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Quest Carbon Capture and Storage Project

CLOSURE PLAN

2017 Version

Prepared by:
Shell Canada Limited
Calgary, Alberta

Submitted February 27th, 2017

Revision: May 5th, 2017

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Acronyms and Abbreviations

AENV	Alberta Environment
AER	Alberta Energy Regulators
AOR	area of review
AOSP	Athabasca Oil Sands Project
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
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
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), a joint venture between Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, has 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 will capture, transport and store 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 *Mine 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. An update was submitted February 28th, 2014 and this submission, on February 27th, 2017 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
- and the storage complex for the permanent storage of CO_2 in the Basal Cambrian Sands, a deep (~2km below ground) saline geological formation.

Following the completion of site closure activities Shell will apply for a Site Closure Certificate. The post-closure period will 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].

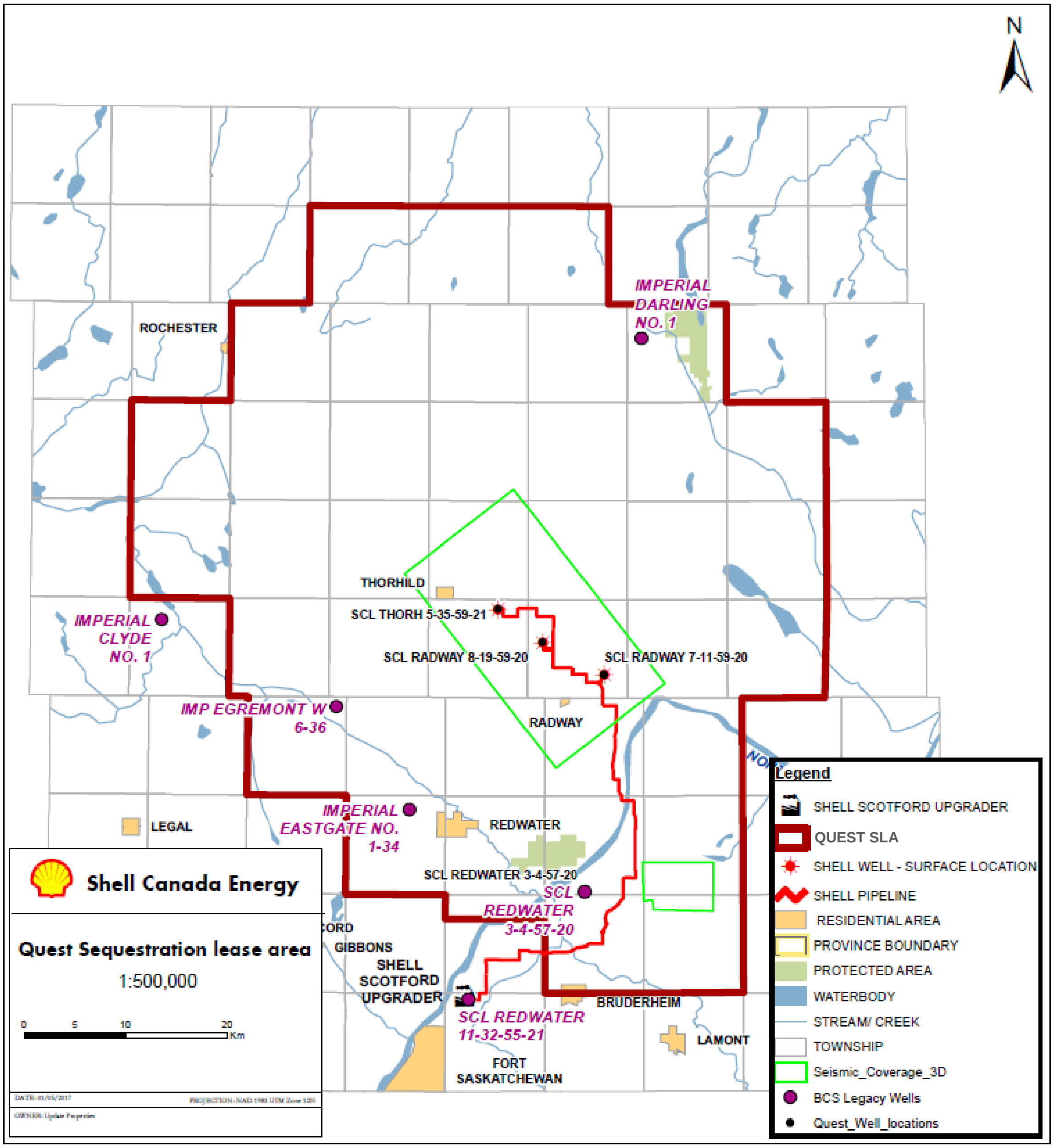

Figure 1-1: Quest CCS Project Components and Sequestration Lease.

1.2. Timeline of Proposed Closure Activities

Commercial operations at Quest were achieved in September 2015. Operations will continue based on continued assessment of economic, technical and regulatory conditions. After the decision is taken to cease operations, CO_2 injection will stop, final Closure and MMV Plans will be submitted to the Regulator, 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, Shell will abandon 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.

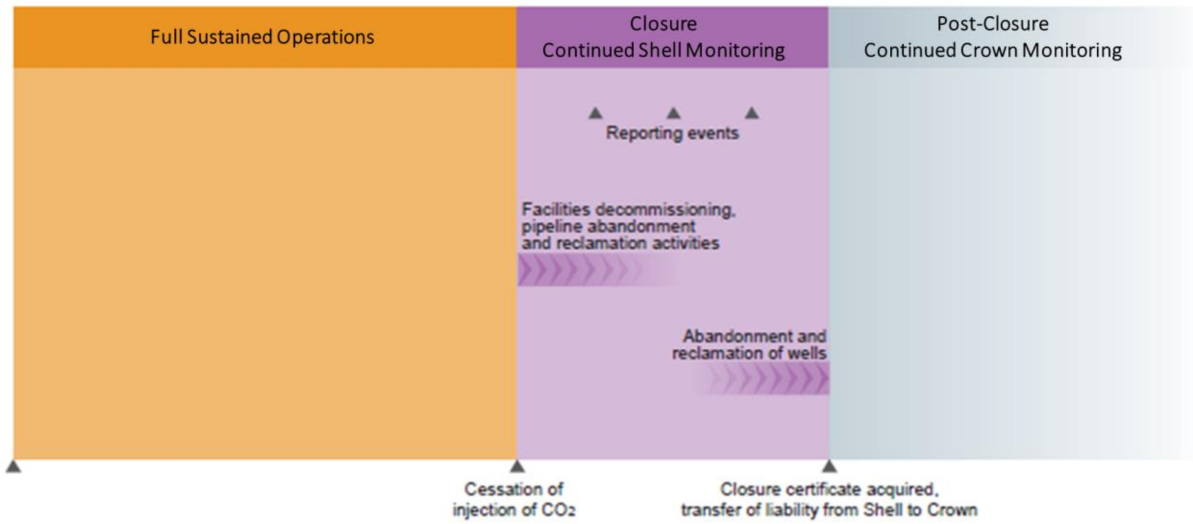

Figure 1-2: Proposed Timeline for Project Operations, Closure and Post-Closure.

