tidal flat beach facies in the Upper Devonian platform to basin reef margin model of Wong (2016) (Figure 8). They are commonly arranged in metre-scale shallowing-upward cycles.
- All Leduc strata are completely dolomitized. Minor secondary anhydrite occurs as nodules and fracture infill and trace amounts of calcite occur as rare fracture infill. Thin green non-calcareous shales are a minor but ubiquitous component of probable karst features. Coarse crystalline dolomite commonly lines centimetre-scale and larger vugs, and pyrobitumen partially lines fractures and vugs.
- Multiple pore types are present, ranging from partial fabric-controlled (intercrystalline and biomoldic vugs) through to mainly non-fabric selective (associated fractures and vugs)
- Porosity is entirely secondary in nature, averages 6 to 7%. Permeability in porous beds ranges from <10 mD to hundreds of millidarcies.
- Fractures are common and are often associated with vugs (typically < 1 cm to 3 cm) and enhanced modified intercrystalline porosity (possible grain-leaching). Most core pieces of potential reservoir rock contain some degree of fracture/vug association.
    - Fractures are generally subvertical and less than a few centimeters high; the tallest fracture observed was less than 10 cm. Apertures are commonly 1-2 mm with partial mineralization.
    - Fractures are common within thin tight beds and often “bleed” into areas of enhanced secondary dolomite porosity and vugs, thus acting to potentially connect porous beds.

- Fractures are an important element of reservoir quality internally; however, they do not cut across stratigraphy significantly and thus do not pose a risk to reservoir seal / containment.

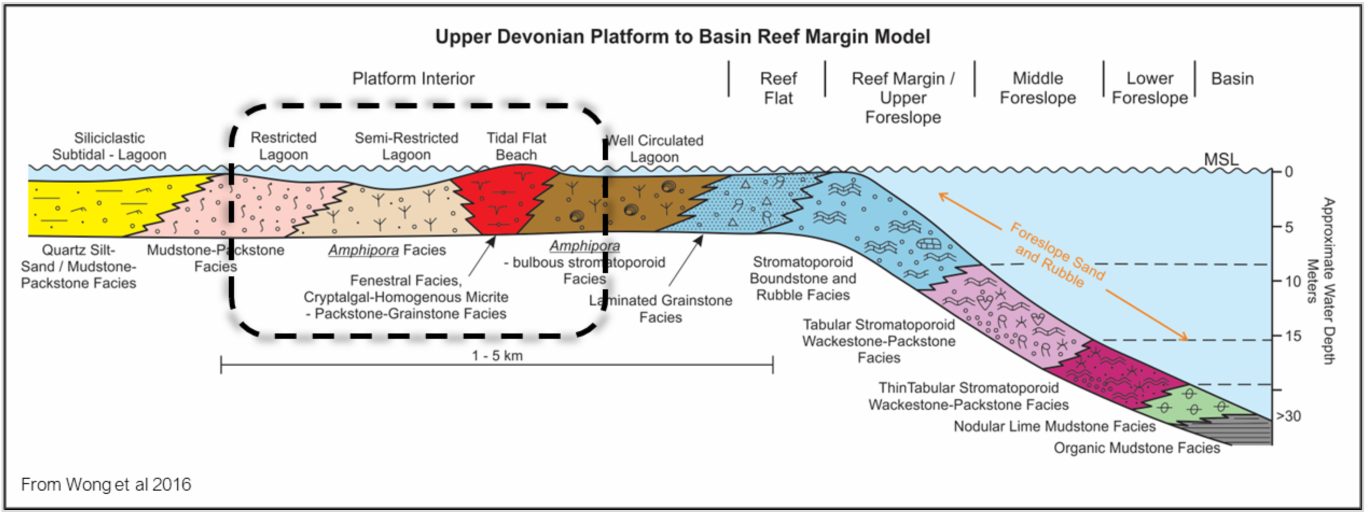


**Figure 8: Upper Devonian platform to basin reef margin depositional model (from Wong, 2016).**

## ORIGINS PROJECT TARGET AREA

Enhance drilled project well 04-36 in February 2024 through the entire Leduc Formation as the first CCS well drilled for the Origins Project. Situated about 10 km west of Clive battery, 04-36 reached total depth at 2210 m in the Cooking Lake Formation. A full suite of logs was run across the Leduc section, and 89.5 m of high-quality Leduc core were recovered, representing the first significant cored section of the Bashaw reef complex below the uppermost reservoir section.

Figure 9 shows project well 04-36 Leduc core description. Core recovery and quality was excellent. In total 88 full diameter core samples were analyzed for grain density, porosity and permeability. Six thin sections were prepared and photographed. These data along with high quality slabbed core photos were integral to the core description process.

Applying the facies classification developed at Clive. Key findings are:

- The facies observed, including the nature and amount of porosity, diagenesis, fractures, vertical stacking of facies, and overall reservoir quality are very similar to what has been described at Clive, and support the same platform interior lagoon to tidal flat facies / reservoir model. These observations enable greater predictive certainties associated with modeling reservoir quality throughout the Leduc for the Origins Project in this area of the Bashaw reef complex.
- The basal 10 m of core recovered at 04-36 is dominantly limestone (Figure 9 and Figure 10) with poor reservoir potential, consistent with petrophysical interpretations in uncored wells penetrating the entire Leduc platform complex. Depositional facies include stacked cycles of platform interior lagoon and tidal flat facies, similar to the dolomitized facies in the upper part of the Leduc at 04-36 and in the Clive pool.
- High-gamma spikes on the core gamma log correlate both with karst-related green shales and clay-enriched and/or stylolitic deeper lagoon facies, suggesting they may be useful for interpreting facies and improving correlations in uncored sections.

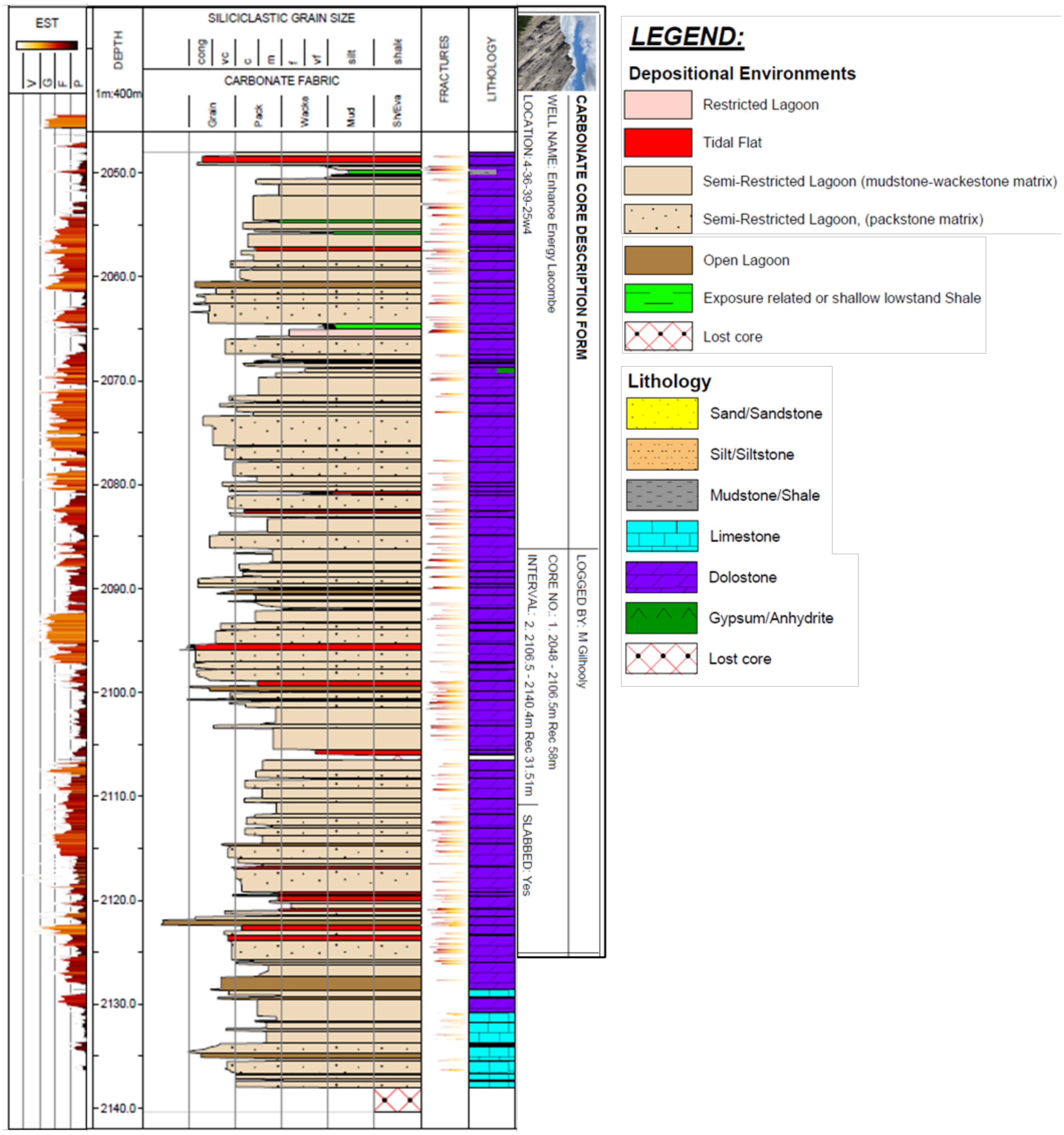


**Figure 9: 100/04-36-39-25W4/00 Leduc Formation core description.**

Petrophysical analyses were completed by Petrel Robertson Consulting Ltd. (PRCL) using HDS-2008 software and digital (LAS format) log curves. The effective porosity and water saturation are shown in **Figure 10**, tracks 5 and 6 respectively. The analyses completed on 04-36 shows 100% water saturation in the porous intervals through the Leduc.

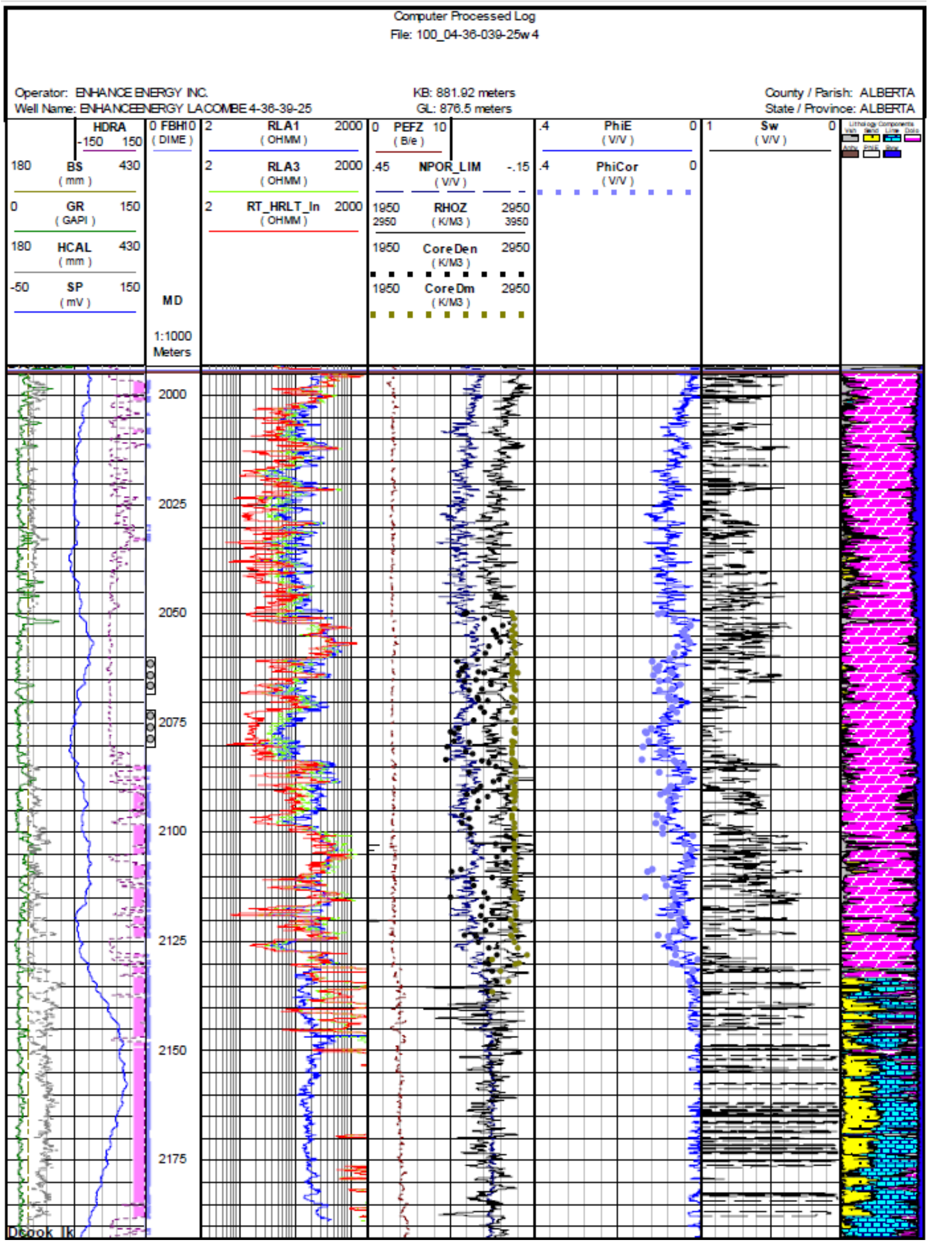


Figure 10: Petrophysical analyses of well 100/04-36-039-25W4/00 including limestone section.

## Leduc Formation Reservoir Parameter Summary

- Structure: Regional southwesterly dip at 6 m/km in the Origins Project Target Area (**Figure 11**)
- Thickness: >200 metres in the Origins Project Target Area (**Figure 12**)
- Porosity: Average Porosity 6 -7 %

- Permeability: up to hundreds of millidarcies
- Reservoir continuity: Excellent lateral continuity of reservoir facies, enhanced by pervasive dolomitization

Strata of the sequestration complex in the Origins Project Target Area, including the Leduc Formation, are correlated on **Attachment 9: Cross section A-A'**.

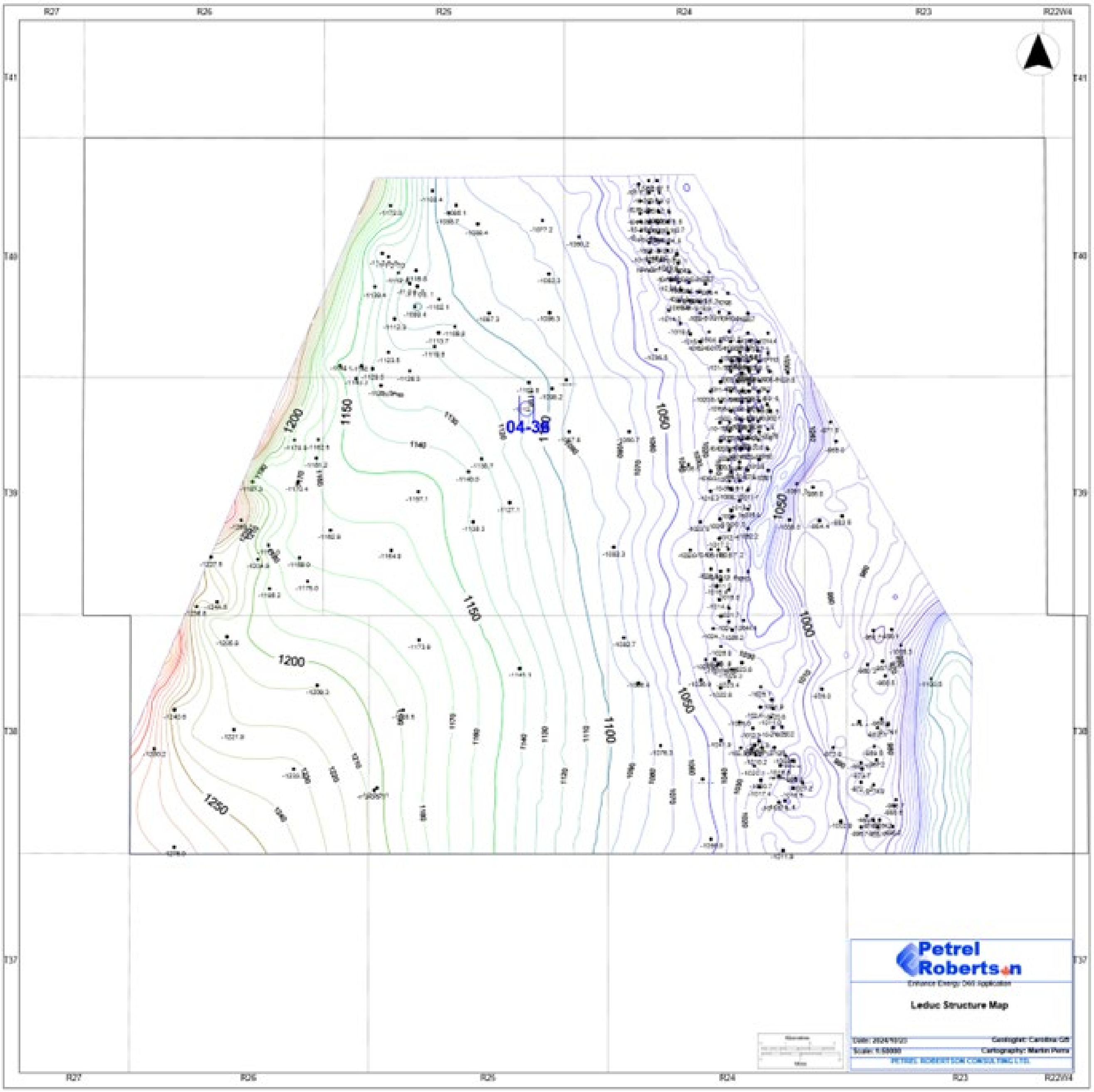


Figure 11: Structure map, top Leduc Formation, Origins Project Target Area, 04-36 well location is highlighted. Contour interval 10 m.

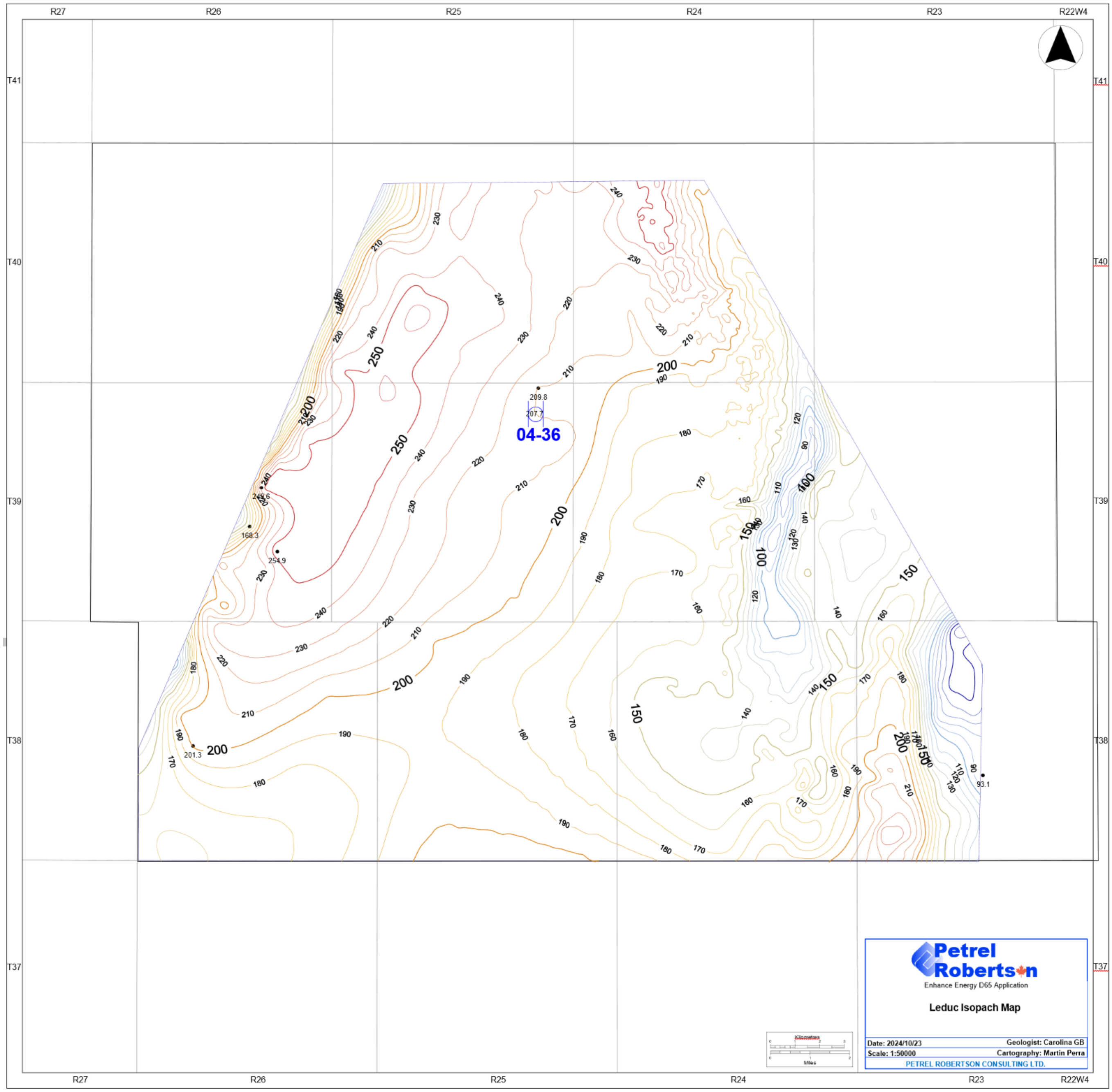


**Figure 12: Isopach map Leduc Formation, Origins Project Target Area. 04-36 well location is highlighted. Contour interval 10 m.**

### 2.2.3 Stratigraphic Analysis – Ireton Formation Caprock (Confinement Strata)

Basin-filling shales of the Ireton Formation surrounded and eventually covered Leduc Formation reefal buildups in the Western Canadian Sedimentary Basin (Stoakes, 1980). Ireton shales are recognized as a regional aquitard and are the primary seal for oil and gas pools hosted in Leduc Formation reefal buildups. At the Bashaw reef complex, Hearn et al (2011) recognized the Ireton aquitard as the principal control to cross-formational fluid flow between reservoir strata in the Leduc Formation below and the Nisku Formation above (**Figure 13**).

