Quest Carbon Capture and Storage Project

CLOSURE PLAN

2023 Version

Prepared by:
Shell Canada Limited
Calgary, Alberta

October 2023 Update

Table of Contents

List of Tables

List of Figures

Acronyms and Abbreviations

AENV	Alberta Environment
AER	Alberta Energy Regulators
AOR	Area of Review
AOSP	Athabasca Oil Sands Project
BATEA	Best Available Technologies Economically Achievable
BCS	Basal Cambrian Sands
BGWP	base of ground water protection
C&R	conservation and reclamation
CCS	carbon capture and storage
CO_2	carbon dioxide
CSTR	carbon sequestration tenure regulation
HMU	hydrogen manufacturing unit
InSAR	Interferometric Synthetic Aperture Radar
LBV	Line Break Valve
MMA	Mines and Minerals Act
MCS	Middle Cambrian Shale
MMV	measurement, monitoring and verification
PI	Productivity Index
RFA	Regulatory Framework Assessment
Shell	Shell Canada Limited
Shell Scotford	Shell Scotford Complex
SLA	Sequestration Lease Area
SMA	Seismicity Monitoring Area
the Project	injection and storage of CO_2 in the BCS saline aquifer
UWI	unique well identifier

1. Introduction

1.1. Scope of Closure Plan

Shell Canada Limited (Shell) on behalf of the Athabasca Oil Sands Project (AOSP) Joint Venture and its participants, comprising Canadian Natural Resources Limited and an affiliate (70%), Chevron Canada Limited (20%) and 10% Shell Canada Limited through certain subsidiaries, received approval from the Alberta Energy Regulator (AER) under Approval Number 11837C [1] (the "Approval") to construct, operate and reclaim the Quest Carbon Capture and Storage (CCS) Project (the "Project"). The Project captures, transports and stores carbon dioxide (CO_2) from the existing Scotford Upgrader, Fort Saskatchewan, Alberta (Figure 1-1).

As part of the Project the Alberta Minister of Energy, pursuant to Section 116 of the *Mines and Minerals Act* [2] (the "MMA" or the "Act"), granted Shell six (6) Carbon Sequestration Leases that comprise the Quest Carbon Capture and Storage Sequestration lease area (Figure 1-1). The lease approval required the submission of an initial Project Closure Plan pre-start up and subsequent Closure Plan updates [3]. On April 28, 2011, the initial Closure Plan was submitted as a key component of the sequestration lease applications. Updates were submitted February 28th, 2014, February 27th, 2017 (with revision May 5th), and February 11th, 2020. This latest 2023 Closure Plan (submitted on September 8th, 2023) updates all previous Closure Plans.

The content of this document is in accordance with Part 9 of the MMA [2] and Section 19 of the *Carbon Sequestration Tenure Regulation 68/2011,* (CSTR) [3]. The scope of the Closure Plan update is limited to the storage component of the Project. This includes:

- well pads
- injection wells
- observation wells
- monitoring infrastructure
- the storage complex for the permanent storage of CO_2 in the Basal Cambrian Sands, a deep saline geological formation.

The content of this document is in accordance with the latest Alberta Government MMV principles and objectives for CO_2 sequestration projects (Version 2) [19], section "During Closure Period Stage", which states to continue to monitor all wells and facilities and perform all closure activities in compliance with legislation (e.g., regulations, standards, directives), applications, and approvals.

This includes demonstrating compliance in respect to the abandonment of wells & facilities, and reclamation requirements, and that the conditions specified in the regulatory requirements in place at the time have been met.

Following the completion of site closure activities Shell will apply for a Site Closure Certificate. The post-closure period will then begin with the issue of a Site Closure Certificate that will transfer the long-term liability from Shell to the Crown in accordance with the MMA [2].

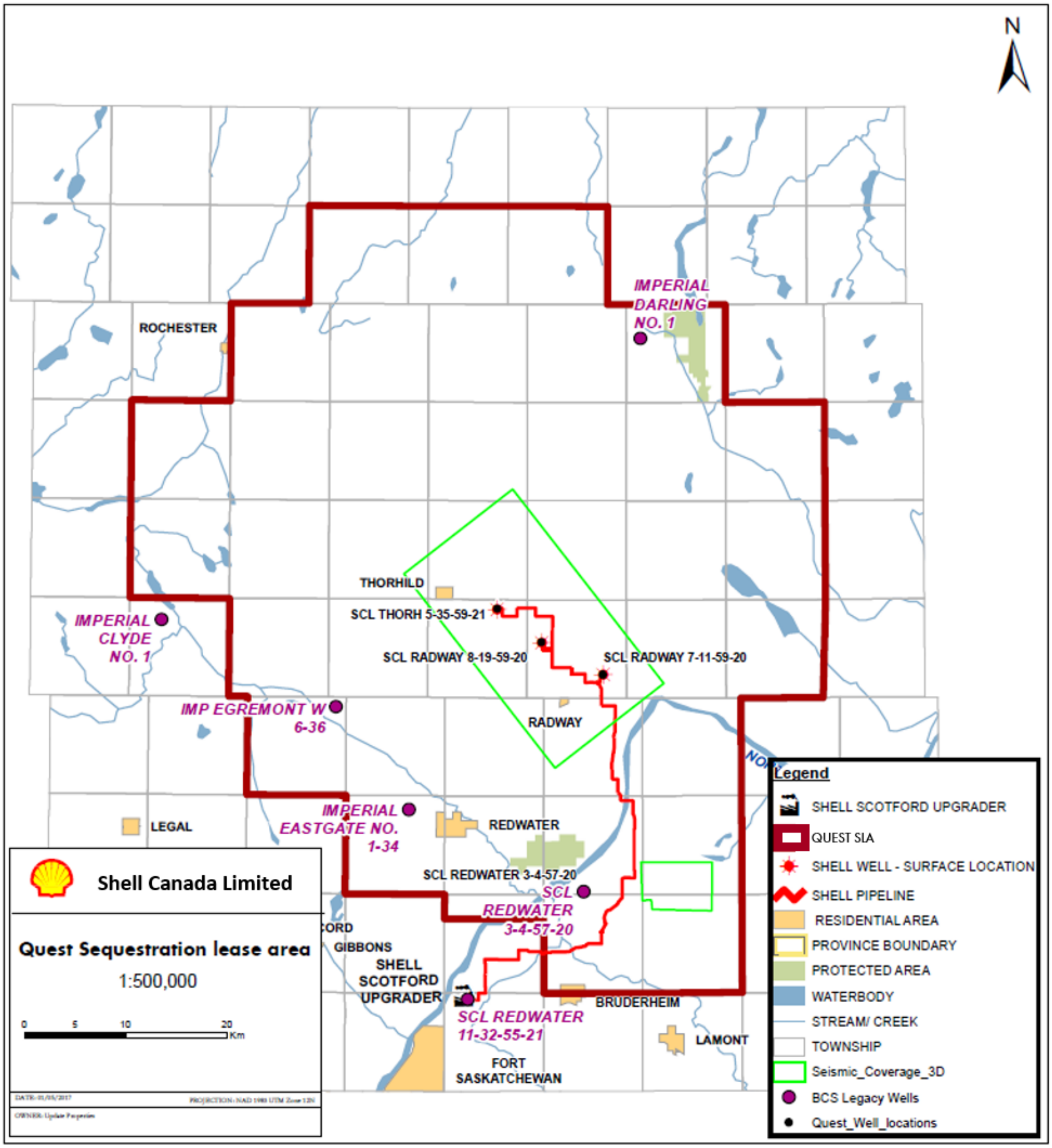

Figure 1-1: Quest CCS Project Components and approved Sequestration Lease Area (SLA) for Quest storage.

1.2. Timeline of Proposed Closure Activities

Commercial operations at Quest were achieved in August 2015. Operations will continue based on continued assessment of economic, technical and regulatory conditions. After the decision is taken to cease operations, up to/including a total of 27 MT of CO_2 sequestration is achieved, as noted in the approved Alberta Energy Regulator (AER) Approval Number 11837C, injection will stop. This is anticipated around year 2040 or likely after +/- 25 years of project life. Final Closure and Measurement, Monitoring and Verification (MMV) Plans will then be submitted to the Alberta Energy Regulator (AER), and closure activities will commence. The injection wells and storage infrastructure will remain in place to continue the monitoring and verification processes as planned during the closure period to demonstrate sustained compliance with the required performance criteria in place.

Towards the end of the closure period, anticipated to be approximately 10 years, Shell will decommission the injection wells and reclaim the surface in accordance with the regulatory requirements in place at the time. Following site closure activities, Shell will apply for a Site Closure Certificate.

The post-closure period will occur following the issuance of a Site Closure Certificate that in accordance with the *Mines and Minerals ACT, Chapter M-17, Part 9, Section 120* [2] will transfer the long-term liability from Shell to the Crown. Figure 1-2 shows a schematic timeline for the proposed closure activities.

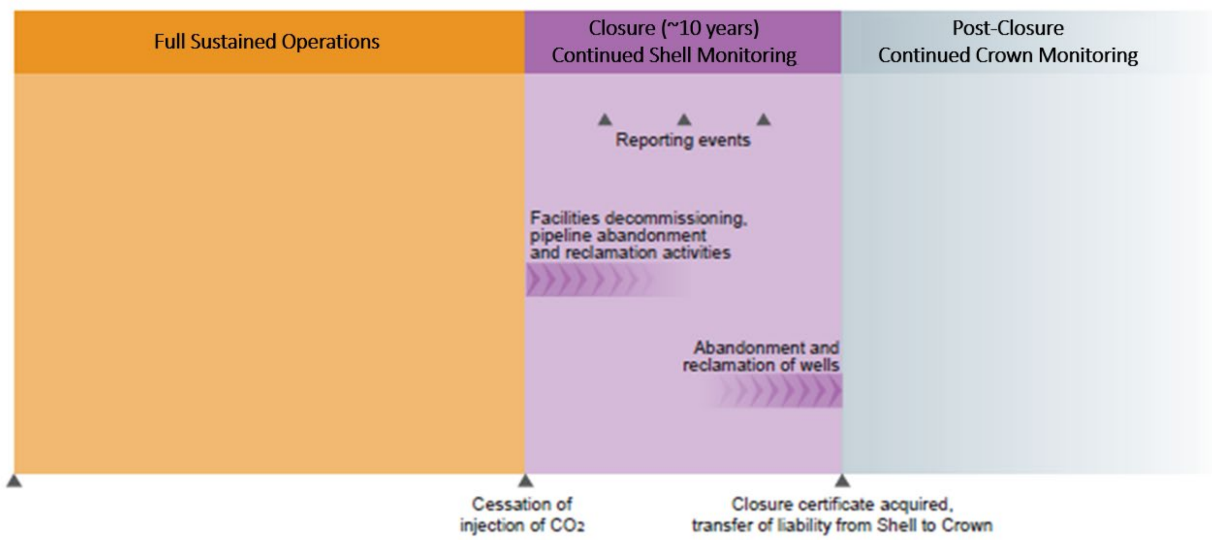

Figure 1-2: Proposed Timeline and Schematic for Project Operations, Closure and Post-Closure.

1.3. Closure Requirements and Recommendations

Shell is committed to executing the closure of the Project in accordance with the requirements of all applicable regulations under the MMA [2], the CSTR [3] and/or other new requirements that apply to CCS projects.

