APPENDIX Q: MEASUREMENT, MONITORING AND VERIFICATION PLAN

Meadowbrook Carbon Storage Project

CSA Measurement, Monitoring and Verification (MMV) Plan.

October 21, 2024

Submitted by Bison Low Carbon Ventures Inc.

Meadowbrook Carbon Storage Hub **October 21, 2024.**

Proposed Monitoring, Measurement and Verification (MMV) Plan for the Phase 1 CSA approved area.

The Meadowbrook carbon storage project requires an MMV and risk management plan for the initial phase Carbon Sequestration Agreement (CSA) application that address's the degree to which our activities will not only deliver on the safe, secure and permanent geological storage objective of the tenure award, but assess how they may impact other land use activities, wildlife habitat, hydrocarbon recovery, alternate mineral tenure/pore space use, and any other land use. The phase 1 CSA MMV plan presented herein, is intended to ensure long term containment and permanent safe storage of carbon dioxide (CO_2) and demonstrate a robust iterative risk management plan incorporating assessment, measurement and mitigation of risk through the life of the project. Phase 1 is expected to start at 70-100ktpa in 2025 and add volume as customer demand and reservoir performance support. All phase 1 volumes will be delivered via tractor trailer and the pipeline connection of the Hub to a larger customer will signal progression to phase 2 and will be the subject of a second AER application and approval. All phase 1 storage operations will occur on a single wellsite at 16-29-57-25W4M.

As required for our D065 approval, and as per section 17(1) of the Carbon Sequestration Tenure Regulation, Article 9.2 of our Carbon Sequestration Evaluation Agreement (CSEA), and article 3 of CSA 5924070002, Bison Low Carbon Ventures Inc. will request AER approval of our MMV plan for the portion of our tenure defined on Schedule A to CSA 5924070002 between Bison and the Minister, effective July 30, 2024 (and attached here for reference).

In support of our request, we have considered and incorporated a plan to address the following issues, and their related uncertainties.

1. Risk Management Plan And Emergency Preparedness.
2. Atmosphere- Air Quality Measurement And Monitoring.
3. Hydrosphere- Groundwater Quality Measurement And Monitoring.
4. Biosphere Impacts (Soil Quality, Vegetation And Wildlife).
5. Geosphere- Downhole CO_2 Containment Monitoring.
6. Geosphere- Geophysical Plume Monitoring.
7. Geosphere- Monitoring For Induced Seismicity
8. Geo-Chemical Interaction Of Brine/CO_2 And Rock.
9. Geo-Mechanical Characterization And Mechanical Earth Model. (Including Thermal Effects)
10. Hydraulic Isolation And Legacy Well Risk.
11. Pipeline Design, Monitoring And Dispersion Modeling.
12. Post Project Closure Plan.
13. Potential Effects On Hydrocarbon Recovery.
14. Potential Impact On Current Land Use.
15. Potential Impacts On, And From, Alternative Pore Space Uses.
16. Conservation Of Pore Space As A Resource.
17. Bison LCV Risk Management Process Schematic.

In support of the discussion of these MMV program elements we also include the following appendices;

1. CSA 5924070002 (Appendix M D065 application)
2. Bison MCSH Risk Registry (Appendix P D065 application)
3. Millenium Baseline Groundwater Study
4. 16-29 water well lithology log.
5. Matrix Groundwater Survey plan.
6. 16-29 well data (LOT, SRT). (Appendix J & O D065 application)

7. 16-29 completion/recompletion well schematics. (Appendix G D065 application)
8. ESG 16-29 site Seismicity data March-May 2024.
9. Geo-Mechanical Characterization and Analysis.
10. TSR report.
11. SLB 1D Mechanical Earth Model
12. Legacy well assessment. (Appendix H D065 application).
13. Species at Risk Assessment for 16-29-57-25W4M site.
14. Goechemistry - Reactive Transport Model for MCSH

In recent years, several international authorities have published guiding principles for MMV plans of Carbon Capture and Storage (CCS) projects which underscore the importance of site-specific risk assessments that are adapted to storage performance over time. Our proposed MMV and risk management program incorporates principles from CSAZ741, the Alberta Energy March 2022 ‘Principles and Objectives’ guidance, the July 2024 guidance from AER regarding amendments to D065 around seismicity and MMV, and learnings from precedent project annual reports (Quest), in a plan adapted to our specific project and reservoir. Human health and safety are the primary concerns in the design and operation of all phases of the project including the MMV and risk management plans. Beyond that, the data collected and analyzed as part of the MMV plan is intended to ensure minimized impact on the environment by compliance with all AER/AEPA regulations and permanent containment of the CO_2 throughout all stages of the evaluation, development, operation, abandonment, and post-project closure operations. It is expected that based on project performance, discussions with the AER, and an assessment of risk on an ongoing basis, that the frequency and design of the MMV program elements may change to be more relevant and effective.

Evaluation Phase activities are complete, our CSA has been approved, and we are integrating all data gathered into the final technical support for our AER approvals (D065, D051, D071) including this MMV plan, which we intend to submit to the AER as soon as practical.

The scope of operation proposed in our request for AER D065 approval, to which this MMV program is to be applied, is the construction and operation of a single CO_2 injection site that will receive, temporarily store and inject up to 500ktpa of trucked liquid phase CO_2. Increased volume up to our design capacity of 3Mtpa and the pipeline connection of the Hub to emitter customers will be the subject of a subsequent application at a later date, timed to coincide with an emitter customers project start.

1. Risk Management Plan and Emergency Preparedness

The project risk management plan delivers an evolving site, scope and time specific assessment of project risks and incorporates the MMV program derived data to measure performance, adjust practices and inform decisions. As mentioned previously, the risk management plan is based on the process and principles outlined in CSAZ741 and incorporates ongoing site-specific assessment, avoidance, measurement, mitigation, and reporting of project and process risks. An integral element of the plan is our risk registry which evolves through a monthly multi-disciplinary review as the project progresses, knowledge is gained, and as risks change or are identified. A copy of the current risk registry is attached to this application (Appendix 2). Going forward, we will incorporate an independent audit, and industry best practices commitment, to ensure our program meets or exceeds the required standard.

Our risk management plan is entirely consistent with Bison values as a company and our objective for the Meadowbrook project. The guiding principle in assessing risk prioritizes human health and safety over project performance. Our internal risk management plan is augmented with the resources of external subject experts to provide a level of independence and ongoing critical assessment. **Jeff Weaver**, Founder and CEO of InUnison Technologies Corp. provides extensive experience and expertise in the areas of Safety, Training, Competency, Maintenance and Management of Change to Bison and the MCSH project. The integrated management system, and the associated technical advisors, provided by InUnison will provide the tools to the project that assist in protecting all stakeholders and operations, lower our risk profile, and drive compliance.

From a general safety perspective, CO_2 in low concentrations is not considered a health risk (air we breath is 400ppm) but at a high enough concentration for a long enough period, CO_2 can be an asphyxiant. CO_2 is also heavier than ambient air and will settle until it disperses. CO_2 is not combustible. Our operation will handle >95% pure CO_2 in a liquid phase under high pressure and low temperature, which facilitates safer long-term handling (corrosion) and storage. At atmospheric conditions CO_2 is a gas, heavier than air, and any release will flash to gas phase and dissipate in a matter of minutes to concentrations not considered a health hazard. In most Alberta weather conditions (10C and 70% humidity) a CO_2 release will be visible as it condenses to snow or fog. Project specific modeling of the dispersion plume created by a catastrophic release in terms of release rate, volume and duration will inform the D071 (Emergency Preparedness and Planning) risk assessment. This will inform the design of the pipeline system in later phases, but in phase 1, will concentrate on the dispersion risk from a 55t storage tank onsite. Design considerations to reduce the likelihood of a failure, reduce the volume if there is a failure, and increase the chance of detection before a failure will be combined with location considerations, to mitigate potential health impacts.

The potential release rate and volume for this phase of the project will be limited by the capacity of the trailers used to transport (25t, and 35t B train) and store (55t) the dense phase CO_2 (2200kpa, -24C) delivered by tractor trailer to the initial Meadowbrook storage site at 16-29-57-25W4M. Initial volumes will be delivered by and from Ferus Industries Ft Saskatchewan facility. Any additional volumes sourced will be delivered by Ferus or other licensed, bonded contractors with experience handling similar materials.

With regards to emergency planning for the proposed Bison installation, the worst case scenario would entail a catastrophic failure of one of the 55 tonne liquid CO_2 storage tanks. Assuming a 100% full tank operating at -24C and 2200kPaa this would result in a release of approximately 25,000 Sm^3 of CO_2 assuming the entire tank volume converted to gas phase. More likely, given the sudden drop in temperature, a portion of the volume would form a solid, dry ice, which would gradually sublimate to gas phase. For the purposes of calculating the length of time for the vessel to depressurize, an 8" failure in the vessel wall was considered and it was determined that the vessel would attain atmospheric pressure in just over one minute. From a safety perspective, the extreme cold would pose a risk to personnel in the immediate vicinity. In addition, gas phase CO_2 is heavier than air and hypoxia would be a risk in confined or low lying areas close to the venting tank. However, given the relatively low potential volumes of gas phase CO_2, the concentrations would disperse in the atmosphere very rapidly in the area surrounding the facility and would pose very limited risk or impact to people or animals outside a 100m radius of the facility. Regarding risk to operating personnel in close proximity, those risks are mitigated by Bison's safety program and Standard Operating Procedures.

Bison has reviewed the safety protocols of operators involved in trucking liquid CO_2 and concludes that there are limited stakeholder risks in the event of a release of CO_2 from the proposed facilities and consistent with other operators operating under similar conditions, recommends a 100m EPZ.

As a practical comparison, modeling of a 1500ton release from a fullbore rupture of a 50km 8" pipeline at 11Mpa had a maximum $158m^2$ plume of 10% CO_2 concentration 2.5m high after 3 minutes (UK Energy Institute reference). A full rupture of all three tanks onsite would release approximately 10% of that volume and form a plume much smaller than the $150m^2$, on a lease where the first $500m^2$ in any direction (assuming a 10m wide plume focused in a single direction) would be contained within the lease boundary.

Failure of a high pressure steel container (pipeline or vessel) can have an explosive effect that would pose a significant risk for a short distance. This risk would be greatest at our plant site and be mitigated by proper design, ongoing testing and preventive maintenance, proper training and safe work practices.

2. Air quality measurement and monitoring (Atmosphere)

Bison has engaged with Millenium EMS Solutions Inc. (MEMS) and SenseNet Inc. to deliver our atmospheric monitoring strategy for emissions and leak detection. We have designed a robust innovative program that will be refined as data is generated.