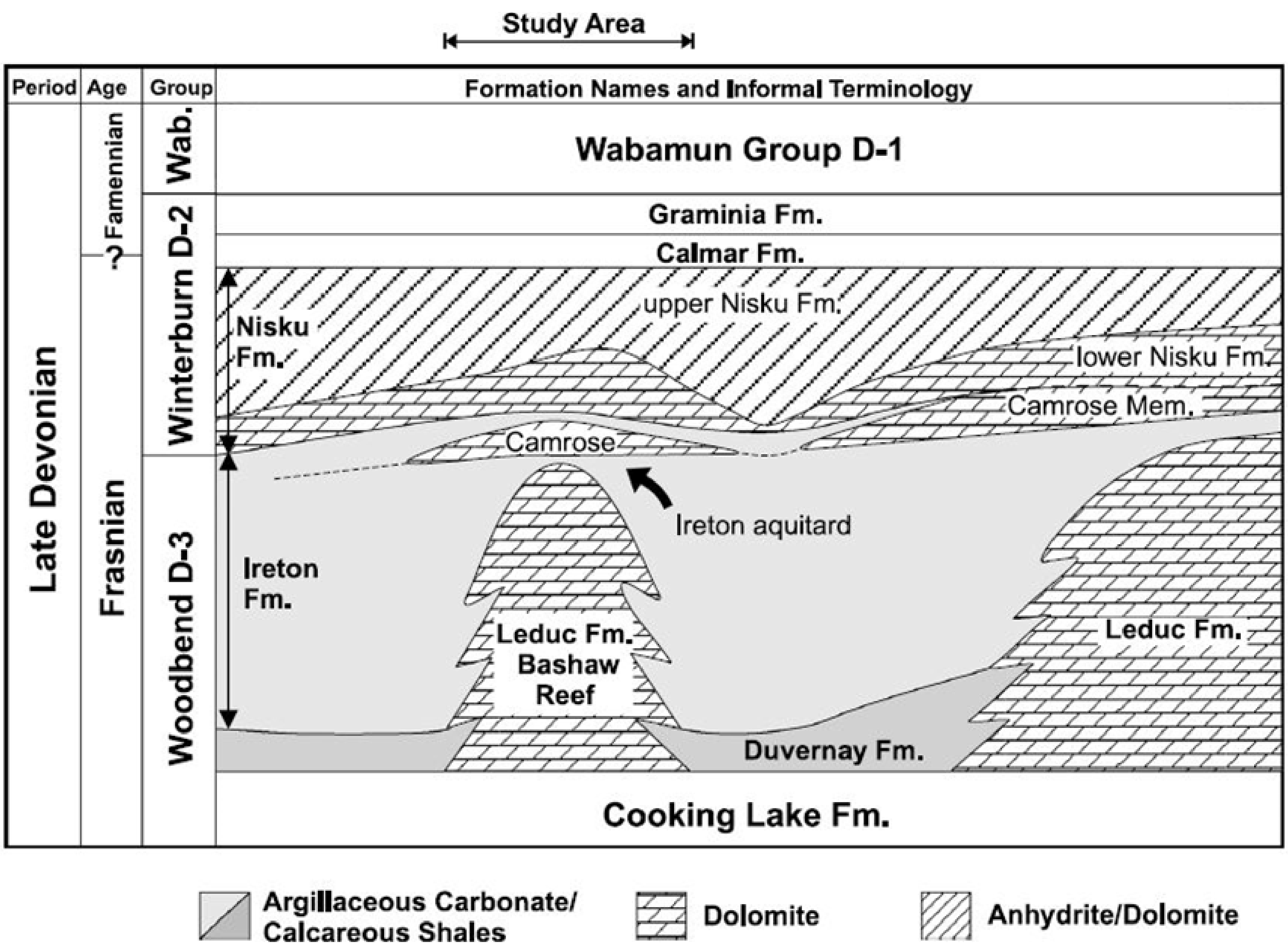


**Figure 13: Schematic lithostratigraphic cross-section of Upper Devonian strata in east-central Alberta, highlighting Ireton aquitard separating the Leduc and Nisku / Camrose reservoirs (from Hearn et al, 2011).**

Core analysis data through the Ireton across the Bashaw reef complex confirms its shale-dominated character. Gilhooly logged a complete (~9 m thick) Ireton shale section at Ember Clive 16-26-39-24W4, approximately 10 km east of the Enhance 04-36 injection well, identifying primarily lower foreslope to foreslope facies with poor porosity described in the top few meters otherwise confirming the Ireton section as an effective caprock (Attachment 9: Cross section A-A').

Characterizing the Ireton aquitard in detail, particularly its continuity and integrity as an effective fluid barrier in the Bashaw reef complex area, is made more challenging by the variable presence of the Camrose Member. Stoakes (in Glass, 1990) defined the Camrose as:

> "a sequence of bedded, tabular stromatoporoid framestones with abundant corals, Amphipora floatstones with a dark bituminous carbonate matrix and occasionally sedimentary breccias interbedded with a light micritic carbonate. ...When traced onto the Bashaw reef complex it becomes too difficult to separate from carbonates of the underlying Leduc and overlying Nisku."

The Camrose Member proper is difficult to correlate consistently on a regional basis, but calcareous shales and marls in the middle of the Ireton produce distinctive log signatures that can be correlated with confidence in many places, particularly in wells with modern log suites. Attachment 9: Cross section A-A' illustrates the correlations:

- The mid-Ireton interval of marls and calcareous shales can be correlated with confidence in 12-30-39-24W4 and westward and within that interval we have correlated a Camrose Member clean carbonate. Above the calcareous interval we see clay-dominated shales of the upper Ireton, and a similar lower Ireton shale interval below
- Between 12-30-39-24W4 and 10-29-39-24W4, which are 2.5 km apart, the upper Ireton interval pinches out, and the calcareous mid-Ireton interval, including the clean Camrose carbonate, changes facies to thicker, clean Camrose carbonates that merge with overlying Nisku carbonates, as noted by Stoakes. This relationship is shown schematically in Figure 13.

Enhance mapped the Ireton Formation and Camrose Member in the Origins Project Target Area, based on correlations illustrated in **Attachment 9: Cross section A-A'**. The Ireton Formation total isopach map shows the Ireton confinement interval to be >15 m thick in the vicinity of the Enhance 4-36 well and the Ireton remains >4 m thick throughout the Origins Project Target Area, above the threshold for hydraulic isolation as established by Hearn et al., 2011.

### IRETON FORMATION CONFINEMENT PARAMETER SUMMARY

- Structure: Regional southwesterly dip at 6 m/km (Figure 14)
- Thickness: Generally, 15-20 metres in the Origins Project Target Area, but locally thinned by relationship with Camrose Member (Figure 15)
- Porosity: Low ineffective porosity in shales; isolated 2-7% porosity in Camrose Member
- Permeability: Very low in shales; isolated 1-60 mD in Camrose Member
- Continuity: Continuous throughout the Origins Project Target Area; thickness varies with variable development of Camrose Member.

Additional analysis of secondary confinement strata of the Calmar and Stettler Formations is included in section Geological Caprock Assessment.

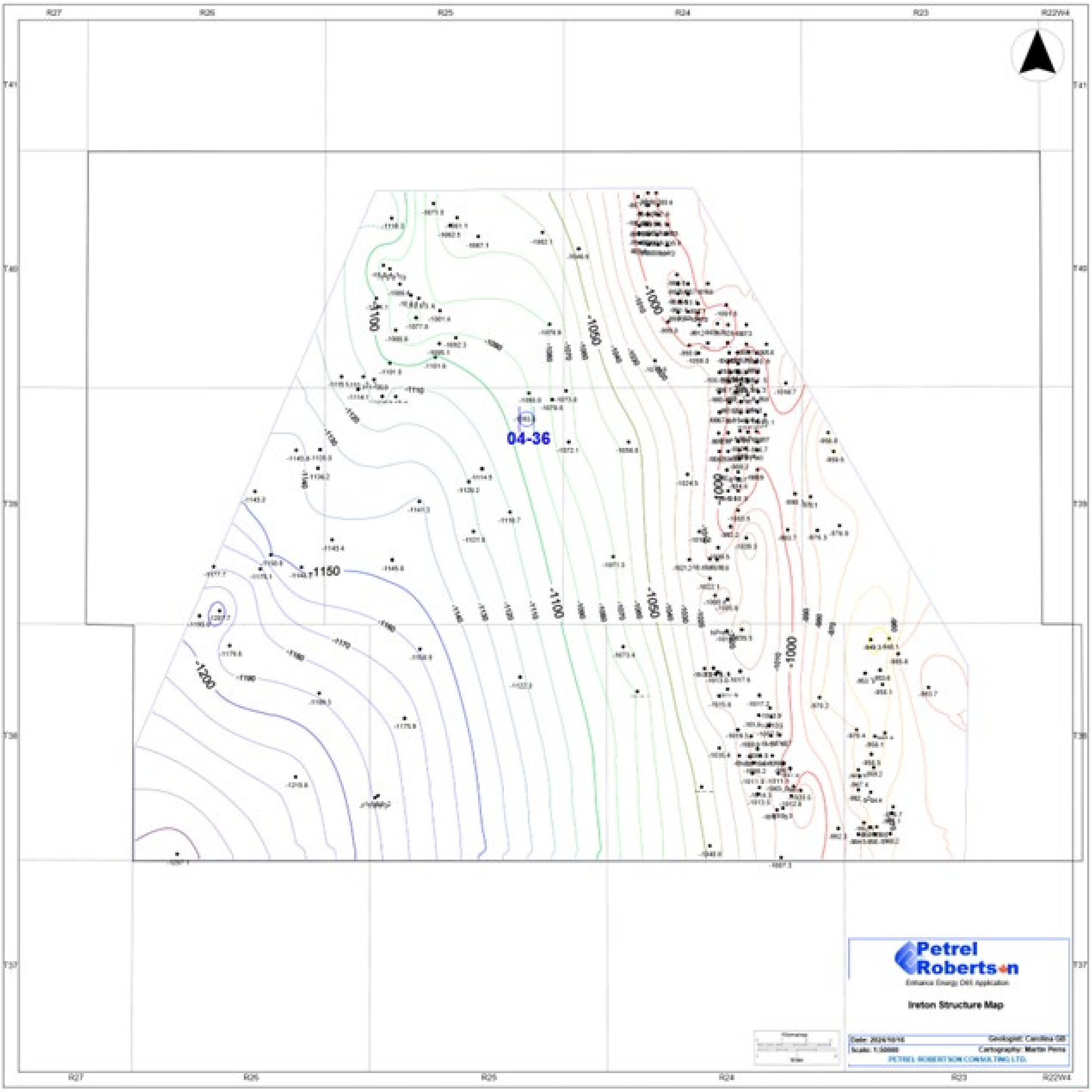


**Figure 14: Structure map, top Ireton Formation, Origins Project Target Area. 04-36 well location is highlighted. Contour interval 10 m.**

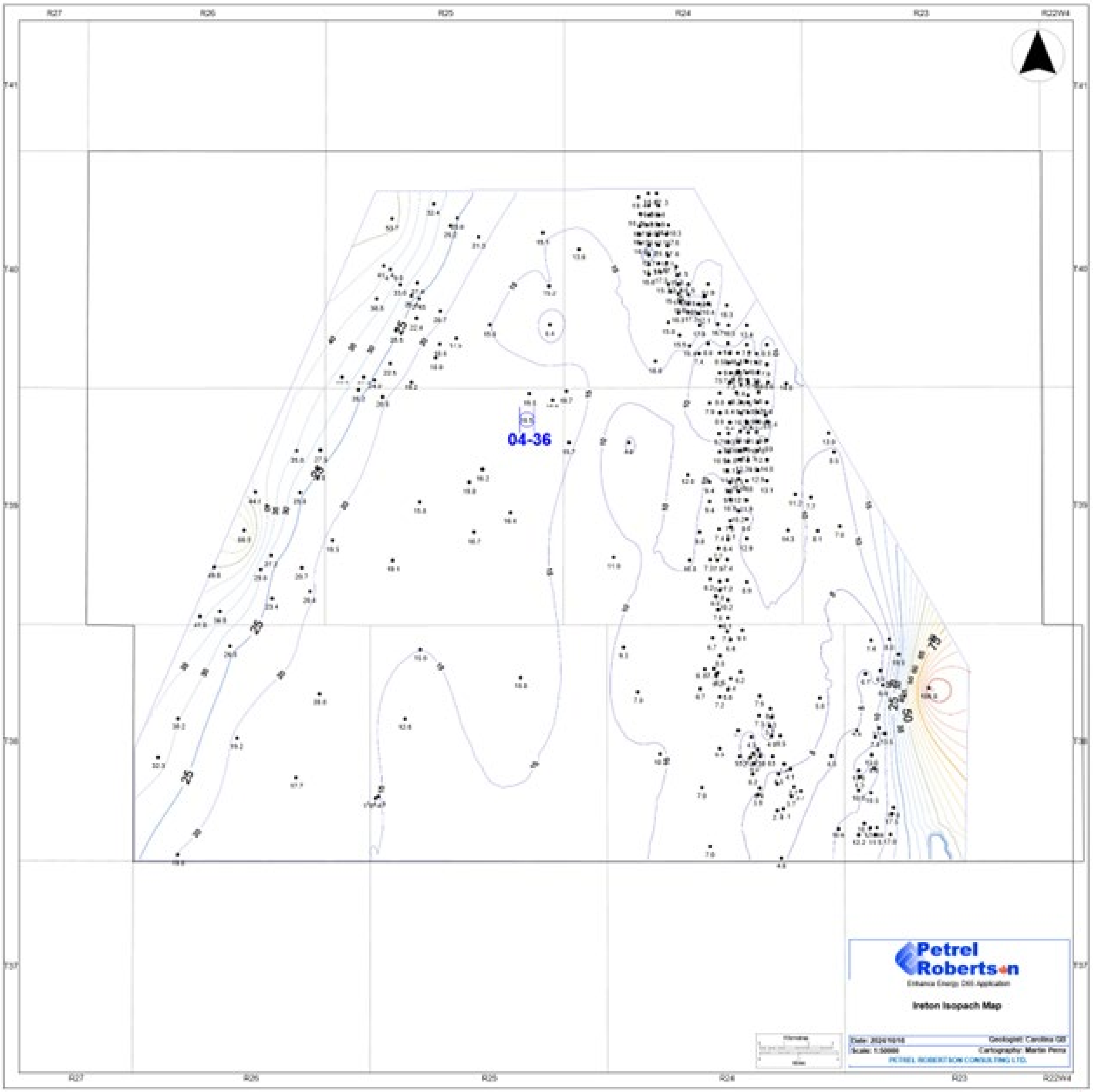


**Figure 15: Isopach map Ireton Formation, Origins Project Target Area, 04-36 well location is highlighted. Contour interval 5 m.**

## 2.2.4 Geological Caprock Assessment

Reservoir and caprock components of the Origins Project overlain on the Upper Devonian stratigraphic succession are illustrated in Figure 16. The Leduc disposal reservoir is capped by the Ireton shale, which is designated as the primary caprock; the Ireton includes in places carbonate-rich strata of the Camrose Member. Regional secondary seals for the Project occur in thin continuous shales of the Calmar Formation, and in evaporitic strata of the overlying Stettler Formation. The Graminia and Blue Ridge members cannot be mapped with confidence in the study area.

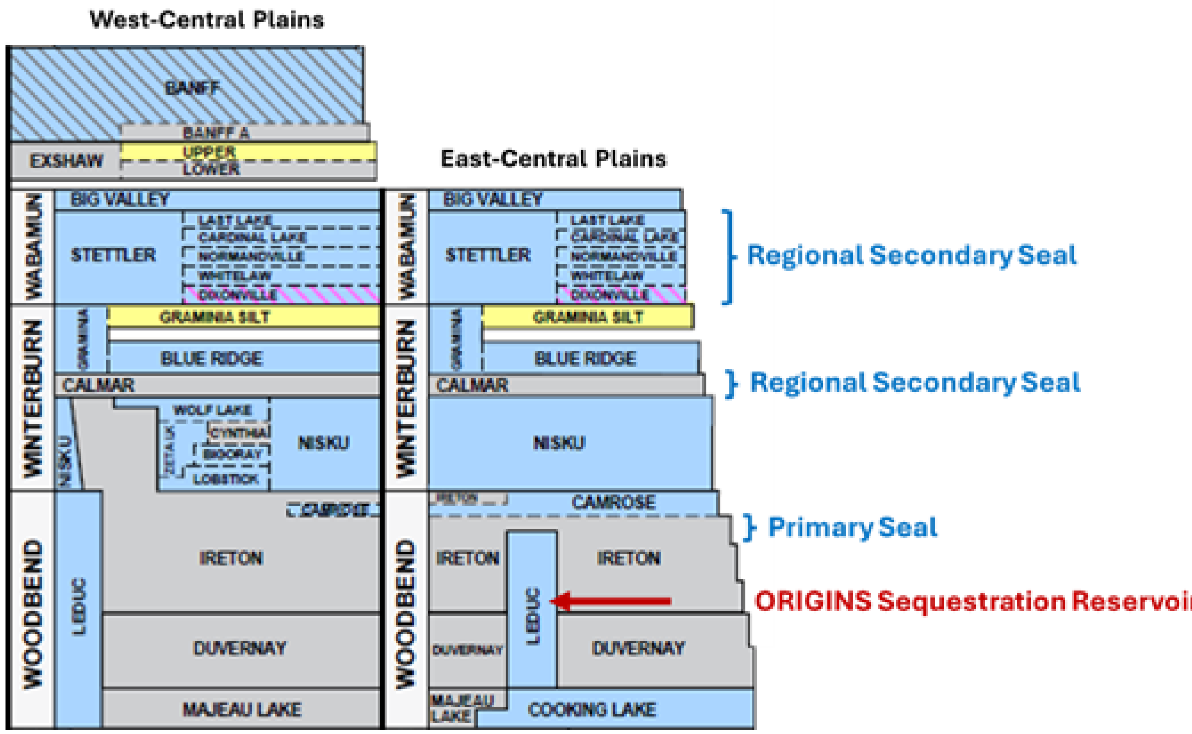


**Figure 16: Stratigraphic column, Upper Devonian strata of central Alberta. The east-central Plains column best represents the Bashaw area, but Mississippian Exshaw and Banff Formations occur over part of the study area (after Alberta Geological Survey, 2019).**

Regional settings of the Leduc Formation disposal zone and Ireton Formation caprock / confinement strata were presented in the Geology section, and so these units are only briefly summarized below. This section focuses on the lower bounding unit (Cooking Lake Formation) and regional secondary seals of the Calmar and Stettler Formations.

## Stratigraphic Analysis – Leduc Formation Reservoir

The Leduc Formation was mapped using all available penetrations (~1400) across the Bashaw reef complex. Tops were correlated based on a grid of regional stratigraphic cross-sections, which included as many deep (Cooking Lake Formation) penetrations as possible. However, only about 65 wells fully penetrate the Leduc allowing the underlying Cooking Lake to be picked, with many of these near the platform edges where the lateral extent of the buildup was tested in exploratory wells.

Most Leduc wells penetrate only the upper 25-50 metres of the Leduc to test oil pay, limiting understanding of Leduc thickness and facies architecture below this level. The upper 25-50 metres of the Leduc has been cored extensively across the Bashaw reef complex, although almost all cores are concentrated within producing oil pools, particularly at Clive. Total Leduc thickness ranges up to about 230 metres across the Bashaw reef complex.

### Leduc Formation Reservoir Parameter Summary

- Structure: Regional southwesterly dip at 6 m/km in the Origins Project Target Area (Figure 11)

- Thickness: >200 metres in the Origins Project Target Area (Figure 12)
- Porosity: Average Porosity 6-7 %
- Permeability: up to hundreds of millidarcies
- Reservoir continuity: Excellent lateral continuity of reservoir facies, enhanced by pervasive dolomitization

### STRATIGRAPHIC ANALYSIS – IRETON FORMATION CAPROCK (CONFINEMENT STRATA)

Ireton shales are recognized as a regional aquitard and are considered to be the primary seal for oil and gas pools hosted in Leduc Formation reefal buildups. At the Bashaw reef complex, Hearn et al (2011) recognized the Ireton aquitard as the principal control to cross-formational fluid flow between reservoir strata in the Leduc Formation below and the Nisku Formation above.