Closure criteria are continuously being developed, and the proposed Closure period activities and their timing are subject to change based on the site performance, any regulatory developments, and the Government's requirements. Shell will work with the AER and Alberta Energy and Minerals in between scheduled updates to define future Closure Plan activities.

2. Project Overview

Shell, the managing partner of Shell Canada Energy, holds all necessary regulatory approvals for the Project. Shell Canada Energy operates the Project on behalf of the AOSP. The goal of the Quest CCS Project is to capture and permanently store CO_2 and reduce greenhouse gas emissions from the Scotford Upgrader. The Scotford Upgrader is located near Fort Saskatchewan, Alberta within Alberta's Industrial Heartland.

The three components of the Quest CCS Project are:

- A Capture and Compression facility where CO_2 from the Hydrogen Manufacturing Units (HMUs) is captured and compressed. The method of CO_2 capture is based on a commercially proven activated amine technology called Shell ADIP-X.
- Transport of the compressed CO_2 via a 65 km 12-inch pipeline northeast of the Scotford Upgrader.
- An approved D65 storage scheme [4] for injection of CO_2 into the Basal Cambrian Sands (BCS), a deep underground formation, for permanent storage at a depth of about 2 km below ground level. The security of storage is verified through a Measurement, Monitoring and Verification (MMV) plan [7]. Three injection wells have been drilled and are in use as dictated by the Project volume requirements and operations.

The currently permitted injection plan consists of injecting approximately 1.08 million tonnes of CO_2 per annum to a maximum of 27 MT.

2.1. Sequestration Lease Rights

The CO_2 Sequestration Lease Area (SLA) granted by the Carbon Sequestration Leases is defined as the full extent of 39 townships plus 12 sections. Table 2-1 shows the townships included in the SLA.

Table 2-1: Townships Included within the SLA.

Township	Ranges (W of 4th Meridian)
63	22, 21, 20
62	23, 22, 21, 20, 19
61	24, 23, 22, 21, 20, 19, 18
60	24, 23, 22, 21, 20, 19, 18
59	23, 22, 21, 20, 19, 18
58	23, 22, 21, 20, 19
57	22, 21, 20, 19
56	20, 19 and 21 (sections 25 to 36 only)

In order to meet requirements outlined in the *Carbon Sequestration Tenure Regulation 68-2011* [3], the SLA is divided into six (6) contiguous Carbon Sequestration Leases that together comprise the single Quest CCS Project SLA. The leases granted by Alberta Energy and Minerals are shown in Table 2-2 and Figure 2-1.

Table 2-2: Table SLA Separated into Carbon Sequestration Lease Blocks

Lease Block	Alberta Energy and Minerals Lease Number	Township - Range (W of 4th Meridian)
1	5911050006	61-22, 61-23, 61-24, 62-22, 62-23, 63-22
2	5911050003	60-21, 61-20, 61-21, 62-20, 62-21, 63-20, 63-21
3	5911050001	59-18, 59-19, 60-18, 60-19, 60-20, 61-18, 61-19, 62-19
4	5911050002	56-19, 56-20, 57-19. 57-20, 58-19, 58-20, 59-20
5	5911050004	57-21, 57-22, 58-21, 58-22, 59-21, 56 -21 (Sections 25 to 36 only)
6	5911050005	58-23, 59-22, 59-23, 60-22, 60-23, 60-24

2.1.1. Extent of Zone of Interest

The approved zone of interest (ZOI) for the SLA, pursuant to Section 116 of the MMA [2], was granted to Shell on behalf of the AOSP Joint Venture by Alberta Energy at the time on May 27, 2011. The ZOI includes the interval from the top of the Elk Point Group to the Precambrian basement (Figure 2-2). The ZOI includes two complexes of strata utilized in the Quest Project for CO_2 storage and MMV, respectively:

- BCS storage complex: The BCS storage complex is defined as the series of formations from the top of the Upper Lotsberg Salt to the base of the Basal Cambrian Sands. The injected CO_2 will be permanently contained within the BCS storage complex (Figure 2-2).
- Cooking Lake Formation: On May 24, 2012, Shell received approval from Alberta Energy and Minerals to monitor the Cooking Lake formation in all three deep monitoring wells (DMW): DMW 7-11, DMW 8-19 and DMW 5-35. In 2014 Shell began monitoring the Cooking Lake in Observation Well 3-4 (Table 2-3).

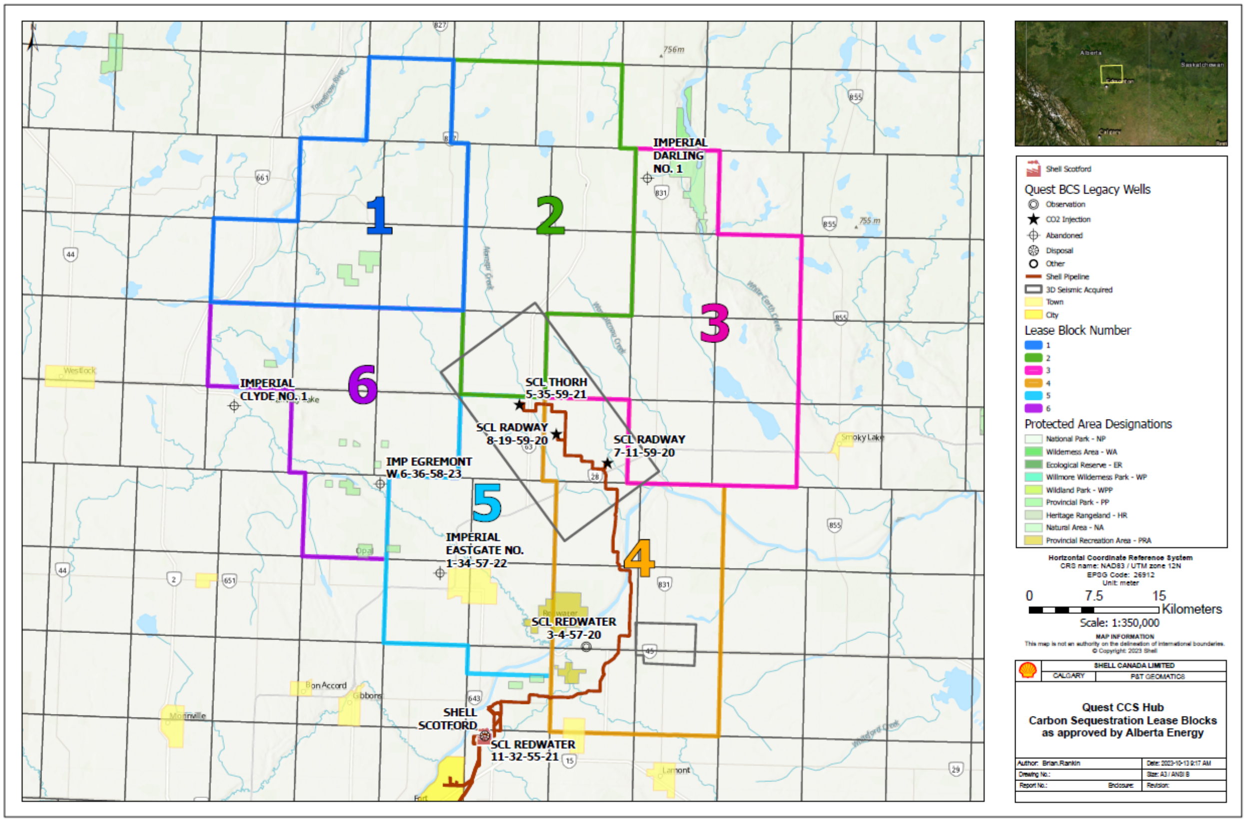

Figure 2-1: Quest CCS Project Carbon Sequestration Lease Blocks as approved by Alberta Energy and Minerals.

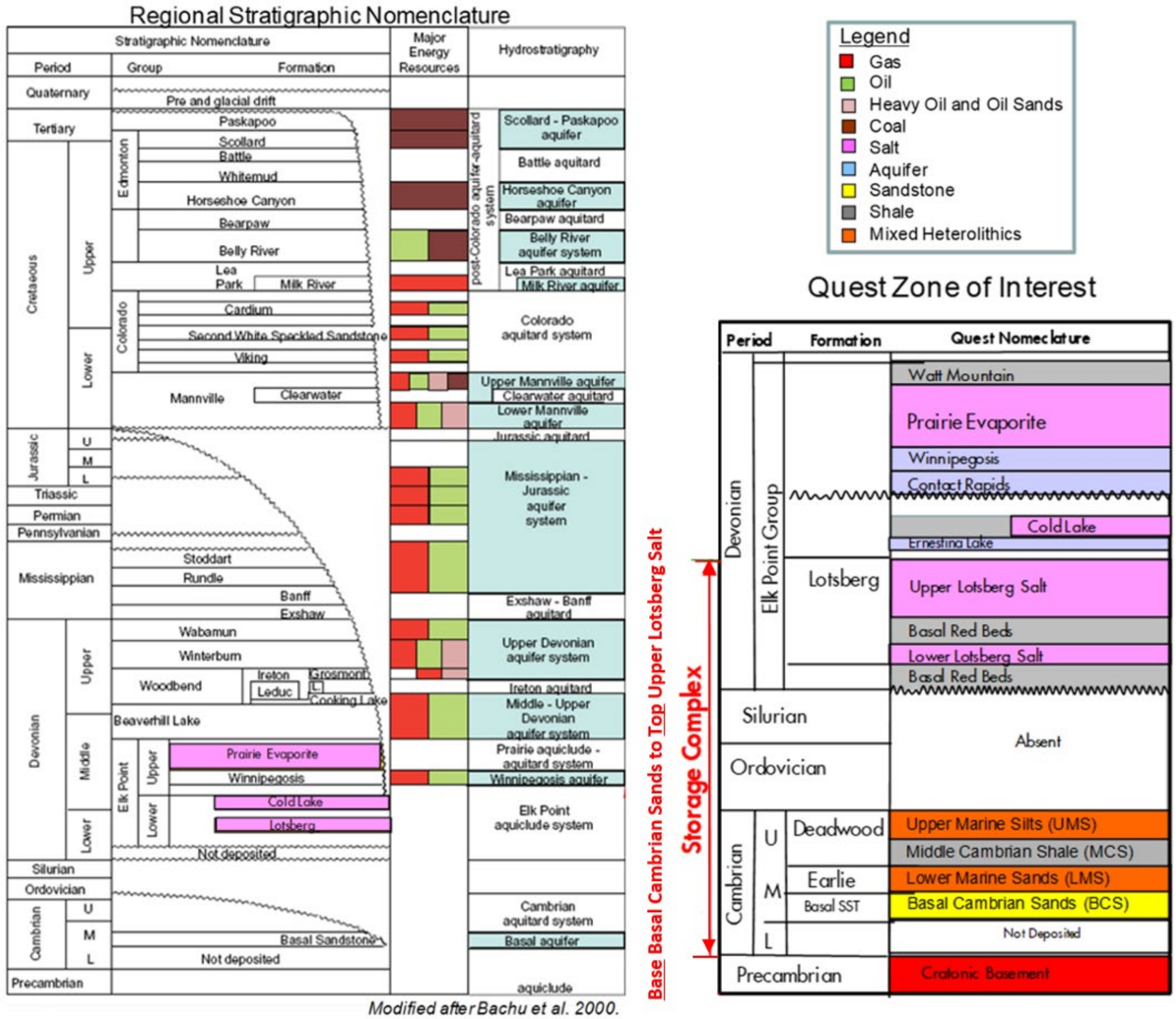

Figure 2-2: Stratigraphy and Hydrostratigraphy of the Southern and Central Alberta Basin

2.2. Project Wells Inventory

The well pads are the primary long-term land disturbance associated with the life of the Quest Project in the SLA, along with the pipeline and LBVs (line break valves).