The 103/16-29 injection well has a non-serious surface casing vent flow that was measured in November 2023 at $4.1m^3/d$ of 96% methane (trace CO_2). As per AER regulations we will re-test the well within 90 days of injection commencing, annually for two years, to determine any changes and the defined go forward monitoring plan required. In addition, we will sample the rate and composition of the SCVF gas at least annually for as long as it lasts.

SenseNet (www.sensenet.ca) will deploy a permanent continuous AI enabled 'mesh net' wireless sensor array sensitive to 40ppm CO_2/CH_4, at our 16-29 injection facility site, and at five other sites and residences within the project area. Our site array will initially require a 12 sensor array around the wellhead area, one gateway to transmit data to the cloud, and soil gas measurement instruments to support source location determination attributable to any atmospheric change. This will be operational prior to commencement of CO_2 injection. The technology is currently deployed in early forest fire detection and is supported by a range of credible sponsors including the Governments of Canada and BC, and is an ideal solution for consistent, real-time, cost-effective monitoring over a wide area. As part of the technologies testing and validation, we will conduct a number of small duration/volume ’leaks’ to optimize arrays and determine sensitivities, which can then be compared against currently deployed solutions.

The four additional deployment sites will be a combination of the two remediated gas migration ‘leaks’, local resident locations and an oil and gas industrial site within our tenure. Access to the SenseNet arrayed data is intended to be available to any stakeholder online, in real time.

In addition, subject to landowner consent, we will conduct **baseline** and annual air monitoring test of all legacy well sites that penetrated the storage complex within 2 miles of the injection well for indications of leaks, GM/SCVF gas releases, for a minimum of three years, and report the results. Any flows will be assessed in terms of rate, composition (isotopic and element) and changes over time.

As reported by Quest (AR 2021), daily operator rounds have proven capable of picking up smaller emissions more quickly than sensors have recognized them, and we will also rely on diligent operators as a primary monitoring mechanism.

3. **Groundwater quality measurement and monitoring (Hydrosphere)**

Alberta Innovates completed a regional assessment of the groundwater resource in association with the Quest project (reference 2, Brydie et al) which provides useful information as our project is within the study area. From Lea Park to surface in ascending order there are 4 aquifers (Basal Belly River, Foremost, Oldman/Horseshoe Canyon and Surface/Bearspaw zone) with the McKay coal zone above the BBR recognized as an aquitard, but the top three being in communication. In our project area the Basal Belly River sand (21m thick, 25% porosity, 10,000ppm TDS) is at 350m and the required surface casing depth today (base groundwater protection) is 429m. Wells in our project area produce from the Horseshoe Canyon (at <10m to 90m depth) with an average TDS of 1350mg/l. The AO for Alberta drinking water is 500mg/l and anything above 4000mg/l is not considered potable. Cisterns for drinking water and dugouts for agricultural use are the preference of many neighbors in our project area. The town of Legal, 2 miles east of the site, and our immediate neighbor to the west have both encountered coal seems >1m within 10m of surface.

Bison commissioned a groundwater resource assessment for the application and surrounding area (by Millenium Environmental Mgmt., appendix 3) and followed up with a baseline groundwater sampling program which began in Q4 2023 (see Baseline data section of the D065 application). A second round of groundwater testing is happening in October 2024 that will re-test all wells from last year and an additional 5 wells. The groundwater resource management program is designed to understand and protect the potable groundwater resource in the project area and recognize any impact the project operations may have on groundwater, including detection of injected CO_2. The further baseline testing is intended to establish an evidence based statistically relevant ‘no effect’ baseline against which any future variations can be measured. These measurements could trigger, or provide backup information to another containment trigger, by recognizing the introduction of CO_2 or crossflow from a deeper more saline aquifer.

Table B1 in Appendix 3 shows the registered water wells in the area within a one mile radius of the injection well and figure 7 is a stick diagram of well depths and water well lithologies. Several wells in the registry are not recognized as being ‘in existence’ by the current landowner and are no longer in use or intended for future use. We have agreement to test four more neighbor wells once a well clean out can be performed. We will retest 8 baseline groundwater sources before commencing CO_2 injection and will test all wells at least once annually after that. Triggers we will monitor which could signal contamination by injected CO_2 include a) increased salinity or CO_2 concentration, b) acidification (pH change), c) an increase in trace element concentrations, d) change in the C+ isotope 'finger print'.

Our routine analysis will look for these triggers and track detailed water elemental analysis, metals, physical properties, conductivity, pH, TDS, and a gas compositional analysis of any gas exsolved from the sample. When CO_2 or methane are recovered in sufficient quantities, we will also complete an isotopic analysis to finger print against any future increase or compositional changes.

Work to date has shown that the potable aquifer potential in the application area is variable and low quality. Naturally occurring springs (artesian flow) are present in the area and dugouts are commonly used. A majority of wells on record are not used for domestic or agricultural use and owners had limited interest in testing. We have tested (rate, water chemistry, gas composition where available) five neighbor water sources in use (three wells, one dugout, one spring), in addition to analyzing water from a deep observation well drilled on our injection well site. These results are consistent with the Alberta Groundwater Atlas.

Bison's deep groundwater monitoring well was drilled to 90 m with the intention of testing all productive aquifers capable of producing potable water. A copy of the lithology log from the well is Appendix 4 and shows that no aquifers were encountered until 75m below ground level. The well did encounter a low quality sand over the basal 15m of the well and we did encounter a hydrocarbon show (gas TSTM) near the base of the well. Water recovered from a bail test had TDS 4400 mg/l. The static water level was 49m and no sustained rate could be determined as fluid level continued to drop. Based on the water quality, water rate and paucity of uphole aquifer presence, we do not plan to drill additional observation wells but will continue to test this well as part of the 'baseline' and 'ongoing' monitoring programs. Gas analysis indicated 96% CH_4 and 1.5% Nitrogen and is highly likely coal bed methane derived.

As the well does not have multiple aquifer levels it remains a single zone bottom hole completion with a sand pack over the bottom 10+ meters. We will annually sample and analyze fluid, gas (dissolved and free, isotope on any CO_2, CH_4), pressure and free water level, and report this information annually as part of our project report.

The Meadowbrook project does not require, or plan for any diversion or industrial use of surface water, or shallow non-saline groundwater resource in the commercial phase of our project. The 16-29 well and all future observation and injection wells will cement surface casing to a minimum depth signaled by the AER (base of groundwater protection is 400m in our project area), which is deeper than the deepest recognized potable water resource in the area (<90 m). Surface casing will isolate and protect any potable water zone from communicating with a deeper saline aquifer, or CO_2 sequestration zone. Surface water drainage from all sites will be managed to ensure runoff does not enter any watercourse or leave the lease.

For the sampled groundwater to be properly assessed we also need to monitor the composition and key isotopic fingerprint of the injected CO_2 stream. **We will monitor and measure gross gas mass and composition annually, and report that data.** Should we recognize elevated levels of CO_2, methane or any sign of H_2S in the groundwater, we will use the isotopic data to identify the source. Generally, it is recognized that d13C isotopic values range by source from -9 (air), -19 to -27 (vegetation) to >-33 from geological sources. H_2S produced by bacterial reduction of HCO_3 is also isotopically different from thermally derived H_2S at depth.

Appendix 5 summarizes the specific details of the groundwater sampling and analysis program that will gather additional baseline data in late 2024 and continue through at least the first two years of the project.

4. **Impacts on the Biosphere, including Soil quality (monitoring and impact) and Vegetation, Wildlife or Human Health (discussed in HSE section).**

Impact on the biosphere could occur as a result of excessive surface disturbance, leaks to the atmosphere or spills affecting soils, groundwater, or the biota that reside in those environs. Minimizing our effect on the biosphere will include reducing our footprint whenever possible. New land use will be minimized. In this initial phase our surface disturbance will be localized to a single <2ha wellsite. At full commercial scale, we will add three well-sites (2ha) and one plant site (3-4ha) to the previous count of >300 sites within the boundaries of the tenure. Sites will be connected by a 30m wide pipeline 'right of way', which will be reclaimed and returned to agricultural use once installation is complete. Where possible, we will re-use existing leases, lease roads and rights-of-way. There are no pits or flares associated with the post drilling phases of either the Evaluation or commercial phase activities. CO_2 migration through a soil horizon would represent a breakdown in containment or loss of hydraulic isolation and should be detected by other MMV methods before becoming a soil concern, but soil monitoring at all locations identified as potential hazards is part of the trigger recognition protocol. Spillage of produced fluids at surface, especially saltwater, could negatively impact the biosphere but is unlikely as the project targets injection, not production, and any fluid recovered at our facility from line pigging or CO_2 stream dehydration will be safely gathered, stored in bermed tanks and disposed of as per AER regulations. Any spills that may occur will be reported as required to the AER and result in a revised Operations risk assessment.

We will conduct **baseline** soil gas sampling at all sites we develop, and regular right-of-way inspection of all pipeline routes to recognize early indications of any impacts. The initial phase of the project (the subject of this application) includes development of only the 16-29 injection well site. As identified previously as a portion of the SenseNet air monitoring, we will have a soil monitoring capability at a minimum of 6 sites initially, including an 12 probe array at 16-29, three adjacent reclaimed sites, and a legacy site flagged by our stop light risk assessment as warranting further observation. Each site will also deploy a continuous measurement sensor (EMS). The intention would be to recognize the presence of any CH_4 or CO_2 and then identify the source and mitigation strategy most appropriate.

We will monitor soils for signs of potential migration from the storage complex at the 16-29 injector site utilizing an 12 station array with measurements at .5, 1.0 and 2.0m depth as shown on the attached site plan (appendix 5). This survey will be deployed for baseline data in October 2024 and subsequently the 36 measurements will be completed in the spring once fields are dry, seeded and initial signs of uniform germination are visible at surface (early June), and again at the point of maximum crop development (late September). This data set will establish a baseline and performance history against which any changes in surface soil gas can be measured.

In addition, we will acquire a photogrammetry survey over 150% of the forecast plume area at an appropriate resolution to assess vegetative health. This involves a multispectral photo mosaic via drone to establish a soil health indicator that will be replicated annually and provide an early indication of change over a wider aperture than possible with soil sensors. Change visible on the PG survey will be followed by sensor deployment to help ascertain if it can be correlated to project emissions in any manner. The baseline survey will be acquired in October 2024.

Significant effort will be spent on determining the pre injection profile as an accurate baseline determination of any legacy emissions. This will properly differentiate leaks attributable to the storage project from any existing emissions, and also provide critical information from a credit accounting perspective. It's not quite as simple as suggesting gas migration issues are CH_4 and we will be injecting CO_2, although both those assumptions are correct, as CMC has shown with their Newell County project that bacterial sulfate reduction has generated isotopically unique CO_2 in SCVF's. This needs to be identified, properly characterized, and differentiated isotopically from injected CO_2, which the monitoring program will be designed to accomplish.