Core analysis data through the Ireton across the Bashaw reef complex confirms its shale-dominated character. Gilhooly logged a complete (~9 m thick) Ireton shale section at Ember Clive 16-26-39-24W4, approximately 10 km east of the Enhance 04-36 injection well, identifying primarily lower foreslope to foreslope facies with poor porosity described in the top few meters otherwise confirming the Ireton section as an effective caprock (Attachment 9: Cross section A-A').

Enhance mapped the Ireton Formation and Camrose Member in the Origins Project Target Area, based on correlations illustrated in Attachment 9: Cross section A-A'. The Ireton Formation total isopach map shows the Ireton confinement interval to be >15 m thick in the vicinity of the Enhance 04-36 disposal well. Where the Ireton is thinner, as at 10-29-39-25W4 and 10-12-40-25W4, the upper Ireton has pinched out and the Ireton isopach represents only the lower Ireton.
Even considering these thin locations, the Ireton remains >4 m thick throughout the Origins Project Target Area, above the threshold for potential breaching established by Hearn et al., 2011.

**Ireton Formation Confinement Parameter Summary**

- Structure: Regional southwesterly dip at 6 m/km (Figure 14)
- Thickness: Generally, 15-20 metres in the Origins Project Target Area, but locally thinned by relationship with Camrose Member (Figure 15)
- Porosity: Low ineffective porosity in shales; isolated 2-7% porosity in Camrose Member
- Permeability: Very low in shales; isolated 1-60 mD in Camrose Member
- Continuity: Continuous throughout the Origins Project Target Area; thickness varies with variable development of Camrose Member.

### LOWER BOUNDING FORMATION – COOKING LAKE FORMATION

The Leduc Formation disposal zone reservoir at Bashaw was built on the widespread Cooking Lake Formation carbonate platform, described by Switzer et al. (1994):

> "An extensive carbonate shelf developed in the east over southern Alberta, Saskatchewan and Manitoba, where underlying Beaverhill Lake sediments had reached a suitable bathymetry for subsequent prolific carbonate production. The strata of this broad eastern shelf vary in thickness between 65 and 75 m, thinning eastward to 30 m in southwestern Manitoba. The Cooking Lake carbonates consist of peloidal and skeletal limestone

(brachiopods, crinoids, stromatoporoids, bryozoans). Unlike the majority of the younger Woodbend carbonates within the eastern shelf area, the Cooking Lake interval is relatively undolomitized."

The top of the Cooking Lake is abruptly terminated and capped regionally by a submarine hardground surface. Carbonate shoal development within the upper Cooking Lake was important in localizing subsequent Leduc reef growth, as at Bashaw.

The Leduc / Cooking Lake contact has not been documented in detail in the Bashaw Platform area, as it is penetrated by relatively few wells and has not been a target for core acquisition. It is challenging to correlate, as logs show no distinctive markers to separate similar undolomitized carbonate platform facies above and below (Attachment 9: Cross section A-A').

The base Leduc / top Cooking Lake therefore does not appear to represent a significant bounding or containment surface that would significantly impede the movement of fluids. However, given the massive volume of the Leduc disposal reservoir and the buoyancy of supercritical $CO_2$, we do not expect the Cooking Lake to play a significant role in $CO_2$ disposal in the Origins Project Target Area.

### Regional Secondary Seal – Calmar Formation

In the Bashaw Platform area, the Calmar consists of quartz siltstone, green shale and dolomite lying unconformably on the upper Nisku. It is the product of deposition in restricted marginal marine, coastal plain and fluvial-deltaic settings (Gilhooly, 1987; Potma et al., 2001). Cores across the Calmar generally reflect upper Nisku coring targets, where coring started just above the Nisku. Most cored intervals were not analyzed because of their dense appearance or returned very low values of porosity and permeability.

On logs, the Calmar is a highly distinctive shale break between carbonate and evaporite lithologies of the Nisku Formation below and Stettler Formation above (Attachment 9: Cross section A-A'). It is generally 3-4 metres thick across the Origins Project Target Area, dipping to the southwest.

PRCL concludes that Calmar Formation shales are consistently developed across the entire Bashaw Platform, including around the 04-36 sequestration location, and act as an effective regional secondary seal, isolating the Leduc storage reservoir from overlying units.

**Calmar Formation Confinement Parameter Summary**

- Structure: Regional southwesterly dip at 6 m/km (Figure 17)
- Thickness: Generally, 3-4 metres in the Origins Project Target Area (Figure 18)
- Porosity: Low ineffective porosity
- Permeability: Very low
- Continuity: Continuous throughout the Origins Project Target Area

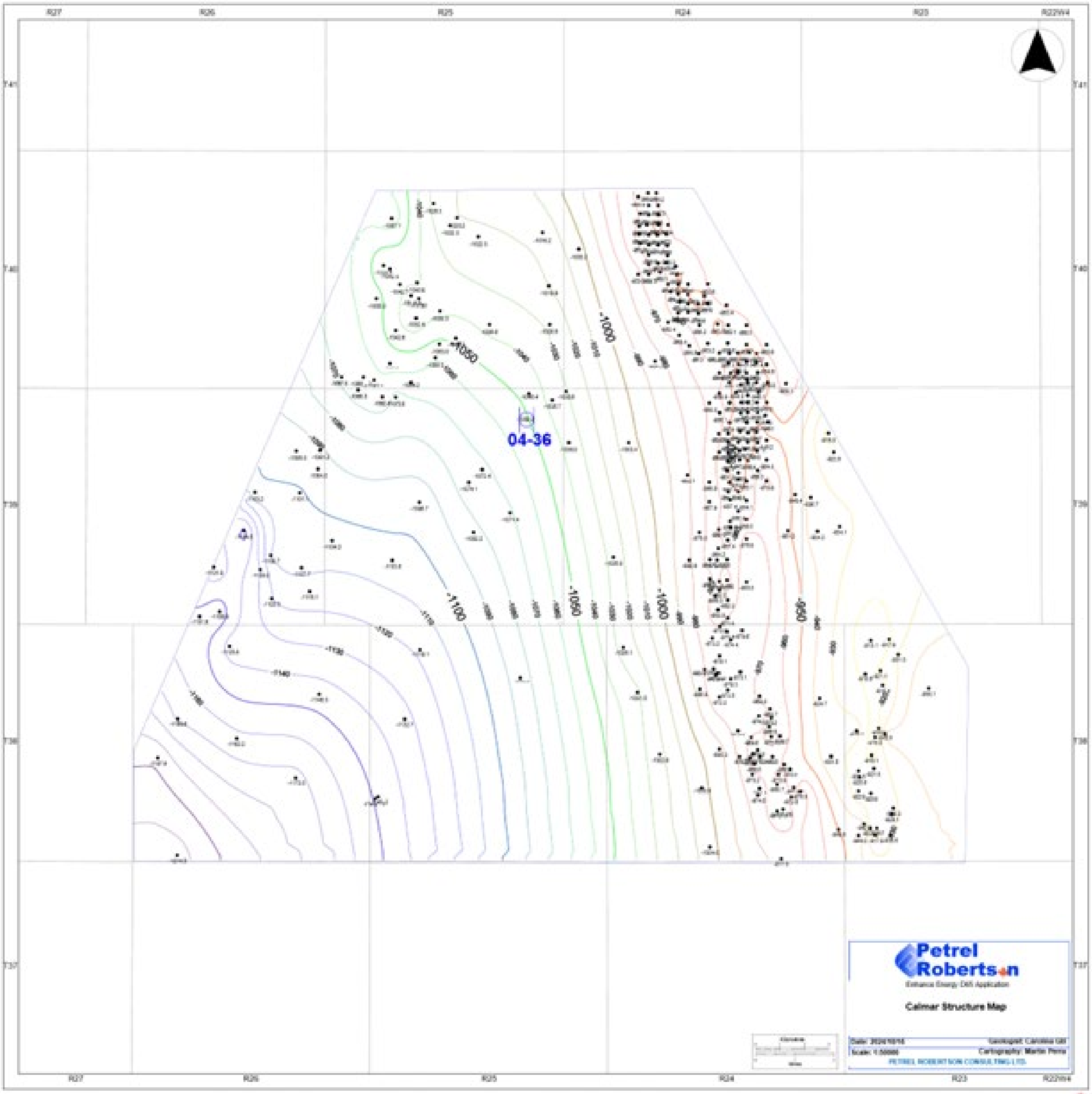


**Figure 17: Structure map, top Calmar Formation, Origins Project Target Area. 04-36 well location is highlighted. Contour interval 10 m.**

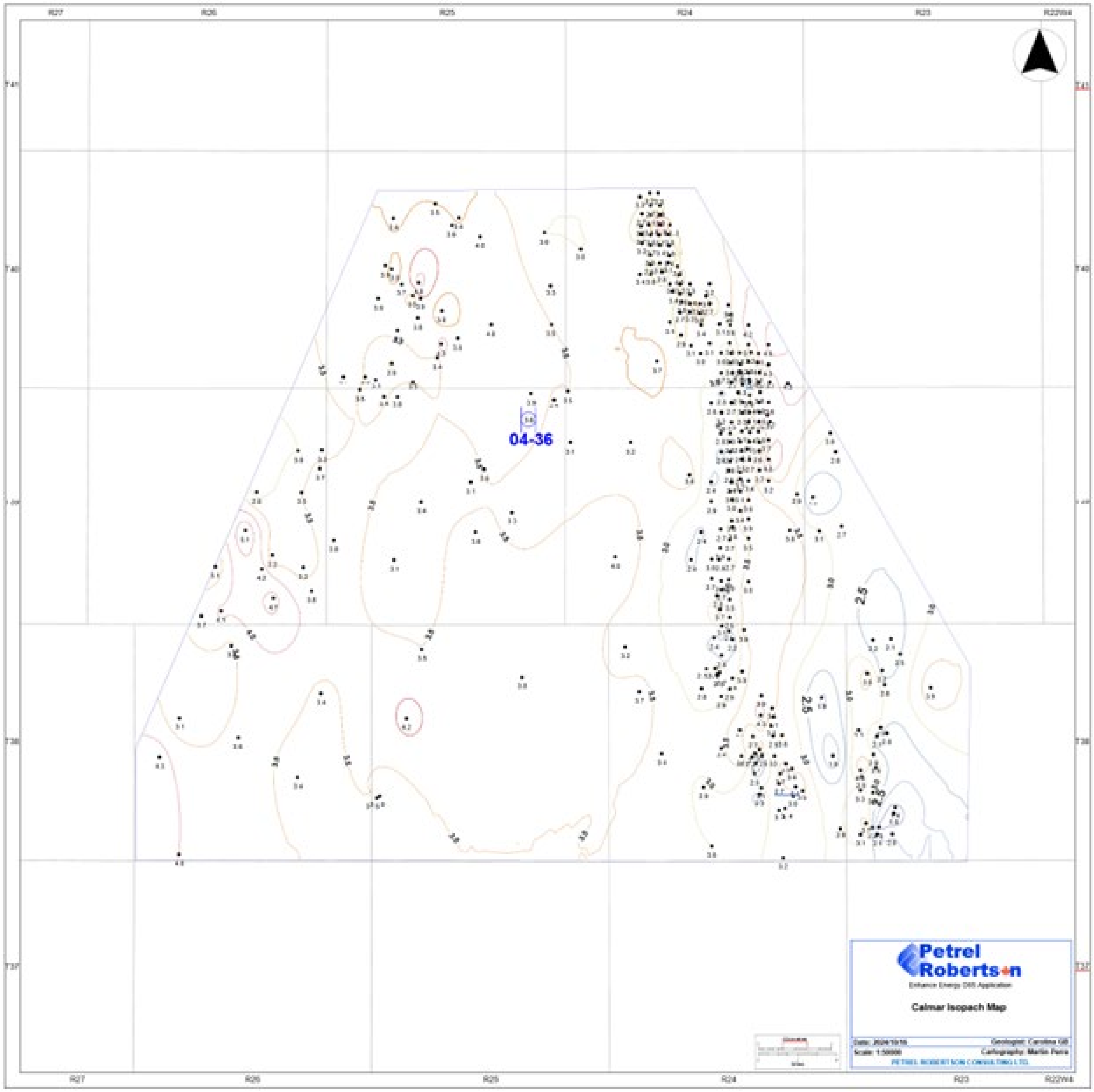


**Figure 18: Isopach map Calmar Formation, Origins Project Target Area, 04-36 well location is highlighted. Contour interval 0.5 m.**

## Regional Secondary Seal – Graminia Formation

Above the Calmar Formation, the Graminia Formation is an interval of interbedded siltstone, limestone, dolomite and shale. In the Bashaw area, Graminia strata are thin and restricted landward equivalents of type Graminia strata of central and western Alberta (Potma et al., 2001). Graminia lithologies are apparent on some wellsite drill cuttings logs and in core, but the Graminia cannot be picked as a distinct mappable unit on borehole logs across the Bashaw reef complex area. We therefore include Graminia-equivalent strata that may be present in the Bashaw reef complex area as part of the Stettler Formation.

### REGIONAL SECONDARY SEAL – STETTLER FORMATION

Above the Winterburn Group, the Stettler Formation is a succession of interbedded evaporites dominated by anhydrite and dolomite, deposited in a broad evaporitic shelf setting across southeastern Alberta (Halbertsma, 1994).

Cross-section B-B' illustrates that stratigraphic markers internal to the Stettler can be carried with reasonable certainty across the Origins Project Target Area. Continuity of stratigraphic markers is disrupted in places where stratigraphic intervals (generally 10-30 metres thick) are lost from one well to the next; as illustrated by pink-shaded sections on Attachment 10: Cross section B-B' . Such abrupt changes are consistent with salt solution, an example of which has been documented by Oliver and Cowper (1983) at Rumsey (Twp 33-19W4, just east of Bashaw). They interpreted salt solution to have occurred during Late Cretaceous time (around Second White Specks time), resulting in thicker Cretaceous shales being deposited to fill the new accommodation space. They were unable to relate location of the solution to specific features such as basement topography, pre-Ireton reef buildups or faulting.

Halbertsma (1994) stated Big Valley Formation limestones 10-30m thick form the upper part of the Wabamun Group regionally (Figure 19), but the Big Valley cannot be mapped consistently in the Bashaw Platform area. Drill cuttings descriptions show dolomites at the top of the Wabamun in some wells instead of limestones, suggesting that stratigraphy is more complex than we appreciate. It is particularly difficult to identify a Big Valley pick with confidence where the pre-Cretaceous unconformity incises, and/or where significant salt solution has occurred.

As a result, there is no unique stratigraphic marker defining the base Big Valley / top Stettler in the Bashaw Platform area. The top Stettler therefore was picked as the uppermost continuous anhydrite-cemented unit within the Wabamun (Attachment 10: Cross section B-B' ). It is not stratigraphically consistent across the area, and generally cuts down-section to the northeast. Solution of evaporitic minerals, both at the top and internally to the Stettler has clearly influenced the top continuous anhydrite pick. The overlying interval, referenced as Upper Wabamun, is not the Big Valley Formation as formally described but instead includes both the Big Valley (where present) and post-solution remnants of the upper Stettler.


Figure 19: Leduc depth (TVD) within the $CO_2$ plume max radius.

**Post-Wabamun Erosion and Wabamun / Stettler Mapping**

Over much of southern Bashaw Platform study area, the Wabamun / Stettler is capped by the Exshaw Shale and lower Banff shaly carbonates with an unconformable but low-relief contact (Cross-section B-B'). The Stettler is 190-210 metres thick near the Enhance 04-36 disposal well but is incised by a regional pre-Cretaceous valley to the east (Cross-section B-B' and Figure 18). Even at its thinnest, however, the Stettler is still more than 100 metres thick and consists primarily of impermeable evaporites.
Salt solution within the Stettler is evident between some wells, as shown on Cross-section B-B'. While most clearly associated with pre-Cretaceous valley incision, it has been noted elsewhere across the Bashaw Platform. We have noted no evidence linking salt solution to underlying features in the basement or pre-Wabamun strata, but it is clear that substantial fluid volumes have accessed the Stettler stratigraphic section in order to dissolve and remove salt volumes. The large remaining sections of tight evaporitic strata still offer a secure regional secondary seal.

**Stettler Formation Confinement Parameter Summary**

- Structure: Regional southwesterly dip at 6 m/km (Figure 20)
- Thickness: >200 metres except where incised by pre-Cretaceous valleys (Figure 21)
- Porosity: Locally >10% in dolomite beds; virtually zero in evaporites
- Permeability: Up to tens of millidarcies in dolomite beds; virtually zero in evaporites
- Continuity: Continuous throughout the Origins Project Target Area; erosional relief at top

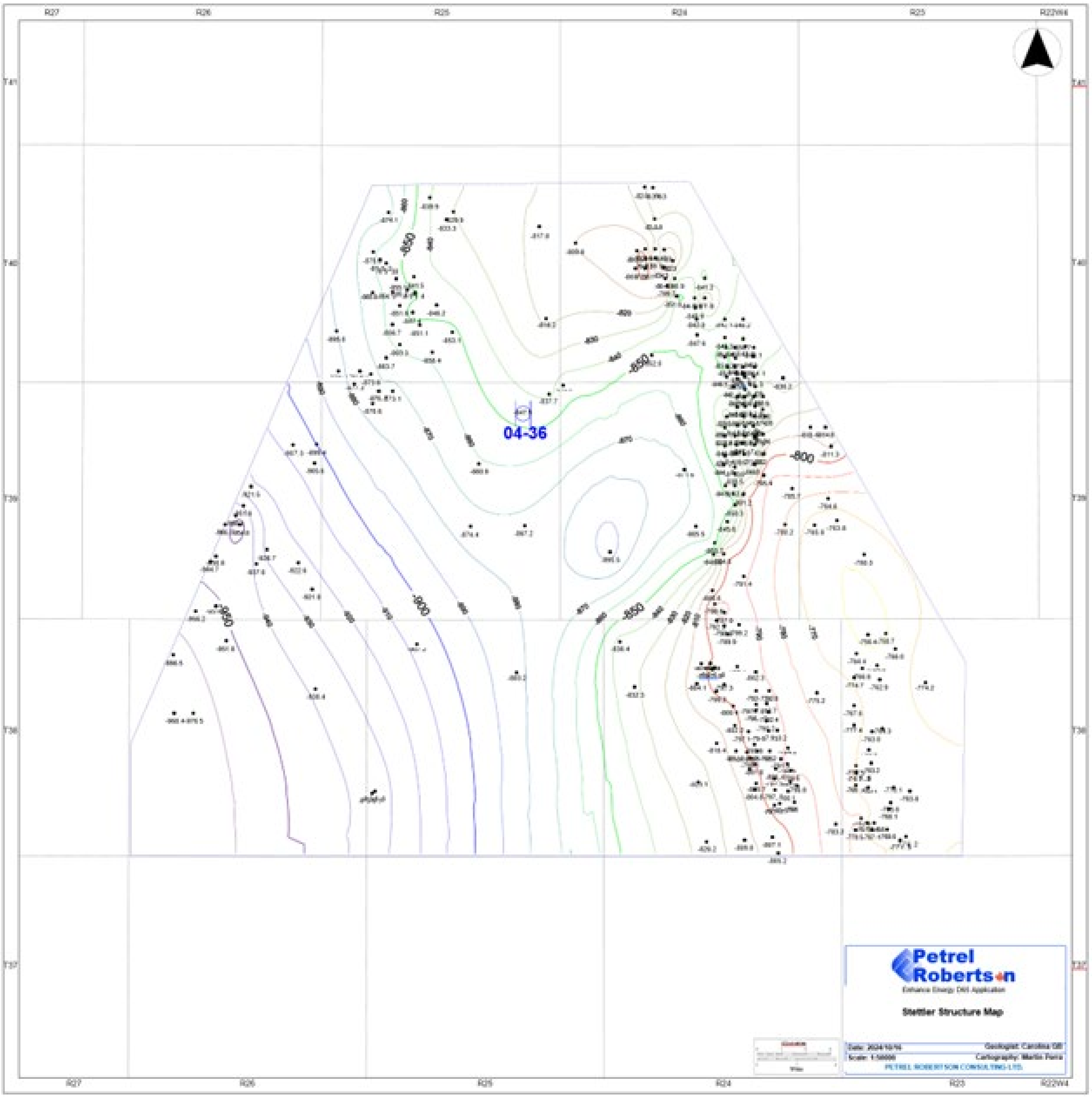


**Figure 20: Structure map, top Stettler Formation, Origins Project Target Area. 04-36 well location is highlighted. Contour interval 10 m.**


**Figure 21: Isopach map Stettler Formation, Origins Project Target Area, 04-36 well location is highlighted. Contour interval 10 m.**

## 2.3 HYDROGEOLOGY

A hydrogeology study was conducted over the study area within west-central Alberta. The objective of the study was to evaluate the hydraulic relationship between the Woodbends, Winterburn, Wabamun and Mannville Groups within the study area.