There are three injection well pads associated with the Project, each between 130 m by 130 m and 150 m by 150 m in size. Each well pad consists of a BCS injection well, one deep monitoring well located ~40m from the injection well and between two to five groundwater wells that are less than 200 m deep and approximately 25 m from the injection well (Table 2-3).

There is a fourth well pad at 03-04-057-20W4 that is 21 km south of the closest injection well (IW 7-11) and has only one deep observation well (Redwater 3-4) that is being utilized to monitor the pressure in the Cooking Lake Fm. This well is not an injection well but an observation well.

Table 2-3: Pad and well UWIs for Quest injection and monitoring wells

Pad	UWI	Well type	Well name in this report	TD formation
Outside SLA (no longer part of Quest)	103/113205521W400	Appraisal (Abandoned)	Redwater 11-32	Precambrian
03-04-057-20W4	100/030405721W400	Observation Well	Redwater 3-4	Precambrian
08-19-059-20W4	100/081905920W4/00	Injection	IW 8-19	Precambrian
	102/081905920W4/00	Deep Monitoring	DMW 8-19	Ernestina Lake
	1F1/081905920W4/00	Groundwater	GW 1F1/8-19	Lea Park
	UL1/081905920W4/00*	Groundwater	GW UL1/8-19	Foremost
	UL2/081905920W4/00*	Groundwater	GW UL2/8-19	Foremost
	UL3/081905920W4/00*	Groundwater	GW UL3/8-19	Foremost
	UL4/081905920W4/00*	Groundwater	GW UL4/8-19	Oldman
05-35-059-21W4	102/053505921W4/00	Injection	IW 5-35	Precambrian
	100/053505921W4/00	Deep Monitoring	DMW 5-35	Ernestina Lake
	1F1/053505921W4/00	Groundwater	GW 1F1/5-35	Lea Park
	UL1/053505921W4/00*	Groundwater	GW UL1/5-35	Foremost
07-11-059-20W4	103/071105920W4/00	Injection	IW 7-11	Precambrian
	102/071105920W4/00	Deep Monitoring	DMW 7-11	Ernestina Lake
	1F1/071105920W4/00	Groundwater	GW 1F1/7-11	Lea Park
	UL1/071105920W4/00*	Groundwater	GW UL1/7-11	Foremost

Legend: * well name used in Shell but not official UWIs as these wells do not require a well license because they are less than 150m depth.

3. Storage Performance Criteria for Site Closure

To meet storage performance goals, MMV activities are planned to be executed to deliver against the following targets during the site closure period.

3.1. CO_2 Inventory Accuracy Target

Shell has approval from AER to inject up to 27 million tonnes of CO_2 (14,500 million cubic meters at standard conditions of 15ºC and 101.325 kPa) into the BCS formation with the constraint that the shut-in reservoir pressure will not exceed 26 MPa and that the CO_2 is to be permanently stored within the BCS storage complex [1].

To establish confidence that the conditions for site closure are met, the accuracy of the reported inventory of CO_2 stored will comply with the Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers, approved under the SGER in 2015 [8], under the CCIR from 2018 to the end of 2019 [9a] and replaced by the Technology Innovation and Emissions Reduction Regulation (TIER) from January 1, 2020 [9b]. The sources/sinks associated with the subsurface are monitored as part of the MMV Plan and are included in the protocol as follows:

P20 - Emissions from Subsurface to Atmosphere

Under normal operation, this source/sink is negligible and is excluded from quantification. However, emissions from leakage events must be quantified and included consistently with the approved measurement, monitoring and verification plan.

Table 3-1 quantification methods as explained in the protocol.

Table 3-1: Methodology from Table 6 of the Quantification Protocol [8] defining the P20

P20 - Emissions from Subsurface to Atmosphere	$Emissions_{Subsurface\ to\ Atmosphere} = Mass\ CO_2e_{leaked}$					
	Mass of CO_2e leaked from the Subsurface to Atmosphere/ Mass CO_2e_{leaked}	t of CO_2e	Estimated	If a leak event occurs, the mass of CO_2e leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5%. In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied. Refer to Appendix B for further guidance.	N/A	Estimation would be required for reporting to The Alberta Energy Regulatory authority. Direct measurement is likely not possible, but the use of engineering estimates and accounting for the uncertainty would be a reasonable approach in
						the event leakage occurs.

3.2. Conformance Performance Target

It is also essential to assess whether injected CO_2 behaves as expected and how site performance has evolved relative to the predictions. As such, the following conformance performance targets are used:

- Observed storage performance conforms to predicted storage performance within the range of uncertainty.
- Knowledge of the actual storage performance is sufficient to provide confidence in the long-term effectiveness of CO_2 storage within the storage complex.

3.3. Containment Performance Target

It is necessary to continually monitor and assess whether any migration of injected CO_2 or BCS brine out of the BCS storage complex has occurred and, if so, whether any identified migration has impacted the environment or human health. In order to monitor and assess CO_2 migration, the MMV plan [7] supports the following performance target:

- Measurements of any changes within the MMV datasets caused by CO_2 injection are sufficient to demonstrate the absence of any significant impacts as defined in the Environmental Assessment.
- Measurements of any changes within the MMV datasets caused by CO_2 injection are sufficient to trigger effective control measures to protect human health and the environment.

3.4. MMV Plan Overview

The focus of the MMV plan is to assess containment and conformance within the BCS storage complex as well as assess the induced seismicity risk. The MMV Plan is designed on the following key principles:

- Compliant to all regulatory requirements
- Quest Project-specific
- Site-specific (regarding the Injector Wellsites, associated Areas of Review, the SLA, and potential cumulative and regional impacts)
- Risk-based, fit for purpose, and transparent
- Adaptive
- Provision of timely warnings towards CO2 stream containment and conformance anomalies
- Ability to monitor every domain of review
- Based on sound science and engineering – use best available technologies economically achievable (BATEA)

The 2023 MMV Plan [7] is the seventh update to the MMV Plan submitted to the AER and GoA since the start of the Project. The first conceptual plan was submitted as part of the D65 disposal application in 2010 [4]. In fulfillment of AER condition 7, a pre-baseline MMV Plan was submitted in October 2012, an interim update was provided in February 2014 and a pre-injection MMV Plan was submitted January 31, 2015. The 2017 MMV Plan [5] submission integrated learnings from the initial injection phase monitoring, the 2020 MMV Plan [6] continued to be adaptive and incorporated updates from this operational phase; the latest update 2023 MMV Plan [7] has continued on this trend.

As new information about conformance and containment monitoring performance becomes available, the MMV Plan will be adapted to ensure it continues to be effective. Any changes will influence the content of the MMV Plan but not the outcome, which by definition meets the performance targets. The latest 2023 MMV Plan [7] has incorporated additional information on seismicity risk assessment, optimization/effectiveness of monitoring technologies, and emergency response plans in accordance with the latest guidance from the regulator.

4. Storage Performance Evidence

Storage performance evidence includes all the information on conformance and containment that support the Storage Criteria discussed in Section 3. Evidence is provided in the AER Annual Status Reports [10].

4.1. Injection Performance Update

From 2016 onwards, the Quest Project has achieved yearly injection targets of approximately one million tonnes since operation commenced in August of 2015. Injection rate and volume fluctuations occur and are a result of capture facility optimizations and planned maintenance, such as plant turn arounds.

All three injection well locations are actively operated, and injection volumes are balanced across the three as required by the operators.

4.1.1. Total Quest CO_2 Injection Summary

The quantity of carbon dioxide (CO_2) captured and injected is found below in Table 4-1, current to the end of 2022.

Further details and annual reporting on rates, volumes, pressures, and temperatures (bottom hole and well head) are reported as monthly averages in the AER Annual Status Reports, Section 3.1 [10]).

Table 4-1: Total Quest CO2 Injection Summary

TOTAL Mass of Injected CO_2 (thousand-tonnes)					
Year	**5-35**	**8-19**	**7-11**	**Total**	**Cum Total**
2015	-	210	161	371	371
2016	-	568	540	1108	1479
2017	-	589	549	1138	2617
2018	91	511	464	1066	3683
2019	340	352	436	1128	4811
2020	306	278	356	940	5751
2021	389	290	376	1055	6806
2022	293	377	300	971	7777

4.1.2. Injectivity Estimate

Before startup of the Project, injectivity (stated in terms of Productivity Index - PI) estimates were updated as a result of the 2012/2013 drilling and production testing programs. The results of the initial well tests showed the PIs of each individual injection well (IW 7-11, IW 5-35, IW 8-19) to be more than the full Project requirement.

To date and overall, the Quest Project has more than sufficient injectivity to take full Project rates up to approximately 150t/hr utilizing all three injection wells. Current performance indicates no further infill well development will be required to meet injectivity requirements for the currently approved total CO_2 volume.

Injectivity performance, such as dynamic Injectivity Index and Bottom hole temperature plots can be found in Section 3.2 of the AER Annual Status Reports [10].

4.1.3. CO_2 Emission Measurements

The MMV results of the measurements of CO_2 emissions from subsurface to atmosphere, in concordance with the SGER Alberta Protocol [8] pre-2018 and the CCIR [9a] from January 2018 to date. These are reported in quarterly audits, commencing with injection start-up in August 2015.

Estimated released mass of CO_2 to atmosphere

The estimated released mass of CO_2 to the atmosphere for the operating period to December 31st, 2022, is equal to zero, as no trigger events have been identified that would indicate a loss of containment. The P20 value of CO_2 has been reported as zero in 2022.

4.2. Conformance Performance

Conformance means that the storage complex is behaving in a predictable manner and consistent with the subsurface model-based predictions. Conformance monitoring tasks verify storage performance.

4.2.1. Current Model Description

The dynamic model is evaluated annually against injection and reservoir performance data and demonstrates acceptable correlation between modelled and observed performance. In 2011, the original static model (Gen-4) for Quest was completed, this model included data from one of the three injector wells, IW 8-19. This detailed model underpinned subsurface technical understanding that has supported the Quest project to date.

Since the original Gen 4, the static model has been periodically updated to represent the most updated view of the BCS reservoir properties with the latest well and injection data. Thus far, all model outcomes have resulted in fundamentally similar outcomes.

4.2.2. Pressure Prediction

The pressure build-up in the BCS is forecast to be less than 2 MPa (Delta P) at the injection wells by the end of the Project life. The expected pressure forecast figures can be found in Figure 3-8 of the AER Annual Status Reports [10]. This pressure increase, of less than 2 MPa, is less than 12% of the Delta P required to exceed the BCS fracture extension pressure and less than 25% of the pressure increase required to exceed the AER operating constraint on bottom hole pressure (D65 approval condition).

The assumption for the forecast is that going forward an equal amount of CO_2 will be injected in each active well for the remainder of the life of the Project.

4.2.3. CO_2 Plume Prediction

The current model incorporates injection well rates & pressure data to the end of 2022 and the results of the vertical seismic profile (VSP) campaigns. Additional data from other seismic imaging tools will be incorporated when possible to improve calibration of modelling outcomes. Modelling and current data set continues to predict CO_2 plume lengths in 2040 of 2 to 4 km, with a potential to reach 6 km. The range in total length is dependent on the volume of CO_2 injected over time and the unique reservoir characteristics at that specific well location.