We will not be developing pipeline infrastructure during this phase of the project so dispersion modeling of a plume was not undertaken for this project application.

Liquid phase (2200kpa, -24C) CO_2 will be transported in 26-35t loads via tractor trailer and stored at similar pressure and temperature onsite in 55t trailers designed, licensed and utilized specifically for CO_2 in oilfield and industrial applications in Alberta today. Ferus Industries Inc. is the transportation contractor for the initial contracted volumes and is licensed and insured for the provision of those services and equipment. The SenseNet sensor array at the 16-29 site will identify any emissions attributable to unloading/tank leakage or injection related leaks. The sensitivity to identifying leaks will be determined, demonstrated, periodically tested, and reported. We are targeting process losses of 1% or better.

Table 3 Exposure reactions to carbon dioxide

Concentration in air (% v/v)	Effect
1 %	Slight increase in breathing rate.
2 %	Breathing rate increases to 50 % above normal level. Prolonged exposure can cause headache, tiredness.
3 %	Breathing increases to twice normal rate and becomes laboured. Weak narcotic effect. Impaired hearing, headache, increase in blood pressure and pulse rate.
4-5 %	Breathing increases to approximately four times normal rate; symptoms of intoxication become evident and slight choking may be felt.
5-10 %	Characteristic sharp odour noticeable. Very laboured breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness.
10-15%	Within a few minutes exposure, dizziness, drowsiness, severe muscle twitching, unconsciousness.
17-30%	Within one minute, loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death.

With regards to the health risk of a catastrophic failure of one of the 55 tonne liquid CO2 storage tanks. Assuming a 100% full tank operating at -24C and 2200kPaa this would result in a release of approximately 25,000 Sm3 of CO2 assuming the entire tank volume converted to gas phase. More likely, given the sudden drop in temperature, a portion of the volume would form a solid, dry ice, which would gradually sublimate to gas phase. For the purposes of calculating the length of time for the vessel to depressurize, an 8" failure in the vessel wall was considered and it was determined that the vessel would attain atmospheric pressure in just over one minute. From a safety perspective, the extreme cold would pose a risk to personnel in the immediate vicinity. In addition, gas phase CO2 is heavier than air and hypoxia would be a risk in confined or low lying areas close to the venting tank. However, given the relatively low potential volumes of gas phase CO2, the concentrations would disperse in the atmosphere very rapidly in the area surrounding the facility and would pose very limited risk or impact to people or animals outside a 100m radius of the facility. Modeling of large scale ruptures (UK Energy Institute reference) shows a dispersion of much larger leaked volumes to <5% concentration in <3 minutes and a 'Significant likelihood of toxicity' of >60 minutes. Regarding risk to operating personnel in close proximity, those risks are mitigated by Bison's safety program and Standard Operating Procedures.

The entire surface area of the phase 1 CSA tenure is considered habitat for endangered or species at risk (Sage Grouse and raptor) and the entire Evaluation tenure is within a migratory bird 'fly way'. **Baseline** surveys conducted by qualified independent biologists have been completed on work to date and will establish if the presence of species at risk will have an effect on either the timing of activity or location of a segment of the project. We did respond to an expressed concern over impact on migratory birds and adjusted the test well location away from the edge of Manawan Lake until further review and engagement could properly assess and inform landowner concerns.

5. **Downhole CO2 containment and monitoring (Geosphere).**

This application requests approval to inject up to .5Mtpa for 15 years into a single injection well at 16-29-57-25W4M, for a total injection volume of <10Mt. As summarized in the reservoir modeling portion of this application, the static plume (base case) for this volume should have a radius from the well of < 1000m and cover an area of 2.5sq km after 15 years injection and 4.5 sq km 15 years after injection ceases (30 years on). The modeled plume outline is included as figure R-14 in the reservoir modeling section of the D065 application, with a version included below (figure 1). Notwithstanding the relatively small volume, this phase of the project should provide important conclusive evidence of near wellbore containment, injectivity effects, and plume visibility. We are highly confident of containment being established with the Evaluation phase well operations completed to date, and that the methodology we propose for this initial commercial phase will properly monitor that stability, and immediately identify any loss of containment.

Containment today. Wellbore isolation of the injection zone has been established by multiple independent measurements in the 16-29 well (Array Annular Sensor and DAS/DTS data transmission during Leakoff and step rate injectivity testing) and will be re-confirmed annually as part of our D051 injection well approval with the AER through annual packer isolation testing and continuous real time monitoring of the storage interval and caprock integrity.

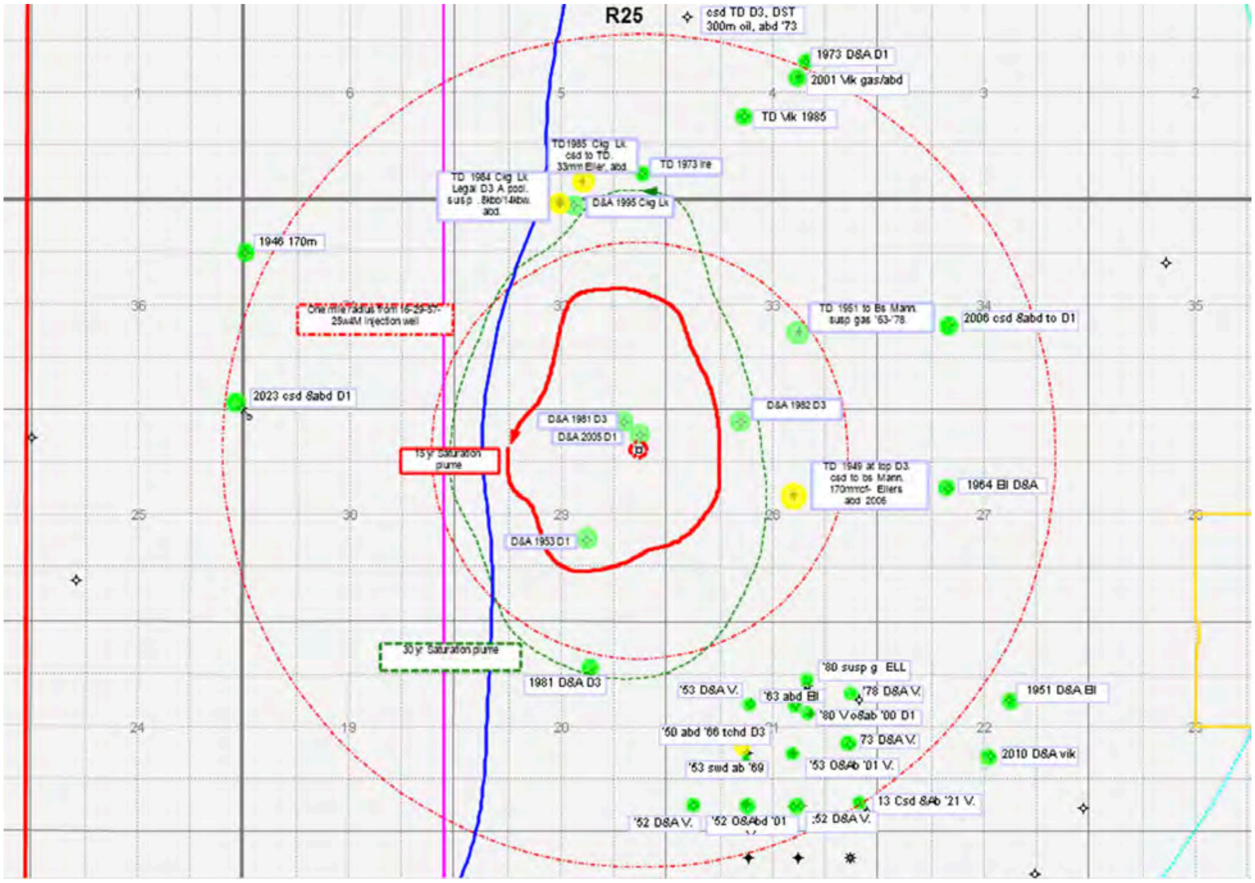


Figure 1. Saturation plume after 15yrs injection & at 30 years centered on 16-29-57-25W4M. 1 &2 mile radius from 16-29=red dash. Amber/green= legacy stop light designation

The 16-29 Evaluation phase well was designed with multiple objectives in mind, including the acquisition of all key data required in support of the final characterization of the Woodbend Grp. for safe permanent commercial scale storage, and hopefully future use of the wellbore in the project as an injector and/or observation well. With multiple objectives in mind and recognizing lost circulation resulting from a combination of formation under-pressure and exceptional reservoir quality as a primary consideration, the well was drilled and cased into the caprock (Ireton), with the nearest uphole aquifer (Nisku) behind casing, and the storage complex (Leduc and Cooking Lake formations) left open hole. The well operation included a core of the Ireton caprock, and a Leakoff test below the casing set 8m above the top Leduc, which confirmed integrity of the Ireton caprock, and no communication to the Nisku (operation summary and report attached as appendix 6). The SCAL of the Ireton core included detailed mineralogy (SEM, XRD), tight rock analysis, unconfined stress analysis and measurement of some geomechanical properties.

- As part of the casing string set above the storage complex, Bison deployed two Haliburton Array Annular pressure and temperature sensors strapped external to the casing string, as part of a fibre optic bundle that also included DAS (acoustic) and DTS (temperature) cables, that are cemented in the Nisku interval and are generating real time P&T data today (reservoir pressures of 8603 and 9201kpa and Temperatures of 47.5 and 48.2 degrees celsius respectively, at depths of 1235 and 1270m kb, on Sept 19, 2024) and have been operational through the Leak-off and step rate testing portions of the well. We have attached two presentations of the data (appendix 6) which clearly demonstrate isolation of the base Nisku sensor from any pressure response during the Leak-off test of the Ireton caprock, and isolation of the base Nisku sensor from any pressure response to the Leduc step rate test. The Distributed Temperature Sensing (DTS) cable will also provide a qualitative assessment of any breakdown in containment being reflected in a temperature change along the well, as zones begin communicating.

On drilling the storage complex we did experience significant losses in both the Leduc and Cooking Lake formations that appeared to stabilize at a fluid level that equilibrated to the estimated BHP, which gave us an 'on the fly' early indication of injectivity, but also compromised the value of formation fluid sampling we were able to obtain via MDT testing.

Well Completion operations in October 2023 involved a chrome alloyed bottom hole assembly that will protect all tubulars exposed to a formation brine/CO2 mixture from corrosion. (program attached as appendix 7). A step rate injectivity test and fall off, where 800 m3 of freshwater were injected at rates up to 4.0m3/min (approximately equal to 2Mtpa), was completed and confirmed injectivity of at least four times that required for the initial phase, and twice our target for the commercial phase, on an injectivity/well basis. The BHIP of 13,000kpa, only increased 15% above static formation pressure and is >1000kpa below hydrostatic pressure. As mentioned previously, and visible on the Haliburton sensor chart (appendix 6), the Leduc pressure gauge shows only minor pressure response downhole to the stair step change in rates, and the sensor reading the lower Nisku zone pressure does not move at all. The gauge reading also covered the Leakoff test in the Ireton and confirmed that there was no annular, fracture, or reservoir communication from the storage reservoir through the caprock to the Nisku 'quiet zone'.