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.

Alberta Energy's Regulatory Framework Assessment (RFA) [4] was submitted in November 2012 and issued in 2013. The RFA recommendations are not regulatory requirements at this time; however, Shell has voluntarily incorporated these recommendations into the Project Closure Plan.

Closure criteria are still 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 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, thereby reducing 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 [5] 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 [6]. To date 3 injection wells have been drilled, with only 2 in current use as dictated by the Project volume requirements and operations.

The injection plan consists of injecting approximately 1.08 million tonnes of CO_2 per annum (to a maximum of 27 Million tonnes).

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 are shown in Table 2-2 and Figure 2-1.

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

Lease Block	Alberta Energy 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 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 basement. 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 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 DMW 3-4 (Table 2-3).

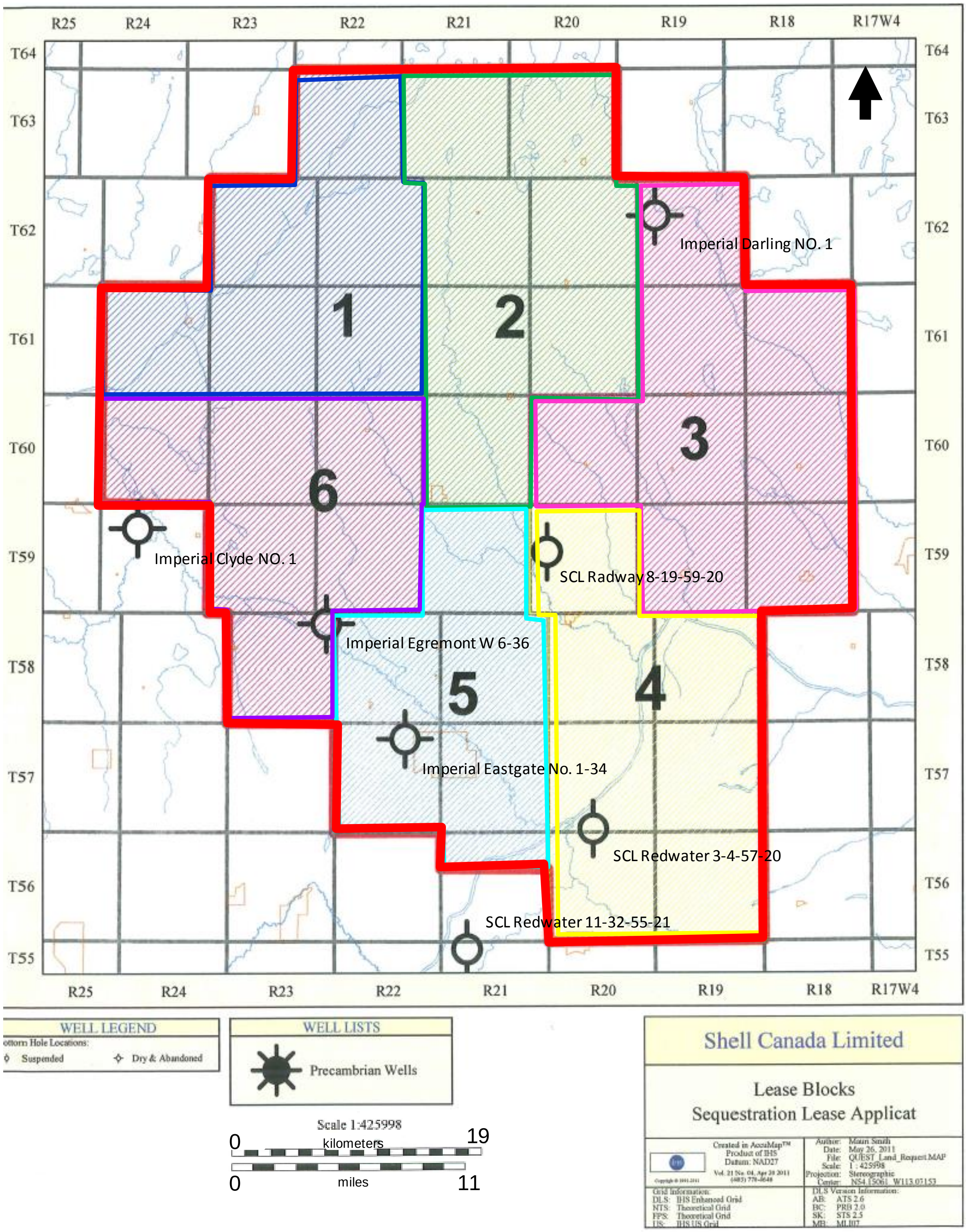

Figure 2-1: Quest CCS Project Carbon Sequestration Lease Blocks as Approved by Alberta Energy.