Details and plots of the current plume prediction can be found in Section 3.4.3 of the current (2022) AER Annual Status Report [7]. Future reporting will occur within subsequent Annual Status Reports [11].

Additional uncertainty will continue to be reduced past year 2023 onwards as the dynamic model is annually calibrated to operational injection data, additional pressure data (e.g., fall-off pressure data from shut-in), and reservoir performance.

4.2.4. Conformance Monitoring Results

Time Lapse Seismic Results

Time-lapse seismic and VSPs have been used to track the CO_2 plumes.

The baseline 3D time-lapse surface seismic survey was acquired over two winters in 2010 and 2011 and covers an area of 435 km^2 (Figure 4-1). It is expected that a survey of this size will be adequate to monitor the CO_2 plumes as they develop at each of the injection wells over the life of the Project. The footprint of future time-lapse surveys will be adjusted to cover the expected plume sizes as the Project moves forward.

Eight 2D walkaway VSP (VSP2D) baseline surveys were acquired along eight different azimuths at each injection well using Distributed Acoustic Sensors (DAS) fibers in Q1 2015 (pre-injection). The first and second monitor campaigns acquired VSP2D over IW 8-19 and IW 7-11 in Q1 2016 and 2017, respectively. A third monitor campaign in Q1 2019 acquired VSP2D data over IW 8-19 and IW 5-35. A fourth monitor campaign in Q4 2021 acquired VSP2D data over the IW 5-35.

Results from the VSP2D data show that the measured time-lapse anomalies are smaller than the forecasted CO_2 plume, but larger than the theoretical minimum plume size. Further discussion of the VSP results is included in the annual AER Status Reporting for the relevant time periods [10, 16, 17].

Regional baseline 2DSEIS was acquired in 2021(Figure 4-1) to provide 2D coverage of the seismic anomaly extent with good offset distribution over the expected seismic anomaly. Future acquisitions will be planned as needed based on indications from a Tier 1 technology that data collection is required.

A monitor 3D survey was acquired in Q4 2021 over IWs 5-35 and 8-19. Results from this survey demonstrated 3D surface seismic can be used as a monitor technology achieving a root mean squared repeatability ratio (RRR) of 7% (where 0% indicates perfectly repeatable datasets and 141% is perfectly non-repeatable). Results from this demonstrate the seismic anomaly size is within the acceptable range of uncertainty of the reservoir model.

The DAS VSP and time-lapse 3D results will continue to be used to inform the plume modelling, plume growth forecasting and support demonstration of conformance.

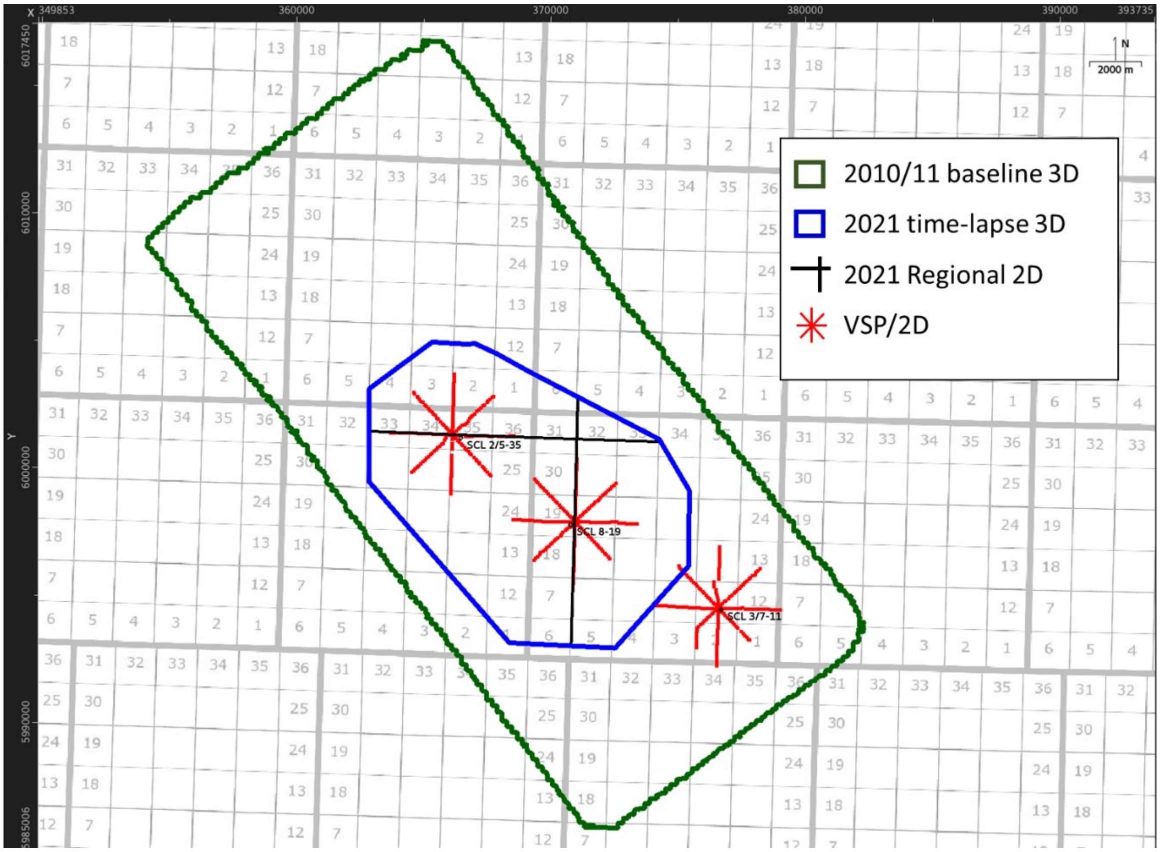

Figure 4-1: Quest Seismic Data Acquisitions

InSAR Results

InSAR is a viable technology for assessing unexpected surface heave. Its value, however, is limited for continuous monitoring given the site-specific characteristics of the Quest site. Based on the observed and modelled pressure build-up within the BCS, expected to be less than 1.5 MPa after 25 years of injection (using a two well injection scenario), dilation within the BCS storage complex will be small. The resulting surface uplift will likely fall within the noise levels of the measured ground displacement.

As a result, InSAR has limited value for continuous monitoring (in respect to both conformance and containment) since it is not expected that the plume would ever cause sufficient heave to be seen. In case of an escalation scenario, there might be value as contingency technology for containment monitoring.

Hence, The InSAR technology is considered a contingency monitoring technology with a focus on the AOR (area of review) of the Quest SLA. In 2017 the following process was established: Radarsat-2 satellite images are collected monthly, but not processed nor analyzed. These images would be used in the event of another MMV technology or observation indicating the need for further investigation.

BCS Pressure Monitoring Results

Downhole Pressure Temperature (DHPT) gauges in the injection wells are used to monitor the development of fluid pressure inside the BCS storage complex. The DHPT gauges provide direct continuous measurements of pressure changes at the injection wells. The data and figures, such as of actual Bottom Hole (BH) gauge response vs. modelled pressure response, previously included here, can be found in Sections 4.3.1 and 4.3.2 of the AER Annual Status reporting [10].

4.2.5. Model to Performance Conformance

Consistency between predicted and observed storage performance is a defined measure of conformance. This means demonstrating that no significant discrepancy exists between the model-based predictions, the observed behaviour of the CO_2 plume, and the region of elevated fluid pressure inside the BCS storage complex. Section 3-3 of the current (2022) AER Annual Status Report discusses the actual pressure build-up in the reservoir compared to the history-matched modelled pressure response to the end of 2022 [10].

The low injection pressures required to meet injection/rate targets thus far provide additional confidence that the required injection pressures will stay low over the life of the Project. Accordingly, this validates that it is extremely unlikely for CO_2 leakage to occur via fracturing or fault reactivation.

In conclusion, conformance is demonstrated as the observed pressure build up in the reservoir to end of 2022 as being consistent with the model-predicted expectation case [10]. Subsequent years results will be available in the AER Annual Reporting [11].

Planned Model Updates

The current static model incorporates all data from the Project Site Selection phase, the 2012-2013 drilling campaign of all Project wells, BCS core descriptions, associated paleo-depositional environmental interpretations, and seismically derived data (e.g., rugose Precambrian surface). Annual updates to the dynamic model are ongoing to incorporate injection and reservoir performance data (including shut-in periods history-matching fall-off data points). As additional injection performance and MMV data become available, a decision will be taken whether recalibrated static reservoir models are needed to reflect the latest development; a consequential decision whether to update dynamic models would follow thereafter.

4.3. Containment Performance

The Project is designed for permanent secure containment of CO_2 and BCS brine within the BCS storage complex. Section 3.1.3 of the MMV Plan [7] discusses the potential threats to containment and Section 4.8 Performance Targets for CO_2 Inventory Accuracy.

Assessment of loss of containment is based on a tiered system of the various technologies deployed as part of the MMV Plan. Trigger events will be used to initiate any control responses if required to barrier containment. Please refer Section 3.1.5 to the updated MMV Plan for details [7].

4.3.1. Containment Risks

Prior to commercial operation, nine potential threats to containment were identified:

1) Migration along a legacy well, 2) Migration along an injection well, 3) Migration along a deep monitoring well, 4) Migration along a rock matrix pathway, 5) Migration along a fault, 6) Induced stress re-activates a fault, 7) Induced stress opens fractures, 8) Acidic fluids erode geological seals, and 9) Third Party activities.

Each was considered highly unlikely; but in principle, capable of allowing CO_2 to migrate upwards from a storage complex. For additional detail on risk assessment associated with all nine potential threats to containment identified prior to commercial operation, please refer to the 2015 MMV Plan [12].

Re-evaluation and integration of all available data (e.g., Site Selection, 2012-2013 drilling campaign, pre-injection phase monitoring, injection phase monitoring, seismic data, Gen-5, Gen-6, 2022 Inversion Porosity Update modeling of the BCS, and operational performance) results in an update to reflect the current key threat lines associated with loss of containment during the Operations phase in the 2023 MMV Plan to the following:

- Migration along a legacy well
- Migration along a Structural Migration Pathway

The above are still considered highly unlikely. Discussion of these risks and updates to the pre-commercial potential threats can be found in the 2023 MMV Plan [7].

4.3.2. Containment Monitoring Results

Well Integrity Testing

Well integrity assurance is supported by, but not limited to, the data in Table 4-2. In 2014 an independent well integrity review was submitted to support the suitability of the Quest injection wells for long-term CO_2 storage and the MMV Plan activities.

As of 2022-year end, there is no indication of integrity issues in the injection wells: IW 7-11, IW 8-19 and IW 5-35 [10]. The following is a summary of the evidence of the integrity of the Quest injection wells.

The Surface Casing Vent Flow (SCVF) and Gas Migration (GM) testing continue to indicate low flow levels.

DTS data continue to behave in a manner similar to typical wells without any leaks, with no expected leak profiles identified in the data. There is no evidence of any temperature anomalies that would indicate a loss of integrity or out of zone injection.

Tubing integrity logging (caliper) does not show any indication of corrosion in the tubing strings. Hydraulic isolation logging (PNx) in the injection wells demonstrate the containment of the CO_2 in the BCS.