As described in the previous sections, having a robust set of compositional data able to differentiate injected CO2, soil gas and SCVF gas, acquired before and during injection, will be a valuable trigger signal and comparative source identifier of a loss of containment if we recognize CO2 changes in the future.

Based on the planned recompletion of the well we feel that 16-29 well is capable of;

a) **CO2 injection** well in excess of the 1400tpd requested in this application, at a requested bottom hole injection pressure limit of <18,200 kpa. It is estimated that if operating at the licensed capacity of 500ktpa we could run the injection <25% of the time. The pressure and temperature gauges run on the tubing string and open to the storage complex are generating injection and shut in data for the Cooking Lake and will provide the same **storage complex performance** information to determine any discontinuities or potential loss of containment indications from the storage complex, for the initial phase of the operation requested.

b) Containment monitoring of the first 'quiet zone' aquifer above the storage complex (Nisku), and caprock integrity in the wellbore area, are provided by the two Array Annular P&T gauges operating in the Nisku, with proven isolation from the storage complex.

On the basis of the functionality demonstrated, we do not think additional observation wells, or redundancy in injection capacity is required to support this initial phase 1 of the project (<100ktpa). Subject to injection well and reservoir performance, and contracting volumes above 100ktpa, we would complete the phase 1 facility expansion (additional tankage, grid power) and drill a second well from the same wellsite that would provide identical functionality and redundancy in all three roles (storage complex observation, injection, and 'quiet zone' aquifer observation). We feel the two well configuration and facility design requested in this application will support the 500ktpa full volume over the life of the project.

When developing the full commercial project (3 clusters at 1Mtpa) we would also plan to utilize two additional two well clusters, with similar functionality in all three uses.

Mechanical well integrity will also be demonstrated before injection commences, and every year by way of a packer isolation test as required by AER D051. Tubing and Casing Inspection logs will be run every 5 years, or in response to a change in casing pressure.

Potential presence of Faults. The risk of loss of containment owing to the presence and potential for leakage along faults has been assessed through a combination of tools and measurements and is also discussed in the Geomechanical risk section of this submission. We have acquired a grid of seismic data that demonstrates that faults with sufficient offset to displace reflectors above or below the complex are not present within the forecast plume area. We will add to this data set to guide the selection of additional cluster locations. Geophysical plume monitoring will track the potential movement of CO2 vertically along sub-seismic faults, or by any other mechanism. As discussed in the next section, demonstrating the visibility of the plume geophysically is a primary objective of the initial phased approach and will be an important component of demonstrating containment.

As part of the open hole evaluation of the well we also acquired a continuous borehole imaging survey (FMI) that is designed to identify linear features that could represent fractures or faults. There were no fractures or faults associated with the caprock interval.

Future Seismic focused containment Monitoring. The geophysical Induced Seismicity Monitoring, both surface and DAS deployed, will target detection of movement or re-activation along natural or induced faults or fractures in the near wellbore area. In addition, in support of data to assess containment risk we cut a core in the Ireton, conducted a Leakoff test that confirmed an absence of any fractures or faults in the immediate wellbore area, and we also acquired wireline formation micro scanner (FMI) data that would detect and orient evidence of faults/fractures intersecting the wellbore. None of these data provide any indication of elevated containment risk by fractures or faulting in the area investigated by the respective tool.

Following commencement of injection, a fault breach of containment more distal to the wellbore than can be seen in the existing ‘near wellbore’ data will be detected in a proximal area by a change in T or P in the shallow zone observation well, and distally with a change in character in the dispersion plume.

The Leduc formation and Ireton top seal are also extremely well studied in the project area and fault breach is not recognized as a local or regional issue for the Ireton aquitard (Bachu et al 2004, Subsurface Characterization of the Edmonton Area Acid-Gas Injection Operations). Supporting the site specific work we have attempted to demonstrate the integrity of the caprock is the reality that the Ireton is recognized as a world class seal capable of trapping >1bn bbls of oil within 50 miles, which is also a very important factor.

6. Geophysical Plume monitoring (Geosphere).

Initial results from Quest, Boundary Dam and Tomakomai (Japan) projects have been encouraging in supporting 4D (time) seismic data imaging the change in impedance as CO2 displaces brine away from an injection wellbore in the storage reservoir. VSP, 2D and 3D data have all been shown to be effective in certain circumstances. The ability for this to work for Bison’s project will be subject to zone thickness, rock quality, acoustic attributes, volume injected, saturation change and frequency content of the data. Our initial Biot Gassmann fluid replacement modeling of CO2 displacement of brine in the Woodbend Grp. carbonates at Meadowbrook suggests that we should be able to see a response as the plume migrates in the reservoir.

Prior to the start of the commercial CO2 injection in significant volumes we will acquire a **baseline** three element Walkaway Vertical Seismic profile (WVSP) data acquisition program utilizing a vibrator energy source shooting into a buried surface geophone array and the DAS delivered via the fiber cable, to show the response against which the plume development will be measured over time when compared with subsequent surveys (4D). At the later of 1 year post injection startup, or injection of 100,000t of CO2 and periodically thereafter, we will re-shoot the WVSP and seismic surveys, in a time lapse fashion to measure the expansion and orientation of the fluid substitution effect (CO_2 plume) in the reservoir. This is not only intended to help verify visibility in the storage complex (i.e. containment) but if CO_2 enters an overlying formation it is highly likely it will demonstrate a similar fluid substitution effect that would be visible and be an early indicator of non-conformance or loss of containment.

The planned program layout is shown below and in the initial two surveys will involve the acquisition of 2D Vibroseis, 3D mega-bin, and 3D crossed array surveys that will allow us to determine what acquisition effort strikes the balance between required data quality to effectively image the plume, and cost. Several other parameters (sweep, buried vs surface phones) will be tested and the optimal configuration will be adopted for future surveys. As the plume begins to exceed a distance of approximately 600m offset from the injector, additional seismic arrays will augment VSP data in mapping the expanding plume.

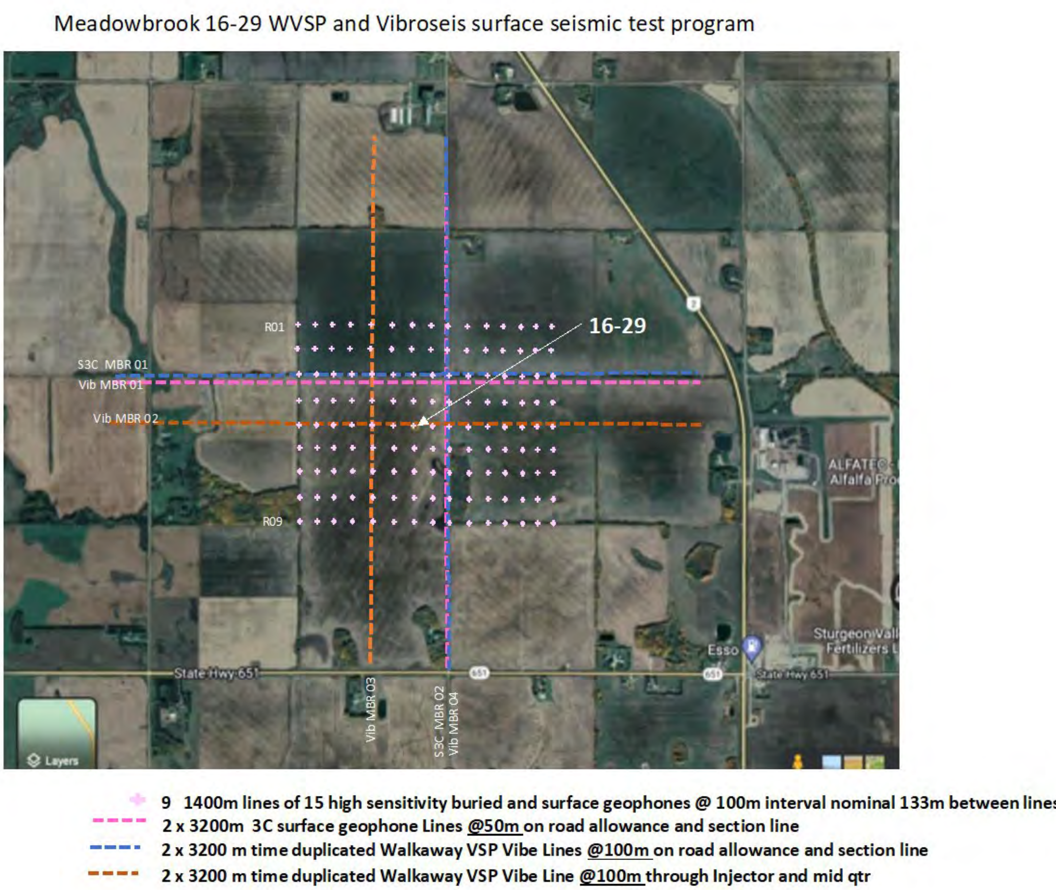


Figure 2. Proposed multi aspect Seismic survey layout, first baseline to be acquired fall 2024.

Using a combination of the seismic plume modeling for area, pressure response during shut in periods in the injection zone, and having the ability of follow-up well logging of the injection well for CO_2/water saturation and thickness, Bison should have the best method to monitor the performance of the reservoir in handling the long-term injection of large quantities of CO_2, both during the commercial lease phase of the project, and during the post closure period.

The Distributed Acoustic Sensing (DAS) fiber cable deployed in one well of each cluster, and the array of surface phones required for the ISM, will also be utilized as ’permanent’ receivers for the VSP and plume migration seismic surveys.

7. Monitoring for induced seismicity (Geosphere).

Induced seismicity can result from CO2 or fluid injection where formation pressure increases to a level that causes the rock to fracture, where pressure changes into a fault plane, or where injection into an adjacent reservoir changes the magnitude of in-situ stress. All of these can cause existing zones of weakness to be reactivated by the injected fluid. This is differentiated from natural seismicity but is no less important when considering its possible effect on containment in a CO2 project. Our induced seismicity monitoring efforts target the recognition and measurement (for location, magnitude and risk) of all seismicity that could influence permanent containment and induced seismicity which may affect safety of people or property, structural integrity of the storage complex, or alternate pore space or land use.