The hydrogeological study area covers 1,154 km$^2$ and is located within the Red Deer and Lacombe Counties, and within Townships 37-40, Ranges 23 to 27 west of the 4$^{th}$ meridian. Municipalities in the area include the City of Red Deer, Blackfalds and Lacombe all within approximately 5k. Surface water bodies include Buffalo Lake, 20km to the East, Gull Lake, 22km west and Sylvan Lake, 25km to the West (Figure 22, purple outline).

Disposal fluids must be contained to the storage complex and ensure that there is no migration to other hydrocarbon zones or water-bearing intervals. This section shows hydrogeological evidence demonstrating containment properties of the Wabamun aquitard overlying the Leduc Formation, through review for the potential for cross-formational fluid migration.

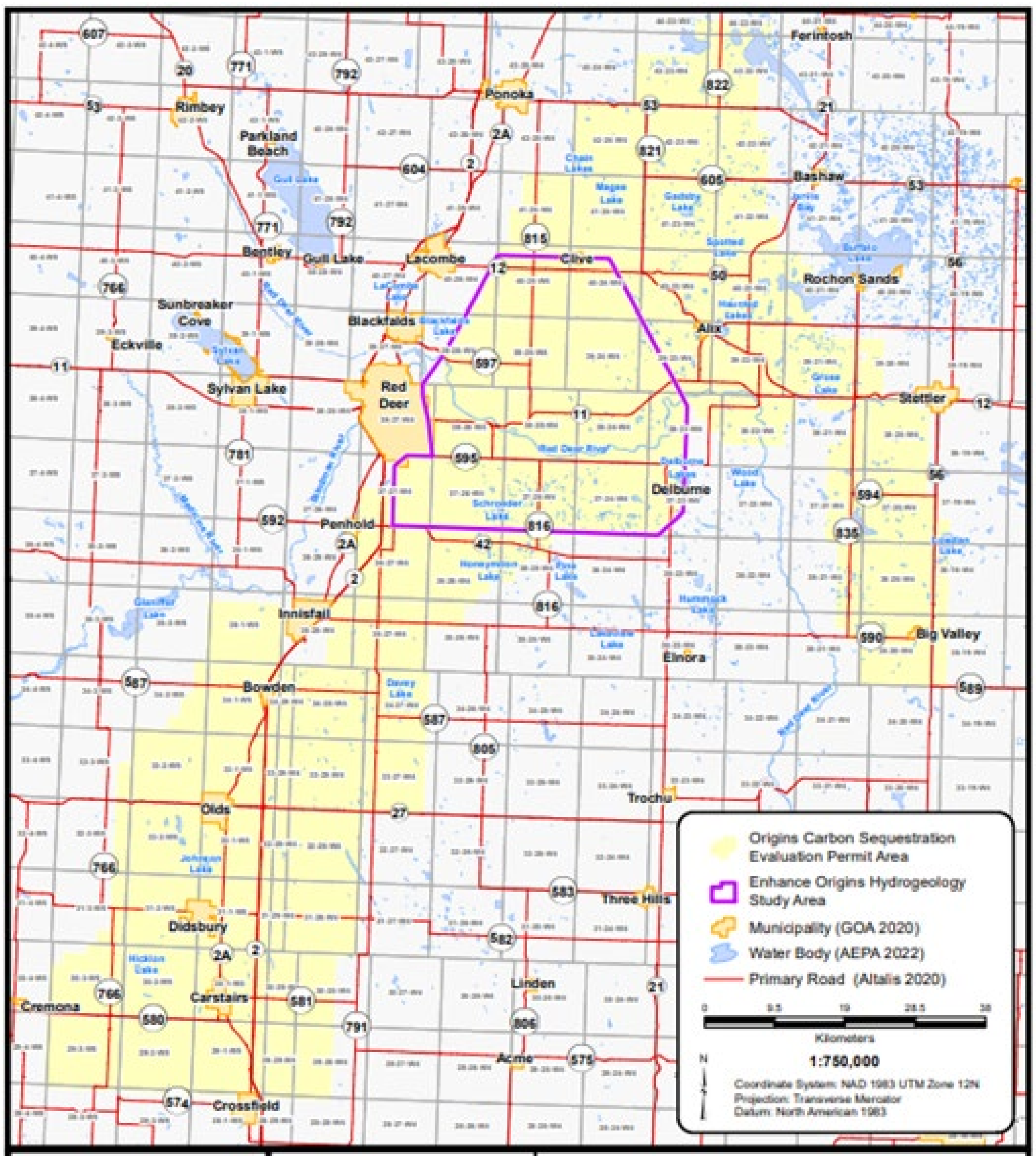


Figure 22: Origins Hydrogeology Study Area Overview Map.

The Leduc and Nisku Formation of the Upper Devonian are historically shown to be in hydraulic communication while Lower Manville Group aquifers are hydraulically isolated from the lower Leduc and Nisku Formations. The hypothesis is that these formations are hydraulically isolated based on the presence of the Wabamun Aquitard and its related containment properties. Hydraulic isolation was assessed based on a review of available Drill Stem Test (DST) records. Additionally, equivalent freshwater heads were estimated from static reservoir pressures that were interpreted from DST records. These were used to evaluate both horizontal and vertical hydraulic gradients and formation water flow within the Upper Devonian and the Manville Groups. A geochemical assessment of available water quality data evaluated the formation water quality differences, or similarities, between the two geologically distinct intervals.

Hydrocarbon production has occurred in the Origins region from a Devonian Leduc Formation reef called the Bashaw Reef Complex platform since the 1950s. The Leduc Formation is comprised of carbonate rocks. The Leduc Formation in addition to the overlain Ireton Formation shale comprises the Woodbend Group. The Woodbend Group has an elevation ranging from -970 meters subsea (mms) to -1,300 mms and dips to the west-southwest.

The Woodbend is overlain by the Nisku Formation carbonates which is overlain by the Calmar Formation, making up the Winterburn Group which ranges in elevation from -930mms to -1,270mms and dips towards the west-southwest.

The Winterburn Group is overlain by Wabamun Formation which consists of the Settler and Big Valley Formations. The Settler Formation is considered and aquitard in conjunction with the Calmar caprock (Wabamun Aquitard) for the Origins project. The Wabamun ranges in elevation from -750 mss to -1060 mss from east to southwest portion of the study area, respectively. The Wabamun Group is overlain by the Manville Group which is comprised of clastic rocks and represents the closest aquifer.

Freshwater hydraulic head of the Woodbend Group ranges from 530m above sea level (m asl) to 995 m asl. It is hypothesized that the low pressures and corresponding hydraulic heads in the Woodbend are due to historical production in the region. Winterburn Group equivalent freshwater head ranges between 650m asl to over 920m asl. Pressure and hydraulic heads are again likely due to production activities in the area. Historical records show limited production in the Wabamun Group between 1982 and 2004. Hydraulic head distributions show a general gradient towards the southwest. The equivalent freshwater hydraulic head ranges from 975m asl in the northeast to 790m asl in the southwest of the study area. The interpreted lateral flow direction is not uniform throughout the entire Study Area. The hydraulic head of the Mannville is at its lowest in the center of the Study Area. The hydraulic head is highest in the northern part of the study area. Pressure vs. depth plots for the Manville Group, when compared to other groups, suggest that it is under pressure. Documented pressures consistently fall below the hydraulic gradient line compared to other formations, where the pressures are relatively consistent with that gradient. This supports the conclusion that the Mannville is not in hydraulic communication with the deeper Devonian Formations.

Water samples are analyzed for all the major ions including sodium, potassium, calcium, magnesium, chloride, sulfate, and bicarbonate + carbonate. Variations and patterns in formation water chemistry and TDS patterns are useful in identifying anomalous conditions or contaminated water samples. Additionally, these observations aid in understanding the chemical evolution and flow paths within and between regional flow systems. Natural waters from this region of Alberta, and the depths involved, tend to have a hydrochemistry consistent with more evolved, older water types. For all wells assessed the dominant cation was sodium (Na), followed by varying amounts of calcium (Ca) and magnesium (Mg) depending on the interval. The dominant anion was chloride (Cl), as expected. The high mineralization value noted for the Woodbend and Winterburn Group samples, compared to Mannville and Wabamun Group samples, is consistent with the expected trend for deeper formation water deposits having higher TDS values. Closer review of the Extended Durov Plot (EDP) suggests that there are two clusters of water types, primarily based on cation distribution. The Winterburn and Woodbend waters plot closely together with sodium and potassium ranging from 30 to 40%. The

Mannville Group samples, on the other hand, display sodium and potassium contents of approximately 15 to 20%. As for calcium ranges, the Woodbend samples range from 20 to 35% of the major cation distribution, and from 14 to 32% in the Winterburn Group. As for the Mannville Group, the influence of calcium on the major cation distribution is lower at 6 to 15%. The Mannville Group TDS values plot closely together and have a geomean of approximately 91,000 mg/L, while the Woodbend (TDS 203,986 mg/L) and Winterburn (156,120 mg/L) yield significantly higher values. This supports the conclusion of hydraulic isolation and lack of cross-formational flow between the two intervals.

The Origins Hydrogeological Study evaluated the potential for cross-formational fluid migration and containment properties of the Wabamun Aquitard overlying the Nisku/Leduc units. This was accomplished by assessing the hydraulic relationships between the Woodbend, Winterburn, Wabamun, and Mannville Groups within the Study Area, The Woodbend and Winterburn Groups appear to be in hydraulically isolated from the Manville Group by the Wabamun aquitard, which prevents cross-formational fluid flow. Major ion chemistry suggests two groupings of formation water type. The Winterburn and Woodbend have similar formation water chemistry given that the two groups are believed to be in hydraulic communication. The formation water of the Manville Group has distinct chemistry difference with lower sodium, potassium, calcium and total dissolved solids (TDS), supporting the conclusion that the Manville Group is isolated from the underlaying Woodbend and Winterburn Groups.

## 2.4 Geomechanical Analysis

Enhance engaged RESPEC to conduct a geomechanical study of the Leduc and bounding Formations which was completed between April 2024 and October 2024. The key findings are summarized below:

**Analog assessment:**

The azimuth of maximum horizontal stress for the Wabamun down through the Leduc is 45 degrees northeast or 225 degrees southwest. This stress azimuth is in general agreement with existing data for the Devonian in the public domain in Central Alberta.

While minimum horizontal stress magnitude was not directly measured at Origins, the ratio between minimum and maximum horizontal stresses was constrained for each stress tensor through an iterative poroelastic strain modeling approach. The lower horizontal stress magnitudes at Origins are thought to be due, at least in part, to the under-pressured fluid gradient observed in the Leduc.

**Tensile stress risk:**

The proposed $CO_2$ injection stream will arrive at wellhead at approximately 5 degC at the coldest. This cold $CO_2$ will arrive at the injector perforations at approximately 17 degC. This represents the most conservative scenario based on observed seasonal delivery temperature variations, assumed injection rate and pressure, and wellbore hydraulics. Injecting this cold fluid will cool the reservoir rock, which is at 65 degC initially before injection at the depth of the upper perforation. Cooling will reduce the stress in the rock and result in a tensile stress condition near the wellbore where cold $CO_2$ is being introduced throughout the injection period (17.5 years simulated). This tensile condition will favor cracking of the reservoir rock wherever the stress is tensile. Given the inherent heterogeneity in the rock structure, it is likely that the formation will exhibit some degree of pre-existing flaws or microcracks and thus the tensile cracking of the formation during $CO_2$ injection is highly probable.

Modeling predicts that this tensile stress region will be limited to the reservoir region near the wellbore and not present in the caprock. The tensile stress region is predicted to extend approximately 200 meters radius from the wellbore in the highest permeability layers. In the lowest permeability layers the tensile stress region is predicted to extend 10 to 20 meters away from the wellbore.

The predicted tensile stress region is also the region where plume temperatures are the coldest. Modeling suggest that this occurs where the plume temperature is less than about 25 degrees C. The cold front that defines this region grows outwards from the wellbore at a rate of about 5 to 10 meters per year. At a location 10 meters away from the edge of the cold front and tensile stress region, in a direction away from the wellbore, the minimum effective stress increases above tensile conditions. Thus, the region of the reservoir that is prone to tensile failure is limited to the cold front region and this region grows slowly outwards at a rate of several centimeters per day. In addition, stress increases rapidly from tensile conditions to compressive conditions moving away from the cold front. Under these conditions the creation of a larger “hydraulic fracture” type of fracturing event during cold injection is improbable because minimum effective stress remains well above fracture propagation conditions beyond the 25 degree C region of the plume.

In the Ireton caprock immediately overlying the Leduc injection zone stress conditions are not predicted to reach a tensile state. Avoiding the presence of cold $CO_2$ adjacent to the Ireton caprock should be a primary mitigation effort. This could be done by selectively perforating lower in the injection zone or possibly by reducing the rate of cooling by introducing warmed fluid during early time. The effectiveness of these mitigation efforts could be addressed with additional parametric modeling.

**Shear failure risk:**

The Origins sequestration zone is under-pressured and permeable. This condition results in a large shear-failure safety factor. Shear failure is not predicted anywhere in the caprock or reservoir.

**Induced seismicity risk:**

No fault displacement or significant large fractures were observed in the area. A normal faulting stress regime is predicted for the Leduc, Ireton and Nisku Formations and a transitional stress regime between normal faulting and strike-slip faulting is predicted for the Calmar through Wabamun Formations. A failure condition would require a reduction of effective normal stress on the order of several thousands of kilopascals and is not predicted to occur anywhere in the model domain at any time during the project in the base case scenario except within the cold inner core of the $CO_2$ plume within the Leduc.

**Subsidence/uplift risk:**

Some degree of subsidence is predicted above the sequestration zone. This is due to thermal contraction of the rock due to cooling. A maximum subsidence amount of 3 centimeters is predicted at the elevation of the top of the Wabamun Formation. Subsidence/uplift at the ground surface could be evaluated with additional modeling.

## 2.5 Petrophysical Analysis

Petrophysical analyses were completed by Petrel Robertson Consulting Ltd. (PRCL) using HDS-2008 software and digital (LAS format) log curves. The effective porosity and water saturation are shown in Figure 10, tracks 5 and 6 respectively. The analyses completed on 04-36 shows 100% water saturation in the porous intervals through the Leduc.

The disposal fluid will be confined to the Leduc Formation and shall not impact hydrocarbon recovery as the nearest hydrocarbon pool is the Clive Leduc D-3 A pool which is outside the modelled plume area and over 5.6 km away from the injector (Figure 23). Modeling of the pressure front indicates that negligible interference with other users of local and regional subsurface pore space, including oil and gas extraction, mineral development, disposal, geothermal activities, reservoir management is anticipated.

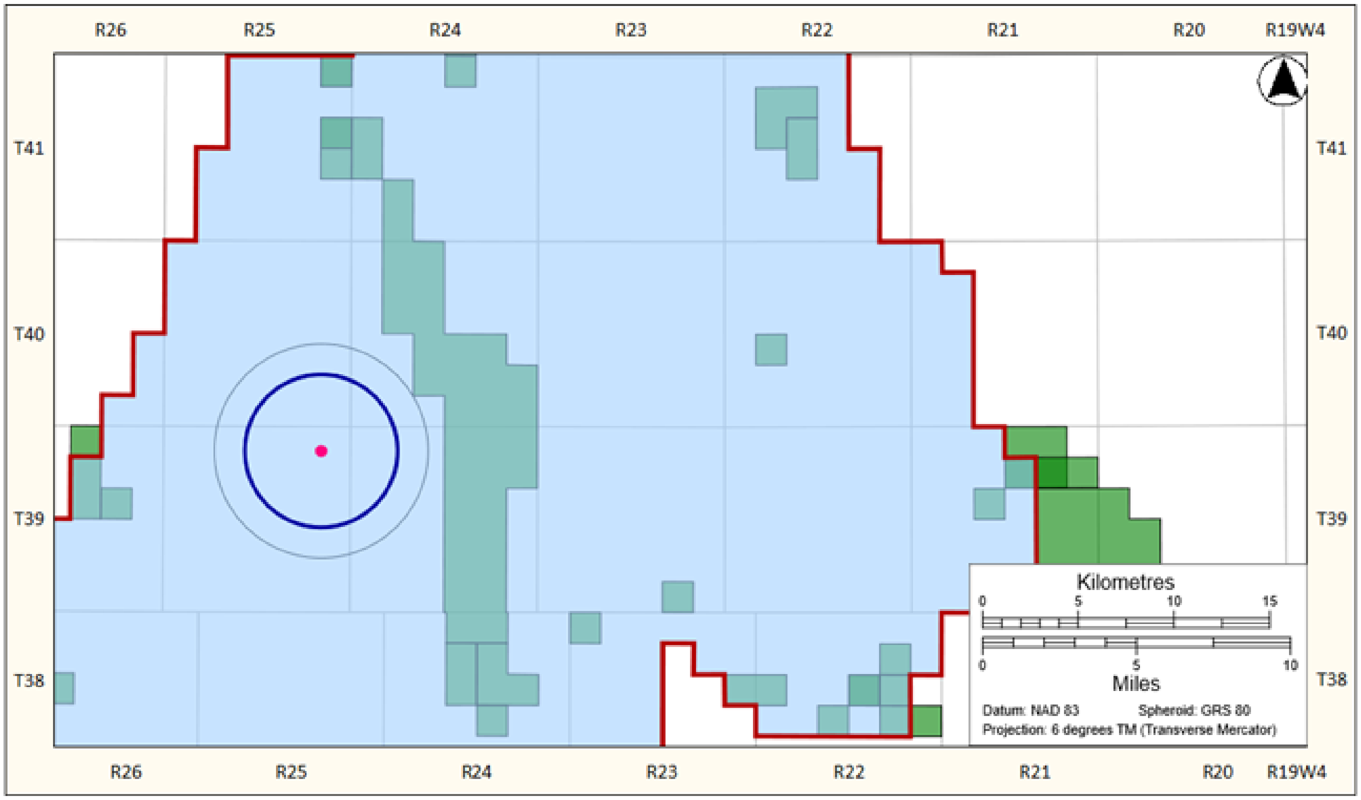


Figure 23: Hydrocarbon pools within the maximum fluid area + 1.6 km:

**Incremental Hydrocarbon Recovery & Depletion of Recipient Pool**

- No incremental hydrocarbon recovery is expected given that the Leduc zone is saturated with water within the disposal area.

**Effect Of Disposal on Ultimate HC Recovery & Producing Wells In Pool**

- No impact is anticipated on the ultimate hydrocarbon recovery since the disposal zone is completely water saturated. The plume is not predicted to encroach on any existing Leduc hydrocarbon producing pools.

**Existing Disposal Scheme(s) In Pool**

- There are no active disposal wells in the subject zone within a 5.6 km radius. $CO_2$ disposal into the water saturated Leduc Zone through the 100/04-36-039-25W4/0 well will have no impact on offset wells.

**Existing Enhanced Recovery Scheme(s) In Pool**

- The proposed project is in a water aquifer system with no hydrocarbon potential. The nearest hydrocarbon bearing pool is the Clive D-3A pool, which is 5.6 km away and is subject to a $CO_2$ EOR project operated by Enhance. Enhance is the operator and the 100% working interest owner of the Clive D-3A pool.

## 2.6 PRESSURE HISTORY

Pressure communication amongst the Leduc and Nisku pools of the Bashaw reef complex via the water leg has been documented as early as 1966 and discussed by Springer & Tsang in (CIM 83-34-24) Innisfail-Clive-Nevis Reef Chain Revisit. The hydrocarbon pools along the Clive-Nevis-Innisfail reef complex received pressure support from the Bashaw Platform Aquifer. The reservoir pressure in the Clive Leduc D-3 A pool (the closest hydrocarbon pool) declined from 1962 to 1983 due to an efflux of fluids from the reef complex caused by decades of oil and gas production which resulted in the withdrawal of approximately 1.7 trillion cubic feet of gas and over 300 million barrels of oil from the platform, resulting in a reservoir pressure decline of 25% below discovery pressures. Production volumes on the platform dropped after 1980, reducing the pressure decline rate in the surrounding Devonian reservoirs.

Figure 24 shows a subset of Clive's pressure history since 2014 with a datum depth adjusted Origins 4-36 Pressure. For reference, the Origins 04-36 pressure is on the same trend as the Clive D-3A pool demonstrating their connection via the greater Bashaw reef complex.