Packer isolation tests are performed annually in the injection wells and all wells passed. (Section 4.10.4, [10]).

Injection well monitoring occurs continuously using tubing head pressure (THP), casing head pressure (CHP) and tubing head temperature (THT).

Subsequent years' results will be available in the AER Annual Status Reports [11].

Atmospheric Monitoring

Above-ground CO_2 levels are monitored using a technique called 'LightSource' which is deployed on each injection well pad. Monitoring at each of the injection well pads has been underway since before injection start-up, with no alarms or triggers indicating a loss of containment to date. As per the 2023 MMV Plan [7], LightSource Monitoring will be retained as a Tier 3 technology and will be deployed as required by other trigger activities [7]. Daily operator rounds (Tier 2) have been established as part of MMV (2017 MMV Plan [5]) to support monitoring of the atmosphere domain.

Table 4-2: Well Integrity Activity (modified from the 2020 MMV Plan [6], Table 4-1).

Monitoring technology	Areal coverage	Data Collection Frequency
SCVF testing	DMWs and IWs	2024, and then proposed 5-year frequency [a]
Gas migration testing	IW5-35 & IW 7-11	2024, and then proposed 5-year frequency [a]
Wellhead pressure-temperature monitoring	IWs	Continuous
Downhole pressure-temperature monitoring	IWs	Continuous
Tubing/Casing Annulus pressure monitoring	IWs	Continuous
Time-lapse casing Inspection	IWs	Log 2 of 3 wells up to 15-years after previous logs [b]
Time-lapse cement bond log	IWs	Log 2 of 3 wells up to 15-years after previous logs [b]
Packer isolation test	IWs	Annually as per Directive 87 and clause 5 f) of approval 11837C
Temperature and Pulsed Neutron logs	IWs	As required
Distributed temperature sensing	IWs	Continuous

NOTES:

a - As per September 28, 2020, AER approval letter testing frequency to be reviewed after 2024 testing

b - Following the two 15-year logs, assess data and determine future casing and cement integrity logging frequency

Table 4-3: Well integrity logging activities.

	IW 8-19	IW 7-11	IW 5-35
2010	CBL-VDL-USIT		
2012			CBL-VDL-USIT
2013		CBL-VDL-USIT EMIT	CBL-VDL-USIT EMIT
2015	RST	RST	RST
2016	PNx Tubing Caliper	PNx Tubing Caliper	
2017	PNx Tubing Caliper	PNx Tubing Caliper	
2018		Downhole Video Log	
2019			PNx Tubing Caliper
2020	PNx, Temperature	PNx and Temperature	PNx and Temperature
2021	Casing HR Vertilog, Casing MFC, CBL-VDL, USIT (Casing and Cement bond)	Casing HR Vertilog, Casing MFC, CBL-VDL, UltraView (Casing and Cement bond)	PNx and Temperature
2022	Tubing Caliper	Tubing Caliper	Casing HR Vertilog, Casing MFC, CBL-VDL, UltraView (casing and Cement bond)

Biosphere Monitoring Activities

During the pre-injection monitoring period, data was collected, processed, and analyzed for remote sensing calibration and characterization of pre-injection environmental conditions. There were five components involved in the biosphere program: vegetation, soils, soil conductivity (as measured with electromagnetic data), soil gas and surface flux, and remote sensing. Findings from these studies are summarized in the third Annual AER Report [14]. The remote sensing feasibility studies for Radar Image Analysis (RIA) to detect BCS brine leakage and Multispectral Image Analysis (MIA) to detect CO_2 leakage demonstrated poor correlation and insufficient resolution and were removed from the MMV Plan [13].

In 2015 and 2016 some additional soil sampling, soil gas and soil surface flux measurements were undertaken. Please see fourth [15] and fifth [16] AER Annual Status Reports for findings.

From 2017 onwards, Biosphere monitoring activities will be undertaken on an as needed basis. For example, in the event other monitoring technologies indicate the need to take samples within the biosphere.

Hydrosphere Monitoring Activities

A groundwater sampling program was executed between 2012 and 2014 to support the pre-injection characterization and monitoring program. Detailed information on the findings from the program can be found in the third Annual Status Report [14].

In 2015, the hydrosphere sampling program was revised due to an improved understanding of the actual risks associated with CO_2 injection within the Quest SLA, resulting in focused sampling within the Area of Review (AOR) and on the well pads. For further details, please refer to the 2015 MMV plan [13].

Continued adaptation of the hydrosphere monitoring program occurred through 2018 and 2019, with discrete planned sampling events suspended in 2019. Continuous water electrical conductivity (WEC) and pH data are collected and analyzed to monitor any potential project impacts to groundwater, with any additional discrete sampling events retained within the MMV plan as a Tier 3 contingency technology.

The evolution of the hydrosphere monitoring program has occurred because of updated project risk profiles, tiering of technologies and the results of the monitoring to date. Discussion of these changes are included in the 2018 AER Annual Status Report [18] and 2020 MMV Plan [6].

To-date, no alarms or triggers indicating a loss of containment have been identified, as discussed within the AER Annual Status Reports [10]. Future reporting will occur within subsequent Annual Status Reports [11].

Geosphere Monitoring Activities

Time-Lapse Seismic Surveys: Time-lapse seismic data (VSP2D, SEIS2D, SEIS3D) are used to verify the absence of CO_2 above the ultimate seal of the BCS storage complex. The detailed results of the VSP baseline and monitor surveys are included in the Annual AER Status Reports for the relevant years. To date no triggers on the DAS VSP have been identified, as there has been no indication of CO_2 above the BCS. As of 2021, as anticipated, the plume growth has exceeded the reliable lateral imaging limit of the time-lapse VSP2D, and the imaging area cannot be extended by increasing the length of the survey lines. As DAS VSP is a Tier 2 technology there is no plan to acquire further surveys unless deemed necessary to investigate a suspected loss of containment. In the future, if determined to be necessary, time-lapse SEIS3D may be used to monitor plume size and geometry. Quest also regularly investigates new technologies and/or unique deployments of established technologies to further the toolkit for cost effective seismic MMV technologies.

InSAR: please refer to Section 4.2.4.

In-Well Monitoring Activities

Seismicity: A temporary microseismic array was installed in DMW 8-19 and began recording baseline seismicity in November 2014. A permanent array was installed in April 2015 after the well was perforated in the Cooking Lake Formation and a pressure gauge installed along with the new array. In October 2022 the array was replaced following well integrity and casing inspection assessment/logging and a new DH pressure/temperature gauge was installed and calibrated.

No locatable events were recorded in the MMV AOR during the baseline period. Since injection startup, there have been multiple locatable events recorded in the SLA, demonstrating the operational sensitivity of the microseismic array. All events have been located within the Precambrian basement. There has been no correlation between seismic event timing and pressure variations. Discussion and reporting of recorded seismic events are included in the relevant year AER Annual Status Reports (Section 4, [10, 16, 17, 18]).

To date, there have been no seismic events that constituted a containment trigger event. Future reporting will occur within subsequent Annual Status Reports [11].

DTS: Continuous Distributed Temperature Sensing (DTS) is deployed using optical fibers permanently installed in each injection well. Data recording began before start of injection.

DTS is utilized as a qualitative assessment primarily by observing rates of change in temperature over time, and the integration of temporal data on CO_2 flow into the injection wells.

To date no alarms or triggers indicating a loss of containment have been identified, as discussed within the AER Annual Status Reports [10]. Future reporting will occur within subsequent Annual Status Reports [11].

DAS: As discussed in the MMV Plan [6], the feasibility of time-lapse walkaway DAS VSP has been demonstrated on the 2015 baseline and 2016/2017/2019/2021 monitor VSP surveys: plume anomaly changes over time can be monitored. Results have shown the plume is growing at a rate consistent with modelled results within the accepted uncertainty range.

DMW Pressure Monitoring: Discrete pressure measurements were acquired in the Cooking Lake in DMW 7-11, DMW 8-19 and DMW 5-35 through MDT/XPT sampling during the 2012/2013 drilling campaign. Continuous pressure data in the Cooking Lake Formation via three monitoring wells, DMW 7-11, DMW 8-19, and DMW 5-35 has been ongoing since Q3 2015. No responses indicating loss of containment have been observed to date (Section 4.3, [10]). Future reporting will occur within subsequent Annual Status Reports [11].

4.3.3. Update to Third Party Wells Penetrating Sequestration Lease

As of December 31, 2022, no third-party wells have been drilled into the BCS storage complex since the last Closure Plan submission or from the time of the original D65 application submission [4]. Currently there are four third party legacy wells within the SLA that penetrate through all the major seals in the BCS Storage Complex (Middle Cambrian Shale, Lower and Upper Lotsberg Salts). These BCS legacy wells are more than 18 km away from the Project injection wells and previous submissions of the MMV and Closure Plans include details of the completions of these wells [12]. The legacy wells include:

- Imperial Eastgate 100-01-34-057-22W400
- Imperial Egremont 100-06-36-058-23W400
- Imperial Darling #1100-16-19-062-19W400
- Westcoast et al Newbrook 100-09-31-062-19W40 (only drilled to top LMS not through the BCS)

Note: we do not expect the CO_2 plume to ever reach these legacy wells.

Update of Containment Risk via Legacy Wells

Reservoir performance and model updates demonstrate that pressures are too low for BCS brine to be lifted to above the Base Groundwater Protection (BGWP) at any of the legacy wells throughout the life of the Project. This is discussed in detail in the 2017 MMV Plan, Section 5.1.2 [5]. As such, this risk was reduced from the initial pre-baseline period MMV Plan risk profile assessment [13], to the current operational risk profile as proposed in the 2023 MMV Plan [7].

4.3.4. Update on any Surface or Subsurface Interactions

To-date, there have been no indication of interactions between the BCS storage complex fluid (brine) or injected Project CO_2 and the surface.

Shell has previously reported to the AER that surface casing vent flows (SCVF) and gas migrations (GM) were identified in the injection wells. Analytical results (composition and isotopic values) confirm that SCVFs and GMs are independent of each other. GMs originate from a biogenic shallow zone, while the SCVFs originate from just below the surface casing shoe consisting of a mixture of thermogenic and biogenic sources. The composition of the SCVFs and GMs confirm that there is no contribution from deeper formations (i.e., below Mannville). Due to the shallow depths of the sources of the SCVFs and GMs, there is no evidence of a pathway that is considered a threat to containment or isolation of the BCS storage complex.

4.3.5. Barriers to Ensure Containment

Following extensive site characterization, there are no known likely migration pathways for fluids to escape upwards out of the BCS storage complex (Figure 3-3 of the AER Approval No. 11837C [5]). Prior to implementing any MMV, several inherent barriers were already in-place to reduce the risk of any unexpected loss of containment due to an unknown migration pathway.

Initial storage risk reductions were achieved through multiple independent barriers implemented through site selection, site characterization, and engineering concept selections. These initial passive barriers are sufficient on their own to make the loss of containment extremely unlikely. Details of these barriers can be found in previous MMV Plan submissions [5, 12, 13].

The MMV Plan provides a comprehensive and reliable means to verify the effectiveness of these initial passive barriers. In the extremely unlikely case that monitoring indicates a potential loss of containment then a wide range of control measures can be deployed in a timely fashion to effectively prevent, mitigate, or remediate any actual loss of containment (updated Tables 3-2 and 3-3 in MMV Plan [7]). These additional active barriers are triggered by monitoring and are designed to be sufficiently numerous and diverse to yield significant additional storage risk reduction.