Seismicity below the storage complex in the PreCambrian basement has been seen at the Quest project but is not considered by Quest to be a mitigatable risk at present as it has generally been below the 2.0ML level, although recognized by Zoback to be increasing in both frequency and magnitude and attributable to injection (figure 3). In Alberta, well completion operations (frac’ing) utilize a ‘traffic light’ approach where seismicity events >2.0ML are reported and events exceeding 4.0ML require operations to cease. We understand Quest has adopted a similar trigger threshold on a voluntary basis and we would propose to do so as well, subject to discussions with the AER. Events exceeding 3.5ML can often be ‘felt’ at surface. Over 95% of events recognized at Quest have been <0.0ML and there were no events >2.0 before 2019 and there have been 7 recognized events >2.0 since 2020 (to YE 2023). It is plausible that this seismicity at Quest is due to injected fluid reactivation of zones of weakness in the basement as the storage complex is in the Basal Cambrian Sand sitting immediately above the basement. As referenced by Zoback (2023, Managing Earthquake Risk) the magnitude of an event is related to the size of the fault that slips, NOT the magnitude of the pressure change, resulting in increased risk with increased pressure plume area and connectivity to faulted terrain (basement vs strata bound). The increase in seismicity in the greater Edmonton area extends across a broad area well beyond the Quest tenure and as more proponents commence operations it will become increasingly critical to understand both the level and location of any increase in seismicity. Although our injection is targeting a stratigraphic interval separate from both basement and the BCS, this evolving seismicity situation frames the backdrop into which both our project and our seismicity monitoring program need to integrate to properly assess and manage OUR induced seismicity risk.

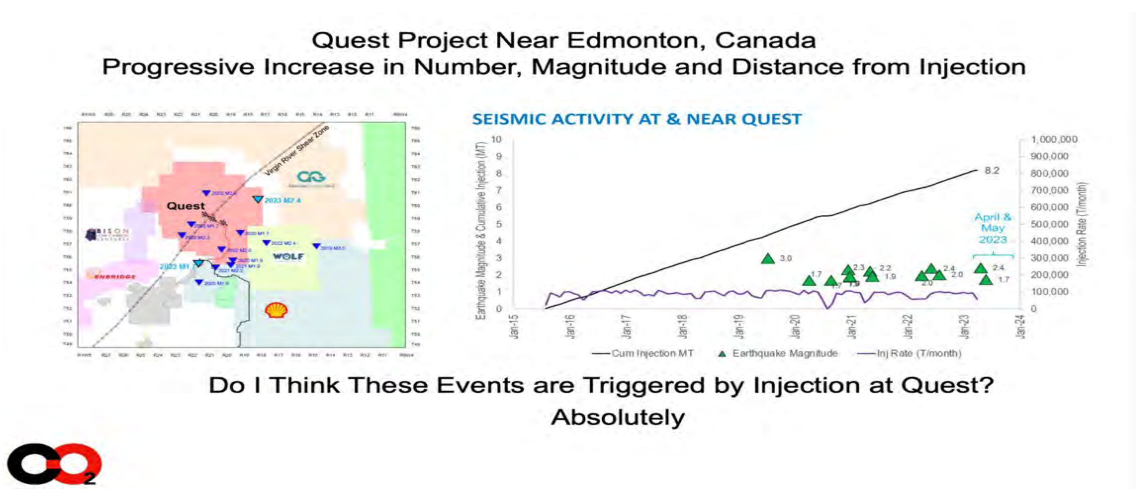


Figure 3..Taken from Zoback, Managing Earthquake Risks Associated with Large-Scale CO2 Storage

An increased level of concern regarding injection induced seismicity has emerged in Alberta in 2023 around events >5.0ML which have occurred in the Springburn area, postulated to result from long term high volume injection into the Leduc Fm. where it represents the aquifer sitting on basement. This induced seismicity only becoming evident many years after injection started is a clear example of the necessity and scope of the measurement and monitoring required. At Meadowbrook, we are extremely unlikely to connect with the basement as there is >700m, including an evaporite interval, between the Woodbend Grp. storage complex and basement. Stratabound seismicity is also very unlikely as the operating injection pressure will be safely below the regulated limit, the reservoir is naturally underpressured to begin with, our operating range is well below SHmin., and there are no fault displacements recognized seismically that could signal a potential risk of re-activation. The AER establishes an injection pressure envelope that we need to operate within to not induce fracturing. In our application that limit would be approximately 90% of predicted SHmin of >26MPa BHIP (>23MPa BHIP). Our injection pressure is not forecast to exceed 70% of the limit, or 18.2MPa BHIP, which was confirmed by our step rate test as more than adequate for as much as 2Mtpa at <13.5MPa BHIP, vs our requested volume of up to .5Mtpa.

The Leakoff test conducted on the Ireton caprock, after drilling out the casing set above the storage complex, confirmed that there was no breakdown with a pressure build to 26Mpa. Operating within the AER approved pressure envelope will significantly mitigate the risk of induced seismicity due to over-pressuring the reservoir by virtue of injection.

Monitoring Plan. Notwithstanding an operating plan to mitigate the occurrence, we will have an active monitoring capability to recognize if seismicity occurs, either induced or natural. We began passive monitoring on March 14, 2024 with the deployment of 5 Hawks geophones arrayed approximately 1500m offset from the 16-29 injection site. This array will record all naturally occurring baseline seismicity until injection begins. This array is capable of detecting events down to 0.5ML scale within the injection area and has demonstrated its effectiveness in picking up events correlatable in time and magnitude with the Alberta Raven system, during our first two data dumps (appendix 8). During the installation of our surface array, we conducted a field test where an artificial source was used and recorded by the surface and downhole arrays. Notwithstanding the ‘lightweight’ surface source (post pounder), indications of the events were seen at all stations and the data is currently being processed and interpreted by our research consortium partner CMC. This data may better inform the lower resolution limit of the existing array. The pre-injection information is a record not a trigger and will NOT be monitored in real time as it is intended to establish a baseline against which we can compare the impacts of injection. We are also conducting our own ‘induced’ surface generated seismicity experiments to determine the operational capability and sensitivity.

Once injection commences we will continue to monitor the surface geophone array to recognize any seismicity that occurs and report magnitude and frequency. This data will be screened and analyzed to identify any anomalous seismicity that could change the risk profile attributable to the containment of the storage complex and trigger an appropriate response, which could include 24/7 real time interrogation, and escalating the induced seismicity monitoring from the surface array to incorporate downhole acoustic measurements via a Distributed Acoustic sensor (DAS) fibre optic cable which acts as a vertical geophone array to help provide the accuracy in depth. If we recognize events of a magnitude greater than 2.0ML that are reasonably correlatable to injection activities we will begin interrogating the DAS cable feed which incorporates downhole measurements which will allow us to more accurately determine the event location in the vertical plane. Bison’s ISM array deployment will be supported by CMC, with data interpretation and interrogation provided by ESG.

The same geophysical fibre infrastructure deployed for ISM also provides a key measurement and verification function by helping seismically image the CO_2 plume as it develops and migrates by way of time lapse walkaway VSP’s (plume Modeling- containment). The DAS cable also provides an ability to recognize and interpret microseismicity which could result if fracture propagation, fault slippage, fluid movement, and pressure relaxation in a formation were caused by pressure changes and associated stress changes within the reservoir.

8. Geo-chemical characterization and CO2/brine/rock interactions.

The introduction of dense phase CO2 to the relative equilibrium in the storage complex will have an impact in a number of areas that need to be measured (or estimated) and modelled for their possible effect on mineralogic changes on injectivity, or containment. Assessing the potential for dissolution, precipitation or dehydration within the storage complex over the life of the project (15 year injection period followed by 500 years post injection) through a reactive transport model (RTM, with Tough2/ToughReact program) was completed by Matrix Solutions Inc. for CO2 injection into the Leduc and Cooking Lake formations saturated with native brine.

The model input parameters included thin section, XRD and SEM analysis of the detailed lithology of characteristic intervals in the Ireton, Leduc and a middle Leduc/Duvernay shale tongue, from drill cuttings from the 16-29 well and the spectral gamma ray/litho-density log derived lithology. The native brine analysis was taken from a drill stem test recovery of a full string of saltwater from 2-5-58-27W4M 1.2 miles north of our site. This well was characteristic of five full column water recoveries within two miles of 16-29. The MDT samples recovered from the 103/16-29 well operation were heavily contaminated with filtrate water (50% and 100%) owing to lost circulation while drilling and were not representative of the native brine.

With respect to potential reactivity with dense phase CO2 in the storage complex, 2D radial modeling work has shown that during injection there was a slight dissolution of dolomite and slight precipitation of calcite and that no other minerals had a significant effect on the reservoir and that there was no meaningful (<1%) change in porosity. There was a slight reduction in pH which was the driving mechanism for dolomite dissolution. By the post injection period the area of the plume is in relative equilibrium and maintains a pH at 6.4. Very small amounts of Ankerite (between 1-2kg/m3 Ca(Fe,Mg,Mn)(CO3)2) begin to be sequestered as a mineral. As the plume contacts the caprock the relative reactivity increases owing to the variations in Ireton mineralogy but the volumes are small and the effects are the same as above plus the dissolution of Siderite, none in volumes considered material. Small amounts of H2S in the brine are quenched by the expanding plume and H2S in the plume area decreases. The acidification of the water due to CO_2 injection results in $H_2S_{(aq)}$ forming with small amounts of $H_2S_{(g)}$ being exsolved from the fluid which will begin to react with any available source of iron (siderite, ankerite or clays in the Ireton) to form pyrite. The full report on the reactive transport modeling is included as appendix 14.

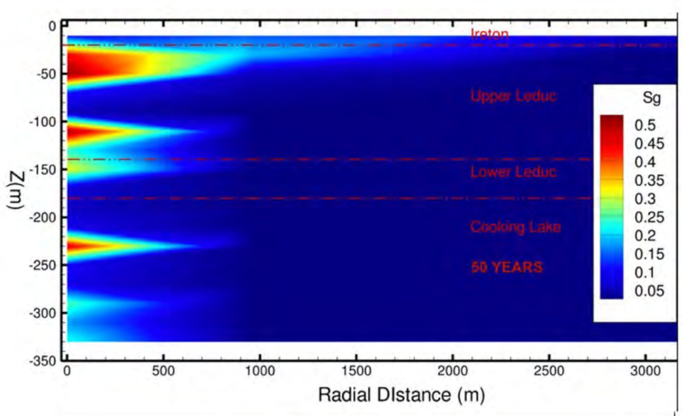


Figure 4. Spatial distribution of CO2 gas phase 50 years post injection (from Matrix RTM report).