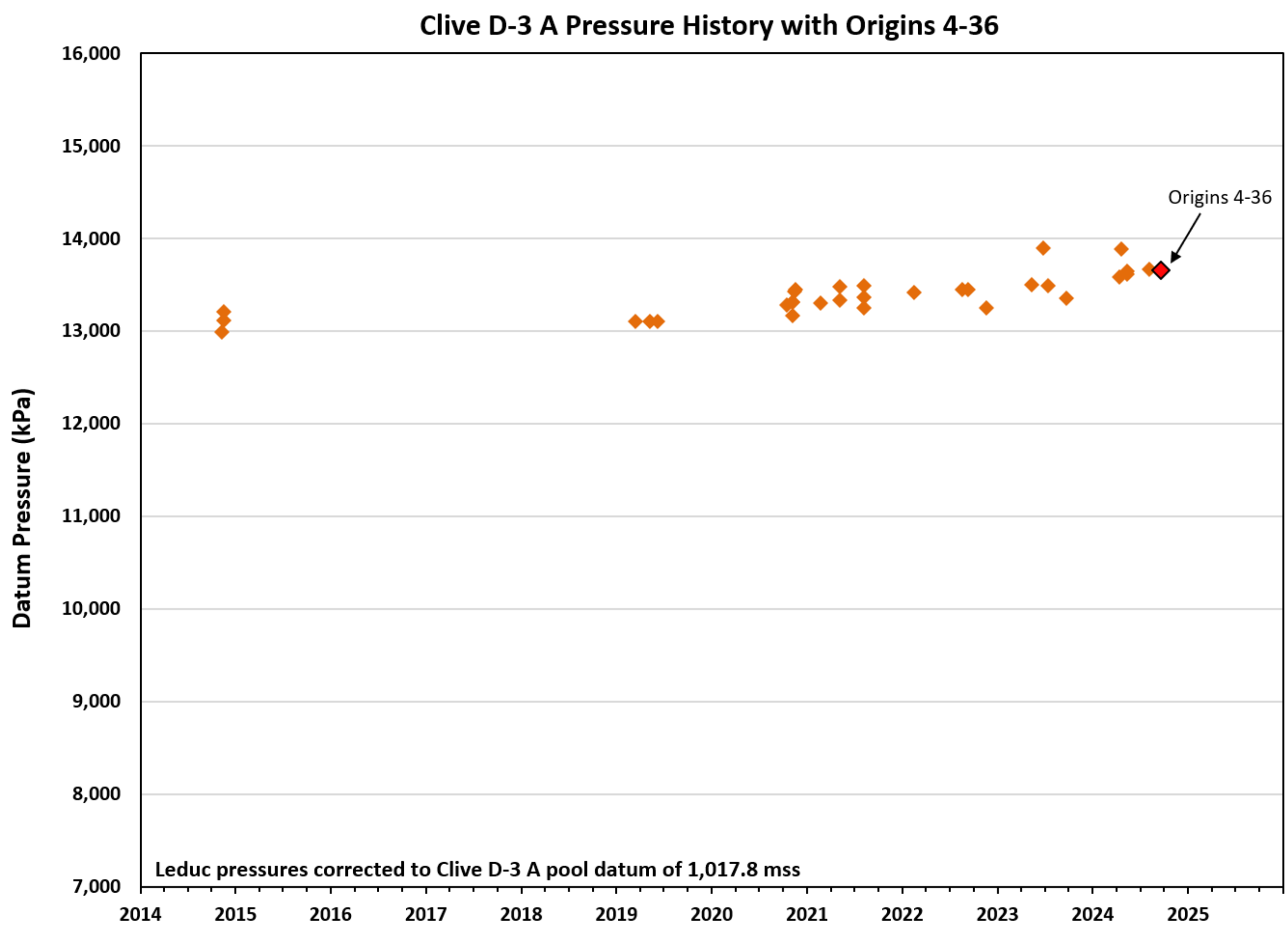


Figure 24: Clive Pressure History with Datum Depth adjusted Origins 4-36 Pressure.

A chronological pressure history for pools in the Woodbend Group can be seen in Figure 25. Figure 25 presents the pressure versus depth of the recorded DST pressures. The DST pressures recorded in the 1950's through the 1960's primarily plot above the hydrostatic gradient line. DST pressures recorded in the 1970's and 1980's primarily plot below the hydrostatic gradient. This change over time further supports an influence from production activities in this interval. This demonstrates the common pressure connection amongst the Woodbend Group pools in the greater Bashaw reef complex. All the pools follow the same pressure history trends over time.

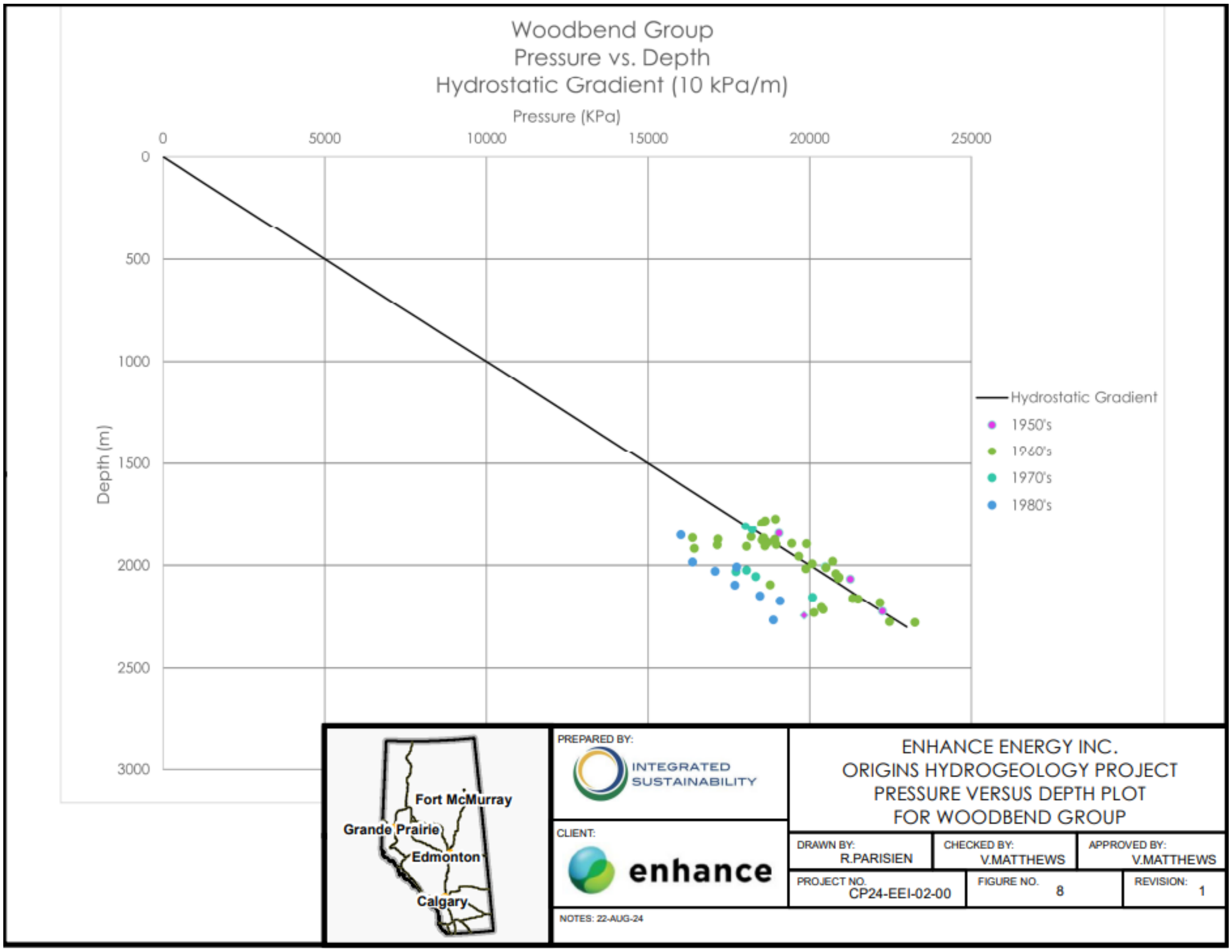


**Figure 25: Chronological Pressure History of Pools in the Woodbend Group.**

## 2.7 GEOMODEL

Petrel Robertson Consulting Ltd. (PRCL) built a three-dimensional (3D) grid of the Bashaw reef complex for the Leduc Formation using SLB Petrel, in which porosity and permeability were modeled and used as input for flow simulation.

- 1389 Leduc well tops and 89 Cooking Lake well tops included. (Figure 26)
- Petrophysical analyses completed on 177 wells to calculate porosity.
- Creation of a porosity and permeability model inside a high-resolution 3D geological grid 50mX50m (~ 300 million cells).

- Porosity modeled by Gaussian Random Function Simulation
- Permeability populated (perm = function(porosity)) (Figure 29)

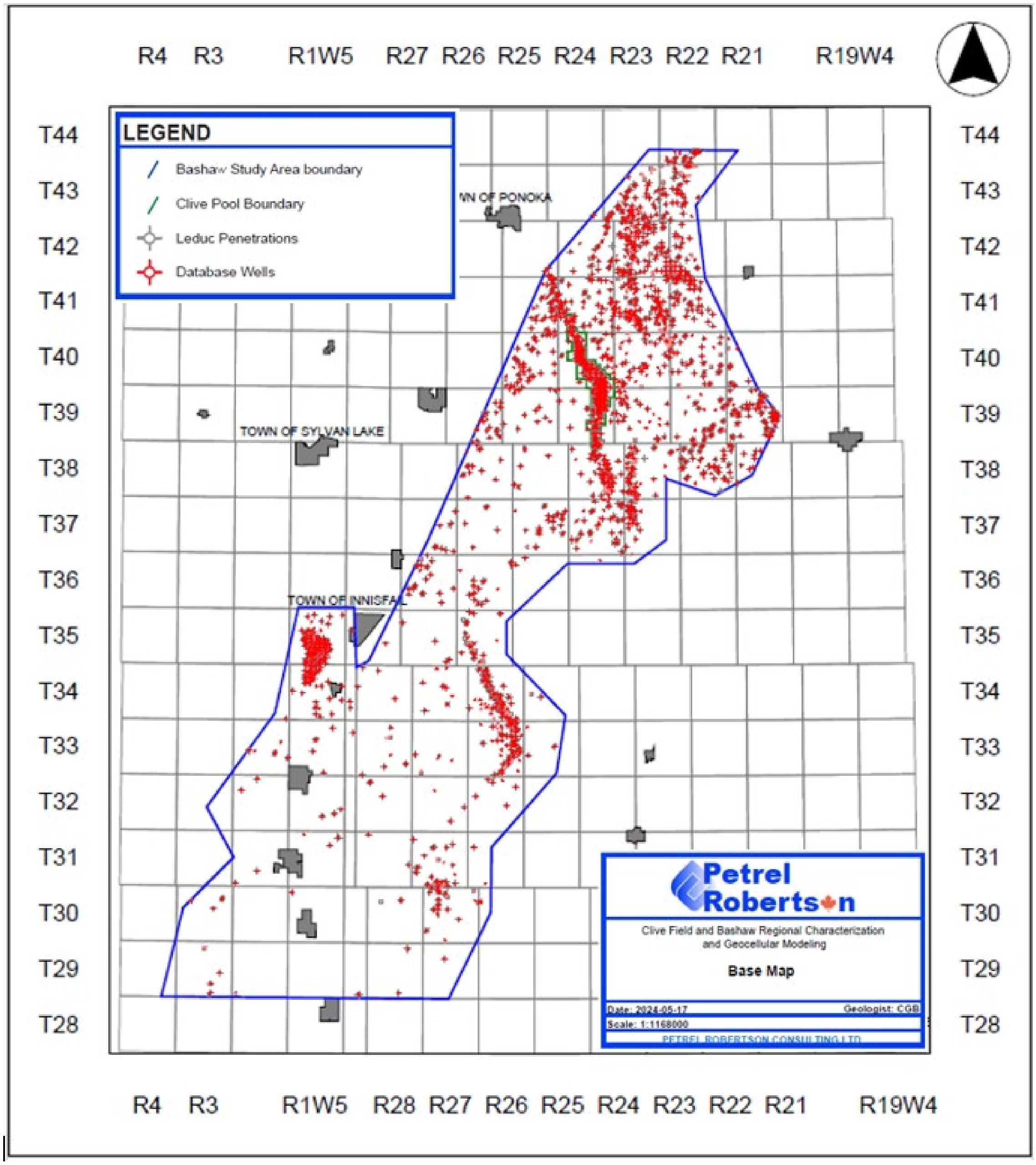


Figure 26: Distribution of wells for petrophysical analysis, Bashaw reef complex.

**Property Modeling**

Porosity was distributed in the simulation grid by interpolation of PRCL porosity logs. Initially a low-resolution model of porosity was distributed in the trend 3D grid using kriging in order to capture overall trend and spatial changes (Figure 27 (a)). This trend property was transferred into the geological grid using the PetrelTM process Upscale Property. Secondly, a high-resolution model of porosity was distributed in the high-resolution 50m x 50m geological grid using geostatistical simulation, and using the porosity trend property as a co-located secondary property (Figure 27 (b)). This high-resolution distribution captures the general trend from the low-resolution trend distribution, while adding noise as high-resolution local changes, as one expects to occur in the platform. Thirdly, the high-resolution property was transferred by averaging in the simulation grid (Figure 27 (c)). This transfer does not alter the porosity distribution in the core of the simulation grid, where the mesh is identical to the mesh in the high-resolution geological grid. It is only away from the simulation core where the cells get larger that the high-resolution porosity model is approximated.

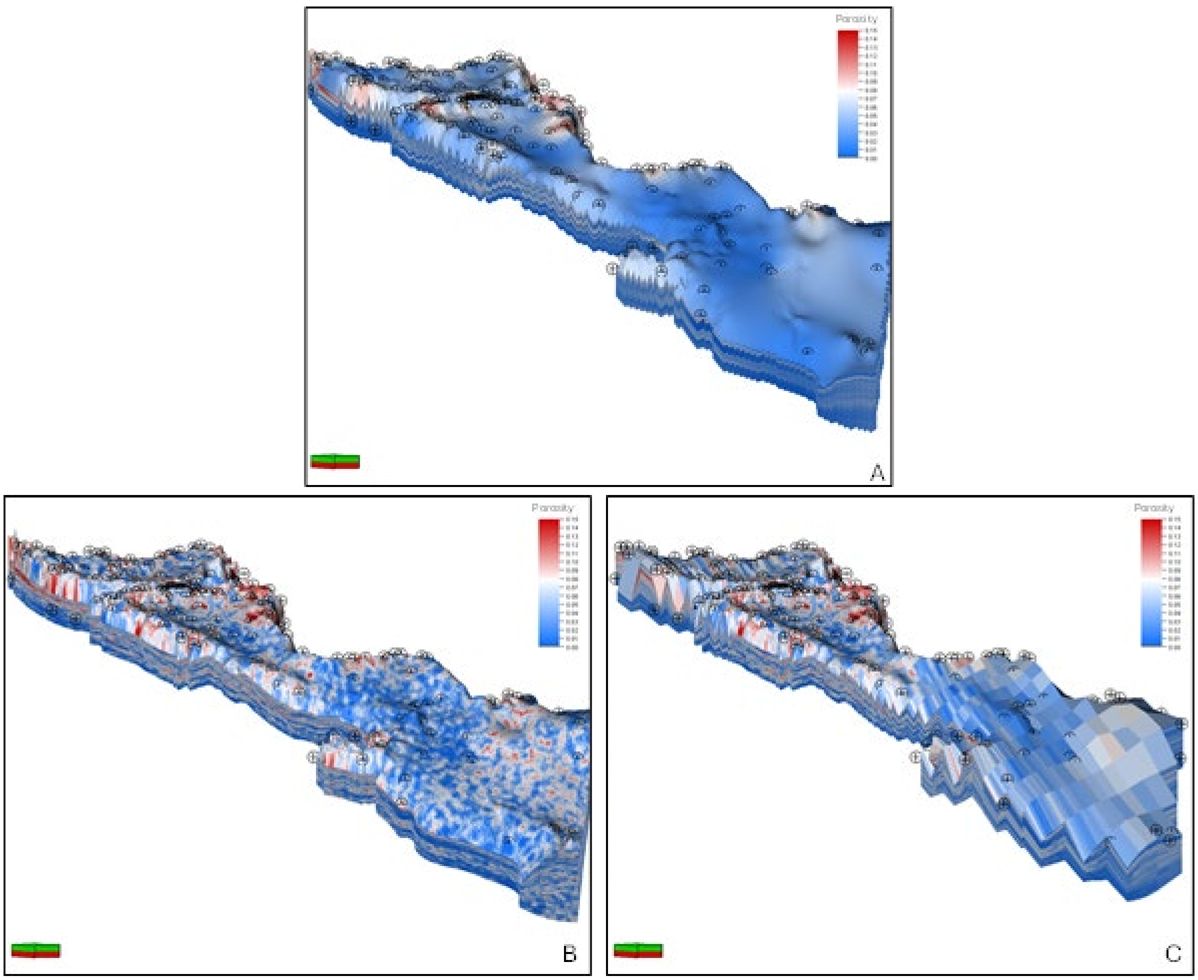


**Figure 27: Porosity distribution on the different 3D grids. (a) 1000x1000m trend grid, porosity trend. (b) 50x50m geological grid, high-resolution porosity distribution. (c) Simulation grid, upscaled porosity distribution.**

## 2.8 SIMULATIONS AND MODELLING

Geological $CO_2$ sequestration (GCS) presents a promising method for long-term $CO_2$ storage. The subsurface environment requires characterization to reflect the complex interactions between various processes. Enhance undertook the modelling of the Leduc Formation saline aquifer to predict the long-term effect of $CO_2$ injection. Numerical modeling is an effective way to capture the driving mechanisms of $CO_2$ injection, making it crucial for accurate projections and the success of $CO_2$ storage operations.

Both compositional and black-oil models are widely referenced in the literature for capturing the interactions between $CO_2$ and brine in storage processes. Compositional models rely on equation of state (EOS) flash calculations, which make them computationally demanding and less practical for large-scale simulations. In contrast, the black-oil approach facilitates PVT calculations using table look-ups for fluid properties such as density, viscosity, and compressibility, which are only dependent on pressure. This makes the black-oil method significantly faster and less prone to convergence issues—both of which are critical when simulating large models. A proper black-oil PVT model for the two-component $CO_2$–brine system was developed and validated against experimental data by Hassanzadeh et al. The details of this PVT model, along with its implications, are thoroughly discussed in Hassanzadeh et al. (1,2). This modeling approach was employed to investigate the $CO_2$ injection scenario into the 04-36 injector using SLB's commercial black-oil simulator, Intersect (IX).

**Model Setup**

**Grid selection:** The initial step in building the simulation model is determining the appropriate grid resolution. This involves balancing a model fine enough to capture critical phenomena—such as $CO_2$ plume migration and pressure distribution—while remaining feasible in terms of computational resources, such as processing power and memory.

In this case, the simulation covers the entire Leduc Formation over a large portion of the Bashaw reef complex (4956 $km^2$), ensuring no boundary effects occur from using a smaller, localized model. To achieve this, grid refinement becomes essential. The fine geo-model is divided into two key regions: the area near the injection well (marked as the "refined area" in Figure 28 (a)) and the surrounding outer region. In the refined area, a higher resolution grid was applied with a cell size ($\Delta x$ and $\Delta y$) of 50 meters. Outside of this area, grid cells expand exponentially in size to reduce computational demand while still maintaining sufficient detail for accurate simulation of larger-scale reservoir behavior. The same considerations must be applied to the vertical grid size to account for gravity override and the lateral extent of the plume. Figure 9-b shows the grid size specifications used in the model, where finer grids were applied near the top, gradually becoming coarser toward the bottom. The model consists of 711 x 678 x 38 (Nx x Ny x Nz) grid cells, totaling approximately 18,318,200 cells, with around 14,600,000 final active cells.

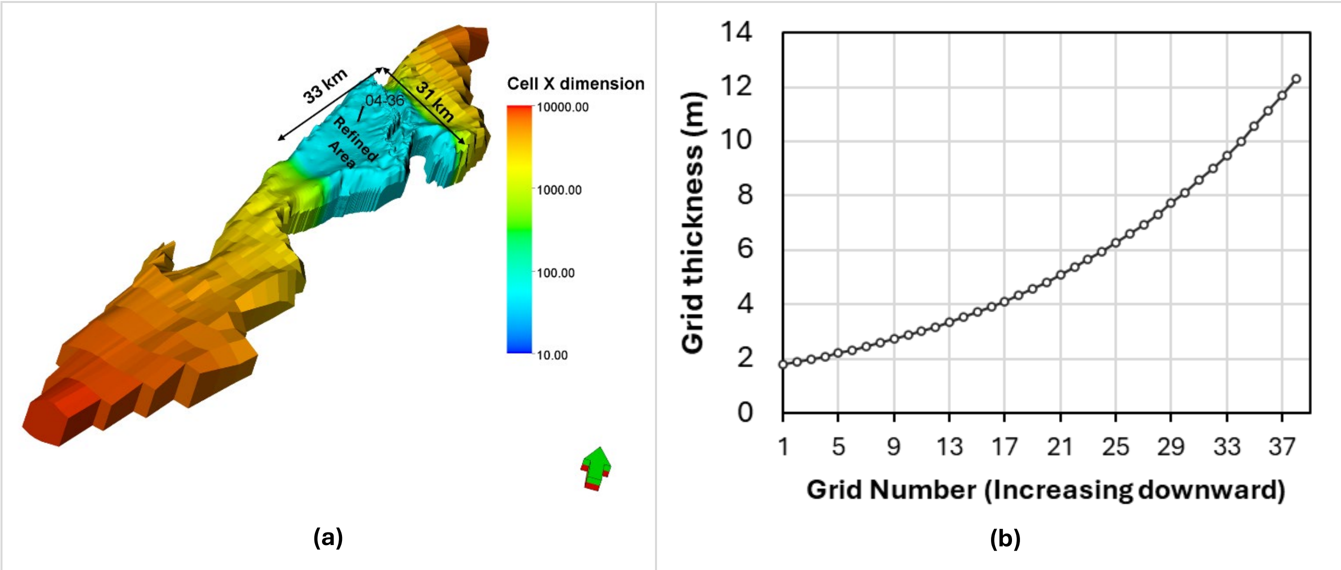


**Figure 28: (a) 3D grid illustrating the grid dimensions in the horizontal direction, highlighting the refined area near the 04-36 injector. (b) Grid thickness versus grid number, indicating the vertical variation in grid thickness from 1.8 meters at the top layer**

**Porosity & Permeability modelling:** To establish the relationship between porosity and permeability, a cross-plot of K90 full-diameter (FD) horizontal permeability versus porosity was created. Figure 29 highlights a considerable amount of scatter in the permeability data for each porosity value. While a regression line could provide an estimate of the mean values (P50), the data, particularly between the 0.05 to 0.1 porosity range, shows a broad distribution. This scatter is skewed toward higher permeability values, which is expected given the presence of large vugs and microfractures in the carbonate rock.