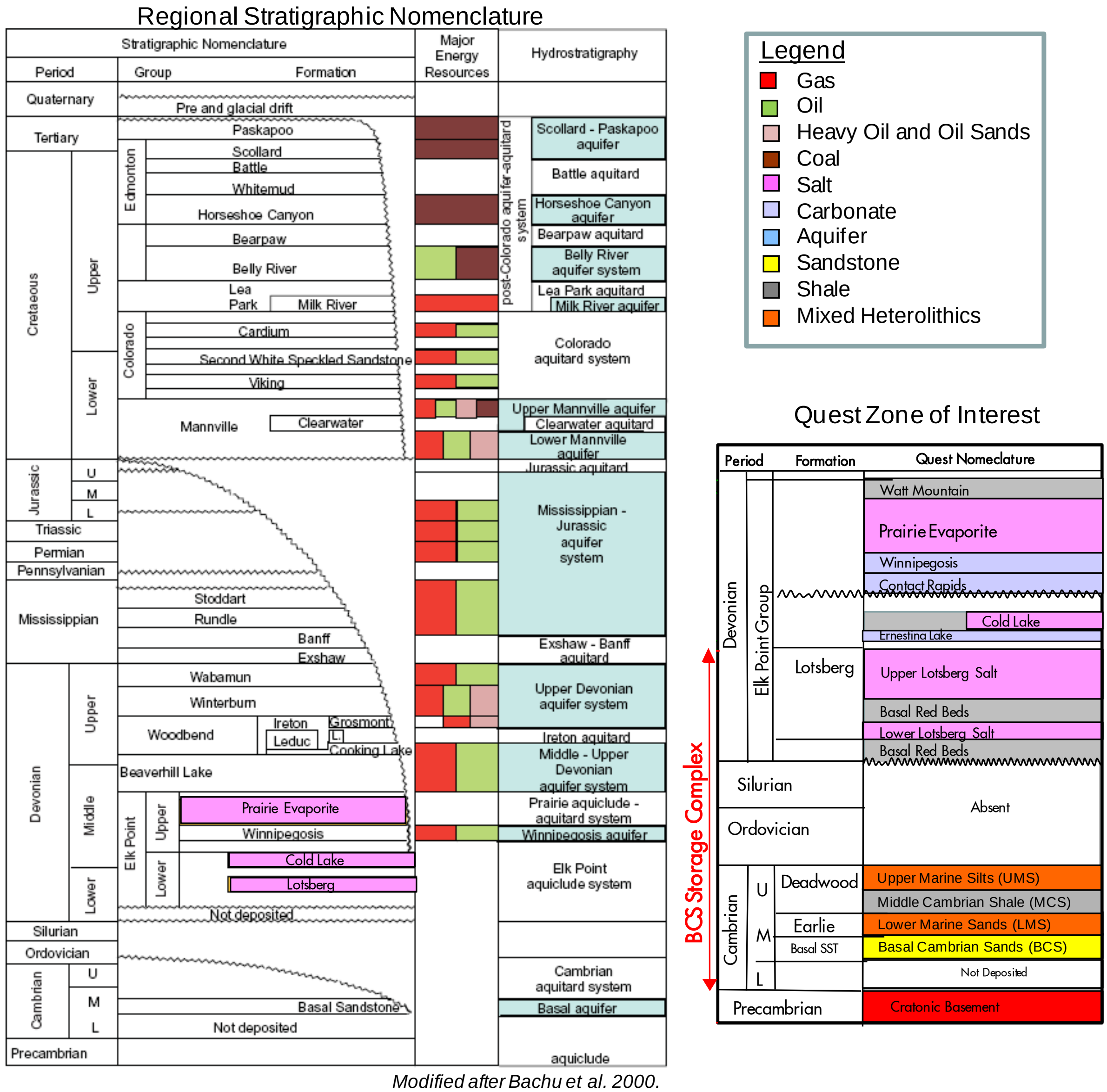

Figure 2-2: Stratigraphy and Hydrostratigraphy of the Southern and Central Alberta Basin

2.2. Project Wells Inventory

The well pads comprise 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 of these well pads has one 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 monitoring well (Redwater 3-4) that is being utilized to monitor the pressure in the Cooking Lake Fm. This is not an injection 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	Deep Monitoring	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 licensed because they are less than 150m depth.

3. Storage Performance Criteria for Site Closure

To meet Storage performance goals, MMV activities are 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 [7]. The sources/sinks associated with the subsurface and monitored as part of the MMV Plan and are included in the protocol is 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 consistent with the approved measurement, monitoring and verification plan.

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

Table 3-1: Methodology from Table 6 of the Quantification Protocol [7] 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 essential 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 [6] supports the following performance target:

- Measurements of any changes within the MMV datasets caused by CO2 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 MMV Plan is designed on the basis of the following principles:

- Regulatory-Compliance
- Risk-Based
- Site-Specific
- Adaptive.

The focus of the MMV plan is to assess containment and conformance within the BCS storage complex.

The 2017 MMV Plan [6] is the fifth update to the MMV Plan submitted to the AER since the start of the Project. The first conceptual plan was submitted as part of the D65 disposal application in 2010 [5]. In fulfillment of AER condition 7, a pre-baseline MMV Plan was submitted in Oct.15 2012, an interim update was provided in February 2014 and a pre-injection MMV Plan was submitted January 31, 2015. The 2017 MMV Plan submission [6] integrates learnings from the initial injection phase monitoring.

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.

4. Storage Performance Evidence

Storage performance evidence includes all the information on conformance and containment that support the Storage Criteria discussed in Section 3.

4.1. Injection Performance Update

Overall, the Project has been running very smoothly. The Quest Project experiences rate changes and volume fluctuations as a consequence of capture facility optimizations and planned maintenance, for example, associated with the April 2016 plant turn around. IW 5-35 has remained in observation mode and has not been utilized for injection to date.

4.1.1. Total Quest CO_2 Injection Summary

The quantity of carbon dioxide (CO2) captured and injected is found below in Table 4-1.

Further details and yearly reporting on rates, volumes, pressures and temperatures (bottom hole and well head) are reported as monthly averages in the AER Annual Report [8].

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

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 well tests supported initial PI's of each individual injection well (IW 7-11, IW 5-35, IW 8-19) to be greater than the full Project requirement.

To date, overall, the Quest Project has more than sufficient injectivity as demonstrated by the utilization of only two of the three injection wells despite full Project rates up to 150t/hr. With the inclusion of the third well, IW 5-35, the existing wells are capable of sustaining injectivity greater than the Project goal of 140t/hr (1.2Mt/year) for the duration of the Project life. No further infill well development will be required to meet injectivity requirements.

Operationally, IW 8-19 has been injecting consistently at approximately 70 t/hr over this time period (Figure 4-1). IW 7-11 has been receiving the remaining available volumes which has averaged about 60 t/hr since August 2015 (Figure 4-2). IW 5-35 has remained in observation mode. The Injectivity stability is illustrated in the dynamic injectivity index plots (Figure 4-1 and Figure 4-2). The dynamic injectivity index adjusts the reservoir pressure as observed in the IW 5-35 to minimize pressure transient bias. Both wells were shut-in for logging in April 2016 which induced some overriding pressure transients. Beyond the transient affects, the plots of IW 8-19 and IW 7-11 illustrate an inverse relationship between dynamic injectivity and injection temperature. This phenomenon is recognized in the CCS community but not understood at this time. Further data collection and evaluation of this relationship will be ongoing in 2017.

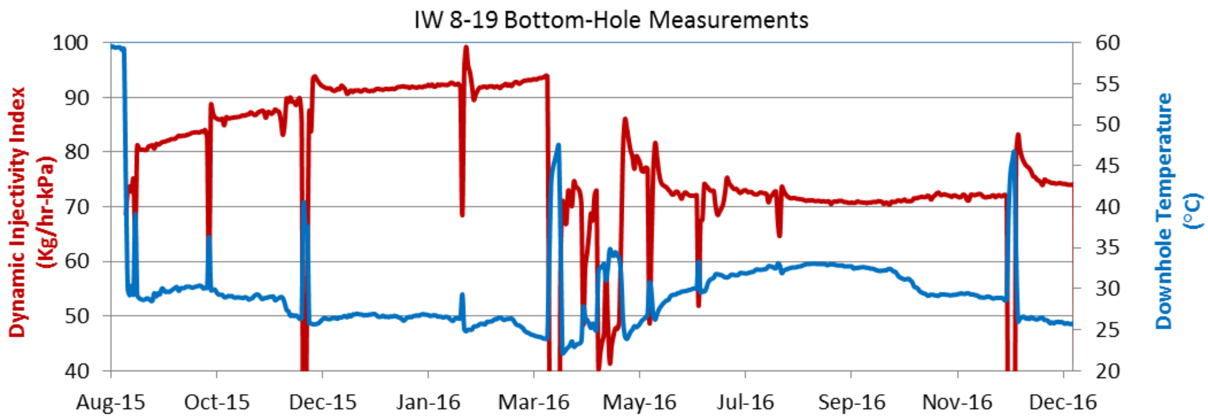

Figure 4-1: Dynamic Injectivity Index and BHT for IW 8-19 over time.