Bison has also discussed CO2 rock interactions with Dr Ben Tutolo of UCalgary, who has performed detailed studies on similar applications (Tutolo et al) in the context of both CCS and EOR. His research work had guided to CO2 and water forming a weak acid (carbonic acid) which has an affinity for causing dissolution and/or precipitation of carbonate minerals (such as the dolomites that make up our storage reservoir) dependent on temperature. The saturating brine today is in equilibrium with the rock and is also slightly acidic (pH 6.0-6.9 at 25C) and considered sour with H2S content of <100 ppm. At our relatively low temperatures (<50C) we were not expected to have a material amount of dissolution, and any degree of precipitation was likely measured in centuries. This expectation was confirmed by the reactive transport modeling.

Thermal induced fracturing of the caprock is a potential problem in a CCS application that is sensitive to assumptions and factors including the thermophysical properties of the rock, the respective temperatures of the formation and the fluid at the sand face, the rate of injection and the standoff from the caprock. Recent work by Samaroo et al has also flagged that temperature change in the formation caused by injection of cold fluid can cause changes in insitu stress and strain, and in some instances induce fracturing. this is discussed in detail in section 9 on Geo-Mechanical risk mitigation.

When considering other thermal or geochemical reactivity issues we recognize it is highly probable that our reservoir will experience ‘drying out’ on long term injection of pure CO2, necessitating our management of salt precipitation in the near wellbore area. The phenomenon has been recognized in several CCS related situations, including Quest and Boundary Dam, and involves progressively increasing salinity of the irreducible water saturated phase near the wellbore, with successive pore volumes of injected CO2. The dry CO2 absorbs a portion of the Swi water, increasing the salinity, and eventually precipitating salt. The most often used resolution is a form of freshwater soak, or wash, on a prescribed frequency which is refined with operational experience. With respect to dehydration specifically our RTM showed that under our reservoir conditions for our period of injection we did not reach conditions where halite would precipitate in the near wellbore area. With larger volumes, higher rates or over a longer period, we expect this would be inevitable at some stage. The mitigative measures to avoid the impact of this if it were to occur would include increasing the injection interval or performing a wash with fluid capable of dissolving halite in the near wellbore area.

9. Geo-Mechanical characterization, Caprock Integrity and Mechanical Earth Modeling.

Geo-Mechanical risk involves assessing the stress regime and the hydraulic integrity of the storage complex and wells that penetrate it, including the risk of fault propagation or reactivation, shear failure of the caprock, hydraulic fracturing (planned or accidental connecting out of zone), and mechanical communication introduced by well penetrations (bad cement, rugose hole).

The work that we have done in assessing the geo-mechanical risk associated with the operation of a CO2 storage Hub at this location includes an integration of published material from similar studies in the immediate area, integration of more than 200 km of seismic data, core based rock geo-mechanical assessment of a portion of the caprock interval, a pressure test intended to introduce failure in the caprock, the integration of that data into a 1D mechanical earth model and a series of simulations of caprock failure and potential reservoir deformation under varying scenarios. The full report summarizing the Geo-Mechanical characterization and analysis of the principal total stresses in the reservoir and the caprock, the mechanical rock properties and the failure envelope, and a failure analysis is attached as appendix 9. This information has been incorporated into a Mechanical Earth Model referred to as a 1D MEM, created by SLB (appendix 11). Appendix 10 describes the geo-mechanical response of the reservoir and the caprock associated with CO2 injection under various relevant scenarios and sensitivities. The results are based on coupled heat, fluid flow and geo-mechanical simulation studies using the GEM model of Computer Modeling Group (CMG). **These workflows characterize the Woodbend Grp. storage complex at the Meadowbrook site as stable today and unlikely to develop any instability from a rock mechanics perspective under the operating conditions for the CCS project**.

In assessing the likelihood of pre-existing faults influencing the geo-mechanical stability, a one mile grid of 2D seismic data was acquired over the western rim of the Meadowbrook reef in order to improve the accuracy of the top reservoir topography interpretation and recognize any regional or local seismic discontinuities that could signal faulting visible at seismic scale. There were no faults identified along the western rim of the reef or within any area that could come in contact with a plume created by this phase of the project (>5 mile radius). There was a possible fault indication 9-10 miles E-NE of the project, at depth, which we would likely attribute to an element of the Snowbird tectonic zone (STZ). The STZ is a basement lineament oriented NE-SW that is postulated to have developed along a subduction hinge in the PreCambrian basement. Although natural seismicity is not recognized in the Edmonton area, and our injection zone is >700m and two salt layers separated from basement, it will be monitored at our project and reported and analyzed if it occurs. We have seismicity monitoring operating onsite today(Appendix 8) and generating data that correlates well with the Alberta Raven survey.

When combined with the understanding of the current reservoir conditions (especially pressure and injectivity), the required pressures to achieve the rates forecast in both the initial .5Mtpa and ultimate 3Mtpa commercial phases of the project, the failure envelope calculated in the geo-mechanical study, and the modeled reservoir capacity, we would conclude that the risk of reactivating or initiating a fault or fracture is very low. This is consistent with the conclusions of similar work in the greater Edmonton area dealing with Devonian reservoirs.

Injection of cold CO_2, as we plan for phase 1 of the project, will cause a cooling of the storage complex by way of conductive heat transfer and dependent on the magnitude of T change, and level of heat transfer from the storage interval to the caprock, it could result in thermally induced stress changes in the storage reservoir or the caprock. The magnitude of this effect and the potential risk it presents is discussed in detail in Part II of the accompanying geo-mechanical report (appendix 10). Recognition and avoidance of this early phase risk was one key driver of the decision to recomplete the 16-29 well to inject lower in the section. The 16-29 well will inject into the Cooking Lake portion of the reservoir at a depth >150m from the base of the Ireton caprock in part to ensure adequate thermal cushion for any migration of cool fluid coming in contact with the caprock. CO_2 arriving and stored in pressurized vessels at approximately -20C will be heated to 5C before injection through the installation of a line heater. Both these design elements have been included in the geo-mechanical modeling.

This issue has a greater chance of presenting a problem in the initial Phase 1 stage where our CO_2 surface temp is approximately -20C as delivered via tractor trailer, vs >15C when delivered by pipeline as envisioned for the large majority of volumes from phase 2 on.

The risk mitigation waterfall to address this risk will employ;

1. listening for microseismicity during early injection,
2. monitoring temperature diffusivity,
3. heating the CO_2 at surface before injection,
4. adjusting the rate of injection to enhance heat adsorption,
5. creating > vertical standoff between the injection sandface and the caprock,
6. injecting into the Cooking lake rather than the Ireton.

Notwithstanding the low risk profile today, an equally important aspect involves our ability to monitor for a breakdown or loss of hydraulic integrity, for any reason, in the operating phase of the project. This is covered in detail in the containment, legacy well and the ISM sections 5, 10 and 7 respectively of this MMV program, but incorporates no less than four strategies/triggers to recognize and assess if, how, and to what degree a loss of containment has occurred. Depending on the severity, an appropriate response could be to report and monitor the situation over an agreed period with an agreed protocol, or it could involve the suspension or re-location of a specific injection cluster, or if severe in the extreme, a suspension and abandonment of the project.

10. **Hydraulic isolation and legacy well risk.**

CO2 containment in the Woodbend Grp. and hydraulic isolation from uphole zones, has been confirmed pre injection at the 16-29 injection well location by;

a) A pre injection packer isolation test.
b) cement bond logs,
c) the placement and response observed from external fibre optic pressure and temperature sensors in the Nisku,
d) a Leakoff test of the Ireton caprock.

Hydraulic isolation will be continually monitored and re-confirmed by the real-time measurements of the 'external to casing' fibre optic sensors in the Nisku and the tubing conveyed gauges open to the Cooking Lake and Leduc (combined the Woodbend Grp.) injection intervals.

Our Evaluation phase activities included a core of the caprock interval and Leakoff test of the Ireton formation which confirmed a pressure envelope up to 26Mpa, below which a failure would not occur in the cap rock. We also completed a step rate injectivity test (SRT) into the reservoir to confirm the bottom hole pressure limits required for injection at both our forecast volumes for this phase of the development (.5Mtpa), and at the full commercial volumes which we had modeled at >1Mtpa/well. The SRT proved injectivity at rates up to 4.0m3/min at 12,967 kpa (1871kpa above static reservoir pressure and >1000 kpa below hydrostatic pressure estimated as 14,300kpa, which is a short duration test at a rate equivalent to 2Mtpa/well. These rates, and formation permeabilities, exceeded our forecast but were not totally unexpected as published studies quote effective permeabilities between pools connected by an infinite regional Cooking Lake aquifer in excess of 2 darcies, and we have Leduc water injection well histories from adjacent pools having demonstrated long term injection at >25,000bfpd and cumulative injected volumes of >100mm bbls/well, with no material pressure effect on the reservoir.

Based on this data we can conclude that we have proven, and can continually monitor, isolation between the storage zone and the first aquifer above the storage zone, and that we can inject the volume that will be requested in our AER scheme approval (up to .5Mtpa) at forecast BHIP that will not exceed 18.2 Mpa, the limit requested and calculated utilizing Table O of D065.

In summary, the 16-29 well will be continuously monitoring the following data once injection begins;

- Nisku (first aquifer above the storage interval) pressure and temperature via fibre conveyed sensors (2 sets) external to the casing. These sensors have confirmed isolation from the Leduc through several subsequent well operations and currently confirm reservoir pressures of 8603 and 9201kpa and Temperatures of 47.5 and 48.2 degrees celsius respectively, at depths of 1235 and 1270m kb, on Sept 19, 2024.
- Cooking Lake Fm., storage interval pressure and temperature, both during injection and shut in periods.
- DAS (acoustic) fibre 'listening' for seismicity AND wellbore events. We have recognized that the DAS configuration provides a useful data source for changes external to the wellbore.
- DTS changes in temperature which could occur with mixing of brine on any loss of containment or breakdown external to the casing.
- Realtime data acquisition will be provided by a permanent onsite interrogator processing and forwarding the fibre optic feed.

Through a combination of the measurements we would expect any loss of isolation to be identified by multiple tools and strategies immediately.

The 16-29 well does have a surface casing vent flow recognized that has been measured at 4.1m3/d (<1 scfm) and sampled. From a shut in pressure of 1890kpa we have determined it is likely from the 225m interval, approximately equal to the McKay coal interval. We will monitor the rate and isotopic composition for any changes annually or when any change is recognized. Our pre drill groundwater resource assessment involved both offset well testing and the drilling of a 90m groundwater test well on our site. We DID NOT encounter a water productive sand capable of a measurable rate but did encounter a ‘gas blow’ at 85-90m which has subsequently died and produces a small amount of water with TDS of 4400mg/l. We will manage the SCVF impact on the shallow groundwater resource in the area by our regular soil gas monitoring program and an isotopic comparison between any biogenic, methanogenic or deep sourced methane. We do not consider the existence of the SCVF to be a risk of migration from depth because the leak off test performed prior to drilling out confirmed the wellbore isolation at the base of groundwater protection (440m bgl) .