The risk assessment methodology is designed to re-visit the operational risks as part of MMV and Closure Plan updates. For example, if the risk assessment changes or if Conformance indications require, the risks that are currently removed from the Operational bowtie can be reintroduced as necessary to mitigate loss of Containment. Resulting MMV activities would be identified and executed to mitigate these risks. The MMV and Closure Plans would be updated as required as per Section 4.1.

5. Operating Plan Update

This section provides a summary of the activities conducted by Shell on the location of the SLA since the licenses were issued in 2011 [3].

The Quest AER Annual Status Report is issued on a yearly basis in accordance with the Approval [1], and detailed reporting of the Project operations can be found in those submissions.

5.1. Project Update

Since the submission of the initial Closure Plan in 2014, the Quest Project completed all major construction and commissioning milestones and has moved into the sustained injection operational phase.

No further well development has occurred within the SLA (Section 2.2) and currently all project injection wells drilled to date (IW 7-11, IW 8-19, and IW 5-35) are on injection. No further well requirements for the initial Quest Project are anticipated.

5.1.1. Operating Procedures

Shell will operate the Project in accordance with AER Approval 11837C Conditions [1]. The following AER Approval Conditions specifically relate to operation procedures and are adhered to as follows:

1) Condition 5f – inform WellOperations@aer.ca if leak or potential leak detected in the tubing/casing annulus or packer in the injection well.
2) Condition 5g – immediately suspend injection and notify WellOperations@aer.ca if fluid movement above BGWP or any zone outside the BCS storage complex.
3) Condition 5h – immediately suspend injection operations if failure of any systems that compromise safe operations of the scheme occur.
4) Condition 5i – immediately report any movement of fluids into or above the MCS, or anomalous pressure changes occurring anywhere within the CO_2 disposal approval area to ResourceCompliance@aer.ca and WellOperations@aer.ca
5) Condition 6 and 25 – provide written incident report within 90 days to ResourceCompliance@aer.ca, WellOperations@aer.ca and the Alberta Ministry of Environment and Protected Areas Water Policy Branch for the following:
   (a) Any movement of fluid out of BCS Formation or above MCS
   (b) Any anomalies that indicate fracturing out of the BCS formation
   (c) Any indications of loss of containment
   (d) Unexpected surface heave, and
   (e) Appropriate mitigative measures taken
6) Condition 26 – immediately notify the Ministry of Environment and Parks at 1-800-222-6514 regarding any loss of CO_2 to the atmosphere, soils or shallow (non-saline) aquifers and provide an incident report as per Condition 6 and 25 above.

5.1.2. Uncertainty and Risk Assessment Updates

The 2023 MMV plan [7], in accordance with the newest AER MMV guidelines contains a risk assessment for seismicity with the intent to address potential risks associated with natural and induced seismicity related to CO_2 injection. It lists two potential consequences of seismicity and discusses the various active and passive barriers that are in place to manage this risk. In addition, the two key project risks to containment: "Migration along an injector well" and Migration along a structural migration pathway" [7] are also reviewed and thoroughly discussed.

Containment risks associated with the "Project Phase" that have been removed from the current Operational MMV Plan are still managed via the Project risk register, with potential data acquisition either ongoing, or with the potential to reintroduce to the Containment bow-tie should the risks' profiles become potentially elevated due to triggers in the tiered technologies or an indication of non-Conformance is identified.

Additionally, at cessation of injection, Closure and post-Closure, the project risks will be re-assessed, updated and re-introduced should the conditions of these periods require.

5.1.3. Defined Areas of Investigation

During the initial phases of the Project the area of review (AOR) for Quest was defined by the SLA (Figure 1-1). This has been updated in the 2017 MMV Plan, Section 5 [5] and this update continues to be valid for the 2023 MMV Plan [7].

MMV operates within the AOR based on the expected volume of CO_2 to be injected during the course of the project. As defined in the MMV Plan, the Quest AOR extends 10 km radially outwards from the active injection wells.

A new Seismicity Monitoring Area (SMA) was introduced which is defined by a 50km radius around the downhole geophone array located in the Quest Injector Well 08-19. Reasons for this SMA definition are:

- It captures the areas of increased regional seismicity observed to date.
- It includes the full Quest SLA.
- It is a reasonable limit within which the downhole geophone array can be expected to detect seismicity that could be of consequence.

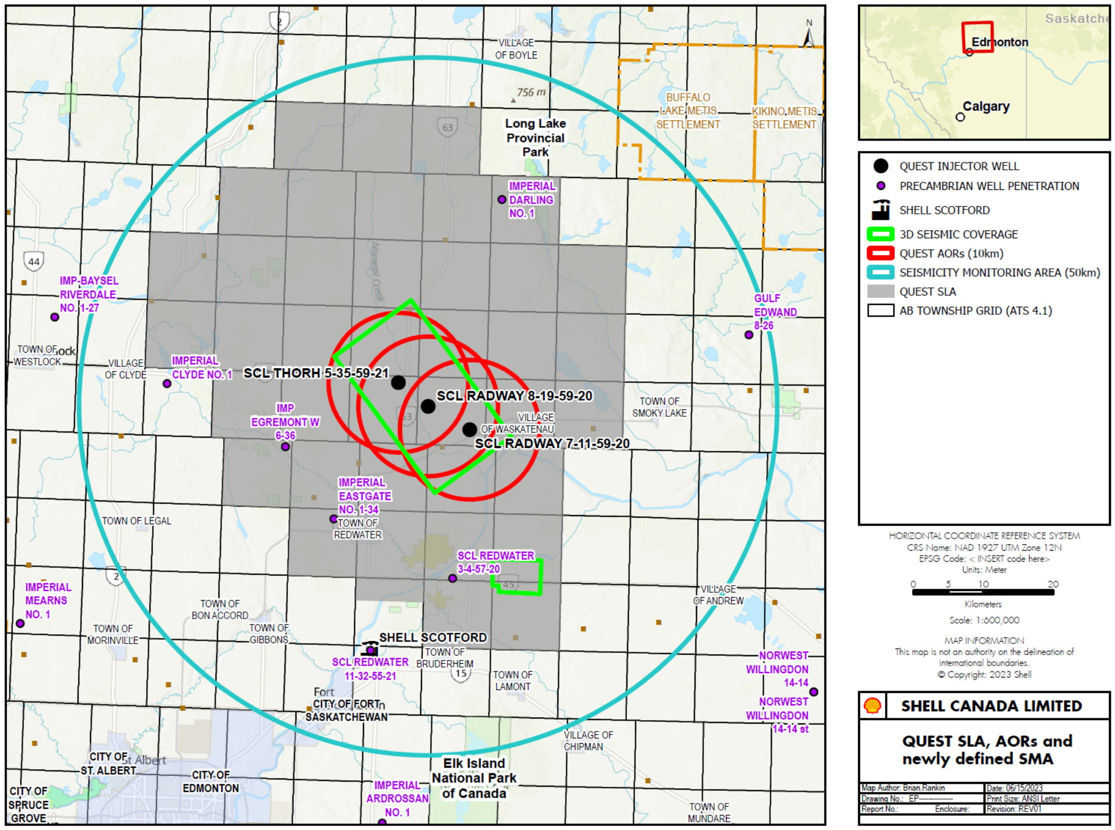

Figure 5-1: Quest AOR with newly defined Seismicity Monitoring Area (SMA).

Please note: The Quest AOR is defined by a 10km radius around each injector well as red circles. The SMA has a radius of 50km around the downhole geophone array in Quest 08-19 shown as teal circle in Figure 5-1.

6. Closure Activities

The Closure Plan focuses on the storage component of the Project and does not address the CO_2 capture infrastructure and the CO_2 pipeline as these are covered under separate legislation.

6.1. Storage Site

The subsurface infrastructure will be abandoned in accordance with the AER's Directive 020: Well Abandonment and Directive 072: Well Abandonment Notification Requirements, and any other regulations and requirements that are applicable at the time of closure.

The surface abandonment of the wells, well sites and access roads will be completed in accordance with the applicable regulations and requirements.

6.2. Well Decommissioning

The Project wells adhere to both regulatory standards and Shell internal requirements. A decommissioning plan will be executed in accordance with relevant legislation and requirements in place at the time.

At the time of abandonment, the Quest wells will follow a phased approach that will consist of:

Phase 1: An observation period following the cessation of injection, keeping selected in-well monitoring to support conformance (Initial Closure, Pre-Abandonment).

Phase 2: The isolation of the BCS, followed by another observation period, in order to support containment of the BCS storage complex while keeping the ability to re-enter the well if required (Later Closure, BCS Abandonment).

Phase 3: The final subsurface and surface abandonment of all wells (Full abandonment) and application of site closure certificate with resulting transfer of liability at end of phase.

Figure 6-1 shows the injection well status during the three phases of abandonment, the details are discussed below.

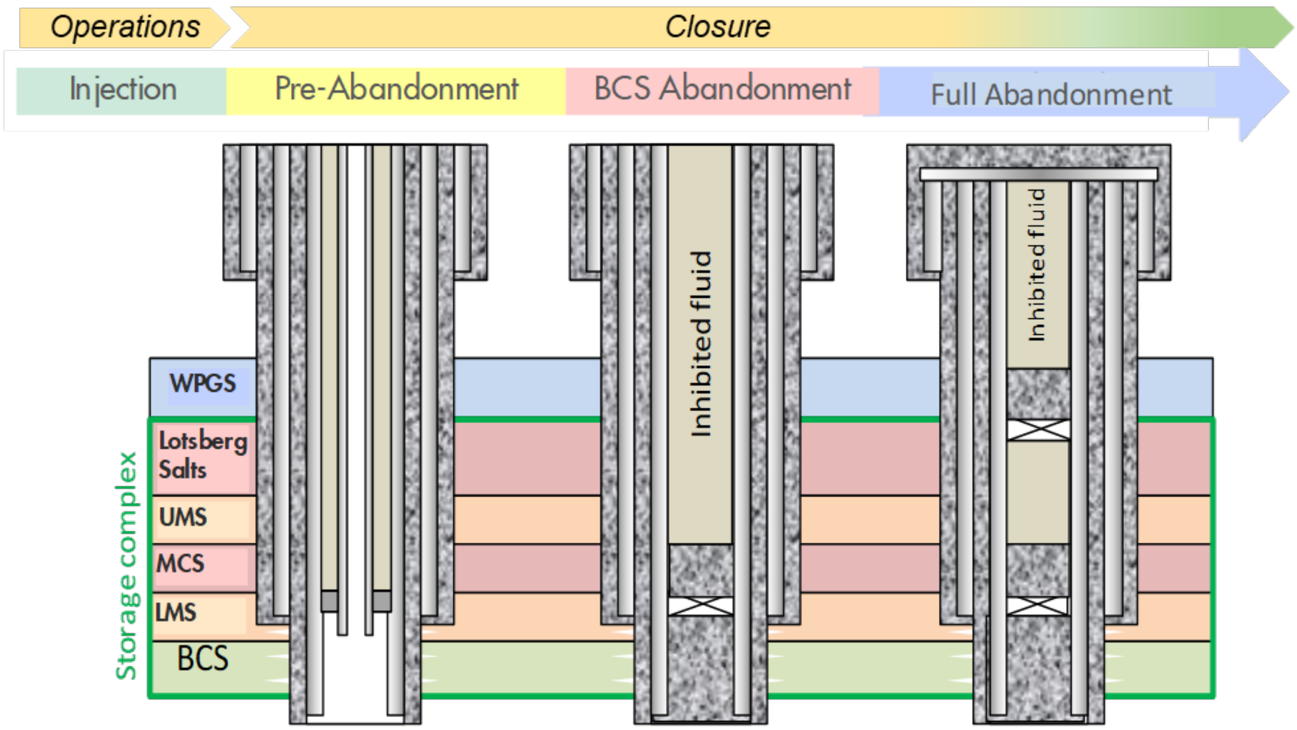

Figure 6-1: IW Schematic for the Three Phases of Well Abandonment.