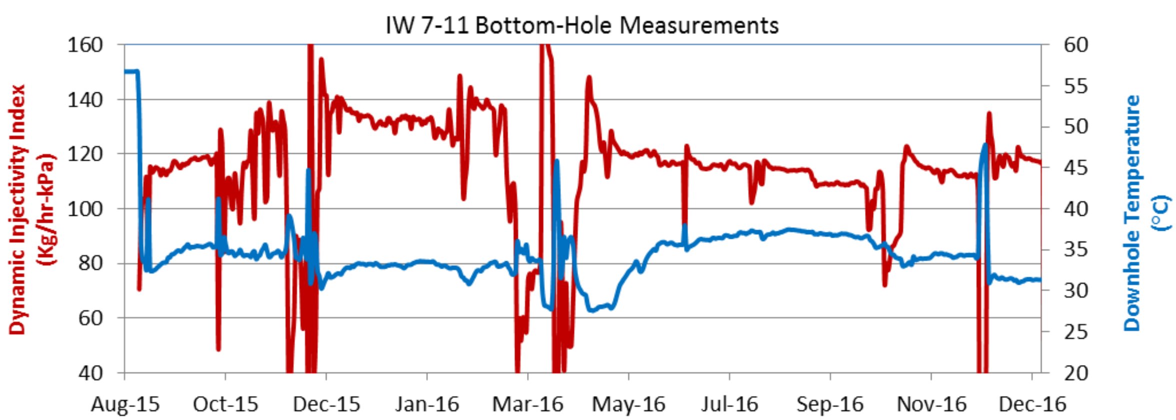

Figure 4-2: Dynamic Injectivity Index and BHT for IW 7-11 over time.

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 [7] 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, 2016 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 2016.

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. This is discussed in Section 4.2.5.

4.2.2. Pressure Prediction

The pressure build-up in the BCS is forecasted to be less than 2 MPa of differential pressure (DeltaP) at the injection wells by the end of the Project life (Figure 4-3). This pressure increase of less than 2 MPa is less than 12% of the DeltaP 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 in Figure 4-3 is that from 2017 onward an equal amount of CO_2 will be injected in each active well for the remainder of the life of the Project.

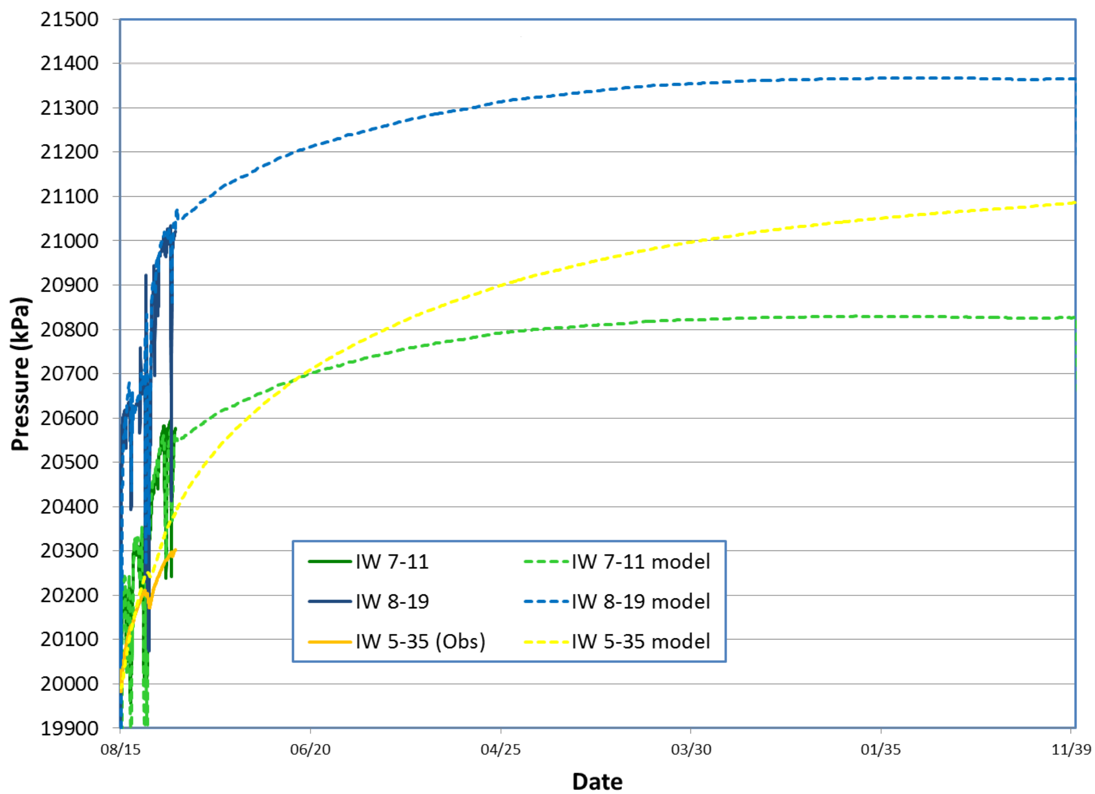

Figure 4-3: Well by well expected pressure build forecast.

4.2.3. CO_2 Plume Prediction

The current model incorporates injection well rates & pressure data to the end of 2016 and the first monitor VSP results. Assuming that injection occurs in only IW 8-19 and IW 7-11, the modelling results predict maximum plume lengths in 2040 of 2 to 4 km. The resulting end-of-life plumes are illustrated in Figure 4-4. The most significant impact on CO_2 plume size will be whether or not IW 5-35 is required for injection.

Additional uncertainty will be reduced in 2017 as the model is tuned to additional pressure data, the second monitor VSP results, and injectivity temperature dependence.