Legacy well risk, refers to the potential for a containment breach from ’historic’ wellbore penetrations through a casing failure, poorly cemented casing or incomplete aquifer isolation on abandonment of the sequestration reservoir, that could provide an avenue for leakage by migration along a pathway that may not be fully contained by the top seal. This risk already exists with every suspended and abandoned wellbore in the province where cross formational flow of fluid, or the potential for a gas migration or vent flow of natural gas, is managed to within an acceptable tolerance with the application of good oilfield practice and adherence to license conditions. The unique aspect of this risk in a CCS project is more of a fiscal risk resulting from a credit reversal, as the potential for this to evolve into either a safety or environmental risk is extremely low both from a released volume and concentration perspective. Notwithstanding the likely low impact of a legacy well related leak we recognize this as having a higher likelihood of occurrence owing to poor cement jobs resulting from lost circulation due to the underbalanced pressure and exceptional permeabilities in the Nisku, Leduc and Cooking Lake intervals.

We have completed a legacy well risk assessment based on a well by well review of AER wellbore records of wells that have penetrated the storage complex and ranked them as to what risk they may represent depending on the age of the well, the original and current status, the amount and quality of information available on the original wellbore condition and configuration, and whether there is a record of any well integrity issue (known gas migration or SCVF occurrence). A well that did not penetrate the storage complex cannot provide a pathway for loss of containment. Historically, D&A wells that have plugs set properly represent a lower legacy leak risk than cased wells that are subsequently abandoned.

This analysis resulted in a ‘traffic light’ ranking where a red or amber ranking would result in **baseline and subsequent periodic** monitoring incorporated into our MMV plan, based on assessment of the following criteria,

a) penetration of the storage complex
b) any recognized migration or flow that remains unresolved.
c) well having been cased to the storage complex.
d) confirmation of proper abandonment (age and data dependent)

Every well that penetrated the storage complex (a) was reviewed in detail. It is given a **green** ranking if it has no flow history AND records show it was abandoned as per AER regs (**no further review planned)**. It is flagged as **yellow** if it has been recognized as having, or having had, a migration issue (b), or the well was cased to the storage complex and sits within a forecast saturation plume area (c+), or the well file review is unavailable or inconclusive as to proper abandonment having been completed (d+). A **yellow ranking requires further investigation;**

- A **yellow** ranking requires further review to designate it as green (no recognized risk) or red (high risk), based in part on its proximity to active development of the tenure,
- All yellow designated wells within 1.5km of a forecast CO2 plume fairway (3km from 16-29) will require a surface inspection, an initial season’s photogrammetry survey, and a 30 day air monitoring test to determine a pre injection baseline.

A **red** ranking would be attached to any yellow ranking that upon further investigation demonstrates recognizable surface flow of gas. We would commit to reporting this to both the AER and the well operator for further monitoring as deemed appropriate by those parties. There have been no red ratings identified by our work to date.

If an initial surface site inspection shows no sign of migration/flow or leak, the ranking shifts to **green**.

The area of application has been assessed and three wells with yellow rankings have been flagged. All yellow rankings will be downgraded to green, or upgraded to red, prior to the commencement of injection.

Further Mitigation of legacy well risk on our project is achieved by:

- avoiding areas with pre-project penetration within areas identified as the likely sequestration plume area, and minimizing the required penetrations to only those needed to manage the project. There are NO producing wells that penetrate the sequestration strata within the forecast plume area. We estimate that there are 7 historic penetrations through the top of the sequestration interval strata (top Leduc Formation) and 3 of those that fully penetrate the section (Cooking Lake Formation or deeper) within the forecast CO_2 plume area. One well, 15-32-57-25W4M, is 1 mile from the 16-29 well cluster site and had a reported gas migration issue that was reported as resolved in 2000. That site has been flagged and will be monitored and reported as part of the MMV phase application.
- integrate any wells that penetrate the sequestration reservoir (future Legacy wells) but are NOT abandoned, into the observation/monitoring scheme to enhance the MMV program. We have identified 2 existing wellbores that could possibly be integrated into the observation/monitoring scheme, if they can be acquired (one is an orphan well). Neither of these wells is within, or relevant to this initial phase application.

In our selection of the 16-29 injector location, consideration was given to the number of penetrations of the Woodbend Reef within the expected plume area, the status of those wellbores as to whether they have/had casing or cement plugs to ensure isolation, the age of the wells, whether there is any AER record of leakage or cross flow, and whether a surface inspection shows any evidence of flow.

11. CO_2 Pipeline design, monitoring and dispersion modeling.

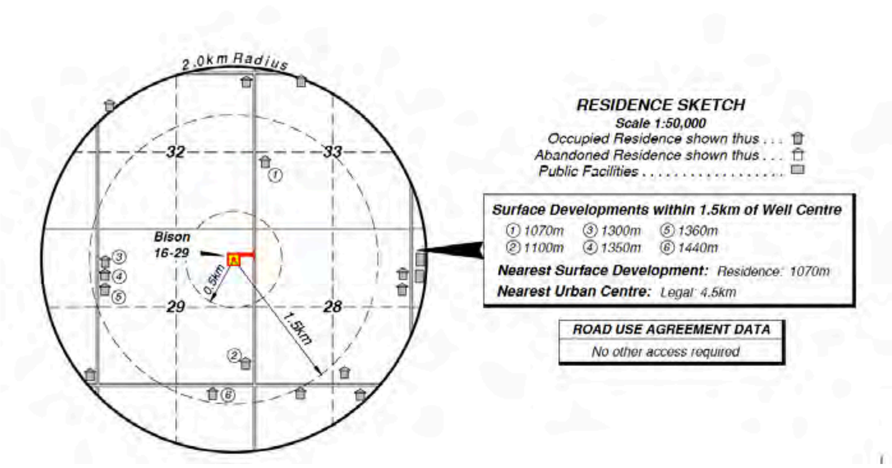
During this initial phase of the project we are not planning for the installation or operation of either an inlet pipeline or injection lines off our lease as all volumes will be trucked under our current plan, and we will only operate a single injection well located on the same site as the receipt/storage/metering facility.

A pipeline from the Alberta industrial heartland area (either connecting to an existing CO_2 trunkline or emitter customer site) is still an integral part of our full commercial development plan, as are injection lines from the central facility to 2-3 injection cluster sites. Once the pipeline is operational, we will be equipped to continuously monitor pipeline inlet and terminus volume, temperature and pressure so that any leak is recognized immediately. There would be emergency shutdown capability on any pressure loss and the pipeline route would be monitored for CO_2 leak detection as specified by AER regulations over the life of the line’s usage.

Guidance contained in CSA Z071 regulations identify the required setbacks of the pipeline from residences and other occupants. Setbacks are a function of pipe volume and the potential release rate and plume size that could develop on a line failure worst case scenario. The pipeline is partitioned with the installation of risers and emergency shut-down (ESD) valves that limit the capacity of an individual segment to a volume less than the volume designated in determining the setback distance. In that manner, even in the unlikely event of a complete failure, the plume dispersion would have CO_2 concentrations below serious human health limits.

We will complete CO2 dispersion modeling prior to finalizing the design of the pipeline to ensure that site specific topography and dominant conditions are factored into the final safe design. During this initial phase we will not be operating any CO2 pipelines.

This application has considered a CO2 release onsite that could arise if we ruptured the onsite storage vessels (150t in total). The EPZ in this instance is considered to be 50m meters from the point of release. The closest residence is 1.07 km away and there are six residences within 1.5 km.



12. **Post-Project Closure Plan.**

At the end of the Commercial Lease Phase of the project we will implement the post-closure stewardship plan that will have been agreed, and updated over the project life biennially with the Alberta Department of Energy (ADOE) and the AER. The description in this section will apply to the scope of our application for a single injector with volumes <.5Mtpa for 15 years (no pipeline), with an understanding that the closure plan will adjust as the project scale and duration increases.

The major elements of the project closure plan will include;

- Ongoing, evolving understanding of reservoir performance and conformance of observed results (pressure, plume monitoring) to the project's dynamic reservoir model, from project start through to suspension of injection. This will frame the stability of the reservoir and injected CO2 plume at the outset of the closure period and guide an informed estimate of the scope and duration, or effort to properly demonstrate a 'stable and permanent' subsurface plume.
- We expect that the first 3-5 years of injection will frame the risk profile we are very likely to experience with respect to conformance of the reservoir performance to the dynamic model as its adjusted with real data, and in confirming the visibility and accuracy of the CO2 plume measurement. Over this period <5% of the ultimate volume we target to store over the project life will have been introduced to the storage complex, and any adjustments required to minimize post closure risk will be incorporated at an early stage.
- We will establish a properly funded closure contingency account (in addition to PCSF and any LMR requirements) to ensure that in any circumstance the operator, on behalf of the JV, is properly funded to complete the required scope and duration of work.
- On the assumption that we have been able to model the plume distribution over the life of the project and that we have not experienced any recognized breaches of containment, the post closure plan would be proposed to the AER, and once accepted, we would proceed as per the agreed plan.
- All wells and monitoring equipment would remain in place until they were no longer required to facilitate reservoir access or monitoring data generation, at which point we would complete the downhole zone

and well abandonment of the 16-29-57-25W4M injection well, and any other wells that have been added to the scheme over its life.

- The surface facilities would be dismantled and any piping buried < 4’ would be removed from the site. There is no pipeline planned for this phase of the project.
- All monitoring equipment would be shut and removed in conformance with the agreed AER plan and schedule.
- Site remediation and reclamation would commence and once complete, a lease reclamation certificate and closure certificate would be sought from AEPA and the AER

We expect to be able to demonstrate that the CO_2 is performing in a stable and predictable manner and meets all requirements of section 120(3) of the Mines and Minerals Act (MMA) requiring we demonstrate sequestration performance and compliance with legislation, applications and approvals. If the project operates in a stable fashion, particularly over the second half of its life, we feel an estimate of the time required to demonstrate the required stability could reasonably be three to five years. We recognize that in different jurisdictions this window has been suggested to be in excess of 20 years in some instances. We recognize the transition of the lease back to the Crown is a performance based exercise and will ‘take as long as it takes’.

13. Potential Effect on Hydrocarbon Recovery

The proposed initial phase of Meadowbrook Hub project will have no effect on hydrocarbon recovery from any existing accumulation and is unlikely to adversely effect any future exploration activity. The project will be restricted to and contained within the Woodbend Group (Leduc and Cooking Lake formations) and have no effect on hydrocarbon recovery from any other zones. The Cooking Lake is not recognized as productive anywhere in the Meadowbrook complex or the surrounding area. The Leduc has been productive within the Meadowbrook complex in two scenarios, both of which are very close to the end of their economic life.