6.2.1. Pre-Abandonment Period (Early Closure)

After CO_2 injection ends (either at a single well pad and/or for the Project), an observation period will take place during which time relevant injection wells will be suspended with the exception of selected monitoring systems, which will continue to operate. The monitoring wells and all other active monitoring technologies will continue normal operational monitoring until authorized by the Regulator in review of the final Closure Plan.

The value of collecting additional reservoir data during this period shall be assessed. If the data is deemed of sufficient value, the wellbore shall be configured in a manner to suspend the well and gather the requisite data.

Once authorization of the final Closure Plan has occurred, the closure period (either for the Project or a proposed portion of the Project), will commence.

The pre-decommissioning period ends once Shell has sufficiently demonstrated containment and conformance.

6.2.2. BCS Abandonment Period (Late Closure)

At the end of the pre-decommissioning period, a cement plug will be set inside each injection well to isolate the BCS. At this time monitoring inside the BCS will end, although the injection wells can still be re-entered at this stage if necessary.

Another observation period follows to confirm successful isolation of the BCS. Monitoring within injection wells will likely measure pressure and temperature changes above the cement plug.

Prior to repairing the SCVFs and GMs a risk assessment shall be performed and provided to the Alberta Energy Regulator and Alberta Energy and Minerals for review. The risk assessment should consider potential for loss of wellbore access during potential SCVF and GM repair and the corresponding inability to access the CO_2 post repair should this be required. The risk assessment should be performed during the BCS Abandonment Period in preparation for potential SCVF and GM repair during Full Abandonment.

The BCS isolation period ends once monitoring demonstrates that the isolation of the BCS within the abandoned injection wells has been effective.

6.2.3. Full Abandonment Period

Once the BCS isolation period ends, cement plugs will be set inside all Project wells (injection wells and monitoring wells), followed by abandonment according to Directive 020 or the regulatory requirements of the day.

Shell recommend that all in-well monitoring will end at this time.

These plans may be modified to allow some in-well monitoring systems to be transferred to the Crown for monitoring during the post-closure period as per Section 19h of the *Carbon Sequestration Tenure Regulation 68-2011* [3].

6.3. Well Pad Reclamation

Alberta's *Environmental Protection and Enhancement Act* and the Conservation and Reclamation (C&R) Regulation require that, after an upstream oil and gas facility has been decommissioned, the operator must obtain a reclamation certificate.

Goals outlined by Shell for the reclamation of the well pads include:

- Returning the land disturbed by the Project to equivalent land capability at closure.
- Ensuring that a stable, self-sustaining closure landscape (including landforms, soil, vegetation and hydrological regime) is present after closure.

The basic activities for final reclamation and establishing the closure landscape include, but are not limited to:

- abandoning and decommissioning facilities
- removing infrastructure
- remediating contaminated areas (if required)
- restoring grade and drainage
- alleviating compaction
- replacing subsoil and topsoil
- re-vegetating

Shell will monitor reclamation of soils and vegetation according to AENV's 2010 Reclamation Criteria for Well sites and Associated Facilities for Forested Land.

6.4. Monitoring Infrastructure Decommissioning

Shell expects that monitoring infrastructure will be decommissioned at the end of the closure period.

All monitoring infrastructure that is associated with wells or well pads will be decommissioned as part of the well abandonment and well pad reclamation process described above.

7. Site Closure Certification

7.1. Site Closure Certificate

Shell will apply for a Site Closure Certificate following the execution of site closure activities and submission of the final Closure Plan and MMV report, as per Section 120 of the MMA [2]. The Closure Period before transfer of liability to the Crown will be determined based upon assessment of data obtained from the monitoring program regarding actual storage performance versus predicted performance. These performance metrics are described in Section 3.

The post-closure period will occur following the issuance of a Site Closure Certificate, which will transfer the long-term liability from Shell to the Crown, as per Section 121 of the MMA [2].

7.2. Post-Closure Government Monitoring

Prior to transfer of liability, as per Section 19h of the *Carbon Sequestration Tenure Regulation 68-2011* [3], Shell will provide advice and recommendations on which technologies that could be utilized post-closure. Appreciating that future project operational information and experience will facilitate post-closure monitoring planning, Shell commits to ongoing discussion with the AER and Alberta Energy and Minerals in this regard, particularly as it relates to the post-closure stewardship fund. The outcomes of these engagements will be incorporated into the advice and recommendations Shell will provide and communicate prior to start of closure to ensure sufficient time is available for adequate financial and resource planning by the Government of Alberta.

In addition, Shell will share with the Government of Alberta its knowledge and experience of MMV activities and outcomes according to the terms in the CCS Funding Agreement for the Quest Project, before the transfer of liability. This may take the form of workshops, provision of documents and/or presentations as determined by the appropriate parties at the time.

8. Reporting and Documentation

In accordance with Section 19) (3)g of the *Carbon Sequestration Tenure Regulation 68/2011*, Appendix A contains an inventory of the reports and documents that Shell has submitted to the Regulator or a department or agency of the Crown in right of Alberta or the Crown in right of Canada since the approval of the first Closure Plan in April 2011 that are related to the carbon sequestration lease, whether or not those reports and documents were required to be submitted.

In addition, Shell will provide the Government of Alberta with its knowledge and experience of MMV activities and outcomes according to the terms in the CCS Funding Agreement for the Quest Project, before the transfer of liability.

9. References

[1] Alberta Energy Regulator Carbon Dioxide Disposal & Containment Approval No. 11837C. Issued to Shell Canada Limited May 12, 2015.

[2] Province of Alberta Mines and Mineral Act. Revised Statutes of Alberta 2000 Chapter M-17. Alberta Queen's Printer, Edmonton Alberta. Current as of December 6, 2016.

[3] Alberta Regulation 68/2011, Mines and Minerals Act, Carbon Sequestration Tenure Regulation. 10/1/2012.

[4] Shell Canada Limited Quest Carbon Capture and Storage Project, Directive 65: Application for a CO_2 Acid Gas Storage Scheme. Submitted to Energy Resources Conservation Board of Alberta November 2010.

[5] Shell Quest Carbon Capture and Storage Project, Radway Field and Surrounding Areas, AER Approval No. 11837C, AER Decision 2012 ABERCB008, February 2017 MMV Plan Update.

[6] Shell Quest Carbon Capture and Storage Project, Radway Field and Surrounding Areas, AER Approval No. 11837C, AER Decision 2012 ABERCB008, July 2020 MMV Plan Update.

[7] Shell Quest Carbon Capture and Storage Project, Radway Field and Surrounding Areas, AER Approval No. 11837C, AER Decision 2012 ABERCB008, July 2023 MMV Plan Update.

[8] Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers. Alberta Carbon Offset Program, Government of Alberta. June 23, 2015.

[9a] Quantification methodologies for the Carbon Competitiveness Incentive Regulation and the Specified Gas Reporting Regulation, Government of Alberta. November 1, 2019.

[9b] Quantification methodologies for the Technology Innovation and Emissions Reduction Regulation (TIER), Government of Alberta. January 1, 2020.

[10] Shell Quest Carbon Capture and Storage Project: Annual Status Reports (2019, 2020, 2021, 2022). As per Carbon Dioxide Disposal Approval 11837C.

[11] Shell Quest Carbon Capture and Storage Project: FUTURE Annual Status Reports (2023, 2024, 2025). As per Carbon Dioxide Disposal Approval 11837C.

[12] Alberta Energy Regulators. Quest Carbon Capture and Storage Project Radway Field & Surrounding Areas AER Approval No. 11837C, AER Decision 2012 ABERCB 008 Special Report #1 & Pre-baseline MMV Plan October 15, 2012 Submission. Updated Approvals and Conditions. Received December 3, 2013.

[13] Shell Quest Carbon Capture and Storage Project, Radway Field and Surrounding Areas, AER Approval No. 11837B, AER Decision 2012 ABERCB008, January 31, 2015 MMV Plan Update.

[14] Shell Quest Carbon Capture and Storage Project: Third Annual Status Report (2014). Submitted to AER March 31, 2015 as per Carbon Dioxide Disposal Approval 11837C.

[15] Shell Quest Carbon Capture and Storage Project: Fourth Annual Status Report (2015). Submitted to AER March 31, 2016 as per Carbon Dioxide Disposal Approval 11837C.

[16] Shell Quest Carbon Capture and Storage Project: Fifth Annual Status Report (2016). Submitted to AER March 31, 2017 as per Carbon Dioxide Disposal Approval 11837C.

[17] Shell Quest Carbon Capture and Storage Project: Sixth Annual Status Report (2017). Submitted to AER March 31, 2018 as per Carbon Dioxide Disposal Approval 11837C.

[18] Shell Quest Carbon Capture and Storage Project: 2018 Annual Status Report. Submitted to AER March 31, 2019 as per Carbon Dioxide Disposal Approval 11837C.

[19] Monitoring, measurement, and verification principles and objectives for CO_2 sequestration projects. Version 2. April 5, 2023. Alberta Government. https://open.alberta.ca/publications/mmv-principles-objectives-for-co2-sequestration-projects-version-2

10. Professional Practice Management

This report entitled "Shell Quest Carbon Capture and Storage Project – Closure Plan" was prepared for the Alberta Energy Regulator in September 2023.
It was prepared by Shell Canada Limited under supervision (review, authentication, and coordination) of:

Carrie Rowe, P.Geo
Quest Subsurface Manager, Geologist

The primary responsible discipline, Geoscience, is represented by the following professionals:

Jonathan Hopkins, P.Geo
Geophysicist

And

Jonathan Winsor, P. Geoph
Senior Geophysicist

The secondary responsible discipline, Production Technology, is represented by the following professional:

Rob Liston, P.Eng
Production Technology Engineer

The tertiary responsible discipline, Petrophysics, is represented by the following professional:

Irma Eggenkamp, P.Geo
Petrophysicist

Document Reference Number (if available)	*Document Name*	*Year Submitted*
	D65 Deficiency Letter- response to ERCB-FINAL_6Jun11.pdf	*2011*
	D65 Update_June_2011.pdf	*2011*
	Response to ERCB Deficiency Letter on MMV Oct21_2011.pdf	*2011*
	ERCB MMV Deficiency Letter received 2011-10-17-.pdf	*2011*
	Response to SIR #2_November 2, 2011.pdf	*2011*
	Errata to the EA Volume 2, Section 5_November 2, 2011.pdf	*2011*
	Response to SIR Nov.30 from ERCB_submitted Dec2011.pdf	*2011*
	ERCB seismic and mmv information request received 2011-11-30 .pdf	*2011*
	Shells Request to Transfer Directive 051 Submission to Application 1670112_1806713_2011-07-25.pdf	*2011*
	Directive 051 Closure_1806712 2011-07-29.pdf	*2011*
	Quest Sequestration Lease Application to ADOE April 28 2011	*2011*
	ADOE Quest Sequestration Lease Approval May 27 2011.pdf	*2011*
	1161- 07-3-ZW-8780-0001 Well Programme for Completion and Intervention (Rev 1, 2011-08-2011)	*2011*
	07-3-ZW-7770-0001- Well Technical Specification (Rev 1, 2011-08-11)	*2011*
	07-3-ZW-7770-0002 - Well Technical Specification for Interventions (Rev 2, 2011-08-11)	*2011*
	Q1 2011 Quarterly Status Update March 2011	*2011*
	Q2 2011 Quarterly Update June 2011	*2011*
	Q3 2011 Quarterly Update October 2011	*2011*
	07-0-AA-5726-0001 - Storage Development Plan (Rev 2, 2011-10-06)	*2011*
	Shell Response to Ouelette_(2012.02.28)_Groundwater Review Submission-Tab B.pdf	*2012*
	Shell Canada Limited AER Hearing Decision 2012 ABERCB 008.pdf	*2012*
	Final Quest Directive 65_Submitted to ERCB Nov 2010.pdf	*2012*
	ERCB Approval for Extension of pre-baseline MMV submission date_Sept13_2012.pdf	*2012*
	Special Report #1 Submitted to AER Oct 29 2012	*2012*
	ESRD_Condition_25_MMV Plan Update_Sent_Nov5_2012.pdf	*2012*
	AER Approval for no Mercaptans 2013-12-02.pdf	*2012*
	External Expert Panel Report by DNV	*2012*
	07-3-AA-6619-0001 Capacity Risk and Uncertainty Review. pdf	*2012*
	07-3-AA-6619-0004 Containment Risk and Uncertainty Review.pdf	*2012*
	07-3-AA-6619-0005 Injectivity Risk and Uncertainty Review.pdf	*2012*
	07-3-AA-5726-0001 Integrated Modeling Report (Gen - 4)	*2012*
	Q1 2012 Quarterly Update April 2012	*2012*

	Q2 2012 Quarterly Update July 2012	*2012*
	Q3 2012 Quarterly Update October 2012	*2012*
	Shell Quest - Screening Report - CEAR ref # 10-01-55916 Final signed.pdf	*2012*
	2012 Annual Report March 2012	*2012*
	AER Approval & Clarification Letter RE October 15 2012 MMV Plan & Special Report #1.pdf	*2012*
	Q1 2013 Quarterly Update March 2013	*2013*
	Q2 2013 Quarterly Update September 2013	*2013*
	Q3 2013 Quarterly Update December 2013	*2013*
	2013 Annual Report March 2013	*2013*
	Q2 2013 Quarterly Construction Update June 2013	*2013*
	Q3 2013 Quarterly Construction Update October 2013	*2013*
	Special_Report_#2_Submitted to AER_Jan31_2013.pdf	*2013*
	1st Annual_Status_Report_to AER_submitted Feb_13 2013.pdf	*2013*
	ERCB SIR 2_received Shell March 28 2013.pdf	*2013*
	Response to ERCB SIR march 20 2013 submitted April 25.pdf	*2013*
	Storage Rights Clarification Letter Submitted to AER April 25 2013.pdf	*2013*
	MMV_Bowtie_submitted with Clarification on Storage Rights Letter May29_2013.pdf	*2013*
	ERCB Response to Legal Clarifying Storage Rights received June 3 2013.pdf	*2013*
	Response to ERCB email on Special Report #1 submitted April 23-13.pdf	*2013*
	AER final D65 Approval No 11873A August 8 2013.pdf	*2013*
	AER Sept 5 2013 IR response submitted Sept 20, 2013.pdf	*2013*
	AER Approval and Conditions for InSAR received 2013-10-04.pdf	*2013*
	Self Disclosure to AER - IW 5-35 perfs out of zone_Nov 25 2013.pdf	*2013*
	Shell Response to AER Questions on Well Integrity_Dec 6_2013.pdf	*2013*
	ERCB Dec 7 2012 IR_Response_submitted_Jan_9_2013.doc	*2013*
	AER Approval for SCVF and GM Deferral of Repair received Sept4_2013.pdf	*2013*
	AER denial of Shell initial Proposal to AER for SCVF and GM resolution proposal received June 12_2013.pdf	*2013*
	Shell Approved Proposal to AER for SCVF and GM resolution submitted Aug28_2013.pdf	*2013*
	Letter to ADOE for Clarification to monitoring the Cooking Lake submitted March 27 2013.pdf	*2013*
	ADOE Approval to monitor the Cooking Lake Formation_April 19 2013.msg	*2013*
	Q4 2013 Quarterly Status Update February 2014	*2014*
	Q4 2013 Quarterly Construction Update February 2014	*2014*
	2nd Annual Status Report_to AER Submitted_Jan 31 2014.pdf	*2014*
	Self Disclosure to AER- IW 5-35 perfs out of zone_add info_ Jan 2014.pdf	*2014*
	MMV Plan interim update Feb 14 2014_Submitted.pdf	*2014*

07-3-AA-5706-0001	*2nd Annual Status Report to AER (ERCB)*	*2014*
07-3-AA-5706-0001	*MMV Plan Update and HBMP Plan*	*2014*
07-3-ZW-7770-0001	*Well Functional Specification*	*2014*
07-3-ZW-8780-0001	*Well Programme for Completion and Intervention*	*2014*
07-3-ZW-7770-0002	*Well Technical Specification*	*2014*
07-3-ZW-8780-0001	*Well Programme for Completion and Intervention*	*2014*
	SPECIAL REPORT #3 Tracer Feasibility Report	*2014*
	Surface Casing Vent Flow (SCVF) and Gas Migration (GM) repair deferral request	*2014*
	Gas Migration(GM)- AER letter of Sept 4th, 2013- Monitoring compliance requirements	*2014*
	D65 Injection well amendment application for 05-35 and 07-11	*2014*
	Update to D65 Application: AER Approval Number 11837A: Condition 4	*2014*
07-0-AA-7180-0019	*Annual Summary Report to GoA*	*2014*
	AER D51 Injection Well application 05-35 and 07-11	*2014*
07-3-ZE-7180-0016	*Baseline data and analysis of biogenic flux of CO2 across Quest approval area*	*2015*
	D56 Well License Amendment Approval 08-19-059-20W4	*2015*
	D65 Well License Amendment Approval 11837B 08-19-059-20W4	*2015*
	Consent for Observation in undisposed crown 100/03-04-057-20W4/00 wellbore	*2015*
	Carbon dioxide disposal and Containment Approval No. 11837B- Revision to Table 1 to remove the maximum injection rate restriction per well	*2015*
	AER request letter Re: MS Data plan	*2015*
	AER Approval 11837C	*2015*
07-04-AA-7180-0001	*Division A - Annual Summary Report to GOA*	*2015*
	Division B - Report to GOA	*2015*
07-04-AA-5706-0001	*3rd Annual Status Report to AER (ERCB)*	*2015*
	Annual Surface casing Vent Flow (SCVF) and Gas Migration(GM)	*2015*
	Shell Quest Data Management and Retention *Microseismic Raw (Trigger file) Retention Plan – Request for Approval*	*2015*
	Commercial Operations Certificate	*2015*
07-04-AA-5706-001	*4th Annual Status Report to AER (ERCB)*	*2016*
	Shell Quest Approval No.11837C *MMV Plan –Section 6.2.3.2 change*	*2016*
	Division A - Annual Summary Report to GOA	*2016*

	Division B - Report to GOA	*2016*
	Well integrity discussion- Approval No. 11837C- Condition 5 c	*2016*
	Shell Quest Approval No.11837C *Request for extension, InSAR Efficacy Report (Condition 16)*	*2016*
	Letter-Shell Quest MMV Plan & Approval No.11837C *Synopsis of updates - changes*	*2016*
	Shell Quest Approval No.11837C *Request for extension, Logging Condition 5C*	*2016*
	Annual Submission for SCVF and GM testing	*2016*
	Shell Quest Approval No.11837C: *MMV Plan –Section 6.2.3.2 change request withdrawal letter*	*2016*
	Annual Submission for SCVF and GM testing	*2016*
	AER Approval No.11837C: Directive 13 *Request for non-routine suspension for SCL THORH 5-35-59-21*	*2017*
	Shell Quest AER Approval No.11837C: MMV Plan Update	*2017*
	Shell Quest AER Approval No.11837C: Closure Plan Update	*2017*
	Quest Carbon Capture and Storage Project Fifth ANNUAL STATUS REPORT	*2017*
	Division A - Annual Summary Report to GOA	*2017*
	Division B - Report to GOA	*2017*
	Annual Submission for SCVF and GM testing	*2017*
	Renewal of Environmental Protection and Enhancement Act Approval No. 49587-01-00: First extension of Approval expiry date, Shell Canada limited Oil Sands Processing plant (Bitumen Upgrader)	*2017*
	AER Approval No.11837C: Groundwater Sampling Plan for 2018 &2019 Update to 2017 MMV Plan	*2018*
	Quest Carbon Capture and Storage Project Sixth Annual Status Report	*2018*
	Division A - Annual Summary Report to GOA	*2018*
	Division B - Report to GOA	*2018*
	Amendment to EPEA Approval 49587-02-01: Shell Canada Limited Oil Sands Processing plant (Bitumen Upgrader) Environmental Protection and Enhancement Act Approval	*2018*
	Annual Submission for SCVF and GM testing	*2018*
	Annual Submission for SCVF and GM testing	*2019*
	Shell Quest Approval No.11837C: Request for amendment, Logging Condition 5 C	*2019*
	Division A - Annual Summary Report to GOA	*2019*
	Annual Status Report to AER	*2019*
	Division A - Annual Summary Report to GOA	*2020*
	Annual Status Report to AER	*2020*
	Shell Quest AER Approval No.11837C: MMV Plan Update	*2020*
	Shell Quest AER Approval No.11837C: Closure Plan Update	*2020*
	Repair of Surface Casing Vent Flow & Gas Migration: "REVISED" Shell QUEST Deferral Approval	*2020*
	Shell Deferral Request - Casing Integrity logging - Approval No. 11837C	*2020*

	Shell Canada Approval No. 11837C. Submission of 03/07-11-059-20W4/0 and 00/08-19-059-20W4/0 Hydraulic Isolation Logs	*2020*
	Division A - Annual Summary Report to GOA	*2021*
	Annual Status Report to AER	*2021*
	Annual Submission for SCVF and GM testing	*2021*
	Shell Canada Approval No. 11837C. Submission of 02/05-35-059-21W4/0 Hydraulic Isolation Logs	*2021*
	Shell Canada Approval No. 11837C. Submission of 00/08-19-059-20W4/0: Time-lapse Casing and Cement Integrity Logs	*2021*
	Division A - Annual Summary Report to GOA	*2022*
	Annual Status Report to AER	*2022*
	Bottom Hole Pressure Gauges – Sharing Erroneous Data – UWI: 100/8-19-059-20W4 and 103/7-11-059-20W4	*2022*
	Shell Canada Approval No. 11837C. Submission of 02/05-35-059-21W4/0: Time-lapse Casing and Cement Integrity Logs	*2022*
	Shell Canada Approval No. 11837C. Submission of 03/07-11-059-20W4/0: Time-lapse Casing and Cement Integrity Logs	*2022*