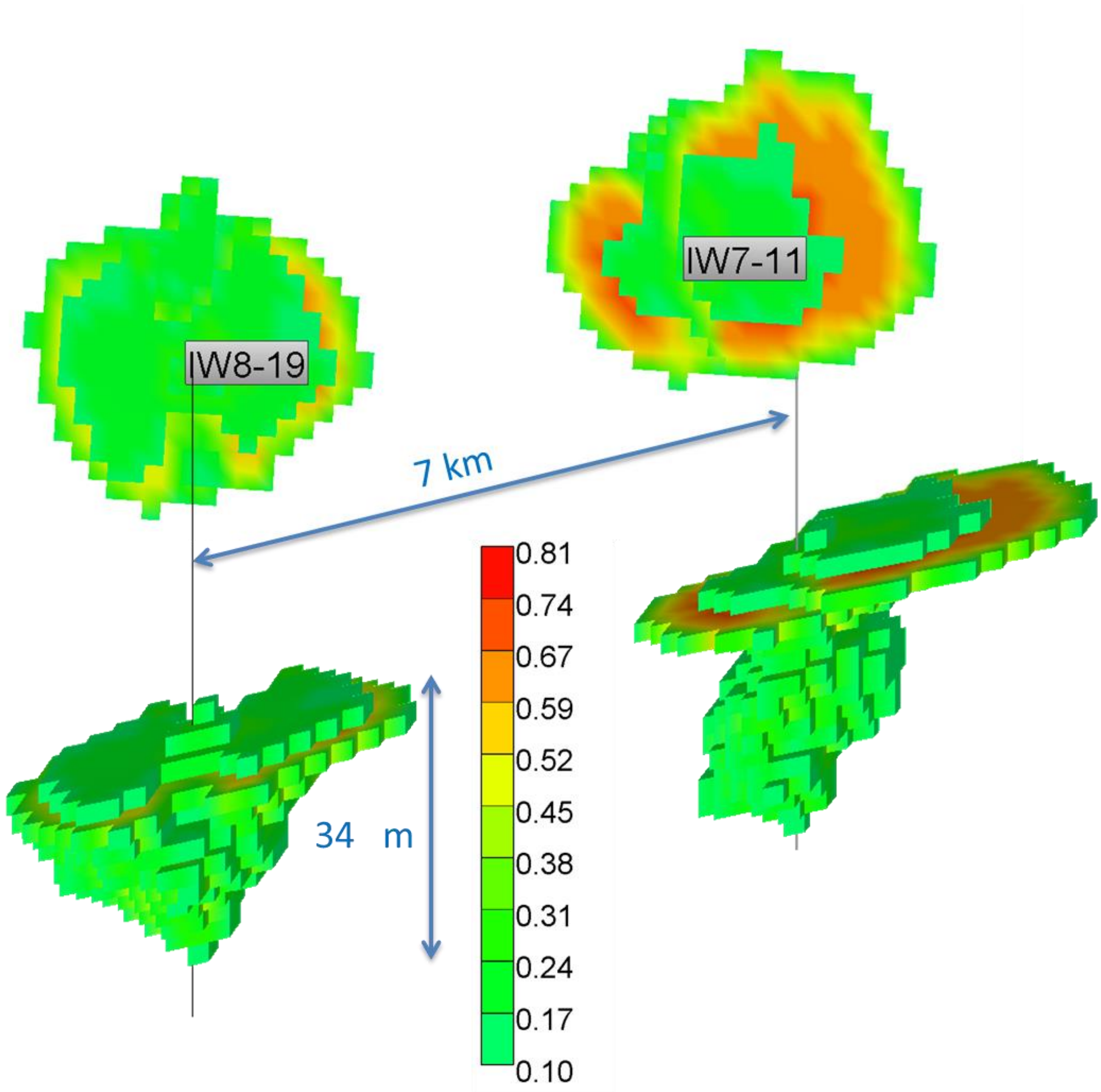

Figure 4-4: Map view and 3D views of the modelled CO_2 plume in 2040.

4.2.4. Conformance Monitoring Results

Time Lapse Seismic Results

Time-lapse seismic and vertical seismic profiles (VSP) are used to track the CO_2 plume.

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 1-1). 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 size as the Project moves forward.

Eight walkaway VSP surveys were acquired at each injection well using Distributed Acoustic Sensors (DAS) fibers in Q1 2015 (pre-injection), and the first monitor survey in Q1 2016. A third VSP was executed in Q1 2017.

Results from the 2016 monitor DAS VSP show that the measured time-lapse response is smaller for wells 7-11 and 8-19 than the forecasted CO_2 plume, but larger than the theoretical minimum plume size. This theoretical minimum assumes that the CO_2 expands cylindrically away from the well at saturations of 100% CO_2. These results indicate that the CO_2 is filling the pore space in the reservoir more effectively than predicted. The VSP results are used to calibrate and constrain plume movement in the modelling, and also to determine the timing and necessity of the subsequent time-lapse monitoring surveys.

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 as a continuous monitoring technology for unexpected containment issues. As injected volumes increase, it may have some value from a conformance perspective. Hence, The InSAR technology will be considered a contingency monitoring technology with a focus on the AOR (area of review) of the Quest SLA (sequestration lease area). It will be used in the event of another MMV technology or observation indicating the need for further investigation.

Note though that satellite image programming and acquisition is planned to continue over the next three years using a single frame centered over the 3 injection well pads.

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 (Figure 4.5).

4.2.5. Model to Performance Conformance

Consistency between predicted and observed storage performance is a 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.

Figure 4-5 illustrates that the actual pressure build-up (solid lines) in the reservoir to date compared to the history matched model (dashed lines). This non-unique solution will be further explored as additional injection data is collected. Note that no injection has occurred at IW 5-35 thus far and reservoir pressure is being monitored.

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.