Along the western edge of the reef there is a series of eight small accumulations, four of which are still producing from one or two wells each, at water cuts above 90% with a total estimated remaining recognized recoverable reserve of less than 31,800 m3 (200,000 bbls) of oil, having recovered 715,445 m3 (4.5 mm bbls) since roughly 1980. The closest currently producing well on this fairway is 18km south of our proposed injection site at 14-32-55-25W4M (operated by Response Energy Corp.). The CO_2 plume from Bison LCV’s scheme is expected to have no effect on these producers as they are downdip and distal to the forecast plume. The increased pressure in the aquifer owing to CO_2 injection will be undetectable during the remaining life at these offset producing wells and minimal (< 3500 kPa) at any point in the future.

The second trap configuration is along the eastern rim of the reef complex and is productive at the Fairydell Bon Accord Leduc ‘A’ pool, 7.5 miles east of our proposed injection site. This was a highly prospective exploration target in the mid 1960’s but no similar accumulations within the Meadowbrook complex have been discovered over the last 60 years. The FBA Leduc “A” Pool still produces from three wells after the recovery of over 2.9 106 m3 (18 mm bbls) of oil and is forecast to have almost 31,800 m3 (200,000 bbls) remaining to be recovered. The plume, as modeled, does not extend within 8 km (5 miles) of the accumulation, and the pressure effect on the Leduc aquifer is predicted to be < 3000 kPa. Bison has met with Coastal Resources, the operator of the Fairydell field, and described our project and its potential impact on the remaining resource.

The western side of the Meadowbrook complex, where Bison LCV’s scheme will be located, is considered the downdip edge and not highly prospective for trapping hydrocarbons in commercial accumulations. Oil shows suggest a reduction in crude gravity to 10-17 degrees API as one moves north, further limiting the exploration prospectivity, and commercial potential.

Current interest is very low as evidenced by land sale activity and the large percentage of open crown land for rights below the base of the Mannville Group. The prospectivity of the geologic section from the base

Woodbend Group to basement is considered very low as there are no local or regional hydrocarbon shows in the Beaverhill Lake or Elk Point within several townships of Bison LCV's application area.

Outside of the immediate CO2 plume area the effect on P&NG activity will be insignificant as the pressure increase in the Woodbend aquifer owing to CO2 injection will be < 3500 kPa, still below the hydrostatic pressure, and should not pose a risk of over pressure for any future drilling activity through the Woodbend Group. We would recommend the AER notify any well licensee drilling through the Woodbend Grp. within our forecast plume area so that they are aware of the pressure anomaly and the need to properly segregate the zone if a well is to be cased though that interval.

14. **Potential Impact on Current Land Use (Commercial and Natural).**

The surface land use impact for this phase of the project will be minimal as we will have only a single site and no pipeline. The main impact will be the nuisance factor of increased trucking on local residents, particularly over the 1.5km of gravel between our site and Hwy 651.

The dominant surface land use in our project area, and at our current site specifically is agricultural. Approximately 80% of the land is actively farmed seasonally with a mix of residential acreages, treed parkland, livestock (chicken, dairy) and light industrial (Alfalfa, tire recycling, oil recycling). We have hosted meetings with the County council, landowners, the Alexander First Nation and business interests in the area and incorporated their initial advice into our proposed plans. Our stakeholder engagement is ongoing. We have contacted over 900 landowners/residents within our CSA tenure and will report on those interactions in a timely manner as you review this application. In addition, we have fulfilled the specific engagement requirements of owners and residents proximal to our activity and the other mineral tenure owners and well licensee's that could be affected by our project.

When considering the full commercial scale of the project and notwithstanding that from an individual property owner perspective, any level of industrial activity may be material, when compared with historic activity to date, our impact on current land use will be minimal. We expect to add no more than 4 sites (<120m x120m, <2ha in total) to approximately 300 well-sites that have been developed within our tenure boundary over the last 75 years of oilfield activity. Of the four, only our single plant site will have more than light vehicle operator activity on a daily basis, none will have pits or flares, and only the plant site will have any equipment noise level.

Portions of our tenure are subject to restrictions to surface access, either seasonally or permanently, based on wildlife or biodiversity restrictions that designate those areas as sensitive habitat. Approximately 65% of the surface area of the tenure is within Sharp Tailed Grouse and Sensitive Raptor ranges which require investigation of the presence, avoidance if present, and habitat protection strategies. Millenium (MEM) has completed a species at risk assessment for the surface activity conducted during our Evaluation phase activity and we did not recognize any impact or encroachment. This assessment is enclosed as appendix 13. We currently do not plan any increased level of surface disturbance, other than associated with the deployment of MMV equipment and monitoring capabilities, in association with the approvals we are seeking in this application. In any case, prior to conducting any operations on the commercial lease, or the residual Evaluation permit, we will conduct the appropriate assessment and adjust operations as results dictate.

15. **Potential Impact on, and from, Alternative Pore Space Uses.**

The Meadowbrook project reservoir has limited potential use in either geothermal or brine mineral recovery as the formation brine is relatively fresh (120,000ppm) and cool (<50C) when compared to similar opportunities that have announced intentions to pilot mineral extraction (190,000ppm+) and geothermal heat recovery (90C+). Bison LCV cannot at this time predict what other resources could potentially be affected, but we will take that into consideration when preparing our annual update reports, and when we execute our monitoring plan.

There are two brine tenures (Indigo and NumberCo) that signal an interest in Lithium within the limits of our Evaluation permit, with Indigo's acreage overlapping a portion of the CSA we have been granted. We have attempted to contact Indigo to describe our operational plan and present our view that our current operation is unlikely to have any impact on their potential activity because our current activity is up-dip from their tenure. We did connect with Mr Paul Cowley who declined the request to meet. CO2 will not migrate downdip unless a pressure sink is created which will minimize our potential impact on the exploitation of their tenure, should they progress its testing. If future brine tenures are awarded updip of the current acreage, or as our project expands either north or south, there is the potential for overlapping influences, but also the potential for collaboration to avoid conflict. The spent brine will need to be re-injected at a location that doesn't interfere with future native brine concentrations, likely up-dip from the actively worked brine production. As long as we locate up-dip of this position, our operations should not interfere.

We have not been able to identify the ownership of the NumberCo through the Alberta corporate registry and as a result have not made contact with them. This block begins >20 miles north of the proposed 16-29 injection site. As modeled, our CO2 plume would not at any point reach that far.

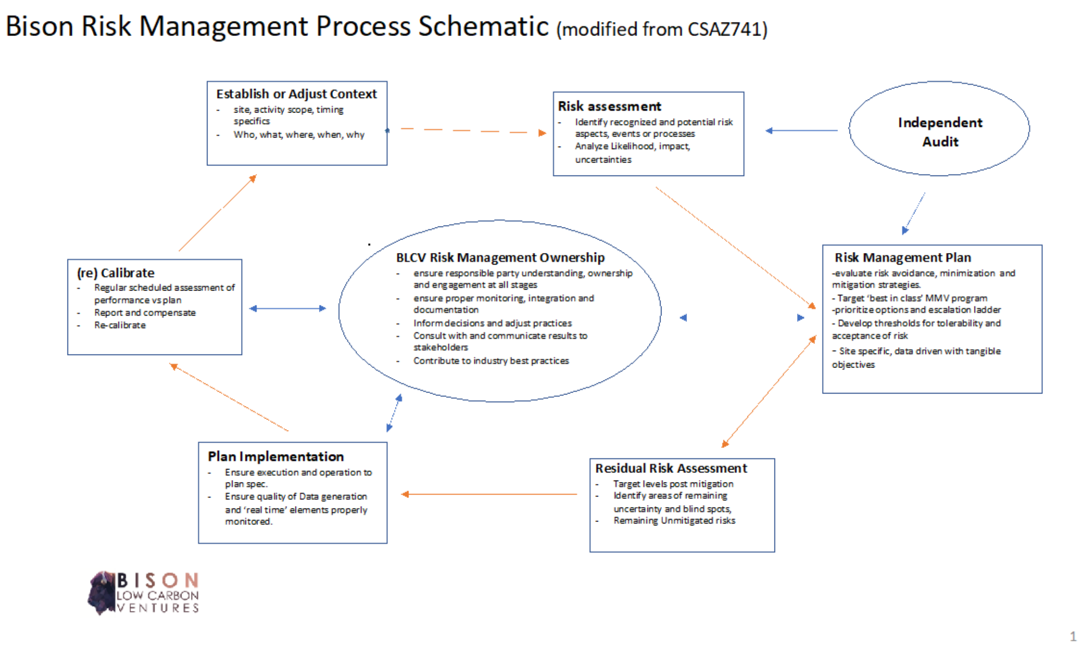
The commerciality of the quality lithium resource in this area is unproven and the intent or ability to progress a possible development in a timely manner is unknown. Using mining brokerage RFC Ambrian research as a source (August 2023 Lithium Market Review), the lowest concentration brine in commercial development anywhere in the world today is a small Argosy Minerals project in Argentina at 325mg/l, with other commercial brine projects having 500-700mg/l. Two projects with relatively low concentrations are under construction or planned in Germany (180) and Argentina (390). Pre-feasibility studies average 330mg/l and range from two Canadian projects at 70mg/l, to South American projects at 750mg/l. Brine concentrations within the Woodbend Grp in this area are <40mg/l. At <15% the commercial limit in production today, and just over half the aspirational goals of the most aggressive developers in the world, we would hope to see a legitimate intention to attempt to develop a resource before materially adjusting the commercial development of the storage complex, but we remain committed to participate in stakeholder discussions of any kind.

Our tenure is immediately offset to the south and northeast by tenures awarded for CO2 injection for CCS into the BCS. Given the significant stratigraphic interval and multiple aquitards between the BCS and the top of the Beaverhill Lake (base of our complex) we expect Meadowbrook to have no effect from, or on, these projects. Approximately two townships south of our tenure, the Enbridge consortium's tenure proposes to utilize the Nisku Formation as the storage reservoir which is the aquifer above our storage interval that we will monitor for confirmation of top seal integrity. We have engaged with Enbridge and discussed the sharing of operational information that could allow each operator to assess the impact on their project from the neighbouring tenure. Both parties were supportive of investigating the concept as we moved closer to the start date.

16. Conservation of Pore Space Resource

We feel our current application addresses that concern and mitigates the risk of 'over allocation' or underutilization of pore space for CCS early in an evolving industry with our request for only a subset of the tenure that was awarded initially, in line with the phased nature of our proposed development. Our application is for a commercial lease over 21% (15,600ha) of our Evaluation Permit of roughly 70,000ha. When compared with the single existing commercial Sequestration tenure issued today (the Shell Quest project) our application proposes to increase the intensity level of usage for sequestration from approximately 2.3t/ha per year at Quest to >30t/ha per year at Meadowbrook. We do hope to expand our CSA tenure as we secure larger committed volumes.

17. Bison LCV Risk Management Process Schematic



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