Relying solely on a P50 regression line may be inadequate for this dataset because the data includes extreme values that affect the central tendency, especially in regions with significant secondary porosity. To account for this variability more rigorously, a binning approach was applied. By calculating the P10, P50, and P90 values for each 1% porosity increment, the analysis provides a clearer representation of the permeability distribution.

P10 reflects the matrix permeability, while P90 captures the influence of vugs and microfractures. By combining these into a weighted average known as Swanson's permeability ($P_{Swanson}$ = 30% P10 + 40% P50 + 30% P90), the method offers a better representation of the overall permeability system, particularly in capturing the enhanced permeability from secondary porosity features. In this figure, the power-law regression line is shown along with its equation. With an $R^2$ value of 0.7, the correlation is considered strong.

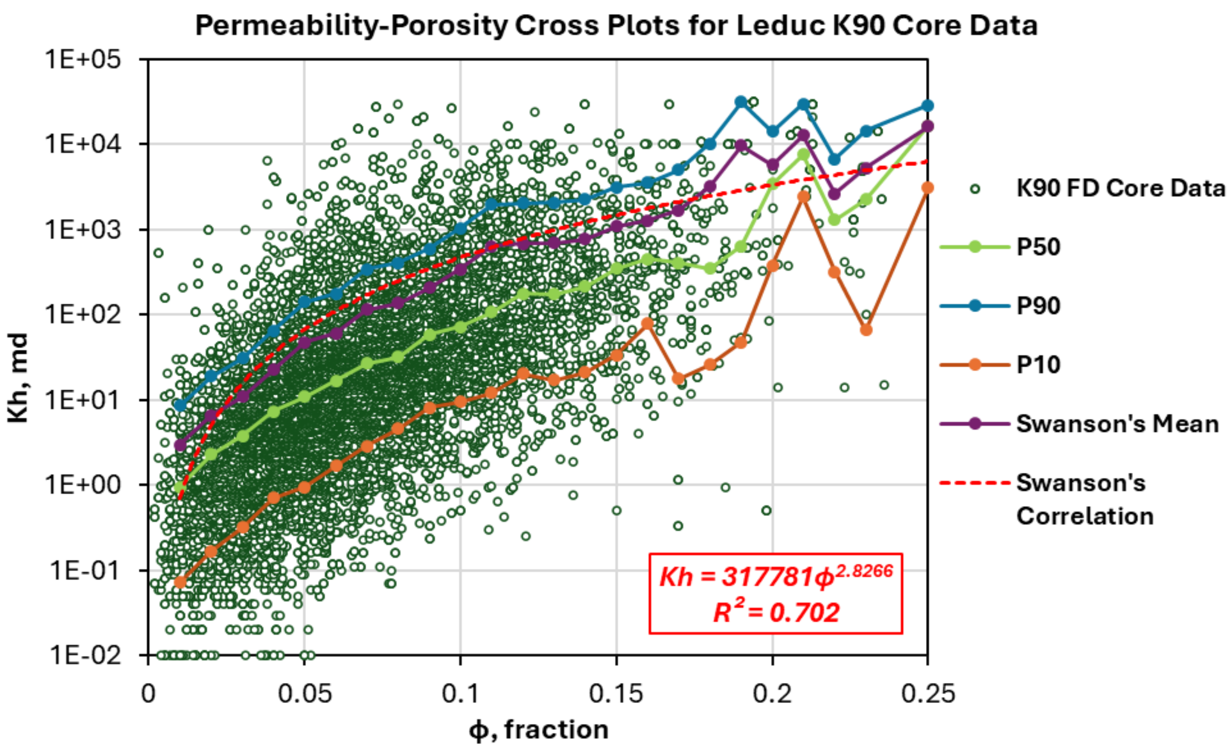


**Figure 29: Permeability-porosity data for Leduc K90 core samples (green circles) with overlaid probability curves, Swanson's mean curve, and related correlation.**

The equation was applied to the fine-grid porosity values obtained from the geological model to calculate the corresponding horizontal permeability. This permeability was then upscaled for integration into the simulation grid model. Figure 30 illustrates the upscaled porosity and permeability values within the 3D grid, accompanied by their respective histograms, showing an average porosity of approximately 6.8 % and an average permeability of around 280 md for the entire platform.

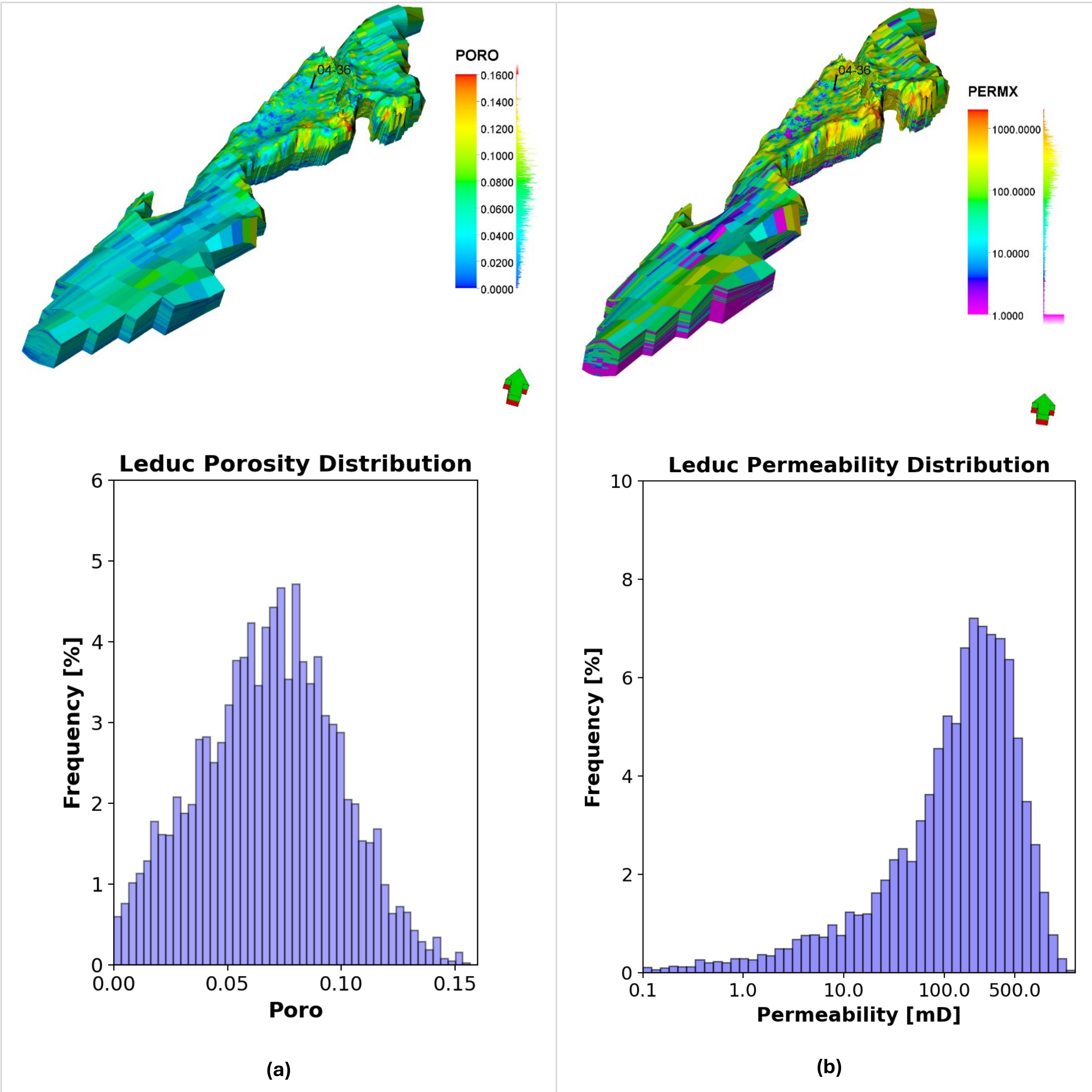


**Figure 30: Upscaled grid properties utilized in the flow simulation model (a) Porosity (b) horizontal permeability.**

In addition to porosity and horizontal permeability, vertical permeability is a crucial geological parameter in modeling $CO_2$ injection into aquifers, often represented indirectly by the vertical to horizontal permeability ratio (Kv/Kh). This ratio influences gravity override, dictating how quickly $CO_2$ migrates upward toward the caprock before spreading horizontally. Accurately defining Kv/Kh is essential for optimizing injection strategies and enhancing the accuracy of reservoir simulation models in $CO_2$ sequestration projects.

One approach involves using the raw value obtained from a Kv vs. Kh cross plot. For all the FD core data available for the Leduc Formation, this value was calculated as 0.14. However, as Begg & King suggest, it is important to account for the baffling effects caused by shale layers, which are expected to be present near the injection well and throughout the reservoir. According to their method, core and log data should be used to determine the frequency of shale layers (i.e., the number of shales per meter), their horizontal extent (e.g., the radius of the shale lenses), and the net-to-gross (NTG) ratio in order to calculate the effective vertical permeability (Kv) or Kv/Kh ratio. Conservative estimates for the 04-36 location suggest a shale frequency of 1 every 20 meters, with a minimum shale lens radius of 200 meters and an NTG value of 1. Using these values in the equation they propose (Eq. 21 in their paper), we calculated an effective Kv/Kh ratio of less than 0.01, which we rounded up to 1%.

**PVT Data:** The model developed by Hassanzadeh et al. was employed to generate the PVT tables necessary for black-oil simulation using the IX simulator.

Figure 31 provides a graphical representation of the PVT behavior of the $CO_2$–brine system as a function of pressure, at a constant temperature of 65°C and a brine salinity of 200,000 ppm, similar to the conditions observed at the 04-36 well location.

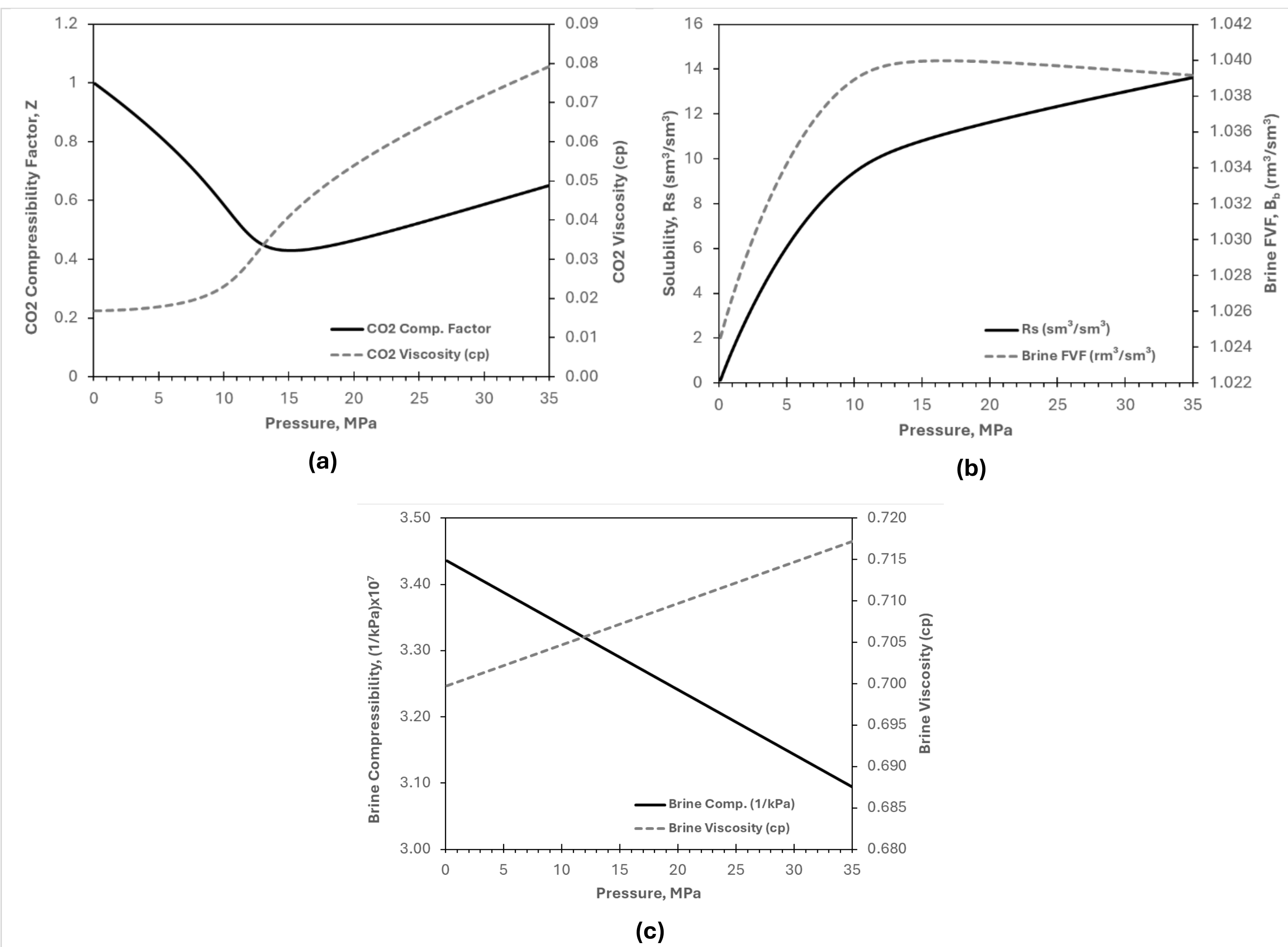


Figure 31: (a) $CO_2$ and (b and c) brine black-oil PVT and transport properties used in the simulations.

The three charts in the figure illustrate key parameters that influence $CO_2$ injection performance.

1. **$CO_2$ Compressibility and Viscosity** (Figure 31 (a)): The $CO_2$ compressibility factor (Z) decreases initially with pressure, then increases, showing strong non-ideal gas behavior. At higher pressures, $CO_2$ acts like a supercritical fluid, with liquid-like density and gas-like viscosity, which is important for predicting how it displaces brine. The viscosity of $CO_2$ also rises with pressure, increasing flow resistance as it is injected deeper or at higher injection pressure**.**

2. **Solubility and Brine Properties** (Figure 31 (b)): $CO_2$ solubility (Rs) increases with pressure, meaning more $CO_2$ dissolves into the brine. Accurately modeling this solubility is crucial for estimating solubility trapping of $CO_2$ and predicting the extent of the $CO_2$ plume, with the Rs curve serving as a critical input for black oil simulations. The brine formation volume factor (FVF, Bb) slightly increases as pressure rises due to $CO_2$ dissolution, but this trend reverses at pressures above 16 MPa.

3. **Brine Compressibility and Viscosity** (Figure 31(c)): Brine compressibility decreases as pressure rises and more $CO_2$ dissolves, making the fluid slightly less compressible at higher pressures. In contrast, brine viscosity remains relatively stable, with only a small increase, indicating minimal changes in brine flow resistance as pressure increases.

**Relative Permeability Data:** Bennion and Bachu conducted comprehensive laboratory measurements of relative permeability for $CO_2$-brine systems under in situ conditions, using various core plugs from formations within the Western Canada Sedimentary Basin. We have adopted the relative permeability data they provided for the Nisku carbonate (matrix only) and modified it to account for the enhanced permeability (matrix plus vugs/microfractures) observed in the Leduc Formation at Clive. This modification is further supported by the image log data from the 04-36 well location, where the secondary porosity assessment indicates that 21% of the total porosity consists of secondary porosity (vugs and fractures) throughout the Leduc. Additionally, the residual water saturation (Swr) of 43% was derived from mercury injection capillary pressure (MICP) analysis.

Figure 32 shows the characteristic drainage relative permeability data used in this project, with the drainage curves for water and gas phases plotted in black. The maximum relative permeability to $CO_2$ is observed at 0.3, and the maximum residual water saturation is 43%. For the imbibition curve (shown in red), it was assumed that, given the water-wet nature of the aquifer, the relative permeability curves for the water phase are the same for both the drainage and imbibition processes. A maximum residual trapped saturation of 20% was applied to the $CO_2$ phase. Additionally, the effect of capillary pressure was neglected in all simulation models.

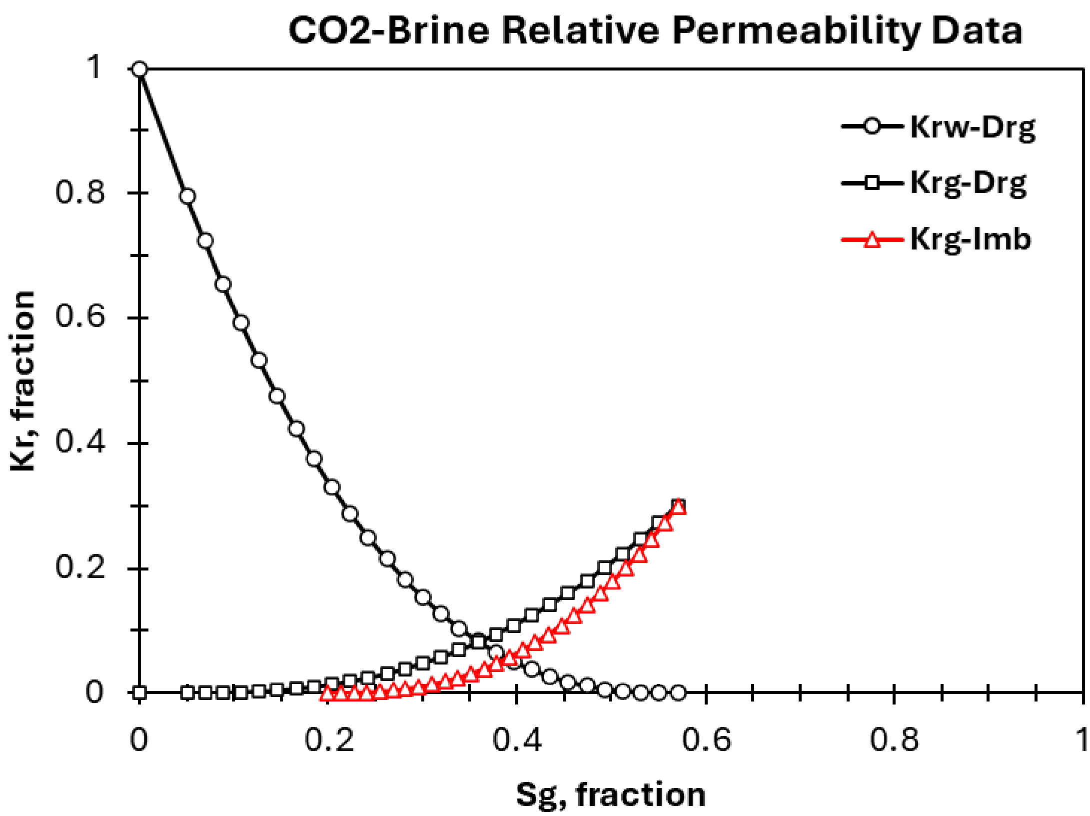


Figure 32: Drainage relative permeability for water and gas along with imbibition curve for the gas phase.

**Rock Compressibility:** Rock compressibility is crucial in simulation modeling of $CO_2$ sequestration projects because it affects the ability of the reservoir to respond to pressure changes during injection, influencing storage capacity, fluid flow dynamics, and the long-term stability of the $CO_2$ plume within the formation. Ashena et al. compiled the most reliable correlations available in the literature for both sandstone and carbonate reservoirs. The primary input parameter for these correlations is the average reservoir porosity (6.5% for Leduc), making them simple and straightforward to apply.

Table 2: Rock compressibility values from different correlations available for carbonate rocks

| Method | Carbonate Rock Compressibility (1/kPa) |
|---|---|
| Hall (1953) | 8.56E-07 |
| Newman (1973) | 15.8E-07 |
| Horne (1990) | 21.9E-07 |
| Modified-Horne (Jalalh, 2006b) | 13.1E-07 |
| Jalalh (2006b) | 1.48E-07 |
| Average value | **12.2E-07** |

Table 2 presents rock compressibility values from those correlations for carbonate rocks, showing a wide range of values. For the purposes of this project, the calculated average value of 1.22E-06 1/kPa was used, as it represents a reasonable estimate despite the large discrepancies between individual methods.