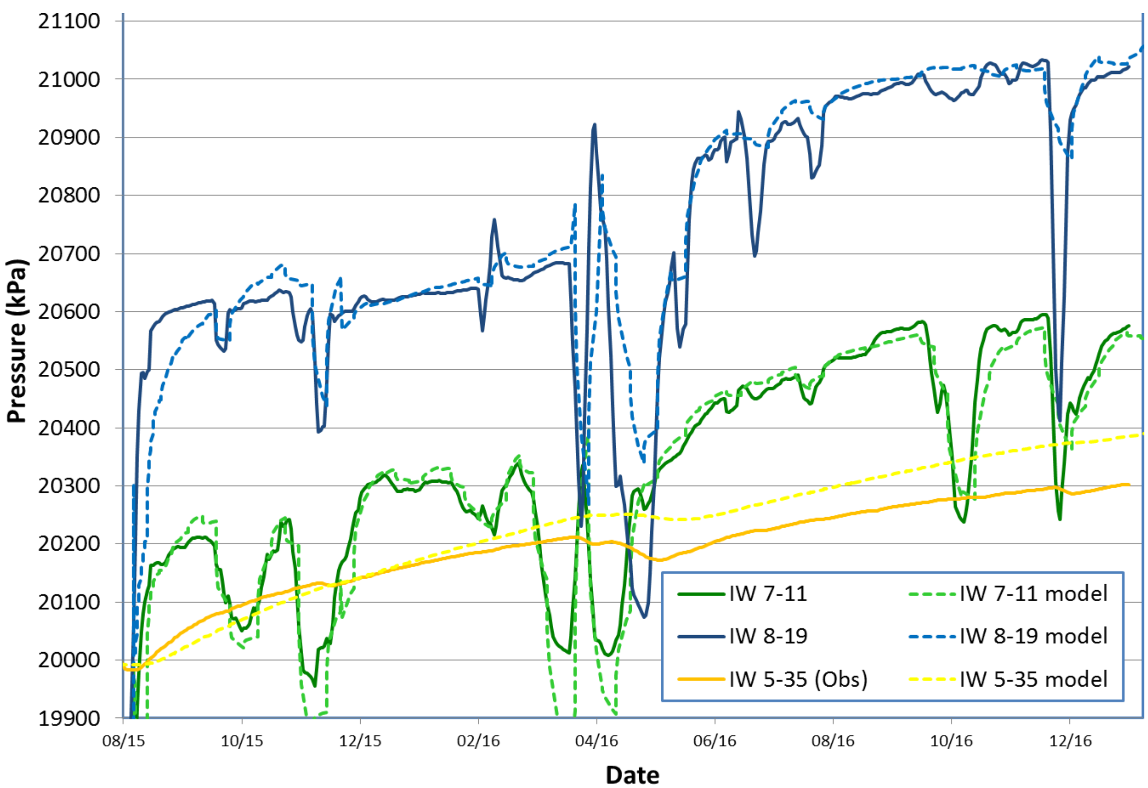

Figure 4-5: Actual BH Gauge Response vs Modeled Pressure Response.

In conclusion, conformance is demonstrated as the observed pressure build up in the reservoir to end of 2016 is consistent with the model-predicted expectation case, utilizing only 7-11 and 8-19 for injection.

Planned Model Updates

The current static model incorporates all data from the Project Site Selection phase [9], the 2012-2013 drilling campaign of all Project wells, BCS core descriptions, and associated paleodepositional environmental interpretations. Annual updates to the dynamic model are ongoing to incorporate injection and reservoir performance data. The need for full dynamic model updates will be based on the need for recalibrated models as additional injection performance and MMV data become available.

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 [6] discusses the potential threats to containment and Section 4.8 Performance targets for containment monitoring.

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 were considered highly unlikely; but in principle are capable of allowing CO_2 to migrate upwards out of the BCS storage complex. A very thorough discussion of MMV containment risks is found in the pre-injection MMV Plan [10].

Previous MMV Plans and resulting monitoring are incorporated and address the above comprehensive risk profile [10]. With the commencement of operations and sustained injection, these risks have been updated and the current MMV Plan adapted accordingly.

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 CO2 storage and the MMV Plan activities.

As of 2016, there is no indication of integrity issues in IW 7-11 and IW 8-19. The following is a summary of the evidence of the integrity of the Quest injection wells.

The SCVF and GM testing that occurred and were reported in 2016 continue to indicate low flow levels. DTS data continue to behave in a manner similar to typical wells without any leaks; no expected leak profiles have been identified in the data. 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 CO2 in the BCS. Packer isolation tests were performed in the injection wells and all wells passed. (Table 4-3)

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

Please refer to the most recent AER Annual Report for any updates on well integrity assurance.

Table 4-2: Well integrity activity (modified from the 2017 MMV Plan [7], Table 4-1).

Monitoring technology	Areal coverage	Frequency
SCVF testing as per AER ID 2003-01	DMWs and IWs, as required	annually by June 30th
Gas migration testing as per AER Directive 020	DMWs and IWs, as required	annually by June 30th
Wellhead pressure-temperature monitoring	IWs	continuous
Downhole pressure-temperature monitoring	IWs	continuous
Annulus pressure monitoring	IWs	continuous
Time-lapse ultrasonic casing imaging	active IWs	every 5 years
Time-lapse electromagnetic casing imaging	active IWs	every 5 years
Time-lapse cement bond log	active IWs	every 5 years
Mechanical well integrity testing (packer isolation test)	IWs	every 5 years
Tubing caliper log	active IWs	every 5 years
Injection rate monitoring	IWs	continuous
Temperature and RST logs	active IWs	as per AER Approval No. 11837C condition 5c and associated logging extension request granted on March 22, 2016
Distributed temperature sensing	IWs	continuous

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	

Atmospheric Monitoring

Above-ground CO_2 levels are monitored using a technique called 'LightSource' that 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.

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 3rd Annual AER Report [11]. 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 [12].

In 2015 and 2016 some additional soil sampling, soil gas and soil surface flux measurements were undertaken. Please see 4th [13] and 5th [8] AER Annual Reports for findings.

Starting in 2017, 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 monitoring program. Detailed information on the findings from the program can be found in the 3rd Annual Status Report [11].

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. For further details, please refer to the 2015 MMV plan [12]. To-date, no alarms or triggers indicating a loss of containment have been identified, as discussed within the AER Annual Status Reports [8].

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 Report [8]. To date, there has been no indication of CO_2 above the BCS.

Once the plume growth exceeds the imaging capability of VSP technology, other time-lapse seismic methods will be employed. The frequency and footprint of future time-lapse surveys will be adjusted to monitor the expected plume size as the Project moves forward.

InSAR: please refer to Section 4.2.4.

In-Well Monitoring Activities

Microseismic: A temporary microseismic array was installed in DMW 8-19 and began recording baseline microseismicity in November 2014. A new 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.

There were no locatable events recorded pre-injection in the baseline period. Since injection startup there have been three locatable events recorded in the SLA, demonstrating the operational sensitivity of the microseismic array. All events were located below the injection formation in the Precambrian basement (Table 4-2). There is no correlation between microseismic event timing and pressure variations.

To date, there have been no microseismic events that constituted a containment trigger event.

Table 4-4: Location, time and magnitude for the locatable events detected in 2016.

Event	Date	Time	TVDss (m)	Northing (m)	Easting (m)	Moment Magnitude	Formation
1	05/07/2016	23:21:56.3	1493	5998083	370712	-1.8	Precambrian
2	29/10/2016	02:36:17.8	1671	5996421	367930	-0.8	Precambrian
3	29/12/2016	09:26:57.9	1938	5997314	372578	-1.3	Precambrian

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

DTS is currently considered a novel technology with regards to its use for wellbore integrity assessment in CO2 injection wells and needs further maturation. At present, it may be used for a qualitative assessment primarily by observing rates of change in temperature over time, and the integration of temporal data on CO2 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 [8].

DAS: As discussed in the MMV Plan [6], DAS feasibility studies and technology development are not supported by the Project needs at this time.

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 four monitoring wells, DMW 7-11, DMW 8-19, and DMW 5-35 and DMW 3-4 has been ongoing since Q3 2015 (Figures 4-6, 4-7).