**Well configuration & injection scheme:** The 04-36 well has been configured as a cased injector, and for simulation purposes, the wellbore is perforated from the top of the Leduc Formation down to the top of the underlying limestone, which is located at the base of the reservoir. This perforated interval extends across 130 meters of the reservoir.
To maintain a controlled injection process and manage geomechanical effects—like sudden pressure surges at the wellbore—the injection rate is gradually increased. The objective is to steadily reach the target of 1.6 MT of $CO_2$ per year. The detailed schedule for this ramp-up is shown in Table 3.

Table 3: Gradual $CO_2$ injection rate increase over the first four months

| Period | $CO_2$ Injection Rate ($sm^3$/day) | $CO_2$ Injection Rate (MTA eq) |
|---|---|---|
| 1st month | 585,411.5 | 0.40 |
| 2nd month | 780,548.7 | 0.53 |
| 3rd month | 1,561,097.5 | 1.07 |
| 4th month | 2,341,646.2 | 1.60 |

**Additional Key Input Data:** Table 4 outlines other important input parameters used in the simulation model. The reservoir is assumed to be isothermal, maintaining a constant temperature of 65°C. It is also assumed that the injected $CO_2$ will rapidly equilibrate to the reservoir temperature, so any thermal effects on flow behavior are disregarded. The initial reservoir pressure is 15,300 kPa at a depth of 2,070 meters TVD (True Vertical Depth) and is assumed to follow a static gradient for other depths.

Table 4: Other Simulation Inputs

| Parameter | Value | Comment |
|---|---|---|
| Reservoir temperature | 65 ˚C | Assumed constant |
| Initial Pressure (Pinit) | 15,300 kPa @ 2070 m TVD | Hydrostatic equilibrium |
| Brine Salinity | 200,000 ppm | Equivalent NaCl concentration |
| Initial Brine Density | ~1130.5 kg/m3 | Variable |
| Initial Brine Viscosity | ~0.7 cp | Variable |
| Injection duration | 17.5 years | ~28 MT cumulative injection |
| $CO_2$ injection temperature | 65 ˚C | Thermal effects can be ignored away from the injection well |

**Simulation Results and Discussions:**
Reservoir simulation plays a crucial role in $CO_2$ sequestration projects, as it enables accurate prediction and analysis of how injected $CO_2$ will behave over time within the subsurface reservoir. Through detailed simulation modeling, engineers can optimize the injection strategy, ensuring $CO_2$ is safely stored without risking leakage or unexpected migration. This predictive analysis is essential for understanding the effects of $CO_2$ on reservoir pressure, geomechanical stability, and fluid dynamics, allowing for the determination of optimal injection rates and well locations. Furthermore, simulation is vital for designing effective seismic plume monitoring, ensuring that monitoring efforts capture the entire $CO_2$ plume as it spreads. It also assists in selecting strategic monitoring locations within the

hydrosphere and biosphere by identifying areas with elevated risk. These capabilities are essential for managing risks, complying with regulatory requirements, and achieving the environmental and economic goals of carbon capture and storage (CCS) projects, ultimately supporting safe and efficient $CO_2$ sequestration.

Figure 33 illustrates the changes in injection rate, Bottom Hole Pressure (BHP), and average reservoir pressure during $CO_2$ injection in the Leduc Formation using the 04-36 injector, targeting a total of 28 MT of $CO_2$ storage. The results indicate that peak BHP of 19,300 kPa is expected to occur when the injection rate reaches its maximum of 2,341 se$^3$m$^3$/day. Over the injection period, the average reservoir pressure across the model will increase from 17,500 kPa to approximately 18,000 kPa, reflecting a pressure change of around 500 kPa at the end of the injection period.

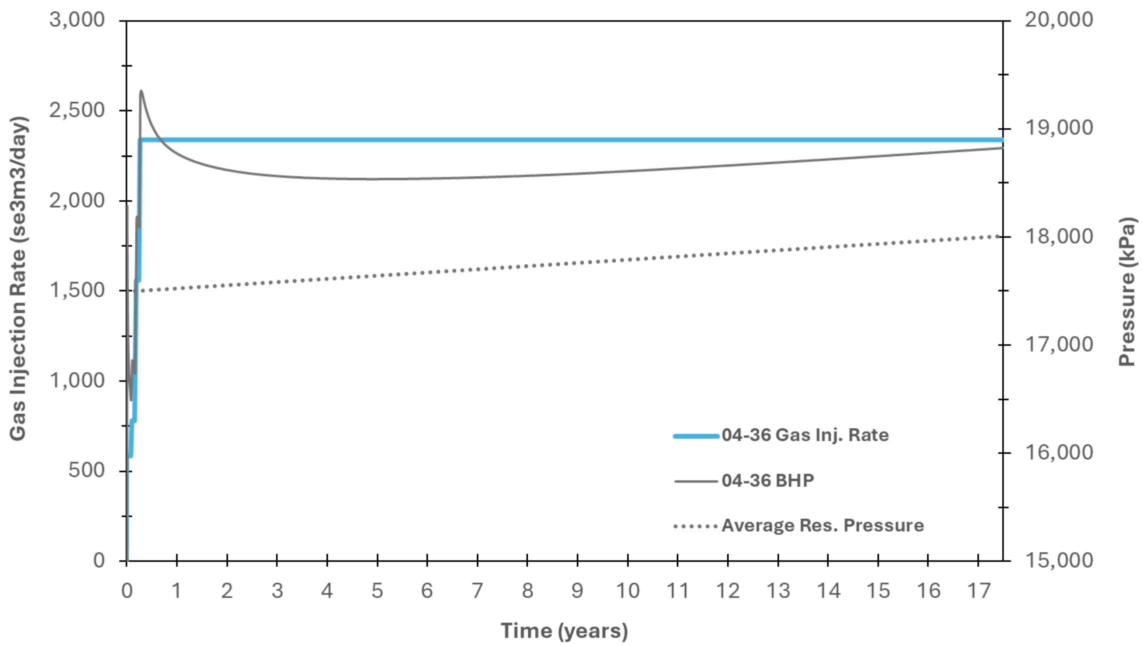


**Figure 33: Injection rate, bottom hole pressure (BHP), and average reservoir pressure over 17.5 years of $CO_2$ injection to achieve 28 MT of storage in the Leduc Formation.**

**Plume development**

Figure 34 illustrates the projected plume development at the end of the $CO_2$ injection period, which spans approximately 17.5 years. Figure 34 (a) shows the horizontal extent of the plume, with a maximum radius of 4 km from the injection site. Figure 34 (b) provides a vertical cross-section view at the 04-36 injection well location. It indicates that the $CO_2$ plume extends to a depth of 135 meters in the vertical direction and indicates slightly higher migration rates as it follows the formation's natural slope leading toward the Clive pool.

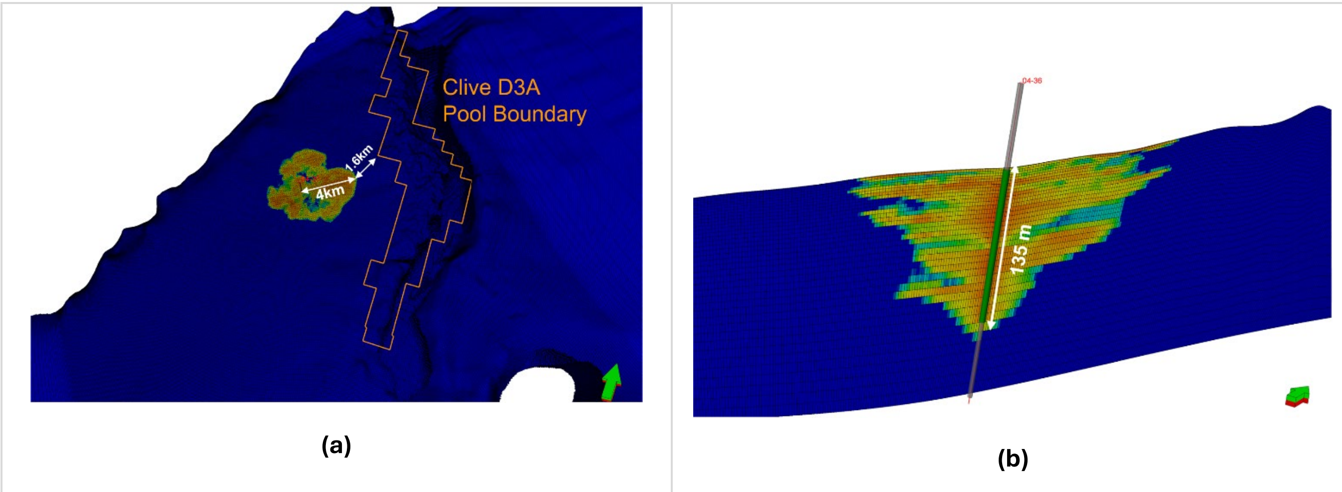


**Figure 34: Plume extension and spread at the end of the injection period (a) Plume areal extend and its edge distance from the Clive pool boundary (b) Cross section of the model at the well location with plume extending 135m on the vertical direction.**

In general, predicting the extent of the $CO_2$ plume over time is a factor in estimating the storage capacity and the effective design of MMV systems. A detailed understanding of the plume's behavior helps in evaluating the potential impact on nearby legacy wellbores and identifying any risks associated with the encroachment into existing hydrocarbon (HC) reservoirs. The current simulation model has successfully met these requirements, providing a reliable basis for predicting plume dynamics. As the injection operation proceeds and additional data is collected, the model can be further refined and calibrated to enhance accuracy, allowing for more informed decision-making and adaptive management of the $CO_2$ storage project. This iterative process will improve the ability to mitigate risks, optimize monitoring efforts, and ensure the long-term safety and effectiveness of the storage site.

## 2.9 Risk Assessment

For carbon sequestration projects, the risk management plan (RMP) specifically addresses the risks associated with $CO_2$ sequestration at a project site and is a fundamental component of the MMV requirement. The RMP shall identify, analyze, evaluate and assign the project risks associated with site selection and characterization process. A site can be considered suitable if the site characterization and assessment process has demonstrated that $CO_2$ storage does not pose unacceptable risks while operating and post closure to:

- Human health and safety
- The Crown
- The environment on both short- and long-term timelines
- Other resources and developments
- Other project developers, owners, operators, etc

The Origins Project Risk Register was developed specifically for the Origins project well (100/04-36-039-25W4). Enhance commissioned a Panel made up of Enhance (internal) experts as well as established industry experts (external) to advise and assess the storage performance of the selected site.

Per CSA Z741-12, the site suitability assessment involved evaluating subsurface criteria, including capacity, injectivity, storage security, pore space ownership, other subsurface activities, other subsurface resources, and need for pressure control. In addition, the project logistical and surface operational criteria including existing and required infrastructure, access to $CO_2$ sources, current and future land-use, population density, proximity to environmentally sensitive/reserved/protected areas and bodies of water, topography as well as various cultural, historical and socioeconomic conditions were also studied.

Please refer to Appendix B: Risk Management Plan for the proposed project.

## 2.10 Evaluation Well

Enhance has determined the need for a $CO_2$ sequestration well in the area and drilled and completed the **100/04-36-039-25W4/00** well as an injector to dispose of $CO_2$ into the Leduc Formation. $CO_2$ capture facilities are in place and will be utilized to feed dense phase $CO_2$ to the injection well. Enhance will tie-in to the ACTL line and will install the required pipeline. Surface facilities and associated approvals will be in place prior to the commencement of operations.

**$CO_2$ Sequestration Scheme Details:**

- Unique well identifier: **100/04-36-039-25W4/00**
- Well Licence Number: 0512681
- Disposal zone top: Woodbend Group, Leduc Formation (1993.94 m MD)
- Disposal zone base: Woodbend Group, Cooking Lake Formation (2195.19 m MD)
- Proposed disposal interval: 1994 – 2132 m (138 m)
- Anticipated cumulative disposal volume: 14.92 E9m3 equivalent to 28 MT over an approximate 17.5-year injection duration
- Injection pressure (BHP): 19,300 kPa at peak
- Packer: The packer will be set within 15 m of the injection zone top

Furthermore, the injection zone is below the base of groundwater in the area thereby eliminating possibility of contamination. The wellbore is completed in the Leduc Formation for $CO_2$ sequestration purposes. The disposal fluid will be confined to the injection formation and shall not impact hydrocarbon recovery. In this area the Leduc Formation is a saline aquifer and therefore no adverse impact from the proposed operation is anticipated.

**Table 5: CO2 Sequestration Scheme Specifics**

| | |
|---|---|
| **Fluid type currently in the disposal interval** | Brine |
| **Confinement strata** | Ireton |
| **04-36 Leduc reservoir thickness** | 138 m |
| **04-36 Leduc average effective porosity** | 6% |
| **04-36 Core permeability** | <10 mD to hundreds of millidarcies |
| **The distance between the proposed disposal well and any Leduc hydrocarbon pool or accumulation** | The closest Leduc hydrocarbon pool is the Clive D-3 A pool which is over 5.6 km from the proposed 100/04-36-039-25W4/00 injector (see also Figure 5) |

From the 04-36 well, 89.5 m of core was retrieved from the well and underwent multiple analysis listed in Table 6.

Table 6: List of Technical Studies and Assessments on the Evaluation Well

| Technical Study or *Assessment* | Conducted by | Data and Date Conducted | Use |
|---|---|---|---|
| **Routine Core Analysis** | Core Laboratories Canada Ltd. | February 2024 | CT Imaging, gamma logs, routine core analysis (saturations, porosity), pressure decay profile, imaging |
| **Geological Analysis** | Core Laboratories Canada Ltd. | February 2024 | Thin sections, petrology, x-ray analysis |
| **Geochemistry Analysis** | Core Laboratories Canada Ltd. | February 2024 | Residual hydrocarbon extraction and analysis |
| **Special Core Analysis** | Core Laboratories Canada Ltd. | February 2024 | Sample quality assessment, sample cleaning and drying, ambient porosity and grain density, capillary pressure tests, water preparation, relative permeability, geochemical analysis |
| **PVT Analysis** | Core Laboratories Canada Ltd. | February 2024 | Synthetic gas generation, dead oil restoration, water analysis, generation of $CO_2$ saturated formation water, measured live brine properties, simulated live brine properties |
| **Injection Test** | Enhance Energy Inc. | September 2024 | Step rate injection test and a fall off. |

## 2.11 Baseline Definition and Data Gathering Plan

Baseline data is critical for CCS Projects for evaluating the environmental and operational conditions of the project before injection begins. Baseline refers to the condition of the environment before CCS activities occur and provides a reference point for evaluating the impacts of the project. Baseline conditions will be determined for the injection reservoir, a geological baseline, groundwater, biosphere, atmosphere and seismic.

The Enhance Clive $CO_2$ EOR Project was baselined and has been collecting data since 2019. This data will be utilized to understand baseline conditions in the area and identify any anomalous data. Isotope fingerprinting has been established for distinct formations within the Clive $CO_2$ EOR project. Different $CO_2$ sources exhibit different amounts of radioactive carbon isotopes (d$^{13}$C and $^{14}$C) that effectively allow samples to be fingerprinted. $^{14}$C can also be used to differentiate biogenic and petrogenic sources.

Data gathering programs for Origins project baseline include:

- designated water well composition
- landowner water well composition
- soil gas chemical composition
- induced seismicity monitoring
- atmospheric gas composition
- isotopic analysis

The selection of monitoring technologies and best practices are driven by the unique characteristics of the reservoir, geology, and existing infrastructure. Routine monitoring techniques encompass the techniques that Enhance has chosen to implement for baseline and ongoing monitoring.

## 2.12 Induced Seismicity

### 2.12.1 Seismic History

Natural seismicity of the area was assessed using historical data from Alberta Geological Survey (AGS) from 2006 to present. Historical seismicity within 20km of the injection well from the AGS RAVEN monitoring network is very low. The two recorded events shown in Figure 35 are classified as suspected earthquakes (SE) and are thought to be naturally occurring (Alberta Geological Survey Earthquake Dashboard).

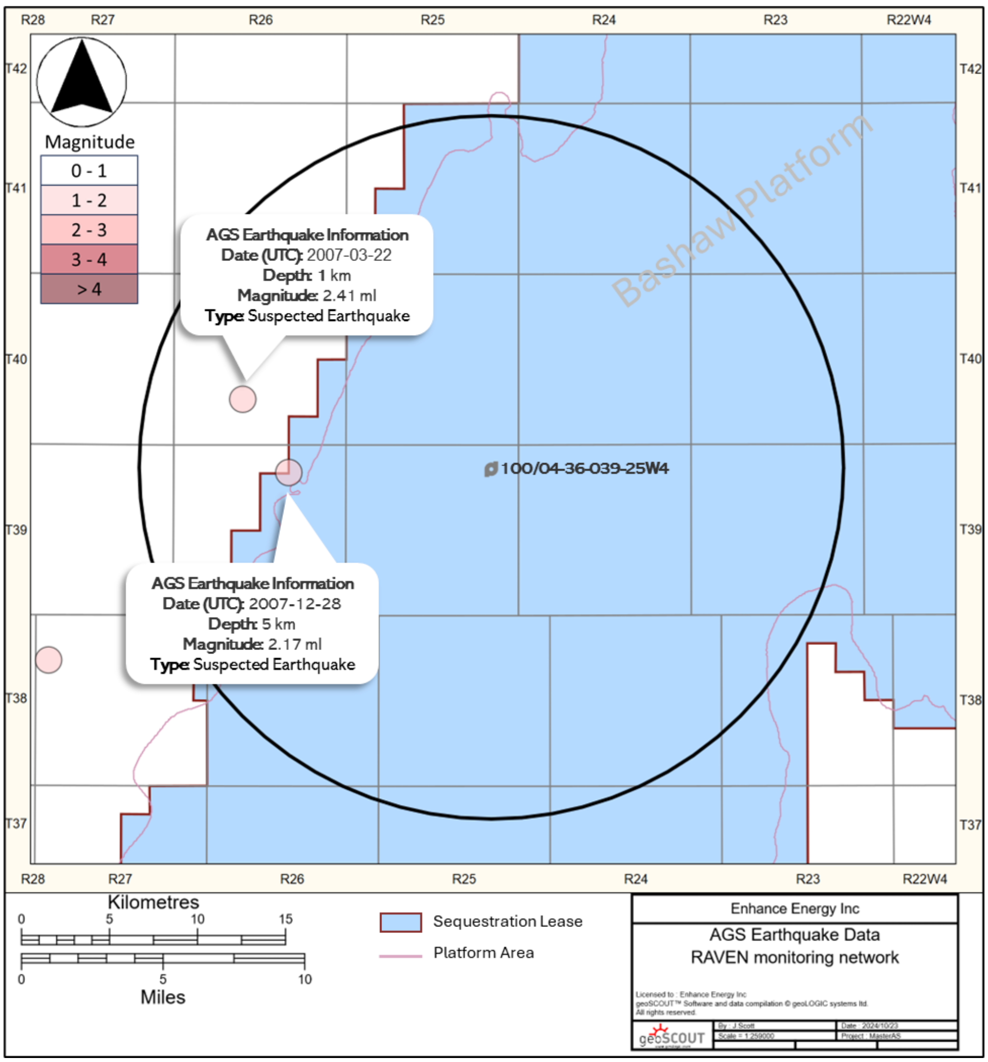


**Figure 35: Historical seismicity within 20km of the injection well from the Alberta Geological Survey (AGS) RAVEN monitoring network showing the location and magnitude of earthquakes from 2006 to present**

Induced seismicity occurs when fluid injection increases pressure at critically stressed or active faults. Faults rooted in the basement can trigger larger seismic events compared to strata-bound faults located higher in the section. Seismicity related to basement-rooted faults has been observed in large-scale water disposal projects in the U.S. It is commonly understood that injection into basal sedimentary formations have triggered relatively small earthquakes. (Dr Mark Zoback, in-house communication).

Though critically stressed basement faults are common in the Western Canadian Sedimentary Basin, including areas with low historical seismicity, detecting these faults remains difficult. Seismic imaging often fails to capture these faults due to depth constraints or their subtle expressions.

### 2.12.2 Seismic Coverage

In the Origins area the Red Deer 3D seismic was acquired to map the subsurface architecture above, within, and below the primary zone of interest, defined as the Ireton-Leduc package around Township (Twp) 39, Range (Rge) 25 W4 (Figure 36). The 3D data was shot in 2001 and originally covered Twp 39-40, Rge 24-26W4; Enhance purchased and reprocessed key portions of this dataset in Q2 2024. A key focus of this geophysical investigation was to assess reservoir and seal integrity at the Leduc level and determine whether seismic data would suggest the presence of faults, shear zones, or structural anomalies that might pose a risk of induced seismicity once injection begins.

The Red Deer 3D data was tied to previously interpreted 2D data in the area and regional well control. The 3D has good correlation with well synthetics and 2D profiles on all major seismic markers and overall seismic character. Data quality above the zone of interest was good to excellent, enabling strong well ties through the Cretaceous and upper Devonian sections. Although some structure was observed on the base Cretaceous unconformity surface, discontinuities, obvious displacements, or anomalous character changes associated with faulting were absent from the stratigraphic intervals at and above the zone of interest. No evidence of solutioning was observed from the zone of interest to the Base Cretaceous Unconformity, which was taken as further support for seal integrity.

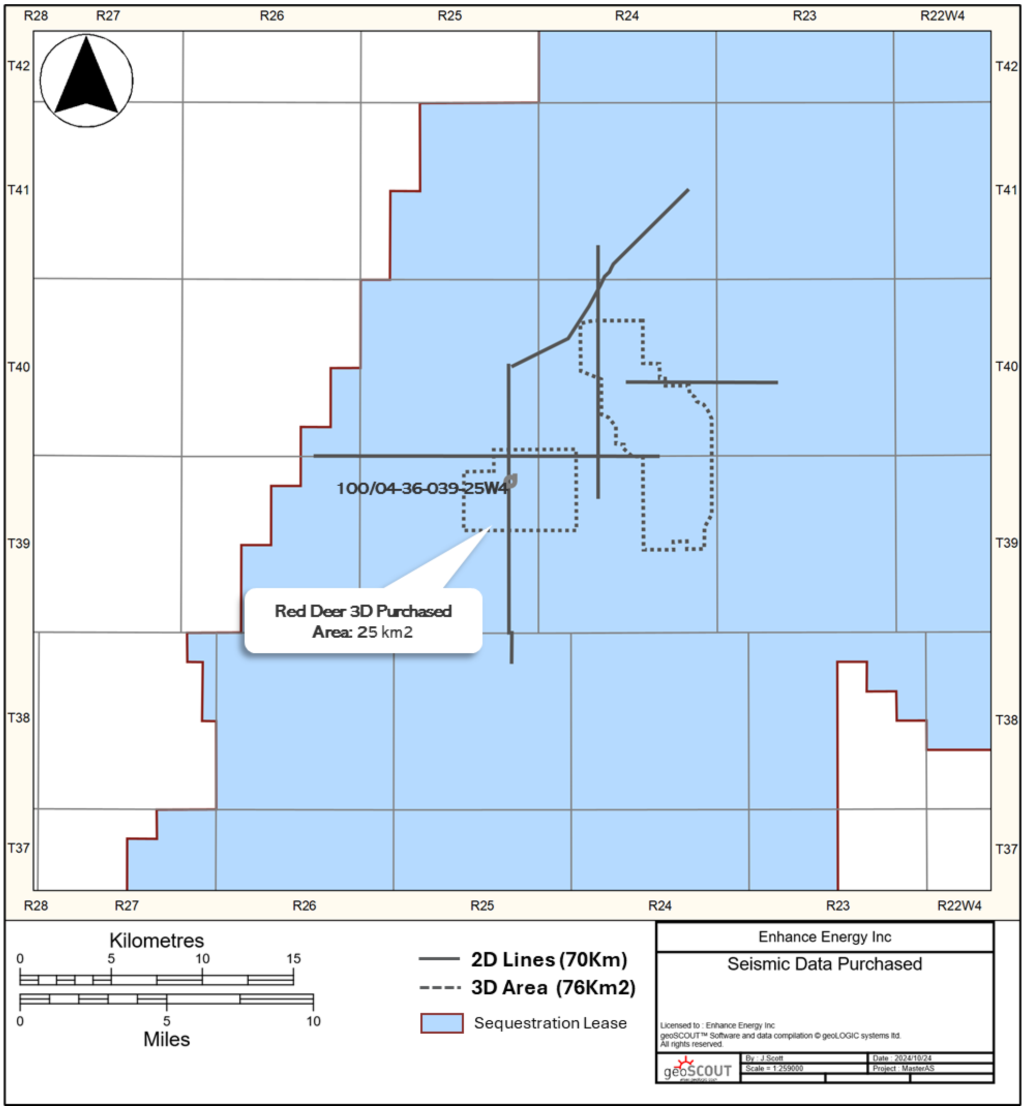


Figure 36: Location of 2D and 3D seismic data purchased on the Bashaw Platform.

Overall, the Red Deer 3D data did not reveal discernible structural or fault displacement features from the Leduc level to the basement. Any structures, if present, are below the resolution limits of the seismic data.

With an 800-meter or greater vertical separation between the Leduc and the Precambrian basement (Figure 37), the lack of detectable structure at depth supports the view that there is no significant hydraulic connection between the injection zone and the basement. This suggests that injection at the Leduc level poses minimal risk of triggering induced seismicity originating from the basement.

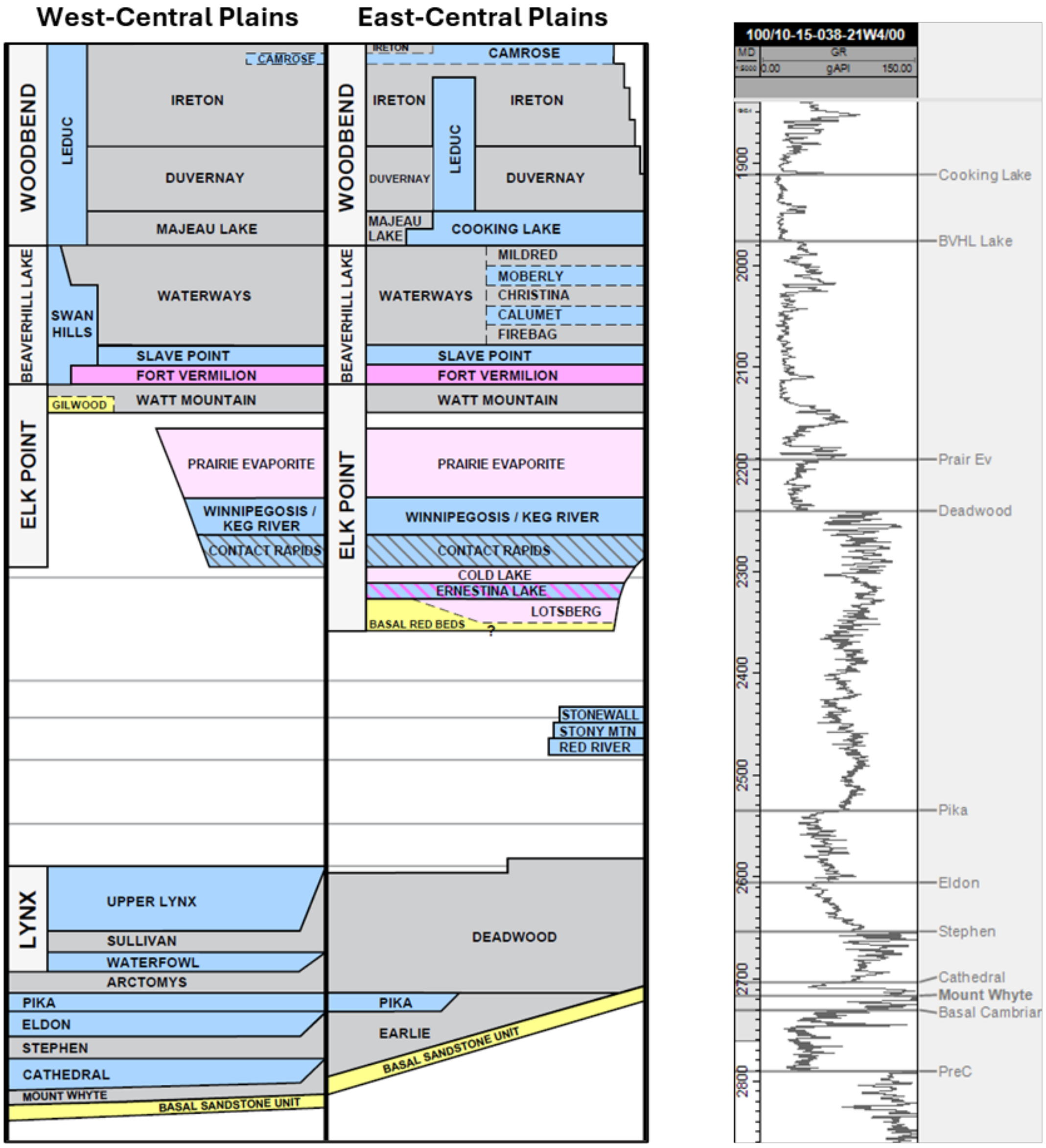


Figure 37: After Alberta Geological Survey (2019): Alberta Table of Formations; Alberta Energy Regulator.

### 2.12.3 Induced Seismicity Hazard Assessment

Origins seismic monitoring and mitigation program is designed to manage the risk of induced seismicity. Induced seismicity is defined as seismic events resulting from human activity. Enhance has mitigated the risks of induced seismicity by selecting a storage location that is inherently safe as validated from the site characterization. The Bashaw reef complex is underlain by the Cooking Lake Formation. The Cooking Lake Formation is an aquifer that allows for pressure distribution vertically, preventing pressure dispersion to the basement which is a major cause of induced seismicity in CCS operations.

The Risk assessment conducted by Enhance Energy identified two risks associated with induced seismicity during injection into the Origins project well. The risks identified are summarized in the Risk Register (refer to Attachment 7) and has a Hazard Score (pre-mitigation) of 6, which ranks them as medium risks predominantly due to the consequence of an event. The inherent safety of the location chosen greatly minimized the risk of induced seismicity. In addition, mitigation techniques such as induced seismicity monitoring (baseline, pre-$CO_2$ injection), injection reservoir pressure and seismic monitoring will be implemented.

### 2.12.4 Monitoring

Induced Seismicity monitoring will be conducted using passive monitoring stations. Four stations in addition to data acquired from one public station (RD.REDDA) will be used. The monitoring stations allow for real time streaming, continuous data acquisition and archiving. Based on station locations and data Location Accuracy Modeling can be done to pinpoint the location and origination depth of the seismic event in determining the cause.

Operational monitoring will be continuous, with downhole pressure monitoring coupled with plume monitoring.

#### Seismic Thresholds and Alerts

The AER Traffic Light System developed for the Red Deer Subsurface Order No.7 will be referenced when referring to the action plan. The Red Deer Subsurface Order No. 7 was developed for hydraulic fracturing. Although CCS operations are different, the Traffic Light System is commonly used by operators and well understood within the area.

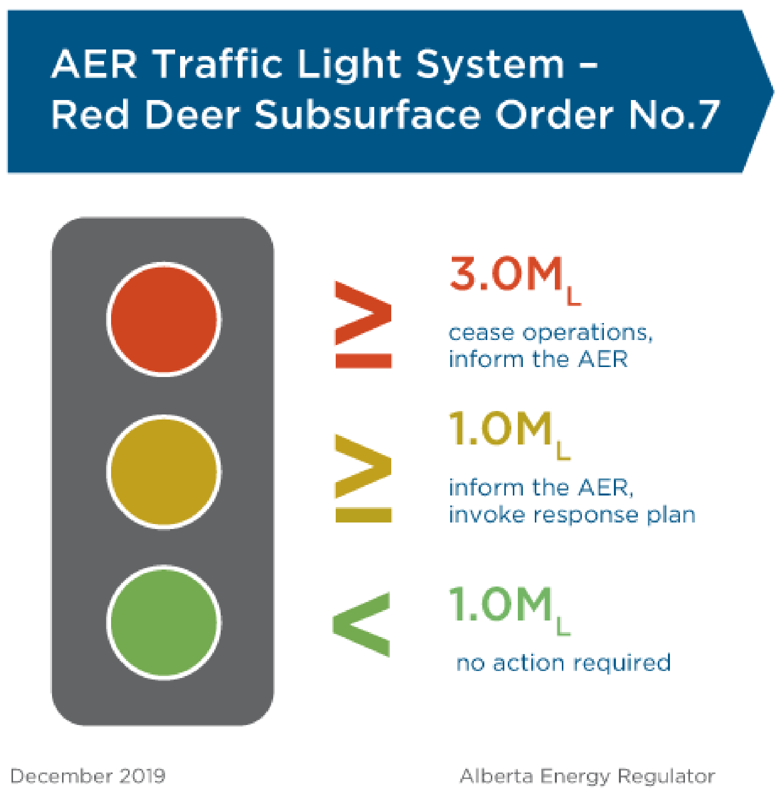


Figure 38: AER Traffic Light System - Red Deer Subsurface Order No.7.

# 3 ORIGINS MONITORING, MEASUREMENT, AND VERIFICATION PLAN

## 3.1 INJECTION FORMATION MONITORING

The injection well pressure will be continuously monitored using downhole pressure and temperature gauges, tied into the Supervisory Control and Data Acquisition (SCADA) system. The injection fluid will flow through an analyzer and a flow meter measuring the composition and volumetric flow rate of the dense phase fluid being injected.

The injection formation will be monitored using seismic technologies. Induced seismicity monitoring will start pre-injection to establish baseline conditions and monitoring will continue throughout project phases. Induced seismicity monitoring stations allow for continuous data collection and real time monitoring. Seismic technology will also be deployed to monitor $CO_2$ behavior in the subsurface, specifically plume growth and movement. Plume monitoring will utilize seismic receivers and sources at set frequencies as outlined in the Geosphere Monitoring section. Seismic data gathered will be utilized to predict plume growth to tune the simulation model forecast throughout the project.

## 3.2 GEOSPHERE MONITORING

In the context of this Project, geosphere monitoring refers to the monitoring of the subsurface below the base of groundwater protection. Monitoring of deep wells within the area is limited, thus shallow gas monitoring and seismic technologies will be utilized. Shallow gas monitoring is covered in the Hydrosphere Monitoring section. The injection well will be compliant with all applicable AER directives. The injection reservoir pressure will follow Directive 40 monitoring frequencies and requirements. The injection well will be tied into SCADA, continuously monitoring the tubing and annulus pressures. In addition to monitoring the properties of the injection reservoir, the fluid injection will undergo monthly compositional analysis and annual isotopic analysis to determine the composition of the injected $CO_2$ and maintain Directive 065 compliance.

Monitoring of the geosphere will rely on seismic technologies in addition to injection well testing and monitoring. Induced seismicity will be monitored continuously with passive monitoring stations appropriately placed around the predicted plume area. The data from the continuous monitoring station and data collected from a public seismic monitoring station will be collected and analyzed regularly with annual updates following Directive 065 requirements. $CO_2$ plume monitoring will also utilize seismic technology. Plume monitoring will be designed based on best practices and simulated plume growth. Data acquisition will include source and receiver deployment with a sparse design.

Baseline data will be collected for both induced seismicity monitoring and plume monitoring purposes. The intention of baseline monitoring for induced seismicity is to understand the natural or background seismicity prior to the start of injection. This data will be used as a comparison in the event induced seismicity is detected during the operations and will help in identifying the source of the event. Plume monitoring baseline is dependent on the specific technology selected. Enhance will be undertaking a feasibility study to select the most appropriate seismic plume monitoring technology prior to commencing baseline acquisition. Data acquisition will occur prior to injection and will be used as a comparison to evaluate changes in the subsurface, thus mapping the $CO_2$ plume changes over time.

Table 7: Geosphere MMV Activities

| Monitoring Activity | Testing Technique | Frequency of Testing | | |
|---|---|---|---|---|
| | | Baseline | Active injection | Post Injection |
| **Most recent AER D65 CCS Approval** | Meet all clauses and requirements specified within Approval | N/A | As per approval | Refer to Directive 065 |
| **Monitor wells as per the dynamic Offset Wellbore Risk Assessment (OWRA) aligned with the AER Approach to risk management** | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management | Monitor wells as per the dynamic OWRA aligned with the AER Approach to risk management |
| **Injection Reservoir Pressure** | AER Directive 040 requirements. | Refer to Directive | Refer to Directive | Refer to Directive |
| **Monitor tubing and annulus pressure on injection wells** | Injection wells | N/A | Continuous tied to SCADA. | N/A |
| **Measure Injected Fluid** | Applicable AER Directives Requirements. Gas Composition Analysis and Volumetric Flow Rate. | Refer to Directive | Monthly | N/A |
| **Induced Seismicity** | Passive monitoring stations | Continuous | Continuous with submissions annually | TBD based on MMV data throughout the project |
| **$CO_2$ Plume** | Seismic monitoring | Once. | Frequency dependent on final technology selection. Evaluate frequency every 3 years. | TBD based on MMV data throughout the project |

## 3.3 Hydrosphere Monitoring

The protection of the geosphere will be inherent for the hydrosphere, however, due to the consequences of contamination, additional monitoring is implemented. The purpose of the groundwater monitoring program is to establish baseline conditions for groundwater quality in the area, which can then be compared to sampling during the project conditions in the event of possible $CO_2$ migration.

The hydrosphere is defined as surface and subsurface fresh water. Monitoring of the hydrosphere will occur within selected intervals occurring above the base of ground water protection (BGWP) which is the depth at which fresh water with a total dissolved solid composition of less than 4,000 mg/mL

The Base of Groundwater Protection (BGWP) at the location of the Origins 04-36 injector well is 327.27 m asl, with the Edmonton Group being the deepest protected geological unit. Hydrosphere monitoring program will commence on multiple fronts, including dedicated water well monitoring, landowner water well monitoring and shallow gas monitoring. Baseline sampling will include chemical composition, electrical conductivity, pH, and isotopic analysis.

- Dedicated Water Well Monitoring – Dedicated water wells are utilized to monitor the BGWP and protect freshwater aquifers. Dedicated water wells allow for high quality, consistent data throughout the lifetime of the project.
- Landowner Water Well Monitoring – Landowner water wells are selected based on location, well completions, landowner cooperation and general suitability. Samples from these wells are collected as close as possible to the source, avoiding treatment systems. The purpose of sampling landowner wells is not to determine water quality but to protect the public and ensure no migration of $CO_2$ into freshwater aquifers.
- Shallow Gas Monitoring – Headers and gathering systems from shallow gas producing formations in cooperation with Operators.

**Table 8: Hydrosphere MMV Activities**

| Monitoring Activity | Testing Technique | Frequency of Testing | | |
|---|---|---|---|---|
| | | Baseline | Active injection | Post Injection |
| **Dedicated water wells** | Within the Base of Ground Water Protection (BGWP) area. | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, Electrical conductivity, pH, and isotope analysis on all samples. | Twice per year, compositional analysis for the first 3 years of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |

| | | | | |
|---|---|---|---|---|
| **Landowner water well surveys** | Selected landowner water wells, where permission is obtained, within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | No monitoring post injection |
| **Shallow Formation Monitoring** | Gas gathering system of producing wells, in cooperation with operators, encompassing well clusters for the MMV Plan Area. | Once. | Twice per year. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |

## 3.4 Biosphere Monitoring

The biosphere is defined as the region of the earth occupied by living organisms. Monitoring of the biosphere will be comprised of soil gas monitoring to provide assurance that $CO_2$ is not migrating from the storage complex to surface through gas migration. The protection of the biosphere will be inherent to the geosphere and hydrosphere. The possible paths of migration to the biosphere include geological features and wellbores. The purpose of soil gas monitoring is to establish baseline conditions for soil in the area during various seasons, which can then be compared to sampling during the project conditions in the event of possible $CO_2$ migrations. The selection of specific soil gas monitoring locations is determined based on the offset well bore risk assessment, simulation modeling, geological structure, and surface access availability.  Samples will undergo chemical composition and isotopic analysis testing. Isotopic analysis from baseline data collection and historical data collection from 2019 to present from the Clive $CO_2$ EOR project will be used to determine unique isotopic fingerprints for distinct zones of interest. Isotopic fingerprinting allows for accurate determination of the source of $CO_2$ withing a gas sample.

**Table 9: Biosphere MMV Activities**

| Monitoring Activity | Testing Technique | Frequency of Testing | | |
|---|---|---|---|---|
| | | Baseline | Active injection | Post Injection |
| **Soil Gas Surveys** | Appropriately located soil gas locations within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |

## 3.5 ATMOSPHERIC MONITORING

The atmosphere is defined as the air mass above ground surface. Atmospheric monitoring will include the near surface air. Atmospheric gas samples will be collected and analyzed for composition and isotopes. Analysis of the air samples, specifically isotopic analysis, look for distinct markers to the storage complex indicating if the $CO_2$ present in the air is natural or the potential resulting from migration. Visual and audible monitoring will be utilized during daily checks of the injection well pad.

**Table 10: Atmosphere MMV Activities**

| Monitoring Activity | Testing Technique | Frequency of Testing | | |
|---|---|---|---|---|
| | | Baseline | Active injection | Post Injection |
| **Atmospheric Gas Sampling** | Appropriate locations within MMV Plan Area | Twice per year, for 1 year prior to injection.<br><br>Chemical composition, and isotope analysis on all samples. | Twice per year, compositional analysis for the first year of injection. Evaluate frequency every 3 years. Isotope analysis will only be done if composition monitoring indicates further investigation | TBD based on MMV data throughout the project |
| **Atmospheric monitoring at well pad** | Checks for signs of $CO_2$ leakage | N/A | Continuous | N/A |

# APPENDIX

1. Appendix A: MMV Plan (This document)
2. Appendix B: Risk Management Plan
3. Appendix C: Closure Plan

# ATTACHMENTS

1. Attachment 1: Sequestration lease boundary
2. Attachment 2: Calculated $CO_2$ plume for the project well
3. Attachment 3: Application area map
4. Attachment 4: Notification Letter
5. Attachment 5: List of notified parties
6. Attachment 7: Abandonment plug summary
7. Attachment 8: Regional hydrogeology study
8. Attachment 9: Cross section A-A'
9. Attachment 10: Cross section B-B'
10. Attachment 11: Summary Report on the Project Origins Site-specific Technical Risk Assessment

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