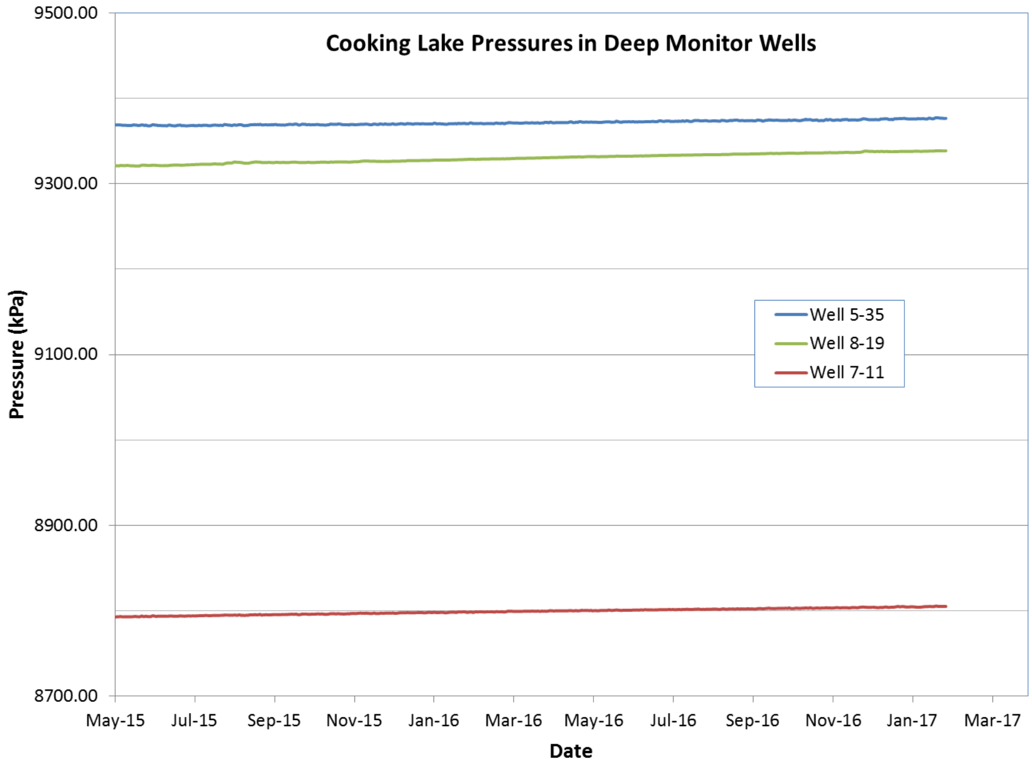

Figure 4-6: Quest deep monitoring well pressure history before and after injection.

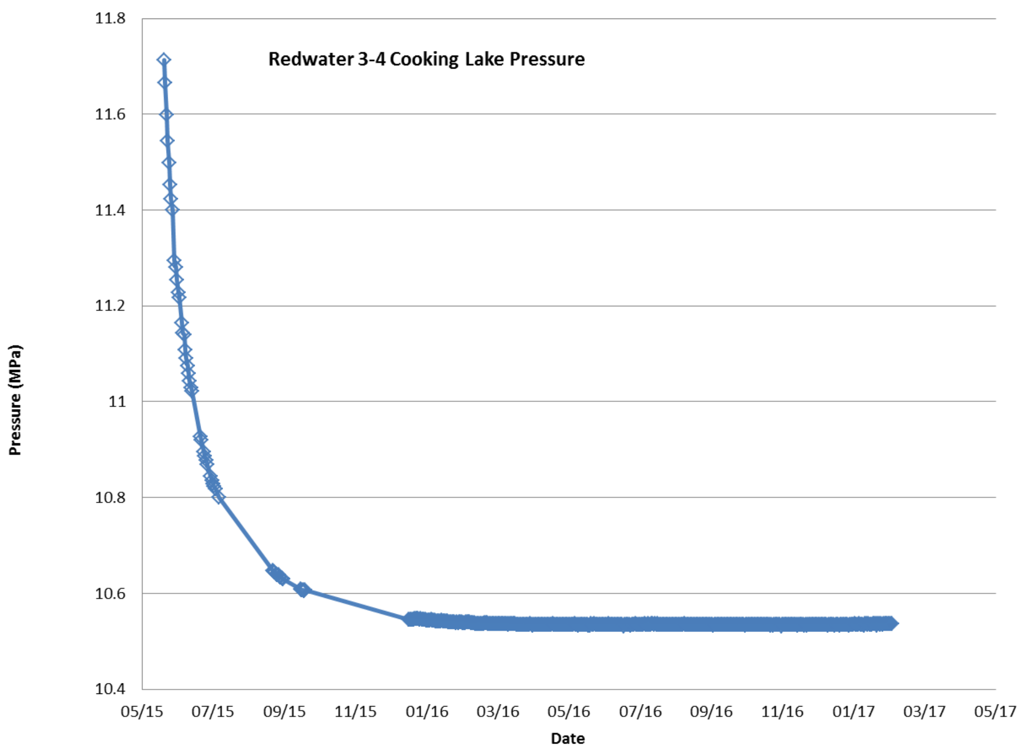

Figure 4-7: Quest DMW 3-4 pressure history.

4.3.3. Update to Third Party Wells Penetrating Sequestration Lease

As of December 31, 2016 no additional 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 [5]. Currently there are 4 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 [10].

- 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)

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 MMV Plan, Section 5.1.2 [6]. As such, this risk is further downgraded from the initial pre-baseline period MMV Plan risk profile assessment [10].

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.

The MMV Plan provides details on the tiered system of the various technologies deployed to assess a potential loss of containment [6].

Shell has previously reported to Alberta Energy that surface casing vent flows (SCVF) and gas migrations (GM) were identified in the injection wells. GMs originate from a shallow zone (< 200m depth), while the SCVFs originate from just below the surface casing shoe (> ~450m depth). Due the shallow depth of the source of the SCVFs and GMs, they are not considered a threat to containment or isolation of the BCS storage complex. The MMV Plan continues to meet the AER conditions (4, 13, and 14) related to monitoring and reporting of the SCVF and GM at these sites.

4.3.5. Safeguards 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 (see Figure 3-2 in MMV Plan [6]). Prior to implementing any MMV, several inherent safeguards 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 safeguards implemented through site selection, site characterization, and engineering concept selections. These initial passive safeguards are sufficient on their own to make the loss of containment extremely unlikely. Details of these safeguards can be found in previous MMV Plan submissions [10, 12].

The MMV Plan provides a comprehensive and reliable means to verify the effectiveness of these initial passive safeguards. 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 (Tables 3-2 and 3-3 in MMV Plan [6]). These additional active safeguards are triggered by monitoring and are designed to be sufficiently numerous and diverse to yield significant additional storage risk reduction.

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 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.

Although the capture unit and pipeline are not included in the Sequestration Lease, a short update is provided in this submission due to completion of construction execution and transfer to operations phase.

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 only two of the three Project wells drilled to date have been utilized for injection, IW 7-11 and IW 8-19. IW 5-35 is monitoring pressure within the BCS and is available for injection should it be required.

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 AEP 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

Details related to the Quest Risk Assessment update during the Operations phase of the Project are included in the proposed MMV plan [6].

Evaluation and integration of all available data-to-date (e.g. drilling campaign, pre-injection monitoring, injection monitoring, modelling of the BCS) provides evidence that of all potential threats investigated (Section 4.3.1), the primary remaining threat to containment at the Quest site is:

2) Migration along an injection well

The risk of leakage, however, from the storage complex along a leakage pathway in the injection wells is very low, based on the following observations:

- The conceptual site model (CSM) for the Quest Project SLA does not foresee a pathway connecting the source 'CO_2 within BCS' to any receptor (e.g. overlying aquifers) (Fig. 3-2). No pathway has been identified through which CO_2 or saline brine from the BCS could reach aquifers above the base of the groundwater protection (BGWP) zone. Furthermore, pressures are insufficiently low for BCS brine to be lifted to above the BGWP zone (Section 5.3.1 in Reference [4]).
- The evaluation of the cement bond in the injection wells (IWs), 100-08-19-059-20W4 and 103-07-11-059-20W4, which are currently used for CO_2 injection, behind both the intermediate casing and the main casing shows isolation of the BCS storage complex with a good bond across all three seals (MCS and the Lower and Upper Lotsberg Salts).
- The evaluation of the cement bond log from injection well 102-05-35-059-20W4 (not used for injection as of Q1 2017) indicated non-ideal cement bond across the MCS which could potentially extend into the LMS baffle below. There is, however, good cement from the top of the BCS to the intermediate casing shoe providing an effective isolation of the BCS. Further, the good cement across the Lotsberg Salts provides significant additional isolation of the BCS storage complex. Consequently, the risk of a leakage pathway developing at the 102-05-35-059-20W4 injection well is still considered very low.

Surface casing vent flows (SCVFs) and gas migrations (GMs) were detected in the IWs and are being reported on to AER on an annual basis in the Annual Reports [8]. Analytical results confirm that SCVFs and GMs are independent of each other. Due to the shallow depth of the source of the SCVFs and GMs, they are not considered a threat to containment or isolation of the BCS storage complex. The latter is assessed via analysis of future SCVF data.

5.1.3. Area of Review Update

During the initial phases of the Project the area of review (AOR) for Quest was defined by the SLA. This has been updated in the 2017 MMV Plan, Section 5 [6].

MMV operates within the AOR based on the expected volume of CO2 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.

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.

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.

Phase 3: The final subsurface and surface abandonment of all wells

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

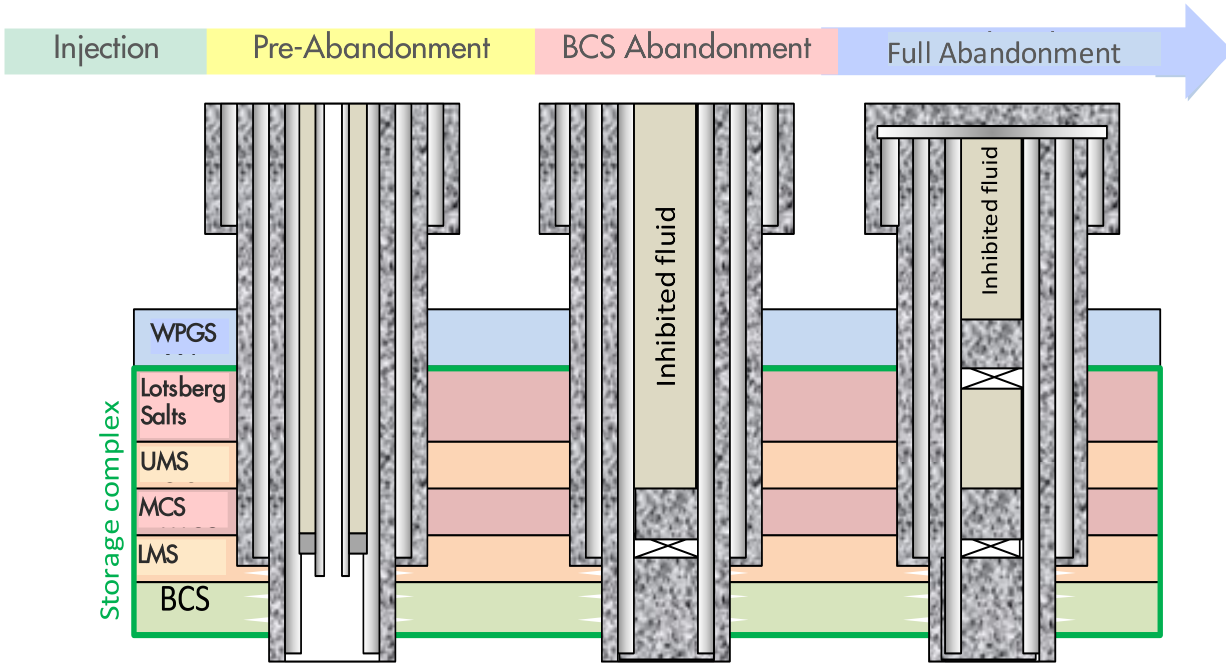

Figure 6-1: IW Schematic for the Three Phases of Well Abandonment.

6.2.1. Pre-Abandonment Period

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.

Once authorization of the final Closure Plan has occurred the start of 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

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.

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.

It is Shells recommendation 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. 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.

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 may 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 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 communicated prior to start of closure to ensure sufficient time is available for adequate financial and human resources 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] Carbon Capture and Storage: Summary Report of the Regulatory Framework Assessment. Alberta Energy. 2013.

[5] 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.

[6] 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.

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

[8] Shell Quest Carbon Capture and Storage Project: Fifth Annual Status Report. Submitted to AER March 31, 2017 as per Carbon Dioxide Disposal Approval 11837C Conditions 10 and 17.

[9] Quest Storage Development Plan Controlled Document No. 07-0-AA-5726-0001. Oct. 6, 2011.

[10] 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.

[11] Shell Quest Carbon Capture and Storage Project: Third Annual Status Report. Submitted to AER March 31, 2015 as per Carbon Dioxide Disposal Approval 11837C Conditions10 and 15.

[12] 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.

[13] Shell Quest Carbon Capture and Storage Project: Fourth Annual Status Report. Submitted to AER March 31, 2016 as per Carbon Dioxide Disposal Approval 11837C Conditions 10 and 17.

Appendix A - List of Reports Submitted to Regulatory Agencies

Document Reference Numbers (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

Document Reference Numbers (if available)	***Document Name***	***Year Submitted***
	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
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	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
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	Q4 2013 Quarterly Status Update February 2014	2014
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	2nd Annual Status Report_to AER Submitted_Jan 31 2014.pdf	2014
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	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

Document Reference Numbers (if available)	*Document Name*	*Year Submitted*
	Shell Quest Approval No.11837C MMV Plan –Section 6.2.3.2 change	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 5 c	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